



# The Future of Electricity Retailing and How We Get There

Frank A. Wolak and Ian H. Hardman



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Frank A. Wolak is the Director of the Program on Energy and Sustainable Development (PESD) and the Holbrook Working Professor of Commodity Price Studies in the Department of Economics at Stanford University, Stanford, CA USA 94305-6072. e-mail: [wolak@zia.stanford.edu](mailto:wolak@zia.stanford.edu)

Ian H. Hardman is a Research Associate at the Program on Energy and Sustainable Development (PESD) at Stanford University, Stanford, CA USA 94305-6072. e-mail: [ihhardman@stanford.edu](mailto:ihhardman@stanford.edu)

## 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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## 1. Intro - Two Paths to the Future of Electricity Retailing

Electricity retailing is at a crossroads. Technological change is eroding revenues from the traditional electricity retailing business model. However, these new technologies also have the potential to create new revenue streams for electricity retailers. This logic suggests two potential regulatory responses: (1) a *reactive* approach where the regulator takes actions to address each technological change that impinges on the electricity retailers on a case-by-case basis, or (2) a *forward-looking* approach that anticipates these technological changes and makes the necessary investments in electricity supply infrastructure and enhancements to the regulatory process necessary to maximize the expected benefits electricity consumers obtain from these innovations.

### 1.1 The Reactive Approach

Each of these regulatory responses involves costs and benefits. The *reactive* approach has the advantage of only addressing the technological changes that actually occur and have a sufficiently large negative impact on the retailing sector to merit a regulatory response. However, this approach may not result in the adoption of the full range of available technologies or the realization of all the economic benefits that these technologies can deliver to consumers and producers of electricity. Nevertheless, this approach may be the most appropriate response for some jurisdictions because of their existing infrastructure, regulatory institutions, and renewable resource base.

As we argue below, regions without the widespread deployment of interval meters, significant existing rooftop solar generation capacity, and modest renewable energy goals should pursue a reactive approach. We suggest regulatory reforms to transmission and distribution network pricing and default retail pricing and other regulatory reforms to increase the competitiveness of retail markets and allow cost-effective deployment of distributed solar, storage, and other load-shifting technologies.

## 1.2 The Forward-Looking Approach

The *forward-looking* approach has the potential downside that the costs of certain investments in electricity infrastructure or enhancements to the regulatory process are incurred in anticipation of investments and regulatory rules that do not ultimately materialize. The upside of this approach is that it prospectively implements the infrastructure investments and regulatory process enhancements that allow the retailing sector to realize fully the benefits of these new technologies. This approach may be the most appropriate response for some jurisdictions because of the ambitiousness of their climate goals, richness of their renewable resource base, and the current state of their physical and regulatory infrastructure.

Regions with widespread deployment of interval meters, significant installed rooftop solar generation capacity, and ambitious renewable energy goals are ideally suited for the forward-looking approach. Regulatory reforms to transmission and distribution network pricing and default retail pricing similar to those recommended for the reactive approach are also necessary for the forward-looking approach. We describe regulatory reforms to the wholesale market design that can increase the competitiveness of retail markets and provide high-powered market-based incentives for cost-effective deployment of distributed solar, storage, and other load-shifting technologies. A major challenge to the success of the forward-looking approach to the future of retailing realizing the full range of economic and reliability benefits is the willingness of regulators and policy-makers to allow consumers to manage short-term wholesale energy and ancillary services price risk. We describe a number of market design and regulatory policies that exist around the world that severely limit or eliminate the incentive for consumers to manage short-term wholesale energy and ancillary service price risk. We suggest a number of policies that limit the potential downside to consumers from managing short-term price risk and thereby increase the likelihood that regulators decide to allow consumers to manage short-term price risk.

These two regulatory responses bound the set of possible approaches regions can take to adapt to these new technologies. Understanding the costs and benefits of these two extreme regulatory responses for the future of electricity retailing can provide valuable input to regions deciding the most appropriate path forward for their retailing sector. Which approach, or combination of these two approaches, a region adopts will determine the future structure and operation of their retail electricity sector and the consumer benefits these regulatory changes ultimately deliver.

## 1.3 Outline of Report

The remainder of this report proceeds as follows. To explore the implications of these possible futures for the electricity retailing sector, we first characterize the innovations driving change in the retail electricity sector. These technological changes include the declining costs of electronic monitoring and control devices (including interval meters), distributed solar and other distribution network connected (distributed) generation technologies, and grid-scale and distributed storage technologies. Reductions in the cost of compiling and analyzing interval consumption data and providing actionable information to customers on

their electricity consumption in real time, and the growing demand for electric vehicles and electric space heating are also driving change in the retail electricity sector.

We also describe the major existing economic and regulatory barriers to the least-cost deployment of these technologies throughout transmission and distribution grids. These include the economies to scale and scope in the deployment of interval metering infrastructure, average cost pricing of the transmission and distribution network access and its impact on investment in distributed versus grid scale solar generation, regulated retail tariffs that limit the incentives for active involvement of final consumers in the wholesale market, the limited amount of actionable information and feedback customers currently receive on their electricity consumption, and the limited availability of distribution grid-level monitoring technology and lack of regulatory rules for pricing distribution network services and third-party access to these services.

We then survey the current state of deployment in the major industrialized countries of these enabling technologies and regulatory rules that support a *forward-looking* transition versus a *reactive* transition. On the technology side, the major factors driving the choice between these two approaches are the deployment of interval meters and existing quantity of distributed solar generation capacity. On the regulatory rules side, these factors include the default retail price set by the regulator, the state of retail competition, the willingness of regulators to allow dynamic retail pricing, and rules for third-party access to the distribution network to offer load and generation monitoring and control technologies.

We then proceed to discuss the likely future of electricity retailing under the *reactive* approach and the likely future under the *forward-looking* approach. Each of these futures depends on a number of factors such as the extent to which purely financial participants are allowed in the retail electricity sector, the appetite of the regulator for requiring final customers to manage hourly wholesale price volatility, and the extent to which the jurisdiction has goals to electrify transportation and space heating. Other drivers include the form of the tariffs that the regulator sets for distribution network services and the extent to which the regulator encourages active participation of final consumers in reliable operation of the transmission and distribution networks.

Our general conclusion is that there should be two regulatory approaches to adapting to the new technologies impacting electricity retailing. For regions that are *unwilling* to commit to widespread deployment of interval meters and to charging customers for their actual hourly consumption, a reactive approach is likely to be superior. However, if this approach is adopted in a region with significant distributed solar resources, then reform of transmission and distribution network pricing or explicit regulatory controls on quantity of distributed solar investments must be put in place to limit the amount of inefficient bypass of grid-supplied electricity by entities that invest distributed generation facilities that supply energy at a lower average cost than grid-supplied energy but at a higher marginal cost than grid-supplied energy.

For regions *willing* to commit to widespread deployment of interval meters and to charging customers for their actual hourly consumption, a forward-looking approach is likely to be superior. However, this approach will also require reforms to transmission and distribution network pricing in order to limit the incentive for suppliers to engage in

inefficient bypass of grid-supplied electricity. The wholesale market design in many regions will also have to adapt to allow these technologies to deliver full range of economic benefits to consumers and retailers. With these regulatory and wholesale market design reforms in place, there is little need for additional regulatory restrictions on distributed generation and storage investments. Instead, regions with these reforms in place can rely primarily market mechanisms to produce the efficient amount of investment in distributed solar, storage, and other load-shifting technologies.

The final section of the report suggests a number of directions for future research that can help jurisdictions choose the most appropriate regulatory path for their retail sector and maximize the consumer benefits associated with that regulatory path. A major area for future research with the *reactive* approach is development of regulatory mechanisms that facilitate the least cost deployment of new technologies in regions without the widespread deployment of interval meters. A major area for future research for the forward-looking approach is the feasibility of spatially- and temporally-varying pricing of distribution network services and the coordination of transmission and distribution network operation and wholesale market operation with retailing sector. Another area for future research is the development of a market for distribution network services not provided by the distribution network operator or electricity retailer, what are typically called third-party network services. Finally, an important area for future research for both the reactive and forward-looking approaches is the development of regulatory rules for batteries and load-shifting technologies to earn regulated revenues from providing non-wires transmission and distribution network alternatives and market-based revenues from providing operating reserves and energy.



## 2. Drivers of Change in the Retail Electricity Sector

This section describes the new technologies driving change in the retail electricity sector. These technologies are primarily the result of the innovations in electronic monitoring and communications equipment. Advances in software engineering and the widespread availability of high-speed wired and wireless Internet access are other important contributors to these new technologies.

### 2.1 Mechanical Versus Interval Metering Technology

Historically, electricity meters have been analog devices that must be read manually once per billing cycle. For example, a monthly billing cycle culminates with a meter reading which is then compared to the meter reading from the end of the previous billing cycle. The difference between the former and the latter readings is the customer's electricity consumption during the billing cycle. This metering technology still exists in many industrialized nations and in developing countries.

Reading mechanical meters on a monthly basis makes it impossible for the retailer to charge customers a different price for their consumption during different hours of the billing cycle because only total consumption for the billing cycle is known. Typically, fixed load profiles set by the regulatory process are used to allocate a customer's billing cycle consumption to individual hours of the month within the billing cycle in order to estimate the wholesale energy cost of serving the customer during the billing cycle.

For example, if  $w_h$  is the load profile weight assigned to hour  $h$  in the monthly billing cycle, where  $\sum_{h=1}^H w_h = 1$  and  $H$  is the total number the hours in the billing cycle, then a customer with a monthly consumption of  $Q_M$  has a load-profiled consumption during hour  $h$  equal to  $Q_M w_h$ . If  $p_h$  is the wholesale price during hour  $h$ , then the load-profiled wholesale cost of serving the customer during the month is  $Q_M \sum_{h=1}^H w_h p_h$ . Note that regardless of when during the month the customer reduces demand by one kilowatt-hour (kWh), this

load-profiled cost falls by the same amount,  $\sum_{h=1}^H w_h p_h$ . Consequently, regardless of how a mechanical metered customer's wholesale energy cost obligation for the billing cycle is determined, a one kilowatt-hour (kWh) demand reduction any hour during the month, reduces the customer's monthly bill by the same amount.

This fact has wide-ranging implications for the future of electricity retailing. A simple way of stating this fact, is "If you can't measure it, you can't price it." The customer and his retailer receive the same financial benefit from the customer reducing his consumption by one kWh during an hour when the wholesale price is equal to the wholesale market price *cap* as during an hour when the wholesale price is equal to wholesale market price *floor*. For example, in Electricity Reliability Council of Texas (ERCOT) market, the price cap is equal to \$9,000 per megawatt-hour (MWh) and the price floor is equal to -\$251/MWh. Therefore, a one-kWh demand reduction during any hour in a billing cycle that either or both of these values for hourly price occurs reduces the customer's billing cycle level consumption by the same amount, implying the same change in the customer's bill for that billing cycle.

With mechanical meters or interval meters with monthly billing based on fixed-hourly load profiles within the month, customers have no greater financial incentive to reduce their consumption during hours of the billing cycle with high wholesale prices than they do during any other hour during the billing cycle. Consequently, customers facing a higher monthly load-profile-weighted-average price,  $\sum_{h=1}^H w_h p_h$ , will tend to reduce their consumption during hours in the billing cycle when it is easiest for them to do so, rather than when this action benefits system reliability, reduces the retailer's wholesale energy costs, or reduces wholesale prices. Mechanical meters or interval meters with monthly billing based on fixed-hourly load profiles within the month make it impossible for consumers to realize any economic benefits from retail prices that vary with hourly wholesale prices or from investments in load-shifting technologies.

Interval meters overcome the shortcomings of mechanical meters read on monthly or bi-monthly basis by recording a customer's consumption on an hourly or even shorter time interval basis. There are number of ways that the consumption data collected from these meters are transferred to the retailers. The most common approach is through either a wired or wireless connection to the retailer's back office. Collecting the hourly consumption of electricity for all hours of the billing cycle allows the customer to be billed for their actual electricity consumption during each hour of the billing cycle at the price of electricity during that hour. If  $Q_h$  is the customer's consumption during hour  $h$ , then the customer's monthly wholesale energy cost is  $\sum_{h=1}^H p_h Q_h$ . This implies that a one kWh reduction in hour  $h$  yields a monthly cost reduction of  $p_h$ . Consequently, interval meters enable consumers and their retailers to realize financial benefits from the customer reducing consumption during high-priced periods and shifting some or all of this consumption to low-priced periods.

For customers with distributed energy resources (DERs), interval meters also allow the measurement of the net withdrawals from and injections into the distribution network on at least an hourly basis within the billing cycle. This enables the retailer to pay (and charge) different prices each hour of the billing cycle for injections (and withdrawals) from the distribution grid each hour of the billing cycle. This implies that DERs that inject a larger share of their energy during high-priced hours will receive higher average prices for their

injections. Customers with mechanical meters or interval meters billed based on fixed load profiles during the month have no ability to benefit from hourly price differences during the billing cycle.

In contrast, interval meters allow consumers and their retailers to benefit from investments in load-shifting and distributed storage technologies. Customers can purchase and store energy during low-price hours and sell energy during high-price hours, with the difference between the sell price times quantity of energy sold and the buy price times the amount of energy purchased going towards recovering the cost of the storage investment. Without the ability to measure the net energy withdrawn or injected into grid on an hourly or shorter time interval basis, this revenue stream could not be computed for storage facilities or load-shifting technologies.

Consequently, interval metering is the enabling technology that allows distribution network pricing and retail pricing mechanisms that can provide revenue streams that yield the least cost deployment of these new technologies impacting the retailing sector. In contrast, mechanical meters with monthly meter reading severely limit the ability of distribution network pricing and retail pricing mechanisms to provide the revenue streams that lead to the efficient deployment of these new technologies. In fact, as discussed below, existing approaches to distribution network pricing and retail pricing developed under the vertically-integrated monopoly regime with mechanical meters and monthly meter reading have instead created incentives for inefficient deployment of distributed solar generation capacity versus grid-scale solar generation capacity.

## 2.2 Declining Costs – Sensors, Storage, and Solar

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 around the globe 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. Utilities and grid operators are also taking advantage of innovations in smart devices by incorporating them into their distribution networks to cut down on monitoring costs and to automate network control. The future of electricity retailing will be shaped by the dissemination of these technologies throughout the grid.

Figure 2.1 illustrates that the costs associated with adopting smart technologies have fallen considerably during the last decade. For instance, between 2004 and 2018, the average cost of smart sensors fell by about 66%.<sup>1</sup> These sensors provide detailed, real-time distribution and consumption data to consumers and utilities. Costs were expected to fall by an additional 14% between 2018 and 2020, according to Business Insider Intelligence (Microsoft Dynamics 365, 2018). The declining cost of smart sensors has bolstered distribution network automation by making the adoption of advanced monitoring and control devices

<sup>1</sup>Figure 2.1 only illustrates this trend from 2010 to 2018 (a 46% decline) due to historical data limitations for battery and polysilicon prices.

more economical (NEMA, 2015). Smart sensors facilitate the interconnection of devices that work together to prevent, diagnose, and isolate faults in electricity distribution networks. Sophisticated algorithms and real-time data in tandem with devices like smart relays, automated feeder switches, and voltage regulators allow grid operators to substantially decrease operations and maintenance costs while also improving safety for workers and reliability for consumers (NEMA, 2015; US DOE, 2016b). We discuss distribution automation and network monitoring in more detail in Section 6.2.

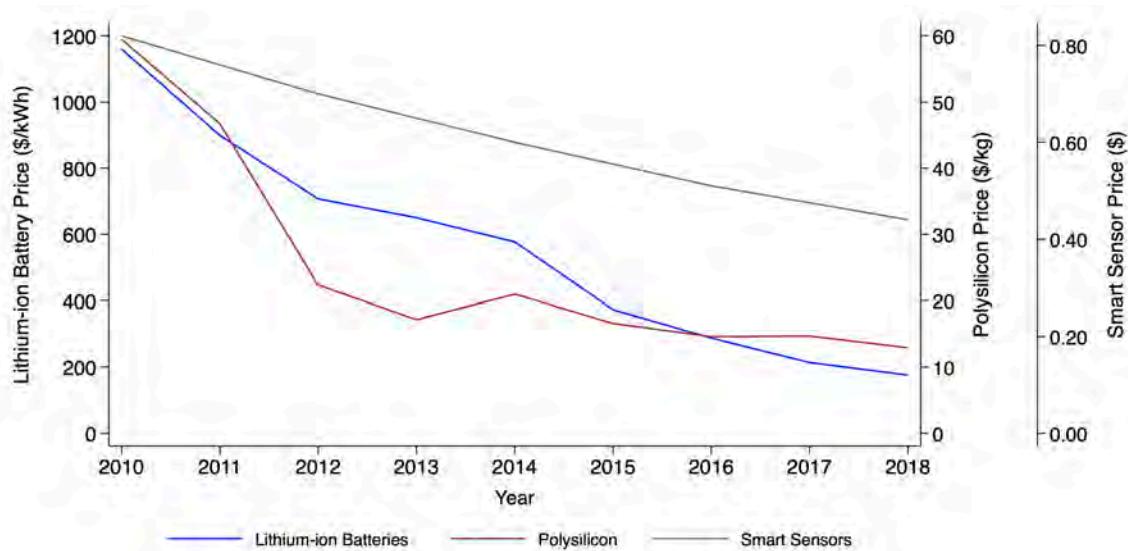


Figure 2.1: Declining Costs of Sensors, Storage, and Solar PV Technology

NOTES: Lithium-ion battery prices and PV grade polysilicon prices are from Bloomberg New Energy Finance (BNEF); both were retrieved from the Bloomberg Terminal (Bloomberg New Energy Finance, 2020h,g). Smart sensor prices—originally from Business Insider Intelligence—were reported by Microsoft Dynamics 365 (2018) (even years only).

Through the late 1980s, the high costs of smart metering infrastructure hampered the widespread adoption of demand-side management programs like dynamic pricing (US DOE, 2016a). Over the last several decades, however, the hardware and IT costs associated with smart metering have declined. According to the Electric Power Research Institute (EPRI), the average *hardware* cost reached \$76 per meter in 2006, having declined by 20% during the preceding decade (EPRI, 2007). Still, actual per-unit *installation* costs (which include the cost of hardware) vary across regions of the world. In 2012, for instance, installations in the United States (US) generally cost over \$100 while the Chinese market saw meters at below \$50 per unit and South Korea experienced prices as low as \$18 (Alejandro et al., 2014). More recently, several providers have quoted prices under \$40 per meter in India in 2018 (Singh and Upadhyay, 2018; Rowlands-Rees, 2018).

The generation and storage equipment connected to the grid have also declined in cost. For example, in Figure 2.1 we see that lithium-ion batteries—used for home and electric vehicle energy storage—and Photovoltaic (PV) grade polysilicon fell in price by 85% and 78%, respectively, between 2010 and 2018 (Bloomberg New Energy Finance, 2020h,g). PV

grade polysilicon (red line)—high purity silicon for producing solar PV ingots—experienced the largest price drop between 2011 and 2012, declining by 52% in a single year. While the net decline in price over the decade was substantial, polysilicon prices did see slight increases during 2014 and 2017. Lithium-ion battery prices (blue line) experienced a steadier and more gradual decline over the course of the last decade.

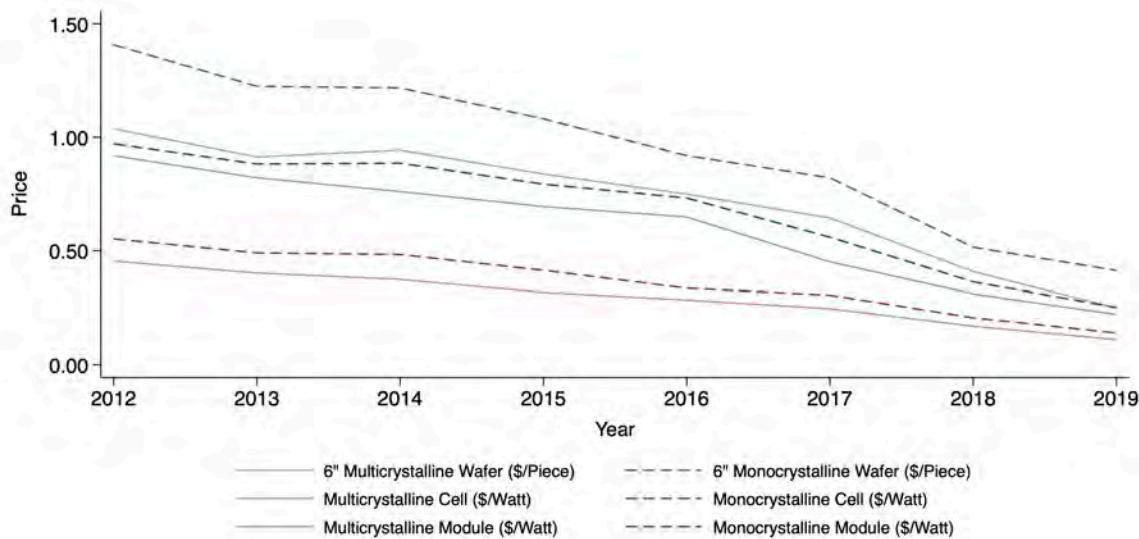


Figure 2.2: Declining Costs of Solar PV System Components

NOTES: This figure was produced using prices from Bloomberg New Energy Finance; prices were retrieved from the Bloomberg Terminal (Bloomberg New Energy Finance, 2020d,a,e,b,f,c). Detailed information on these data can be found in Figure Section B.2.

Monocrystalline and poly- or multicrystalline solar components have correspondingly experienced substantial price declines during the last decade (Bloomberg New Energy Finance, 2020d,a,e,b,f,c). Figure 2.2, produced using raw data from Bloomberg New Energy Finance (BNEF), illustrates these trends for solar wafers, cells, and modules from 2012 to 2019. Solar wafers are thin sheets of either mono- or multicrystalline photovoltaic material that are used to construct solar cells. Multicrystalline wafers are made by combining many small pieces of silicon—providing less freedom for electrons to move around and resulting in a lower efficiency (EnergySage, 2019). Likely due to their lower efficiencies, multicrystalline components (solid lines) have historically been less expensive than their monocrystalline counterparts (dashed lines). Figure 2.2 also illustrates a shrinking gap between mono- and multicrystalline components – particularly during the last five years. Figure 2.3 illustrates that, as this disparity has narrowed, the market share held by monocrystalline systems has surpassed that of multicrystalline systems in a sample of over 1.6 million distributed PV systems in the US (Barbose and Darghouth, 2019). As one would expect, the propagation of monocrystalline systems has led to a large increase in the median efficiency of PV systems in this sample.<sup>2</sup>

<sup>2</sup>The sample used by Barbose and Darghouth (2019) includes an overwhelming majority of the distributed

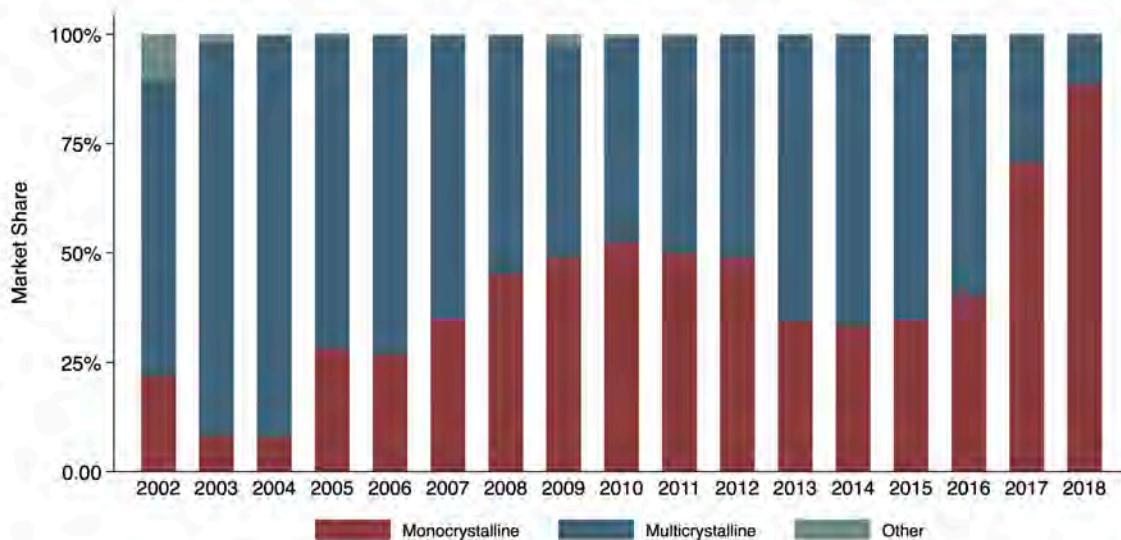


Figure 2.3: Market Composition of PV Technologies for Distributed solar

NOTES: This figure was produced using the dataset from LBNL that accompanies Barbose and Darghouth (2019). These data cover over 1.6 million distributed PV systems installed in the US. While they do not cover every system installed, they make up an overwhelming majority.

## 2.3 Distributed Solar—A Competitor to Grid-scale Electricity

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 grid-supplied electricity. According to *Renewables 2019 Analysis and Forecast to 2024* (“Renewables 2019”)—the most recent renewables report from the International Energy Agency (IEA)—distributed solar capacity made up just over 40% of total solar PV capacity installed around the globe in 2018 (IEA, 2019d).

Figure 2.4, from *Renewables 2019*, illustrates that for the better part of the last two decades, distributed generation units made up the majority of solar capacity installed globally. Indeed, until 1999, the majority of global solar capacity consisted of small, off-grid installations (IEA, 2019d). Distributed systems remained the primary form of solar installation for most of the subsequent two decades. In 2016, however, the global installed capacity of utility-scale solar systems first surpassed global distributed capacity.

During the last two decades, China secured its position as the global leader in solar component production. China is the world’s largest producer of polysilicon with a capacity to produce 388,000 tons in 2018 (Research and Markets, 2019b).<sup>3</sup> However, rapid growth in its solar panel production industry has led to a need to import increasing quantities of the raw material. Indeed, between 2009 and 2017, Chinese imports of polysilicon increased

PV installations in the US (81% of residential and non-residential installations through 2018). Utility-scale installations (defined by LBNL to be over 5 megawatts (MWs)) are not included.

<sup>3</sup>Combined production outside of China is only 210,000 tons (Research and Markets, 2019b).

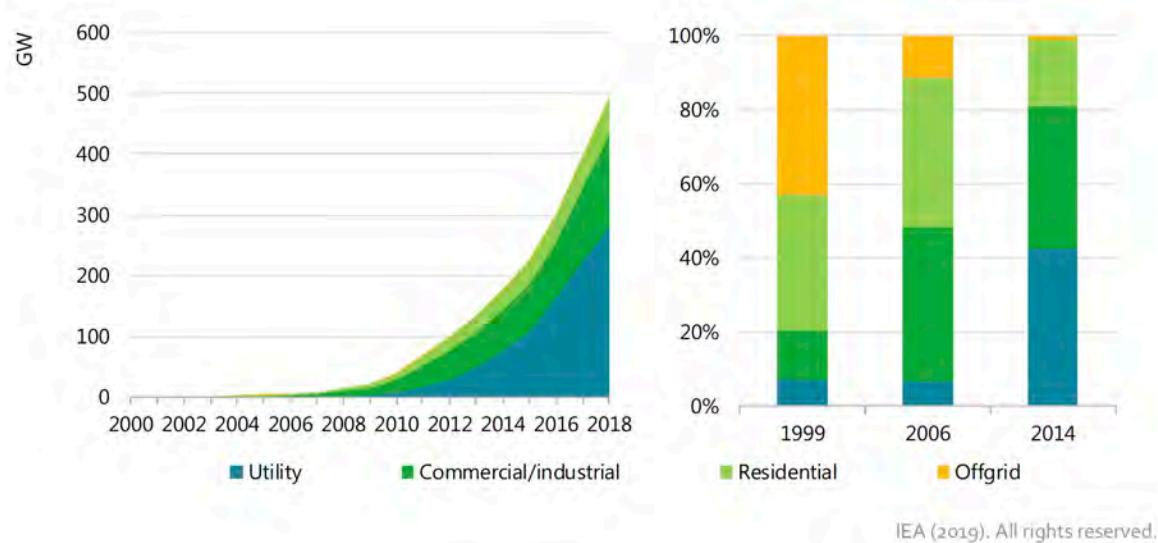


Figure 2.4: Cumulative Solar PV Capacity by Application Segment

SOURCE: IEA (2019) *Renewables 2019*. All rights reserved.

from 9,000 tons to 144,000 tons. As illustrated in Figure 2.5, the increased quantity of polysilicon demanded coincided with the large decline in its price. Besides the declining cost of polysilicon, producers have been incentivized by the Chinese government's offering of numerous subsidies, tax breaks, and generous loans (Ball, 2013). This burgeoning industry led to drastic declines in prices of solar cells, particularly between 2011 and 2012 when oversupply of solar panels sent prices plummeting. Still, Chinese imports of polysilicon continued to grow for most of the decade, finally peaking in 2017 and subsequently decreasing in 2018.

While hardware costs—panel, inverters, and mounting equipment—are relatively consistent across countries, balance-of-system costs vary greatly and account for a large portion of installation costs in countries with higher labor costs like the US, Japan, and the United Kingdom (UK) (IEA, 2019d). Largely driven by declining PV module prices, distributed solar installation costs declined dramatically between 2010 and 2018. Figure 2.6, from *Renewables 2019*, provides the country level breakdown of installation costs for several major distributed solar markets around the globe (IEA, 2019d). It is evident from Figure 2.6 that residential installation costs have generally remained higher than costs for larger commercial and industrial projects, particularly in developed countries like the US and the UK. It is also clear from Figure 2.6 that the most rapid declines in investment costs took place during the first half of the last decade. This trend is consistent with the major drop in PV-grade polysilicon prices between 2011 and 2013 that we observed in Figure 2.1.

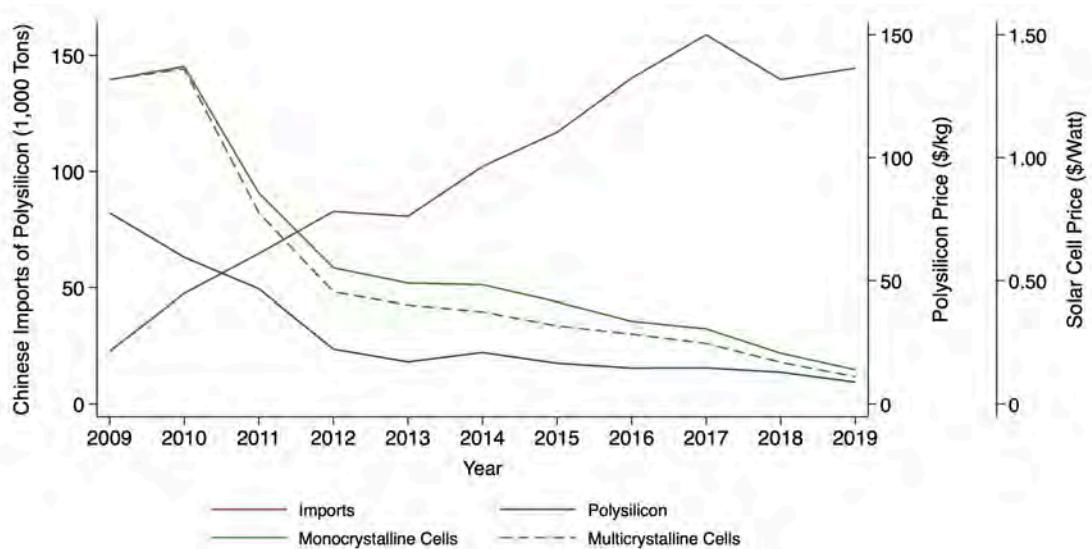
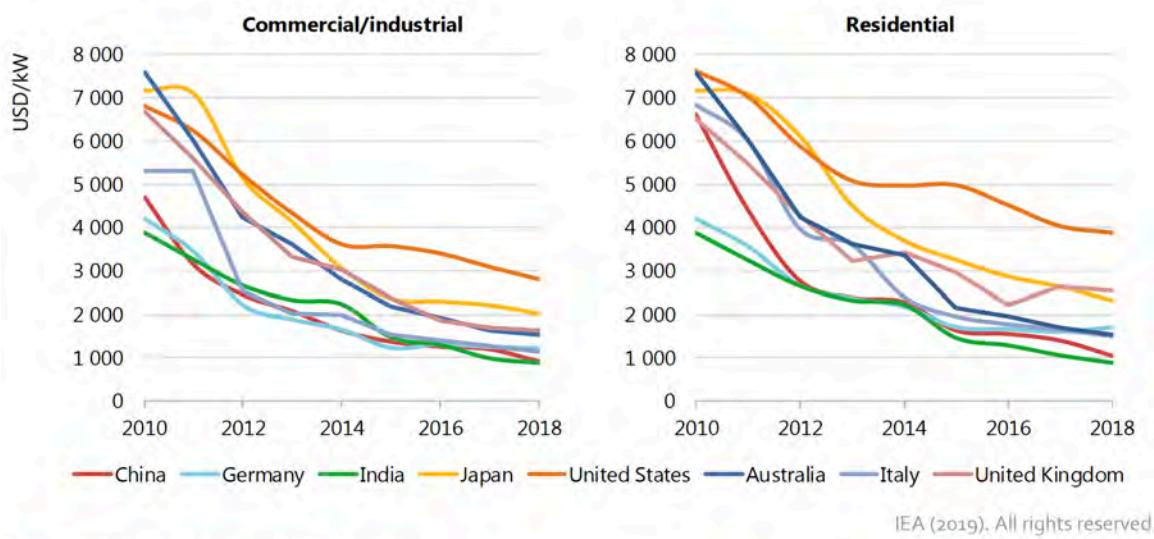


Figure 2.5: Chinese Imports of Polysilicon

SOURCE: This figure was produced using data retrieved from the Bloomberg Terminal. The red line represents the total quantity of polysilicon imported into China (in tons) and is from (Bloomberg, 2020). The Polysilicon price (blue line), and solar cell prices (green lines) are from Bloomberg New Energy Finance (Bloomberg New Energy Finance, 2020g,e,b).



Source: IRENA (2019), *Renewable Cost Database*.

Figure 2.6: Installation Costs for Distributed Solar Systems in Selected Countries

SOURCE: IEA (2019) Renewables 2019. All rights reserved.

According to IEA, the levelized cost of energy (LCOE) for distributed solar also declined substantially between 2010 and 2018.<sup>4</sup> In a number of countries and regions, including Eastern Australia, Brazil, and California the LCOEs of distributed solar are lower than residential, commercial, and industrial retail electricity prices, making investments in distributed solar capacity privately attractive to these customers (IEA, 2019d). Similarly, distributed solar LCOEs in Germany and Japan are lower than residential and commercial retail prices. Unsurprisingly given this information, Germany and Japan—still two of the largest utility-scale solar installers in the world—have substantially more distributed capacity than utility-scale. As shown in Figure 2.7, they maintained ratios of distributed to utility-scale capacity of 2.7 to 1 and 1.6 to 1, respectively, in 2018 (IEA, 2019b).

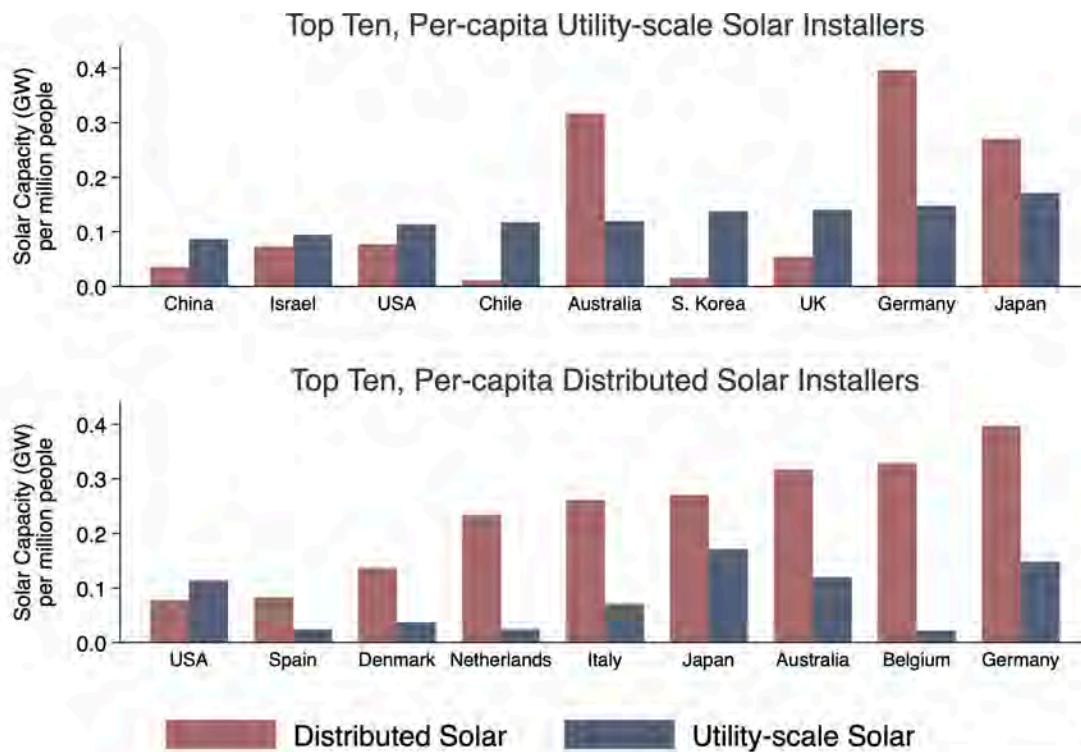


Figure 2.7: Adoption of Distributed Solar Relative to Utility-scale Solar - 2018

NOTES: This figure displays the per-capita distributed and utility-scale solar capacities for the ten countries with the most installed capacity per capita of each type as of 2018. The figure was produced using capacity data from IEA (2019b) and population data from United Nations (2020).

The remaining potential for distributed solar installations is enormous. IEA (2019d) estimates that rooftops alone could provide over 9,000 GW of potential capacity. Likewise,

<sup>4</sup>The levelized cost of energy (LCOE) is the usual way to compare the cost of electricity from generation units that produce energy over many years. The levelized cost of energy from a generation unit is defined as  $LCOE = \frac{\sum_{t=0}^T \frac{C_t}{(1+r)^t}}{\sum_{t=1}^T \frac{E_t}{(1+r)^t}}$ , where  $C_t$  is the net cost of the generation unit in year  $t = 0, 1, 2, 3, \dots, T$ ,  $E_t$  is electricity produced in year  $t = 1, 2, \dots, T$ ,  $r$  is the discount rate, and  $T$  is the number of years the generation unit is in service. If  $r = 0$  then the LCOE is simply the average cost of energy over the lifetime of the generation project.

in 2016, the National Renewable Energy Laboratory (NREL) estimated that the US has the potential to install over 1,000 GW of rooftop solar and that these installations could produce more than 1,400 TWh per year (Gagnon et al., 2016). Figure 2.8 illustrates IEA’s predictions for the combined total of residential, commercial/industrial, and off-grid distributed solar capacity in 2024. The values displayed in the figure were calculated using IEA’s “main case forecast” scenario (rather than the accelerated scenario) provided in *Renewables 2019*.<sup>5</sup> IEA’s forecast predicts that between 2018 and 2024, global distributed solar capacity will increase by almost 150%—reaching almost 530 GW. IEA’s forecast for the US is consistent with the US Energy Information Administration’s (EIA) reference case forecast in the *2020 Annual Energy Outlook* (US EIA, 2020b). Both predict that the US will have around 25 GW of commercial capacity and around 30 GW of residential capacity by 2024.

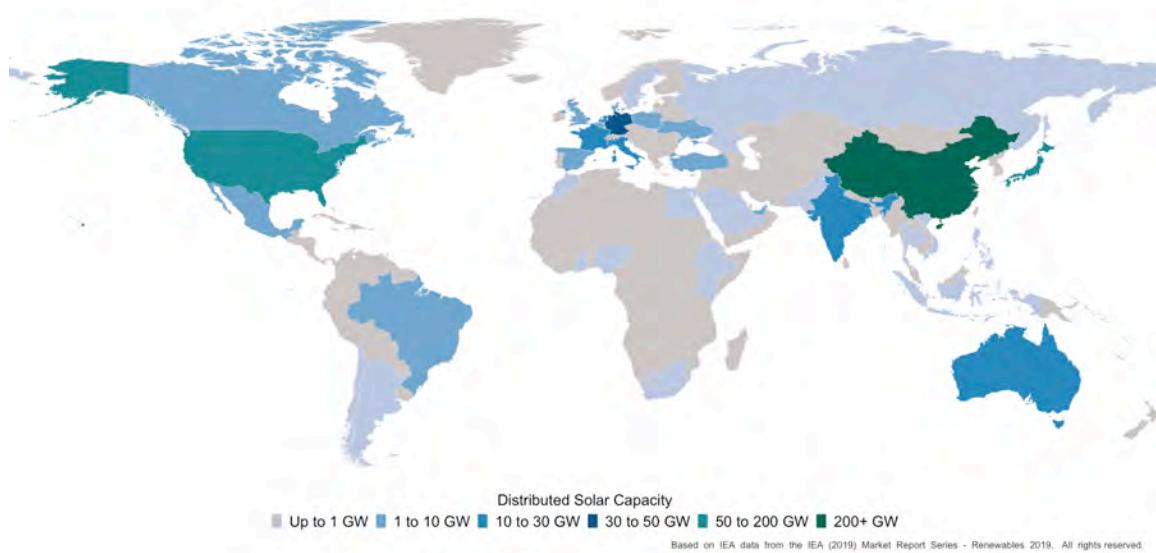


Figure 2.8: IEA’s Distributed Solar Capacity Forecast for 2024

NOTES: Forecast values illustrated in this figure are derived from IEA (2019d) and were calculated using the sum of residential, commercial/industrial, and off-grid capacity projections in the main case. Data were not available for countries shown in gray. More information on these calculations is available in Section B.3.

From Figure A.1, in the appendix, we can see that China is expected to host close to 40% of the world’s distributed solar capacity by 2024, according to IEA’s projections (China currently holds about 24% of the world’s distributed solar capacity). Still, the per-capita installations in China are expected to trail behind a number of European nations, Japan, Israel and the US. This is evident in Figure A.2, in the appendix, which provides a per-capita forecast using IEA’s expected capacity in 2024 and population projections from the United Nations (United Nations, 2020).

<sup>5</sup>For more information on our calculations using IEA’s data, see Section B.3 in the appendix.

## 2.4 Low Cost Two-Way Communication Technologies

The declining cost of electronic monitoring and control devices and software to operate them has led to the development of Distributed Energy Management Systems (DERMSs). Rapid diffusion of smart phone technology and wireless internet access has significantly reduced the cost of providing real-time feedback to consumers on their electricity consumption as well as reducing the cost of communicating with their electricity-consuming devices.

A DERMS is a combination of software and monitoring and control devices that optimizes the operation of a distribution grid with DERs. Some of the tasks a DERMS can perform include, volt/VAR optimization (VVO), power quality control, and the coordination of DERs operation to support reliable operation of the distribution grid. These services are provided by altering power and voltage levels along feeders in the distribution network by controlling smart inverters on rooftop solar systems, capacitor banks, on-load tap changers, voltage regulators, and customer loads.

The DERMS software system knows where every monitored asset is located in the distribution network and can issue instructions to any device with controllers to manage reliability issues in the distribution grid. The ability to control devices could extend down to the individual outlets or electricity devices within a customer's premises as well as a distributed solar inverter or a distributed storage system.

There are extremely inexpensive (approximately \$5) WiFi controlled plugs that customers can switch on and off remotely using a smartphone app. These plugs could also be controlled through signals sent by a DERMS system. Consequently, besides customers remotely controlling their electricity use through their smart phone, customers could also give the distribution network operator, their electricity retailer, or a third-party demand response provider access to these smart plugs to manage the operation of the distribution network in real-time.

The combination of interval meters with a distribution utility back end that can quickly broadcast the customer's consumption and the real-time price of energy to a smartphone application or software application can enable real-time demand response. Customers can program WiFi controlled plugs, a distributed solar inverter, or distributed storage unit to respond to dynamic retail prices or other real-time conditions in the transmission and distribution grids. As we discuss in Section 6.5, customers can also purchase software that operates these devices to balance their comfort level versus energy cost savings.

## 2.5 Electrifying the Transportation and Heating Sectors

Both 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 (Jones et al., 2018; Deason et al., 2018; EPRI, 2018). 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 (Deason et al., 2018; Billimoria et al., 2018).

### 2.5.1 Transportation Electrification

The electrification of the transportation sector is dependent on both the adoption of electric vehicles and the deployment of the infrastructure needed to provide them with energy. This has the potential to reduce GHG emissions and local air pollutants like PM<sub>2.5</sub> and ground-level ozone. The transportation sector accounts for over 40% of final energy use in the US and is almost entirely fueled by petroleum-based products (EPRI, 2018). In the European Union (EU), transportation accounts for about 31% of energy consumption (European Environment Agency, 2020).<sup>6</sup>

In the US, the federal government and several states have taken steps to promote the adoption of these technologies (Jones et al., 2018). California's Zero Emissions Vehicle (ZEV) Standards, for example, require that 9.5% of vehicles sold in the state in 2020 must meet the requirement of emitting zero criteria air pollutants or GHG emissions. The ZEV Standards will become more stringent each year—by 2025, 22% of vehicle sales will need to be from ZEVs.<sup>7</sup> Washington and Oregon, in addition to California, have passed legislation urging or requiring utilities to submit EV infrastructure plans to their respective public utilities commissions (Jones et al., 2018).<sup>8</sup> In addition, federal and state tax credits, Corporate Average Fuel Efficiency (CAFE) standards, and congestion pricing policies have all encouraged EV adoption in the US (Jones et al., 2018).

Figure 2.9 displays several EV adoption trends that occurred over the last decade in the US. By the end of February 2020, there were over 24,000 public charging stations (with over 78,000 outlets/chargers) installed across the country.<sup>9</sup> Panel (a) of Figure 2.9 displays the end-of-year count of public charging infrastructure in all 50 states and the District of Columbia through November 2019. About a quarter of all charging stations—along with 48% of electric vehicles—are located in California (see Panel (c)). However, while California has close to four times as many stations as the next highest state (New York), it is fifth in terms of charging stations per monthly vehicle miles travelled (VMT) (see Panel (b)) and has the smallest ratio of charging stations to EV registrations (1 station per 116 EVs). In fact, California's ratio of public outlets/chargers to EVs (about 1 charger to 57 EVs) is more than 6 times smaller than the global ratio.<sup>10</sup> Wyoming—the least populated state in the country—has the most public charging stations per EV and the District of Columbia has the most relative to monthly traffic volume.

Globally, there are a number of intergovernmental EV adoption initiatives underway. The Clean Energy Ministerial (CEM), a forum of 28 countries promoting clean energy

<sup>6</sup>Transportation consumed 326.9 tonnes oil equivalent (TOE) out of a total energy demand of 1,060 TOE in the EU in 2017. Additionally, we note that the UK left the EU during the writing of this report. However, unless otherwise noted, the UK is included in statistics and information referring to the EU or Europe in this report.

<sup>7</sup>See California Code of Regulations Title 13 §1962.2.

<sup>8</sup>See California Senate Bill 350, Washington House Bill 1853, and Oregon Senate Bill 1547.

<sup>9</sup>To retrieve the most up-to-date count of charging stations, visit [https://afdc.energy.gov/fuels/electricity\\_locations.html#/analyze?country=US&fuel=ELEC&ev\\_levels=all](https://afdc.energy.gov/fuels/electricity_locations.html#/analyze?country=US&fuel=ELEC&ev_levels=all).

<sup>10</sup>There is a distinction between charging stations and chargers/outlets. Some charging stations may have multiple outlets. Statistics referring to these types of infrastructure are differentiated accordingly throughout this report.

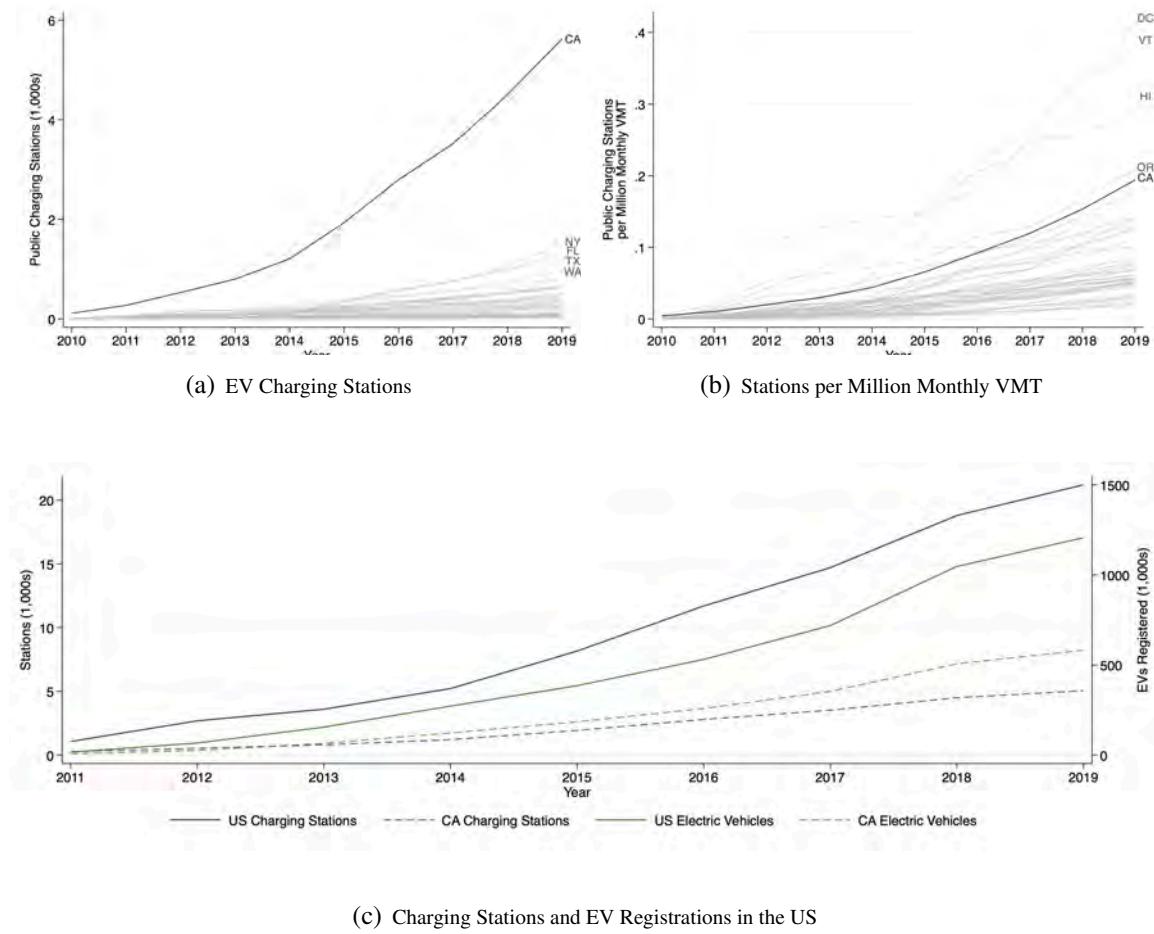


Figure 2.9: US Installations of Public Electric Vehicle Charging Stations

NOTES: Panel (a) provides the raw count of EV charging stations installed in each state in the US. These data were provided to us by the US Dept. of Energy's Vehicle Technologies Office. The count includes only stations that remained open as of November 2019 and are available to the public. Panel (b) displays the number of EV charging stations in each state divided by the annual average monthly vehicle miles traveled (VMT) in that state. VMT data were retrieved from the US Dept. of Transportation (2020). Panel (c) displays the growth in both charging stations and electric vehicle registrations from the end of 2011 to June 2019 for the whole US and for California. EV registration data are from Alliance of Automobile Manufacturers (2019). More information on these calculations is provided in Section B.4.

policy, adopted the Electric Vehicle Initiative (EVI) in 2009 in an effort to help governments address policy challenges related to EV adoption (IEA, 2019a). In 2017, CEM launched the EV30@30 Campaign which set a target for reaching 30% EV market share by 2030 in 11 member countries. Under the EV30@30 Campaign, 39 countries are currently participating in a pilot program for EV adoption (IEA, 2019a). Another initiative, the ZEV Alliance, has been undertaken by several US states, Canadian territories, and European countries in an effort to have all passenger vehicles sold in 2050 and beyond be electric. Norway, the country currently with the highest EV market share (10%), intends to only sell EVs by 2025 (IEA, 2019a).

Still, there remains a gap between the demand for EVs and the supply of charging

infrastructure (Jones et al., 2018). In 2018, there were close to 540 thousand public EV chargers (outlets) installed around the globe—about half of which were located in China (IEA, 2019a). Yet, from Figure 2.10 we can see that China only accounted for about 33% of global electricity consumption from EVs in 2018, according to data from Bloomberg New Energy Finance (BNEF). A potential reason for the density of charging stations in China is that EV models popular in the Chinese market have, on average, less than half the range capability of the top sellers in the US market (Hover and Sandalow, 2019). Furthermore, IEA (2019a) reports that the year-over-year installation rate is slowing and that the global ratio of chargers to electric cars decreased from 0.14 to 0.11 between 2017 and 2018. The EU recommends that Member States maintain a ratio of at least one charging station per ten EVs.<sup>11</sup> If the observed declining ratio of chargers to EVs continues, then the global ratio could fall below this threshold.

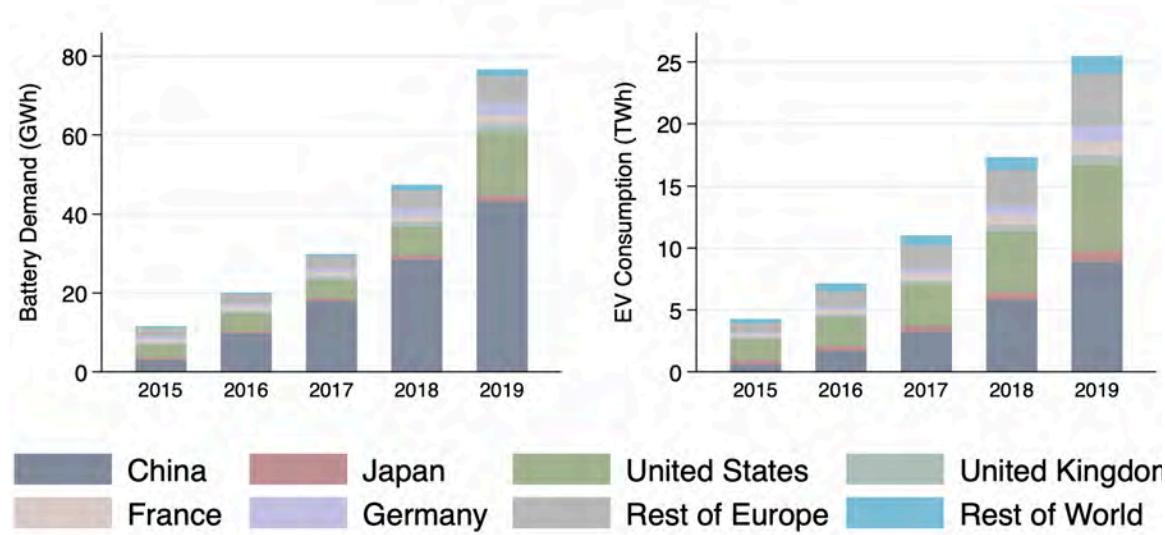


Figure 2.10: Global EV Market Trends

NOTES: This figure displays EV market trends from 2015 to 2019. The chart on the left provides the annual demand for lithium-ion EV batteries in select countries. The chart on the right displays the annual electricity consumption of EVs in select countries. Data for both figures are from Bloomberg New Energy Finance (BNEF) and were retrieved from the Bloomberg Terminal. More information on these data is provided in Section B.2.2.

The infrastructure gap has been a major cause of “range anxiety” among consumers on the margin for purchasing an EV (American Automobile Association, 2020). To combat range anxiety, companies have spent immense sums of money to build charging infrastructure in the hopes that it will catalyze the adoption of EVs. Tesla took this approach when introducing the Model S in 2012 (Jones et al., 2018). Rivian, a new EV manufacturer in the US whose first vehicle has not yet entered production, is also already planning a charging network for its vehicles. Because Rivian’s EVs are aimed at outdoor recreation,

<sup>11</sup>See Directive 2014/94/EU at <https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32014L0094&from=EN>.

their charging network is planned to be installed near the US's National Parks in order to alleviate range anxiety for consumers who enjoy visiting these remote locations (Lanhee Lee, 2020).

The transition to electric vehicles also provides a number of opportunities for demand-side flexibility and load management (Jones et al., 2018). Vehicles are generally driven for only a small portion of the day, leaving large swaths of time available to perform services unrelated to transportation. The ability for power to flow bi-directionally between cars and the grid provides utilities with a number of new opportunities for load management throughout the day (Briones et al., 2012). These systems—referred to as Vehicle-to-Grid (V2G)—are in the early stages of adoption but could have enormous potential as the global EV fleet grows. Batteries in EVs can provide “load-leveling sink services” to utilities that need to store power from intermittent renewable generators like solar PV and wind turbines (Briones et al., 2012). Energy from EVs can be supplied to the grid extremely quickly, circumventing the need for costly peaking power plants. There are currently V2G pilot programs in a number of countries including the US, China, Japan, and Denmark (justauto, 2020).

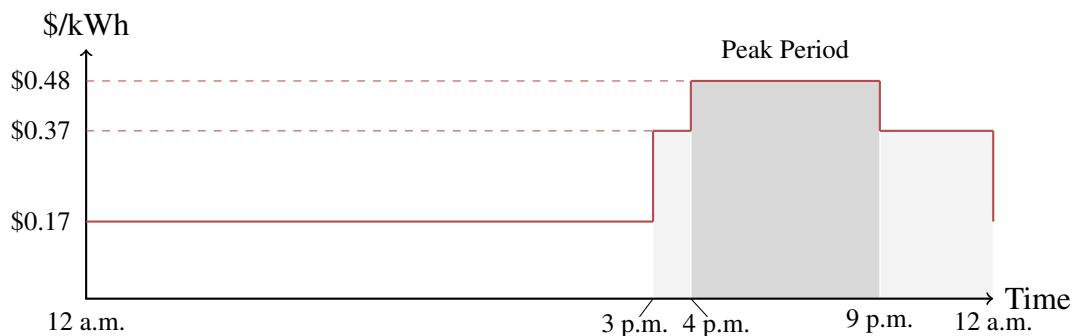
Utilities in the US, Europe, and China have also begun adopting innovative pricing programs specifically tailored to EV charging in an effort to better manage the system impacts from these new sources of consumption (Hover and Sandalow, 2019; Hildermeier et al., 2019; Satchwell et al., 2019). Time-based retail rates provide customers with an incentive for charging their vehicles during hours with lower system load and subsequently lower prices. At the same time, these price plans can make the purchase of an EV more attractive to customers considering the long term cost of fueling their vehicle. By 2017, at least 69% of US utilities had begun considering EV related changes to their existing tariff structure (Hover and Sandalow, 2019). A number of initiatives have been taken by utilities in Alaska, Hawaii, Georgia, Texas, California, and Virginia (to name a few) to adopt these flexible tariffs over the last several years (Satchwell et al., 2019; Hover and Sandalow, 2019; Dominion Electric, 2019a). Georgia Power, for example, offers EV owners a voluntary time-of-use (TOU) tariff with a “super off-peak” period between 11 p.m. and 7 a.m. during which time prices are 78% lower than off-peak prices and 93% lower than on-peak prices. Pacific Gas and Electric (PG&E) offers two TOU rate plans specifically for EV charging which are illustrated in Figure 2.11 (PG&E, 2020). The first plan, shown in Panel (a), covers both home energy use (e.g. heating, lighting, etc.) and EV charging. Because only one meter is used, no distinction can be drawn between the sources of consumption.<sup>12</sup> Panel (b) illustrates an alternative pricing scheme in which the EV charging equipment is metered separately from the rest of the home's energy use.<sup>13</sup> In this case, the customer can choose one of PG&E's other residential plans to cover other home consumption. Dominion Electric provides residential customers with a similar option to meter their electric vehicle separately

<sup>12</sup>See [https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC\\_SCHEDS\\_EV2%20\(Sch\).pdf](https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_EV2%20(Sch).pdf).

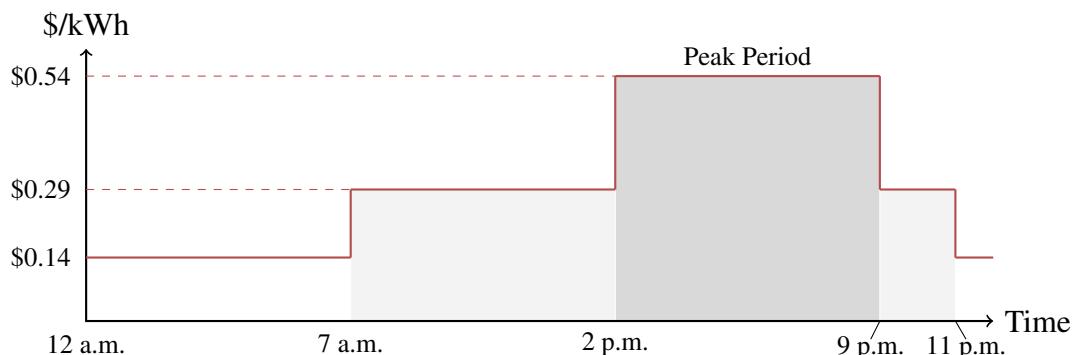
<sup>13</sup>See [https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC\\_SCHEDS\\_EV%20\(Sch\).pdf](https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_EV%20(Sch).pdf).

through two pilot programs offered in Virginia.<sup>14</sup>

Utilities in Spain offer a similar discount of about 81% for EV charging that occurs overnight (Hildermeier et al., 2019). The State Grid Corporation of China (SGCC), one of the country's two state-run utilities, uses a time-of-use program for EV charging where the off-peak price is about 60% lower than during the peak period (Hover and Sandalow, 2019). Moreover, shifting the EV charging load to off-peak periods in these countries has the potential to avert unnecessary spending on new generating infrastructure as EV demand increases (Hildermeier et al., 2019).



(a) Combined Home Consumption and EV Charging Rate



(b) EV Charging Rate with Separate Meter

Figure 2.11: PG&E Electric Vehicle TOU Charging Rates

NOTES: Diagrams based on information from PG&E (2020). Panel (a) illustrates PG&E rate plan EV2-A (Effective March 1, 2020); Panel (b) illustrates PG&E rate plan EV-B (Effective January 1, 2020). Prices shown are the summer rates for both schemes.

## 2.5.2 Heating Electrification

In the US, space heating and water heating accounted for 62% of all home energy consumption in 2015 (US EIA, 2018). While a quarter of US households relied solely on electricity for energy, natural gas still provided the majority of energy for space and water heating

<sup>14</sup>See Dominion Electric (2019a) and Dominion Electric (2019b).

across the country (US EIA, 2018). In 2017, heating in homes and businesses accounted for almost 10% of US carbon emissions (Billimoria et al., 2018). By 2018, 34% of residential buildings and 26% of commercial buildings were heated with electric heat pumps or electric resistance heaters and about 43% of homes use electric water heaters—primarily of the resistance heating variety (EPRI, 2018). Electric heat pumps can be up to three times more energy efficient than natural gas furnaces in moderate climates. Even in colder regions, they can increase efficiency by 150% (EPRI, 2018). Heat pumps also use up to 50% less energy than electric resistance heaters (US DOE, 2020b). In the US, the majority of heat pump installations are in the south where the climate is milder and the cost of electricity is lower. Still, cold-climate heat pumps have progressed technologically and are now considered appropriate in colder climates such as Midwest US states (Deason et al., 2018).<sup>15</sup> Between 2005 and 2015, the share of all-electric homes in the Midwest increased from under 10% to close to 15% (US EIA, 2019b). Where heat pumps are not yet suitable, resistance heaters can be used for electrification (Deason et al., 2018).

A number of pilot programs and studies have been undertaken in order to better understand the potential outcomes of heating electrification in the US. These studies overwhelmingly find heating electrification to be cost-effective in mild climates and in new residential buildings.<sup>16</sup> Electrification of heating systems in existing buildings, however, was not particularly cost-effective through 2018 (Deason et al., 2018; Billimoria et al., 2018).

Electrification of the heating sector not only has the potential to reduce carbon emissions, it introduces a number of options for grid flexibility and demand-side management integration (Deason et al., 2018; Billimoria et al., 2018). One of the key methods of load shifting accomplished by heating electrification is accomplished by heat pump water heaters in anticipation of peak periods. By preheating water when prices are low, consumers can use hot water during the evening peak period at a lower cost to themselves, while also alleviating strain on the grid. Figure 2.12, from Billimoria et al. (2018), illustrates the load shift that takes place when preheating water during the off-peak price period. In the figure's scenario, which is based on Hawaiian Electric Company's residential time-of-use rate, 10% more energy is consumed, but the consumer's bill is 20% lower.

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<sup>15</sup>According to Billimoria et al. (2018), by 2018 there were hundreds of heat pump models that could function at 5 °F and even some that could function efficiently at -13 °F.

<sup>16</sup>Deason et al. (2018) provides an extensive literature review of US case studies on heating electrification.

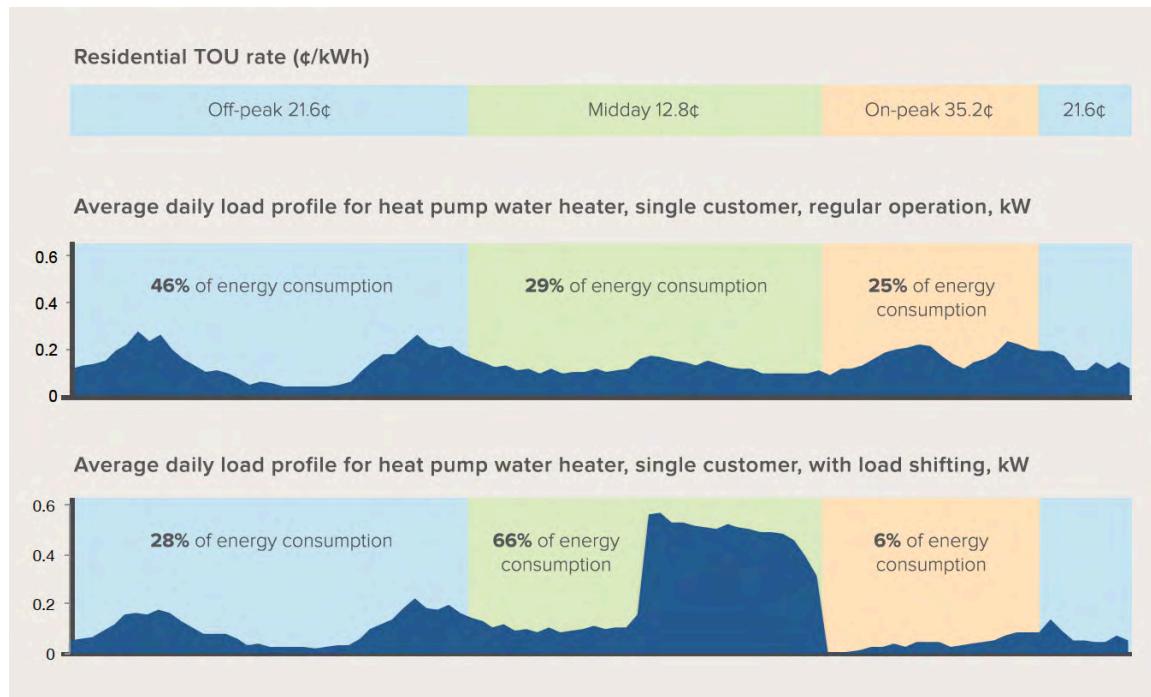


Figure 2.12: Preheating as a Load Shifting Strategy

NOTE: This figure is from Billimoria et al. (2018) and illustrates the load shifting strategy that utilities accomplish with preheating. The scenario featured in this figure is based on the Hawaiian Electric Company's residential time-of-use rate.



### 3. Regulatory Barriers to Change

This section describes regulatory barriers that are major factors in determining the speed at which the technologies described in the previous section have been deployed. Some of these barriers are the result of the regulatory process not putting in place 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 transmission and distribution network services and annual average cost pricing of retail electricity.

#### 3.1 Barriers to Interval Metering Deployment

The benefits that any given retailer or consumer can realize from installing an interval meter are typically significantly less than the benefits that the same retailer or consumer can realize from adoption if all other customers have interval meters. In addition, there are economies to scale and scope in the installation of interval metering technology that the distribution network owner can realize for its geographic service area. Significant reductions in the per-meter installation cost can be realized by installing more meters for a given geographic area (economies to scale) and the same number of meters for a smaller geographic area (economies to geographic density).

There are also substantial data processing and software development costs associated with collecting interval data from the meters and designing and implementing a billing system to utilize this data. A straightforward way to explain the reason for increased back end costs is that in the former regime of reading mechanical meters on a monthly basis a billing system only had to record, validate and bill each customer based on 12 monthly values per year. With an interval meter that can record a customer's consumption on an hourly basis, the billing system must now record, validate and bill based on 8,760 hourly

values during the year. A retailer is unlikely to incur the cost of adopting these systems if only a few customers have interval meters.

Because of these economies to scale and scope in deployment, explicit regulatory mandates have been used to achieve widespread deployment of interval metering technology. A number of jurisdictions, such as the United Kingdom, the State of Victoria in Australia, and the Electricity Reliability Council of Texas (ERCOT) in the United States, have attempted a one-at-time approach where individual customers pay for the cost of an interval meter. In all of these cases, so few meters were deployed that a regulatory mandate was eventually implemented. Only New Zealand has managed to achieve widespread deployment of interval under a voluntary scheme.

The distribution utility benefits from the installation of interval meters through a reduced number of or complete elimination of manual meter readers. These labor cost savings are a substantial fraction of the direct economic benefits to the distribution utility from the deployment of interval meters. The distribution utility also benefits from more rapid and accurate outage detection because if the meter is no longer sending consumption information to the back office, the distribution utility knows immediately that an outage has occurred. Moreover, the locations of the non-communicating interval meters allow the distribution utility to identify the location of the network outage with greater precision. Interval meters can also reduce operating and maintenance costs for utilities and are even being used to combat non-technical losses—particularly in regions where energy theft is a major concern. Because real-time consumption data is immediately sent to the distribution utility’s back office, there are few opportunities for missed or inaccurately reported meter readings favoring the customer.

The major source of consumer benefits from interval metering comes from the existence of a back office that can bill customers based on their hourly consumption, provide hourly consumption data to competing retailers and third-party service providers, and rapidly disseminate this information to the customer and these third-parties to facilitate real-time demand side response actions. The distribution utility realizes little, if any, financial benefit from providing these consumer benefits. This is the primary source of the divergence between the private benefits of interval meter deployment that accrue to the distribution utility and the societal benefits of interval meter deployment that accrue to electricity consumers and retailers.

Moreover, in an environment with retail competition, it would be extremely costly to have each competitive retailer install meters and develop its own back office infrastructure to compile and rapidly disseminate interval metering information rather than to have the distribution utility providing these services for all retailers competing its geographic footprint. This single-source cost advantage is another reason that all regions with widespread deployment of interval metering have done so through a regulatory mandate with cost recovery as a regulated distribution network service. Even New Zealand has a meter service provider that owns the meter and each retailer contracts with the meter service provider to access a customer’s meter.

The private benefits realized by the distribution utility from the deployment of interval meters are likely to be significantly smaller than the market-wide benefits that consumers and

competitive retailers realize in the form of lower distribution network costs and ubiquitous real-time access to data that enables the development of a wide-range of dynamic pricing plans. These pricing plans, in turn, support efficient investments in distributed generation, storage and load-shifting technologies. How regulatory processes account for these market-wide sources of economic benefits can create a barrier to the widespread adoption of interval metering. This divergence between the private benefits to the distribution utility and the broader economic benefits to consumers and retailers is reason that an explicit regulatory mandate is typically required to achieve widespread deployment of interval meters.

## 3.2 Interval Data Access and Interactivity with Consumers

Customer and third-party access to interval data is essential to the development of a competitive retail market. Customers can use this data to comparison-shop by making their monthly or hourly consumption data available to competing electricity retailers and asking for quotes for pricing plans to serve their demand. In markets with interval meters, there are even retailers that act only as financial intermediaries using a customer's interval data and the tariff offerings of all of the competing retailers to find the best tariff for that customer. This financial intermediary is paid based on the difference between what the customer would have paid for energy under their current tariff and what they pay under the new "best" tariff.<sup>1</sup>

Many United States utilities participate in an industry-led approach to providing customers with access to their consumption data in a consumer-friendly and computer-friendly format by clicking on a *Green Button* on their utility's website. The *Green Button* initiative officially launched in January 2012 and currently has over 50 utilities and electricity suppliers signed on to the initiative. These commitments imply more than 60 million residential and business customers will be able to securely access their energy consumption data in a standardized, machine readable format.<sup>2</sup>.

Rapid access to this data by the customer and third-parties is necessary for its use in automated load response devices and energy storage technologies. How this data is made available to customer can also impact the customer's response to this data. Providing this data in a manner that tells the consumer the dollar per hour cost of using specific energy consuming appliances can produce larger demand reductions relative to other approaches as shown in Kahn and Wolak (2013) for consumers of two large California retailers and Stojanovski et al. (2020) for the case of customers of the retailer in Puebla, Mexico. Wolak (2015) studies the impact of providing Singapore households with real-time usage feedback on its monthly energy consumption. The Singapore Energy Market Authority(EMA) implemented an Intelligent Energy System Pilot in which households were provided with in-home display (IHD) units that provided information on each household's real-time electricity consumption. To assess the impact of the real-time feedback provided by the IHDs, the monthly consumption of these households is compared to a control group of households that

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<sup>1</sup>MyBestPlan, which operates in the Electricity Reliability Council of Texas (ERCOT) market, is an example of such a company, see <http://www.MyBestPlan.net>.

<sup>2</sup>A list of these utilities and other companies supporting the *Green Button* initiative can be found at <https://www.energy.gov/data/green-button>

were not provided with these devices before and after this intervention. Wolak (2015) finds that having a IHD unit leads to a reduction in electricity consumption of about 4 percent relative to the control group. This saving is equivalent to about 180 kWh annually for the average house-hold in the sample which translates into roughly 50 Singapore dollars at the relevant retail electricity price. These studies suggest that providing *actionable information* in a timely manner on a customer's electricity consumption and prices the customers faces for use of different electricity consuming appliances at different times during the month is an productive way for retailers to engage with their customers to the mutual benefit of both parties.

One concern that has developed over the last decade is the secure use of the detailed customer data collected by interval meters. While immense amounts of data have been collected, in many instance this data is largely underutilized out of an abundance of caution by utilities and third-parties who are concerned about infringing upon customers' personal privacy (Douris, 2017). We discuss these concerns and some of the solutions that have been proposed in Section 6.1.2.

Interval meters are the enabling technology to allow active participation of final consumers in the wholesale market. The economic and reliability benefits of the new technologies impacting the retail electricity sector cannot be fully realized without interval meters and customers being billed based on their actual hourly consumption within the billing cycle. Hourly consumption data combined with actionable information about how their monthly bill is determined and how their individual appliance-using actions translate into changes in their monthly electricity bill can help the customer to decide when to consume electricity or whether to install devices and software that do this automatically.<sup>3</sup> Finally, pricing plans align the consumers economic incentives for altering their consumption of electricity with the times when the market benefits from changes in their consumption that can reduce the cost of serving all consumers.

### 3.3 Inefficient Transmission and Distribution Network Pricing

Average cost-based retail prices, particularly those that charge for the sunk costs of the transmission and distribution network using a dollar per kWh charge, make it privately profitable for a customer to install a rooftop solar system, even though it would be significantly less expensive on an industry-wide basis for the customer to continue purchase grid-supplied electricity. This approach to retail pricing also favors higher LCOE investments in distributed solar systems over lower LCOE transmission-connected solar systems.

Average cost-based retail pricing makes the decision to install a rooftop solar system an activity that is privately profitable for the typical customer, but not the least cost solution for all of utility's customers. The sunk costs of the transmission and distribution network and the cost of utility-administered programs for energy efficiency and renewables deployment do not vary with the quantity of electricity delivered to the utility's customers. By recovering these largely sunk fixed costs through a per unit charge, customers have a strong incentive to

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<sup>3</sup>Section 6.5 describes current state of offering of these products.

install a rooftop solar system which provides them with lower-priced electricity and shifts a significant portion of the recovery of these sunk costs onto customers without rooftop solar systems.

Recovering the sunk costs of the transmission and distribution grids through the traditional per kWh charge encourages *inefficient bypass* of grid-supplied energy. It also favors investments in distributed solar and storage relative to investments in transmission-connected solar and storage.

Inefficient bypass occurs when a customer's total incremental cost of self-supply, the cost of building the generating unit plus the cost of operating it, is less than the total amount the customer pays for the same amount of grid-supplied energy. Although this action is privately profitable for the customer, it increases the total cost of serving all customers, including the one that bypassed the system, making it a net negative result for society. Inefficient bypass wastes society's resources by increasing *the total costs of providing a given level of service*. In other words, under inefficient bypass, the total cost of supplying all customers with energy rises because of the bypass.

A simple example makes this point clear. Suppose that a retail customer pays an average cost-based price for electricity of 20 cents/kWh. This price recovers the cost of wholesale energy, the sunk costs and operating costs of the distribution and transmission network, and the cost of electricity retailing. Suppose the marginal cost of an additional kWh delivered to customer is 5 cents/kWh, with the remaining 15 cents/kWh going to recover the sizeable sunk costs of the transmission and distribution grid. Suppose that the average cost of energy from installing and operating a rooftop solar panel is 10 cents/kWh. In this case, it makes economic sense for the customer to replace 20 cents/kWh grid-supplied energy with 10 cents/kWh rooftop solar energy. However, this action does not change the sunk cost of the transmission and distribution grid, so the cost of supplying that customer and all other customers has risen,

All other customers in the aggregate must recover the 15 cents/kWh the customer that installed solar panels formerly paid to recover the sunk costs of the transmission and distribution networks. Taking this example further, suppose the customer consumes 1000 kWh before and after installing the solar panels. The customer's bill fell by  $\$100 = 0.10 \times 1000 \text{ kWh}$  because he is paying 10 cents/kWh versus 20 cents/kWh energy. However,  $\$150 = 0.15 \times 1000 \text{ kWh}$ , which he formerly paid to recover the sunk costs of the two grids must now be recovered from all other customers in the form of higher \$/kWh distribution charges.

A practical consequence of this inefficient bypass is a cost increase to other customers. This is distinguished from efficient bypass, which results in reduced costs for other customers. Efficient bypass would occur in the above example if the average cost of electricity from the rooftop solar panel was less than 5 cents/kWh, average marginal cost of grid-supplied electricity. The total cost of serving all customers would fall by the difference between 5 cents/kWh and the average cost of energy from the rooftop solar panels.

### 3.3.1 Inefficient Bypass: An Example from California

The rapid decline in the dollar-per-installed-Watt cost of rooftop solar systems in California and average-cost pricing for grid-supplied electricity by the California Public Utilities

Commission (CPUC) have significantly improved the business case for investments in rooftop solar. Taking the example of Northern California, in 2019 residential consumers in the Pacific Gas and Electric service territory face an average retail price of 22 cents per kWh for their electricity. An investment in a rooftop solar system at \$3.50 per Watt with a twenty-five year lifetime and assuming a 3 percent discount rate implies a leveled cost of energy of approximately 15 cents per kWh. Substituting 15 cents per kWh energy from a rooftop solar system for grid-supplied electricity at an average price of 22 cents per kWh makes economic sense for a residential consumer. This ordering of average retail prices versus the leveled cost of energy from a rooftop solar system holds for many regions around the world.

This average retail price is significantly above the annual average marginal cost of supplying the last kWh consumed to any consumer in California. (This same result also holds for many regions around world.) According to the California ISO, the annual average hourly cost of wholesale electricity (energy and ancillary services) in 2019 was 4.1 cents per kWh.<sup>4</sup> The major variable cost caused by moving electricity from a generation unit to final consumers comprises the losses that occur between the point of injection to the grid and the point of withdrawal at the customer's premises. These losses average approximately 5 to 6 percent of the electricity that is produced each year in the United States. Consequently, the annual average hourly marginal cost of grid supplied electricity in California during 2019 is very unlikely to be more than 5 cents per kWh.<sup>5</sup>

Consequently, the average marginal kWh withdrawn from the grid by a residential consumer costs is less than 5 cents, but the consumer is charged an average price of 22 cents in order to recover the sunk costs of transmission and distribution grid as well as the cost of regulatory mandates such as energy efficiency programs, renewable portfolio standards, and storage mandates. An investment in a rooftop solar system at \$3.50 per Watt is privately profitable for the household, because it allows the consumer to avoid the 22 cents/kWh average price of grid-supplied electricity. However, this decision is clearly not least cost on a system-wide basis because the same sunk costs of the transmission and distribution grid and the fixed cost regulatory mandates have not changed. These costs must now be recovered by a smaller number of kWhs. Consequently, the total cost of supplying energy to all consumers, including the consumer that found it privately profitable to install the rooftop solar system, has increased because of this action.

### 3.3.2 Inefficient Investment in Distributed versus Grid-Scale Solar

Because of economies to scale in the construction of solar generation capacity and the ability to site transmission-connected solar systems in regions with rich solar resources rather than on a customer's rooftop, the LCOE from the typical rooftop solar system is significant larger

<sup>4</sup>California ISO Department of Market Monitoring, *2019 Annual Report on Market Issues and Performance*, p. 3

<sup>5</sup>For example, if the hourly price of wholesale electricity at the connection point to the distribution network is 4 cents/kWh and the marginal losses between this point and customer's premises during this hour is 10 percent, then the marginal cost of grid supplied electricity to this customer during the hour is 4.4 cents/kWh = 4 cents/kWh x 1.1).

than the LCOE from a grid-scale solar facility. Consequently, grid-scale solar generation units are the lower cost solution for achieving a given renewable energy goal relative to rooftop solar generation capacity.

However, the above discussion of the implications of charging for the sunk costs of the transmission and distribution grids using a \$/kWh charge causes customers to find it privately profitable to obtain their solar energy from a rooftop system rather than the less expensive grid-scale system. In order to prevent inefficient bypass of grid-supplied energy from conventional and renewable sources, retail prices must be set closer to the hourly marginal cost of grid-supplied electricity.

What are the long-term implications of continuing with average cost-based pricing of retail electricity at prices for rooftop solar systems in the range of \$3.50/Watt installed, the current average cost per Watt in California?<sup>6</sup> As more distributed solar systems are installed, the quantity of grid-supplied electricity consumed falls. This logic implies that the roughly 17 cents per kWh charge that recovers the sunk costs of the transmission and distribution grids must increase because these costs must now be recovered from the sale of a smaller quantity of grid supplied electricity.<sup>7</sup>

According the California Energy Commission (CEC) there are currently more than 9,000 MWs of distribution network-connected residential and commercial solar energy systems in California. The annual increase in distribution network-connected solar PV capacity has increased each year from 2006 to 2019, as shown in Figure 3.1, which reports cumulative capacity through April 30, 2020.

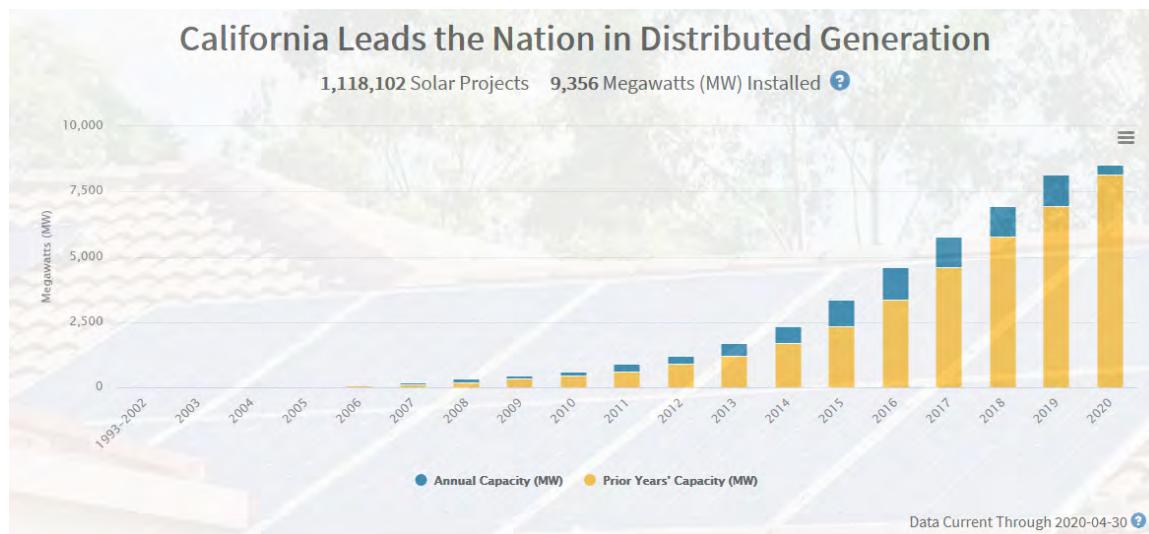


Figure 3.1: California Distributed Solar Capacity 1998 through 2020

NOTES: These figures are taken from the California Distributed GEneration Statistics web-site, <https://www.californiadgstats.ca.gov/>

<sup>6</sup>This price does not include state financial supports or the 30% federal tax credit.

<sup>7</sup>The difference between the average retail price of 22 cents/kWh and the 5 cents/kWh average marginal cost of grid-supplied energy is 17 cents/kWh.

This rapid increase in solar capacity implies that the fixed costs of the transmission and distribution networks and utility-administered public programs must be recovered over a smaller amount of grid supplied electricity, which requires raising the \$/kWh set to recover the sunk costs of the transmission and distribution network and other fixed costs. There is also no guarantee that this \$/kWh average cost-based price can be increased indefinitely to recover these costs.

Failure to address the incentives caused by average cost pricing of the transmission and distribution network will lead to an increasing amount of inefficient bypass of grid-supplied electricity and greater likelihood that transmission and distribution utilities will be unable to recover their sunk costs. If the share of system load served by distributed solar resources is large enough, the utility may need to prohibit the installation of new distributed solar systems or limit the size of systems that can be installed on a customer's premise so that it produces less energy than the customer is consuming. Hawaiian Electric Company (HECO), the utility that serves Hawaii, has had to resort to this solution. Currently, all new distributed solar systems are required to be sized to produce no backfeed to the utility's network.<sup>8</sup> This response by HECO illustrates a significant downside of a reactive approach to new technologies in regions with significant distributed solar resource potential.

### **3.4 Regulatory Reform of Distribution Network Planning and Access**

The increasing deployment of distributed generation and storage implies an increased need for monitoring and control devices in the distribution grid and the back office software necessary to process this data and communicate with these devices. Investments in distributed storage can reduce the need for distribution grid upgrades, but this will also require communication between grid monitoring devices and the distribution utility's back office and as well as communication between the utility's back office and the distributed storage resources. These communication links allow the distribution utility to co-ordinate the operation of the distribution grid with distributed generation resources, distributed storage devices, and other load-shifting technologies. Precisely how this co-ordination will occur depends on how the distribution network is planned, priced, and made accessible to market participants. Reform of the current approach to distribution network planning, access and pricing is necessary to accomplish this.

One approach that fits within the existing distribution network operation paradigm would be to allow the distribution network operator to deploy monitoring devices throughout the network and use the information collected to improve the planning and operation of the distribution grid. The distribution operator could offer regulator-approved tariffs to owners of distributed generation resources, distributed storage devices, and load-shifting devices to compensate them for the network owner controlling these resources in order to limit the need for future distribution network upgrades. The distribution network operator could also propose investments in storage and other load-shifting technologies as way to avoid more

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<sup>8</sup>See <https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/generate-your-own-power> for more information on this rule.

expensive investments in distribution network upgrades.

A minimalist model for the distribution network operator could specify regulated distribution network services and allow third-parties access to these services at regulated prices that allow the distribution network operator the opportunity to recover its costs. For example, monitoring devices that can communicate with the distribution utility's back office could be installed in the distribution network as a regulated investment and all retailers could be granted to access to the resulting data collected at a regulated price. This approach would require a mechanism for coordinating the actions of different retailers take to control the distributed generation and storage units they have access to or own.

A distribution system operator (DSO) model, similar to the transmission system operator (TSO) for wholesale electricity market, could be employed as the mechanism for managing the distribution network operation. This would require setting prices for injections and withdrawals from the distribution network at different locations as way to co-ordinate operation of the various distribution network connected generation and storage resources. The advantage of this approach is that it would allow price signals and market forces to determine where distribution network resources exist and how they are operated. The disadvantage of this approach is that it would require a significant market infrastructure to be put in place, similar to what currently exists for wholesale electricity markets.

Setting hourly prices for energy delivered to different locations distribution network services would provide economic signals for distribution network planning similar to the role played by locational marginal prices (LMPs) in planning the transmission network. These prices could also be used to value the avoided cost of non-wires alternatives to distribution network upgrades to determine when these are lower cost solutions. Section 8.4 discusses this as an important topic for future research.

## 3.5 Potential for Pricing Distribution Network Services

In regions with the potential to develop rich solar resources, pricing the distribution network has the potential to create an entirely new paradigm for electricity retailing. Take the example of Hawaii, where quality of solar resources available to distributed solar generation units is not significantly different from that available to grid-scale resources.<sup>9</sup> The relative scarcity of large tracts of land for grid-scale solar resources on the most populated islands makes it difficult to realize the economies to scale in the construction of solar facilities that exist in the many parts of the continental United States.

Developing a mechanism for dynamic pricing of the distribution network access could significantly improve the efficiency of the deployment of distributed solar resources and storage facilities. These prices could provide the economic signals for where to local these resources and how to operate them. In order to make this approach work, customers will need to have interval meters to record their net injections and withdrawals from the distribution grid at a high level of temporal granularity.

<sup>9</sup>Hawaii is composed of islands with either limited opportunities to site large grid-scale solar facilities or limited need for a large scale solar facility.

## 3.6 Lowering Barriers to Adoption of New Technologies

In closing this section, it is important to emphasize the crucial role of interval metering and dynamic pricing in the least cost deployment of distributed generation, storage, and other load-shifting technologies. Even the economic value derived from investments in high-speed vehicle charging and electricity space heating can be enhanced by existence of interval meters and charging customers based on actual hourly consumption. Without the ability to charge customers for their actual net injections and withdrawals with a high degree of temporal and spatial granularity, it is impossible to realize the full range of economic benefits from investments in these technologies.

Distributed generation and storage technologies can provide both energy and operating reserves, but without information on the price of energy and operating reserves at the resource's location, it is not possible to measure the economic benefits provided by these technologies. Without these price signals, these investments must be financed primarily as rate-based regulatory assets or based on a fraction of the economic benefits they provide. For example, an investment in a combined distributed generation and storage facility may provide a customer with energy when grid-supplied energy is not available, which has some value to the customer. This value, combined with other state and federal government support mechanisms may be sufficient for the customer to invest in this technology. With an interval meter on the premises and the facility owner facing hourly prices for energy and operating reserves at that location, the facility owner could derive substantially more economic value from this investment. These economic benefits cannot be measured and valued unless the customer has an interval meter and faces prices for injections and withdrawals from the grid that are related to the real-time costs these actions impose on the grid.

A *forward-looking* regulatory policy that recognizes more temporally and spatially granular energy pricing can lead to more efficient utilization of the existing grid and reduce the cost of planning, constructing and operating the future distribution grid. This future requires the universal deployment of interval meters with standards for how they are installed, how they collect data, how they make it available to the customer and third-parties. These meters must be combined with the regulatory requirement that all retailers pay the actual cost of serving each customer—based on the customer's actual hourly consumption rather than an hourly load profiled version of their billing cycle consumption. These regulatory rules will reduce the barriers to investments in DERs, DERMSs, and load flexibility.

A *reactive* approach to the installation of interval meters and no standards for how they would be installed in terms of how interval data is collected and disseminated increases the likelihood that there will be more uneconomic DERs installed, which shifts the burden of recovering sunk costs of the transmission and distribution network to consumers that cannot install DERs. However, if there is unlikely to be significant investment DERs in region because of, for instance, limited solar resources, the downside of a *reactive* approach is likely to be small.

This reactive approach is also likely to lead to little storage investment without explicit subsidy support, and little dynamic pricing or other load flexibility programs adopted. The regulator will need to deal with these technologies on a case-by-case basis and it is very

likely that this approach will not lead to the most efficient utilization of the existing grid or the development of the most efficient grid in the future. The upside of this approach is that no investments will be made unless there is an actual need realized. The downside is that many investments in DERs, DERMSs, flexible demand will not be made because it is not possible to finance a business case for them for the feasible pricing plans given the available meters.

Because the *forward-looking* and *reactive* futures each have costs and benefits that depend on a number of initial conditions and policy goals in region, a one-size-fits-all future for retailing is unlikely to exist. Consequently, a major goal of the remainder of this report is to clarify which initial conditions and policy goals should drive the choice between these two futures.



## 4. Current State of Retail Markets

This section surveys the state of retail competition in the United States and globally. This section also surveys the current state of dynamic pricing policies in the United States and globally.

### 4.1 Retail Electricity Markets in the United States

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 implemented retail competition without formal wholesale markets. Twenty states and the District of Columbia have enacted legislation to either fully or partially restructure their retail electricity markets (US EIA, 2020c; Quilici et al., 2019). Figure 4.1 illustrates the current status of state retail restructuring. Other than Vermont, all of New England has enacted legislation to allow retail competition. Much of the remainder of the Eastern Seaboard has as well. All Eastern states with retail competition, except Georgia, exist within the PJM Interconnection, ISO New England or New York ISO wholesale markets.

The extent to which these states have restructured their retail markets varies widely. Georgia, for example, has one of the most restrictive retail competition programs in that only commercial or industrial customers with load of over 900 kW are allowed to choose their energy supplier.<sup>1</sup> All of the restructured states in New England introduced retail competition for all customers of investor-owned utilities (Quilici et al., 2019). This process had generally begun by the late 1990s. Texas, the only western state with full retail competition, restructured its wholesale and retail markets in 2002.

In Figure 4.2 through Figure 4.4, we compare trends for different types of electricity service. Full-service (bundled) utilities provide both energy and delivery services to end-use

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<sup>1</sup>See the 1973 Territorial Electric Service Act at <https://psc.ga.gov/utilities/electric/>.

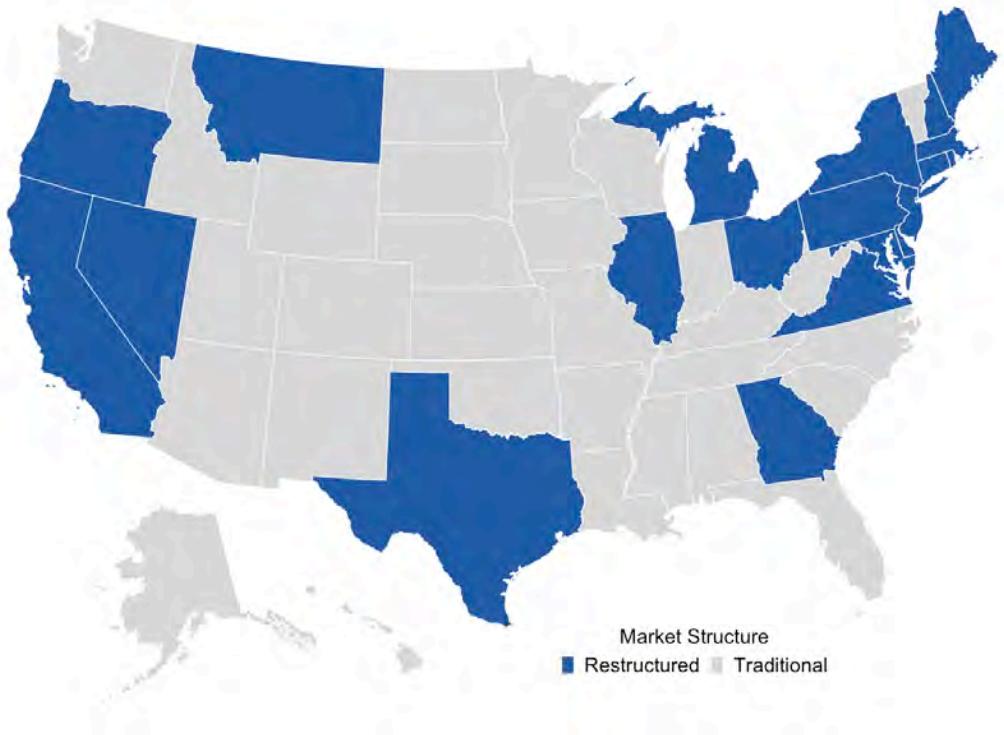


Figure 4.1: US Retail Electricity Market Structures in 2018

NOTES: This figure illustrates the adoption of restructured retail electricity markets in the US. The figure was produced using raw data from EIA's *Annual Electric Power Industry Report* (US EIA, 2020a) and based on information in (Quilici et al., 2019).

customers; these are the types of utilities operating in traditional retail electricity markets. Delivery-only service refers to electricity sold to customers by a utility that “provides only billing and related energy delivery services” and where “another company supplies the energy”. Likewise, energy-only service refers to electricity sold to customers by a utility that “provides only the energy consumed” and where “another electric utility provides delivery services, including, for example, billing, administrative support, and line maintenance” (US EIA, 2017). The final category presented in these figures is restructured retail service. This refers to the combined services provided by delivery-only and energy-only utilities. Hence, Average Retail Revenues (ARR) for restructured retail service are calculated by taking the sum of delivery-only ARR and energy-only ARR. We discuss the methodology used to produce these figures in more detail in the appendix section B.1.5.

Over the course of the last two decades, Average Retail Revenues (ARR)—calculated as the total revenue (\$) divided by the total energy sales (kWh)—of electric utilities have been rising. Using Average Retail Revenue allows us to infer the average price paid for retail electricity during the year while accounting for the fact that retail electricity prices can fluctuate within the year or with the amount a customer consumes in the case of nonlinear pricing. Figure 4.2 displays the national-level ARRs for traditional full-service utilities as

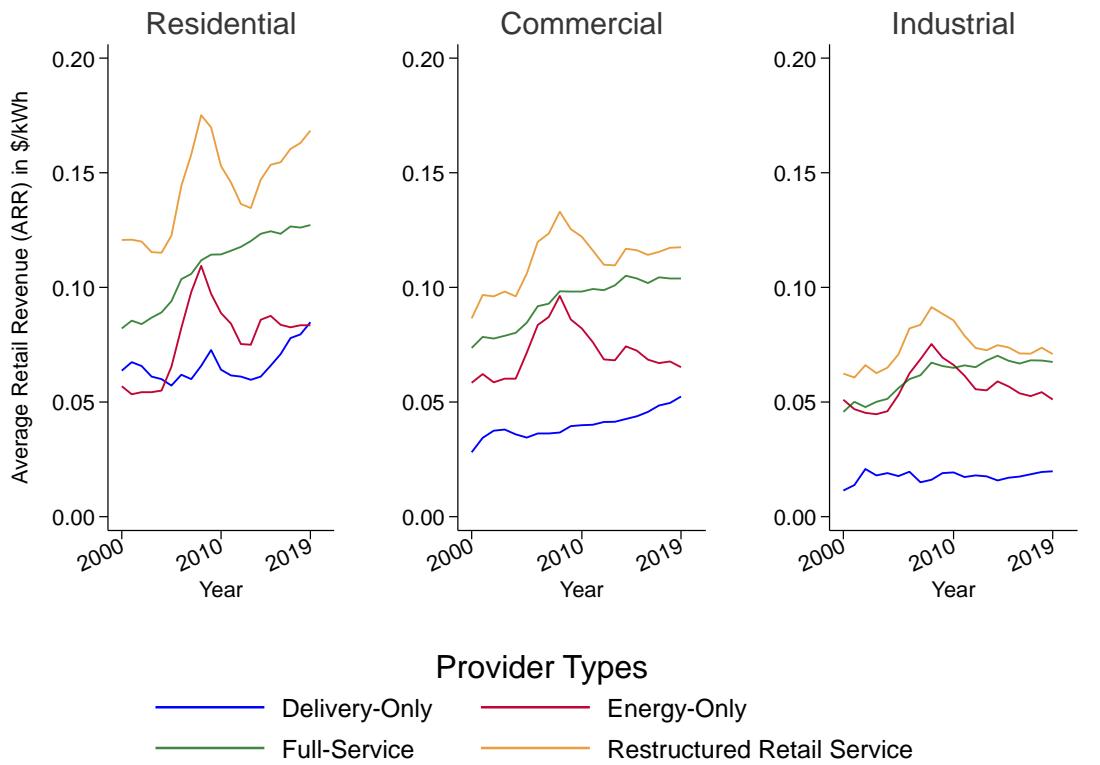


Figure 4.2: Average Retail Revenue (ARR) in the US from 2000 to 2019

NOTES: These figures display Average Retail Revenues for electricity providers in the US across the residential, commercial, and industrial customer sectors. The figures were produced using data from (US EIA, 2020c). The Restructured Retail Service ARR is the sum of delivery-only and energy-only ARRs.

well as those operating in restructured retail markets.<sup>2</sup> In both Figure 4.2 and Figure 4.3, the trend line for restructured retail service ARRs is the sum of delivery-only and energy-only ARRs. Prices have grown across all service types but the the gap between full-service ARRs and restructured-service ARRs has seen the most fluctuation during the last two decades. Overall, the gap has widened in the residential and commercial sectors and narrowed in the industrial sector. This gap peaked in 2008 across each of the three end-use customer sectors—largely due to enormous spikes in energy-only service ARRs that we observe during the years leading up to the Great Recession. Another trend of note is the climbing ARR for residential delivery-only service which surpassed energy-only in 2019 for the first time since 2005.

Additionally, Figure 4.2, shows that industrial ARRs have historically been much less spread out than those in the residential and commercial sector. Interestingly, though, there

<sup>2</sup>While Texas has a restructured retail market, utilities report revenues and sales as bundled providers. Hence, their revenues and sales are incorporated into the full-service ARR trend rather than the restructured retail service ARR trend which is the sum of delivery-only and energy-only service ARRs.

was a period from 2006 to 2010 where energy-only ARRs were actually higher than full-service ARRs.

Figure 4.3 presents the same residential and commercial ARR data displayed in Figure 4.2 in addition to the overall price trends for the levelized cost of energy (LCOE) for distributed and utility-scale solar. By 2017, the LCOE for residential distributed solar was about even with the ARR for restructured retail energy service. For commercial distributed installations, the LCOE had fallen below the ARR for restructured retail energy service, but was still slightly higher than the ARR for full-service energy providers. The LCOEs displayed in Figure 4.3 are for areas with an average climate and no Investment Tax Credit (ITC) or state/local incentives (US DOE, 2017). The US Dept. of Energy's goal for 2020 is to reach LCOEs for residential and commercial distribution network-connected solar of \$0.10/kWh and \$0.08/kWh, respectively. Utility-scale transmission network-connected solar had already reached the Dept. of Energy's 2020 goal of \$0.06/kWh in 2017.

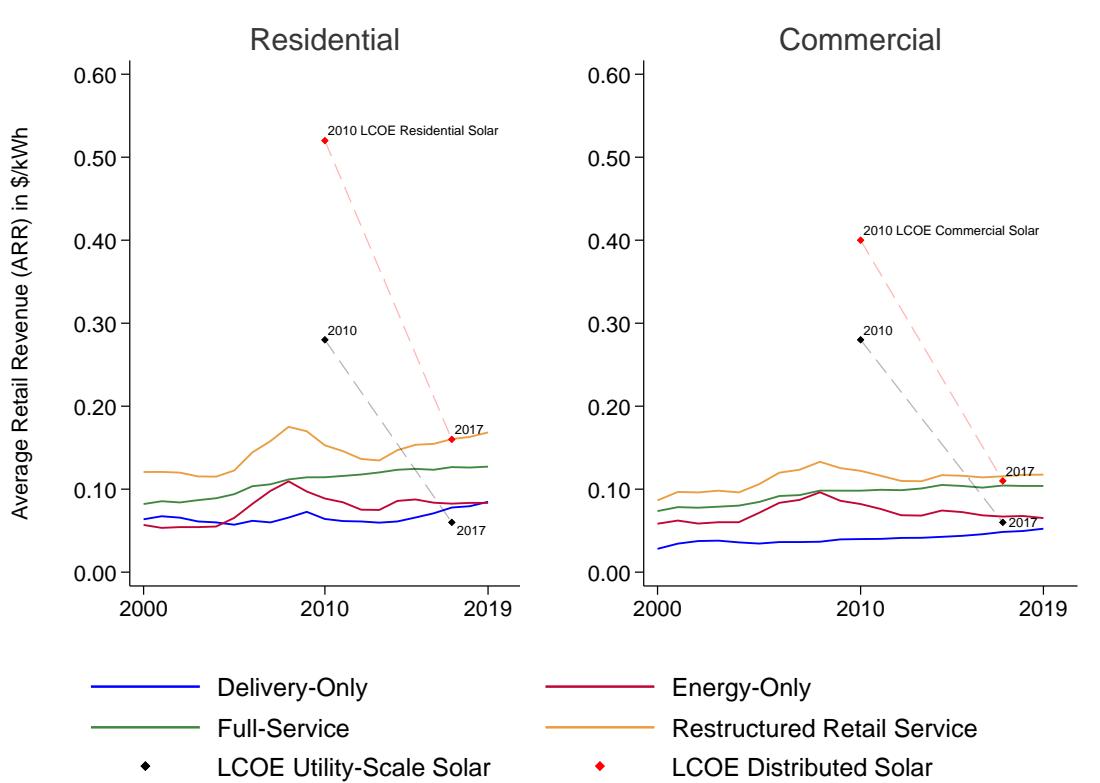


Figure 4.3: Residential Retail Electricity and LCOEs of Solar

NOTES: These figures displays Average Retail Revenues for electricity providers in the US across the residential and commercial customer sectors. The figures were produced using data from (US EIA, 2020c). The Restructured Retail Service price is the sum of delivery- and energy-only service prices. LCOEs of solar are from US DOE (2017) and are for areas with average climate and no Investment Tax Credit or state/local incentives.

Figures 4.4 and 4.5 illustrate the state-level variation in average retail revenues for different types of electric utilities in 2019. Panel (a) of Figure 4.4 illustrates the differences

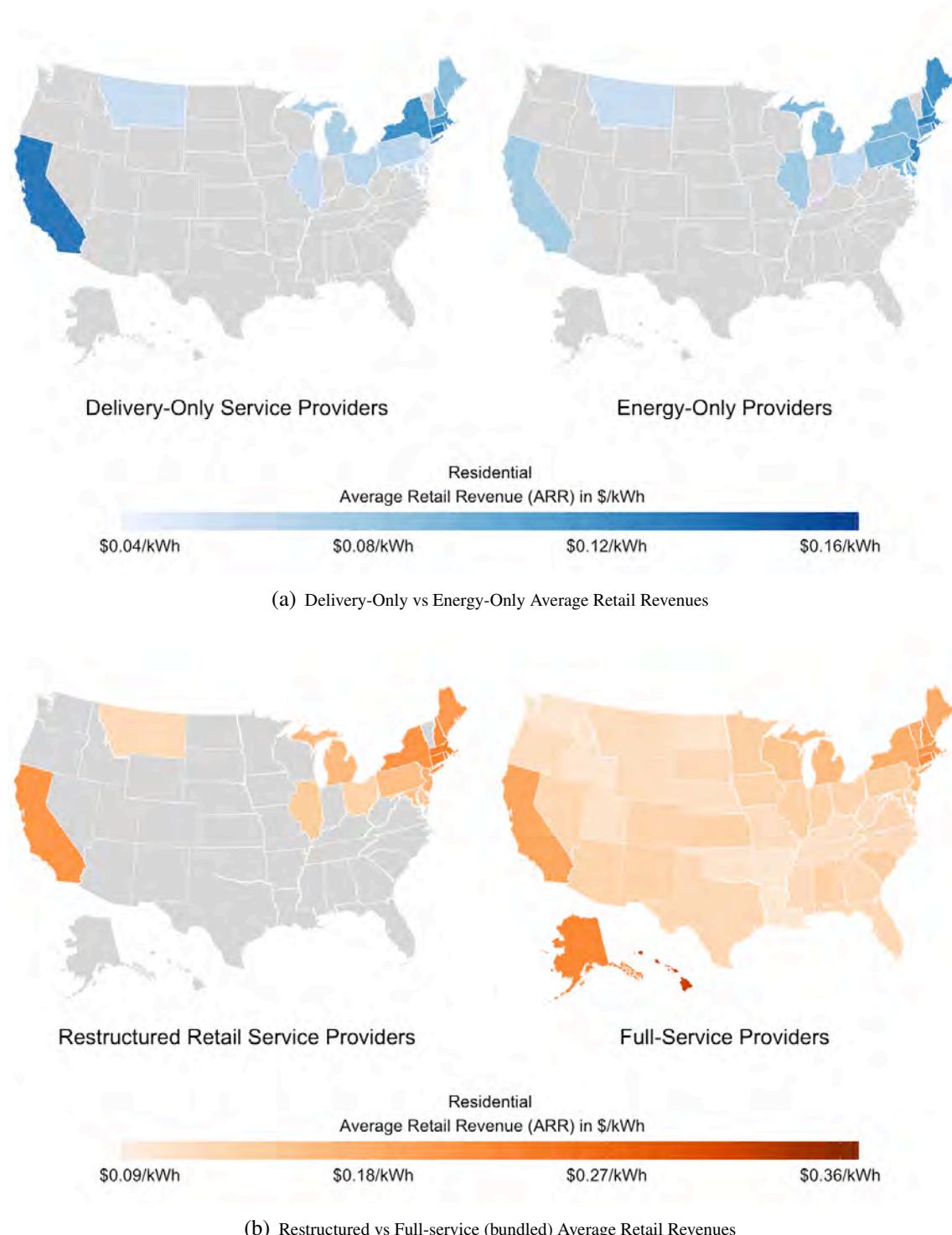


Figure 4.4: 2019 Residential Average Retail Revenues in the US

NOTES: These maps display the Average Retail Revenue (ARR) in each state. Prices are displayed by provider type. The restructured retail service price is the sum of delivery- and energy-only service prices. The figures were produced using data from (US EIA, 2020c). Oregon, Nevada, and Virginia have partially restructured retail markets but do not have residential customers participating. Only commercial and industrial customers participate in these states.

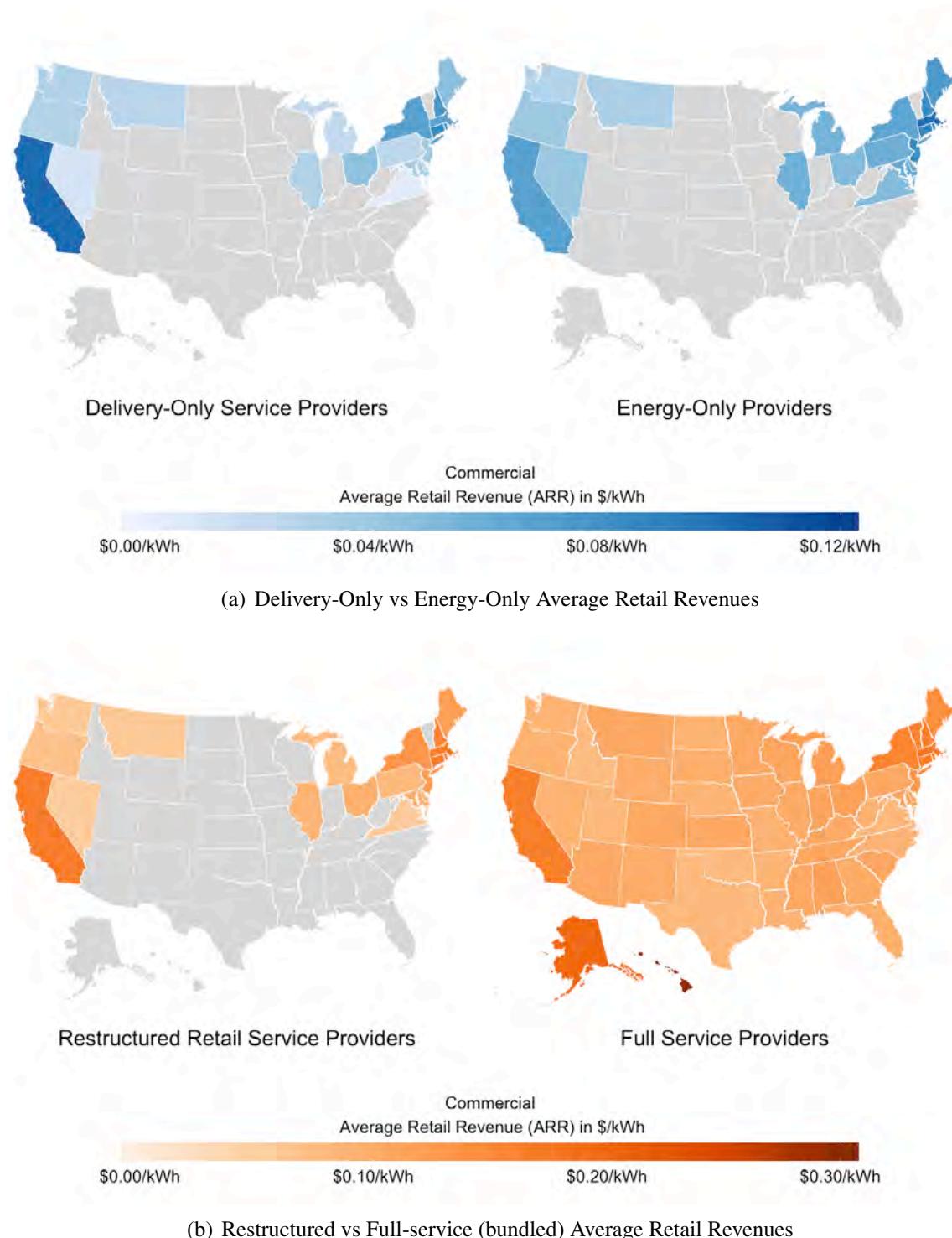


Figure 4.5: 2019 Commercial Average Retail Revenues in the US

NOTES: These maps display the Average Retail Revenue (ARR) in each state. Prices are displayed by provider type. The restructured retail service price is the sum of delivery- and energy-only service prices. The figures were produced using data from (US EIA, 2020c). While Washington does not have a formal restructured market, the state does have a small amount of retail competition for commercial and industrial customers.

between delivery charges and energy charges in the states where residential customers are allowed to participate in retail competition. Of the 16 states with this type of competition, only California, Connecticut, New York, and Ohio have higher average retail revenues for delivery service than energy service. At the national level, the residential ARR for delivery service is about \$0.001/kWh more than for energy service. As is evident from the figure, California's delivery charges are, on average, \$0.06/kWh greater than the state's energy charges. This is due in large part to cost of the California's many regulatory mandates for energy efficiency, renewables, and storage investments. Panel (b) of Figure 4.4 provides the residential ARR variation for full-service utilities around the country as well as the sum of delivery and energy ARRs. Across all states participating in residential retail competition, the ARR for restructured service (i.e., the sum of delivery and energy ARRs) is higher than for full-service. Note, however, that while Texas features full retail competition, the state reports sales and revenues from retail providers at the bundled level and EIA reports these ARRs as full-service providers. Additionally, while Oregon, Nevada, and Virginia have restructured markets, residential customers are not able to participate.

The commercial sector has more participation in retail competition with Oregon, Nevada, and Virginia allowing these customers to buy from delivery-only and energy-only providers. Even Washington, which does not have a restructured market, has a small amount of retail competition for commercial and industrial consumers. In Panel (a) of Figure 4.5, we observe that California and New York were the only state where delivery ARR was higher than energy ARR for commercial customers in 2019. Additionally, while states with residential retail competition experienced lower full-service ARRs than restructured ARRs (i.e., delivery plus energy), the commercial sector experienced almost the exact opposite outcome. Indeed, Connecticut and California were the only restructured states where the full-service ARR was less than the restructured ARR for the commercial sector in 2019.

The state-level maps for the industrial sector are provided in Figure A.3 in the appendix. For the most part, states with industrial customers participating in retail competition experienced similar trends to those with commercial competition. California was the only state where delivery charges were higher than energy charges. In the majority of restructured states, full-service ARRs were higher than restructured ARRs with exceptions in New York, New Jersey, New Hampshire, Massachusetts and Connecticut. Additionally, the District of Columbia had no full-service industrial energy sales in 2019. All industrial sales in D.C. were through restructured utilities.

## 4.2 Retail Electricity Markets Outside of the US

Outside of the United States, numerous other countries and regions have adopted varying degrees of retail competition in their electricity sectors. While legislation is in place to allow competitive electricity retailing in many of these countries, not all have seen much active market participation. Figure 4.6 illustrates the different natures of these policies. Countries shown in green have delegated retail competition rules to their states or provinces. Countries shown in blue have passed legislation allowing for retail competition. Countries shown in pink are rolling out competition in multiple phases and are still transitioning to a free market.

In these countries, customers meeting certain demand thresholds might have the ability to choose their suppliers while other customers do not (e.g. Switzerland).

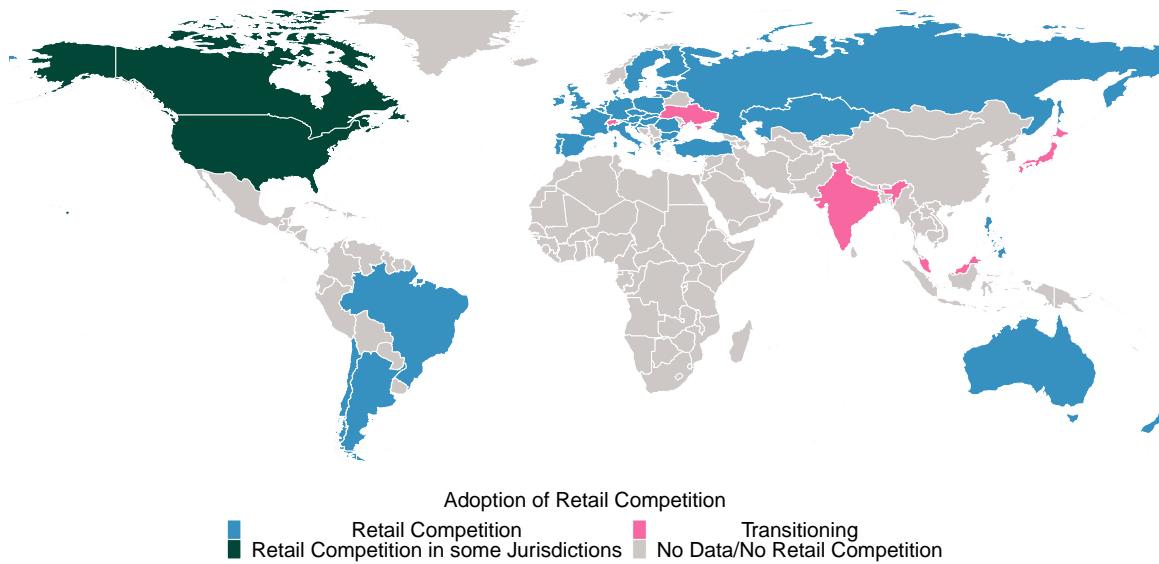


Figure 4.6: Status of Electricity Market Deregulation in Select Countries

NOTES: This figure is based on information from a variety of sources. These sources are cited throughout Section 4.2.

In Canada, each province controls its own electricity market structure. Alberta was the first—and remains the only—province to introduce retail competition (Christian and Shipley, 2019). The deregulation process began with the passing of the Electric Utilities Act in 1995 and the province has an hourly wholesale market and competitive retail market. Alberta has traditional cost-of-service regulation in its distribution and transmission sectors. Currently, there are dozens of competitive generating utilities and consumers have the option to purchase their energy from retailers regulated by the Alberta Utilities Commission, or from a competitive retailer (Christian and Shipley, 2019).

European countries have been introducing retail competition for several decades. In Great Britain, retail competition was rolled out in several phases between 1990 and 1999, beginning with large consumers getting the option to choose their suppliers (PwC, 2013). In 1994, mid-size consumers given this option as well. Finally, small consumers were given the option to choose their retailers by the beginning of the millennium (PwC, 2013). Over the next two decades, the European Union released a number of directives promoting retail competition. The most recent Electricity Directive, Directive (EU) 2019/944, includes rules stipulating that “Member States shall ensure that all customers are free to purchase electricity from the supplier of their choice” and that “suppliers shall be free to determine the price at which they supply electricity to customers”.<sup>3</sup> Poudineh (2019) notes that while Great Britain and Germany have full retail competition, countries like France, Italy, and

<sup>3</sup>See Directive 2019/944 at <https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019L0944&from=en>.

the Netherlands still have some level of regulation in place and limited participation in the competitive market. Outside of the EU, Switzerland has also begun liberalising its electricity market. In 2009, consumers with demand of 100 MWh were given the opportunity to choose their provider. Full liberalisation had not occurred by 2018 but is anticipated and is necessary in order to meet future goals of integrating Switzerland's electricity market with that of the EU (Scholl, 2018).

Some Eurasian countries have adopted retail competition in their electricity markets as well. According to research from the Oxford Institute for Energy Studies, Russia, Ukraine, Kazakhstan, and Turkey have all adopted legislation allowing for retail competition (Poudineh, 2019). Russia began the process of introducing retail competition in 2003 and as of 2019, about 80% of electricity was being traded at competitive market prices. Still, analysis from Thomson Reuters indicates that the country may moving towards a re-consolidation of its energy assets (Josefson and Rotar, 2019). Turkey went through the formal process of unbundling distribution and retail sale in 2013 (Tunç et al., 2019). Ukraine aims to reach a similar level of liberalization to that seen in the EU. Formal restructuring was scheduled to begin in 2019 and the country is still in the transitional stages of introducing retail competition. This transition has been driven in part by the impending integration of Ukraine's grid with the European Network of Transmission System Operators (Prokip, 2019).

In Asia and the Pacific region, several countries have switched to competitive retail markets. Singapore began the process of deregulation with the introduction of the Open Electricity Market (OEM) initiative (Wong et al., 2019). The complete roll-out of this competitive market was complete by May of 2019. Customers have the option to remain on a regulated tariff available from Singapore Power or to purchase from a retailer with a plan that better meets their needs. Singapore Power continues to operate the country's grid and provide delivery service. As of March 2020, 46% of households had chosen to buy electricity from a competitive retailer.<sup>4</sup> Malaysia is in the process of introducing retail competition under the Malaysia Electricity Supply Industry (MESI) 2.0 reforms. These reforms aim to adopt retail competition by 2029 with initial pilot programs beginning in 2021.<sup>5</sup> Japan has liberalised its electricity market in several stages. The second stage, occurring in 2016, introduced competition for low-voltage customers. It was anticipated that the third phase of the market reform would come into effect in 2020. Under this new system, the ten major utilities in Japan will be required to separate their power generation and retail functions from their transmission and distribution functions (Kobayashi and Okatani, 2019). Vietnam is in the early stages of introducing retail competition. Initial phases included the creation of a competitive generation market and competitive wholesale market. Initial pilots for the wholesale market were run in 2016. The Vietnamese government's goal is to develop a competitive retail market between 2021 and 2023 (Nguyen and Trinh, 2019). The Philippines introduced retail competition through its Retail Competition and Open Access

<sup>4</sup>See <https://www.openelectricitymarket.sg/about/open-electricity-market/statistics>.

<sup>5</sup>See [https://www.mestec.gov.my/web/wp-content/uploads/2019/11/MESI\\_2.0\\_IGEM19-web.pdf](https://www.mestec.gov.my/web/wp-content/uploads/2019/11/MESI_2.0_IGEM19-web.pdf).

program after the Electric Power Industry Reform Act of 2001 (PwC, 2013).

India's electricity sector has experienced numerous reforms over the last two decades. While a primary goal in the country is still to provide reliable electricity service to the millions of customers without access, there have also been reforms aimed at increasing competition (Dibyanshu et al., 2019). The Electricity Act of 2003 was the first major step towards a competitive retail market. Like many other countries, an initial roll-out provided competition for large consumers meeting a certain load threshold (PwC, 2013). Most recent electricity market regulation in India has focused on transitioning to renewables and expanding energy access, rather than increasing access to competitive retailing (Dibyanshu et al., 2019). Retail competition is still not accessible to most customers in the country.

In Australia, Victoria was one of the first states to introduce full retail competition to its electricity market. Between 1994 and 2002, customers were granted retail choice—beginning with large industrial customers and ending with small customers. New South Wales had full retail competition by 2002 as well, followed by South Australia and the Australian Capital Territory in 2003, Queensland in 2007, and Tasmania in 2014 (AEMC, 2019). Even while retail choice was allowed in these markets, prices were often regulated for several years after introduction. Victoria gained deregulated prices in 2009, followed by South Australia in 2013, New South Wales in 2014, and South East Queensland in 2016. Regional Queensland and Tasmania have not experienced price deregulation (AEMC, 2019). In July of 2019, price regulation was reintroduced into markets in Victoria, Southeast Queensland, and New South Wales. This price regulation will require that retailers not set standing offer prices for certain small consumers in excess of the Australian Energy Regulator's determined annual price. This price is supposed to serve as a cap on retailer offers and as a reference price for flat rates and TOU rates (AEMC, 2019).

New Zealand has a fully competitive retail market as well. In 2019, 20% of customers switched their electricity supplier and 55% had switched their supplier sometime in the previous five years.<sup>6</sup> Customers had the option to choose from 15 to 37 suppliers in 2019, depending upon their location. This is a large increase over the amount of choice they had in 2011 (the first year data were tracked) when customers had between 5 and 16 options for suppliers.

Some degree of retail competition has been introduced in most major Latin American countries (Poudineh, 2019). Argentina has the longest history of retail competition in Latin America with initial reforms taking place during the 1990s. Currently, customers with load of 30 kW or more are free to choose their supplier (PwC, 2013). Brazil has both competitive and regulated retail markets. Consumers are free to choose their supplier if they have a minimum demand of 500 kW. This restricts the market to mainly larger consumers (Schmidt and Ribeiro, 2019). Chile has a similar policy allowing consumers with installed load of 500 kW to freely participate in the market if they agree to remain in the market for at least four years. Otherwise, customers must have installed load of 5 MW to participate (Jiménez, 2020).

<sup>6</sup>See the NZ Electric Authority's Retail Market Snapshot for the most recent trends: <https://www.ea.govt.nz/monitoring/interactive-dashboards/#annual-retail-market->.

## 4.3 Dynamic Pricing of Retail Electricity

This section first discusses the essential technology and regulatory framework necessary to implement dynamic retail pricing. We then distinguish between dynamic pricing and time-of-use (TOU) pricing and describe why dynamic pricing has superior market efficiency properties relative to TOU pricing. Finally, we survey the range of dynamic pricing programs that currently exist.

### 4.3.1 Necessary Technological and Regulatory Framework for Dynamic Pricing

The widespread deployment of interval meters allows the regulator to require that customers are billed based on their actual hourly consumption rather than a fixed hourly load profile of their monthly consumption. This requirement has important implications for the retailer and the customer. First, by requiring the retailer to pay the actual cost of serving this customer, the retailer now must recover the actual cost of service from the retail price it charges the customer. If the consumer reduces his demand during an hour when energy is expensive, the retailer saves on wholesale energy costs for this customer and potentially other customers and can pass on some of these savings to the consumer.

However, as noted in Section 2.1, if a customer is charged for wholesale energy based on a fixed hourly load profile of its monthly consumption, there is little incentive for the retailer to pass on hourly wholesale prices to that customer. Higher hourly prices for energy will only cause the customer to reduce consumption during hours of the month when it is easiest to reduce consumption, rather than when the wholesale price is highest or when the retailer obtains the greatest financial benefit from customer's demand response. This outcome occurs because, as shown in Section 2.1, billing on the basis of a fixed hourly load profile applied to the customer's monthly consumption means that a 1 kWh reduction in demand reduces the customer's bill by the same amount regardless of when in the billing cycle the consumption reduction occurs.

This logic emphasizes that customers with interval meters must be charged for electricity based on their actual hourly consumption, rather than according to a fixed hourly load profile applied to their monthly consumption. This logic also illustrates why *widespread deployment* of interval metering is more likely to allow this outcome to occur. The retailer is more likely to justify spending the money to develop the back office software to allow it to bill based on the customer's actual hourly consumption if more customers have interval meters. The fixed cost of this back office investment can be averaged over more customers if more of them have interval meters.

Consequently, if the default price that consumers face for their consumption is the cost of their actual consumption for every hour in the billing cycle, this will create the necessary conditions for those customers that are willing to manage hourly wholesale price risk to do so and those with no appetite to do so to pay a risk premium over the annual average wholesale price for insurance against short-term price volatility.

As we demonstrate in Section 7.2, a default retail price that sets a fixed price or fixed-nonlinear price schedule for an unlimited amount of energy based on the expected annual cost of wholesale energy, as is the case in many markets around world, virtually guarantees

that no customer will find it in their financial interest to manage hourly wholesale price risk. Consequently, it is no surprise that regulators and retailers in many of these markets have struggled to find tariffs that cause customers to choose to manage hourly price risk.

#### 4.3.2 Dynamic Pricing versus Time-of-Use Pricing

There is significant confusion in the regulatory community and industry between the economic efficiency benefits of dynamic pricing versus time-of-use (TOU) pricing. Put simply, TOU is typically only one fixed price better than a single fixed price of electricity, whereas dynamic pricing has the potential to be 8,760 times as efficient as a single price. Dynamic pricing can set the efficient price of energy for all 8,760 hours of the year, whereas TOU pricing typically sets two different prices for the entire year that vary depending on the time of day. Consequently, the economic efficiency properties of TOU prices are much closer to a single fixed price for the year than dynamic pricing.

In general, dynamic pricing is when the price a customer faces varies with the hourly wholesale price. In this case, a customer with an interval meter has an incentive to reduce their consumption when this reduction benefits both it and the retailer most. In contrast, TOU pricing sets different prices for consumption depending on the time of day, regardless of the hourly wholesale price. The typical TOU price charges the customer a higher price during certain hours of the day and a lower price during the remaining hours of the day, regardless of the value of the hourly wholesale price. Consequently, the TOU price provides an incentive for the customer to shift consumption away from the higher priced hours of the day even if the wholesale price is lowest during these hours of the day.

TOU pricing does not require the customer have an interval meter, only a mechanical meter with two registers—one to measure consumption during the higher priced hours of the day during the billing cycle and the other to measure consumption during all of the other hours of the day during the billing cycle. The fact that the TOU price does not require that a customer have an interval meter should make it clear that the same incentives for when demand responses occur for single fixed price are relevant for TOU prices. Similar to a single fixed retail price, raising TOU prices provides an incentive for the consumer to reduce consumption during high-price periods on days when it is easiest for the consumer to reduce their demand, rather than the days when wholesale prices are highest or this reduction provides the greatest system-wide benefits.

TOU pricing does very little to address the fundamental reliability and economic challenges facing the electricity retailing sector, which is providing economic incentives for active demand-side participation to maintain the real-time supply/demand balance in regions with an increasing amount of grid scale and distributed wind and solar generation. In fact, TOU pricing could even exacerbate some of these challenges. For example, a customer with a distributed storage system facing a TOU price with a price differential greater than the round-trip efficiency of the storage device could create a virtual money pump by filling their storage unit during low-priced periods and consuming from it during the high-price periods, regardless of the hourly marginal cost of grid-supplied electricity. Such a TOU price could finance storage investments, but if average hourly wholesale prices throughout the day are relatively constant, this storage investment is simply a regulatory arbitrage investment that

provides little system reliability benefits or wholesale energy cost reductions.

Flexible demand is a customer characteristic that is particularly valuable to system operators in an intermittent renewable future. A single price tariff or a TOU tariff does not reward this customer characteristic. Only a price that varies with hourly system conditions can reward this characteristic by charging a high price when the system operator needs demand to reduce and by charging a low price when the system operator would like to demand to increase. The former typically occurs when there is little intermittent renewable energy production and the latter typically occurs when intermittent renewable energy production is close to system demand. Both of these circumstances can arise in regions with significant intermittent renewable generation capacity, sometimes even within the same day or week.

Between 2015 and 2019, the percentage of US customers enrolled in advanced tariffs (including TOU) increased from 5.1% to 7.1% (US EIA, 2020a). The EU has also seen increased availability of advanced and dynamic pricing programs. In 2018, 16 of the 28 Member States offered TOU pricing—up from 13 in 2017—and eight offered real-time arrangements. Additionally, while only France offered critical peak pricing in 2017, Denmark and Latvia joined in 2018 (ACER and CEER, 2018, 2019).

### 4.3.3 Survey of Existing Dynamic Pricing Plans

This section surveys the range of dynamic pricing plans that have been experimented with or actually implemented by an electricity retailer. These include real-time pricing (RTP), variable peak pricing (VPP), critical peak pricing (CPP), and critical peak rebate (CPR) plans. The key differences between these arrangements are highlighted in Table 4.1 and Figure 4.7.

For reference, Panel (a) of Figure 4.7 illustrates a traditional, hour-by-hour electricity consumption schedule. In this example, generation costs are lowest at night when people are asleep and are not running appliances or using electric lighting. Wholesale prices generally begin to increase around 7 a.m. when people wake up and prepare to go to work or school. Generation costs generally peak between 5 and 9 p.m., during which time people are at home cooking, running appliances, and making use of electric lighting. Generation costs can also increase during this time because some intermittent renewable units—primarily solar PV—are no longer producing electricity. Consequently, in the absence of a significant energy storage infrastructure, other sources must produce electricity.

Panel (b) provides an example of an RTP arrangement in which the tariff reflects the hourly generation costs and wholesale market prices as they fluctuate throughout the day. Prices are generally relayed to the customer on a day-ahead or hour-ahead basis in order to allow the customer a chance to react to the signal and change their consumption. Panel (c) illustrates a simple example of a VPP plan in which off-peak periods are static but the on-peak price can change to reflect the wholesale market price. The daily peak is generally announced on the day before the VPP price is in effect. Panels (d) and (e) illustrate CPP and CPR arrangements, respectively. A “critical peak” event is generally declared on a day where high wholesale prices or distribution system contingencies induce the utility to greatly increase retail prices. Utilities are typically constrained to declaring these events a limited number of times per year. In the CPP scenario, the retail price increases dramatically,

encouraging customers to cut back on their consumption or face a heavy penalty. In the CPR scenario, customers are instead presented with an opportunity cost: continue consuming at the usual electricity rate or cut back below some consumption threshold and receive a rebate. In Section 5.3, we provide examples of these programs in practice in US and abroad.

Wolak (2010) compares the performance of real-time hourly pricing, CPP, and CPR pricing plans in an field experiment on randomly selected sample households in Washington, DC. Using a difference-in-difference estimation framework, Wolak (2010) finds that customers on all of the dynamic pricing plans substantially reduce their electricity consumption during periods with high retail prices. The hourly average treatment effects associated with each of these dynamic pricing plans are larger in absolute value for households with all-electric heating and households with smart thermostats. Low-income households have significantly larger hourly average treatment effects than higher income households on the same dynamic-pricing tariff. The results of these experiments are also used to investigate two hypotheses about differences in the customer-level demand response to the three dynamic pricing tariffs. First, for the same marginal price during a critical peak period, CPP yields a larger hourly average demand reduction than CPR pricing. Second, the demand reduction associated with higher hourly prices is very similar to the predicted demand reduction associated with the same price increase under CPP. This outcomes occurs because periods with hourly high prices during the day tend cluster during the period of the day when a CPP event could be called.

An additional shortcoming of the CPR programs was initially identified in Wolak (2007), a field experiment with residential customers of the City of Anaheim Public Utilities (APU). Although this experiment found that customers used an average of 12 percent less electricity during the peak hours of the day on critical peak days than customers in the control group, this experiment also found evidence that customers increased their consumption during peak periods of non-critical peak days in order to set a higher baseline relative to which their rebate would be determined. This result points out a problem with all rebate based dynamic pricing programs: how to set the customer's baseline level of consumption for a given critical peak period event. If, as was the case for the APU experiment, it is set based on the average of peak period consumption in days leading up to the critical peak period event, customers have an incentive to increase their consumption in order to receive a higher rebate. Bushnell et al. (2009) discusses the perverse market efficiency consequences of rebate based approaches to dynamic pricing and demand response programs.

The opportunities for dynamic pricing have grown rapidly as smart meters have been deployed around the globe. The majority of customers in the US, China, New Zealand, and a number of European countries are now equipped with these devices and can therefore be enrolled in dynamic pricing if their utility offers. Still, while the infrastructure is ready and waiting, only about 20% of US utilities were offering any sort of advanced tariff (including TOU) in 2019 and only about 5.6% were offering dynamic pricing (e.g. real-time, VPP, CPP, or CPR) (US EIA, 2020a).

It is important to emphasize, that a major reason for the limited adoption of dynamic pricing plans is because customers have very attractive fixed-price default pricing options available to them. As we discuss in Section 7.2, these default fixed retail prices significantly

reduce any financial benefit a customer might receive from switching to a dynamic pricing plan.

Table 4.1: Retail Tariff Arrangements

Program	Characteristics
Real-time Pricing	<ul style="list-style-type: none"> <li>• Dynamic</li> <li>• Retail price fluctuates hourly or more often</li> <li>• Reflects changes in wholesale price on day-ahead or hour-ahead basis</li> </ul>
Variable Peak Pricing	<ul style="list-style-type: none"> <li>• Dynamic</li> <li>• Prices set on daily basis</li> <li>• Varying on-peak and constant or TOU off-peak rates</li> <li>• On-peak price becomes available the previous day</li> </ul>
Critical Peak Pricing	<ul style="list-style-type: none"> <li>• Dynamic</li> <li>• Pre-specified high rate for limited number of days or hours</li> <li>• Very high “critical peak” prices during certain hours</li> <li>• Critical peak prices can often be 3-10 times greater than standard prices</li> <li>• Event days are often limited to 10-15 per year</li> </ul>
Critical Peak Rebate	<ul style="list-style-type: none"> <li>• Dynamic</li> <li>• Encourages reduced consumption when wholesale market prices are high</li> <li>• Provides rebate to customers who reduce consumption at provider’s request</li> <li>• Event days are often limited to 10-15 per year</li> </ul>

**Notes:** These definitions are based on US EIA (2017) and IRENA (2015).

Failure to adopt dynamic pricing programs has been cited by regulators and policymakers as a major foregone benefit of large-scale smart meter roll-outs. When regulatory cost-benefit analyses for interval meter deployments are conducted, some level of dynamic pricing adoption is often included as a potential benefit of roll-out (VAGO, 2015; Tractabel, 2019). However, many of these regions that included benefits from some level of adoption of dynamic pricing plans, also have default fixed prices for residential consumers that effectively eliminate any incentive for these customers to switch to a dynamic pricing plan.

In 2009, Victoria, Australia became one of the first regions in the world to enact a large-scale, mandatory smart meter deployment. The program was expected to generate a net benefit of up to AU\$775 million. Although a Deloitte report commissioned by the Victorian Government in 2011 estimated a net cost of AU\$309 million, Victoria continued the roll-out.

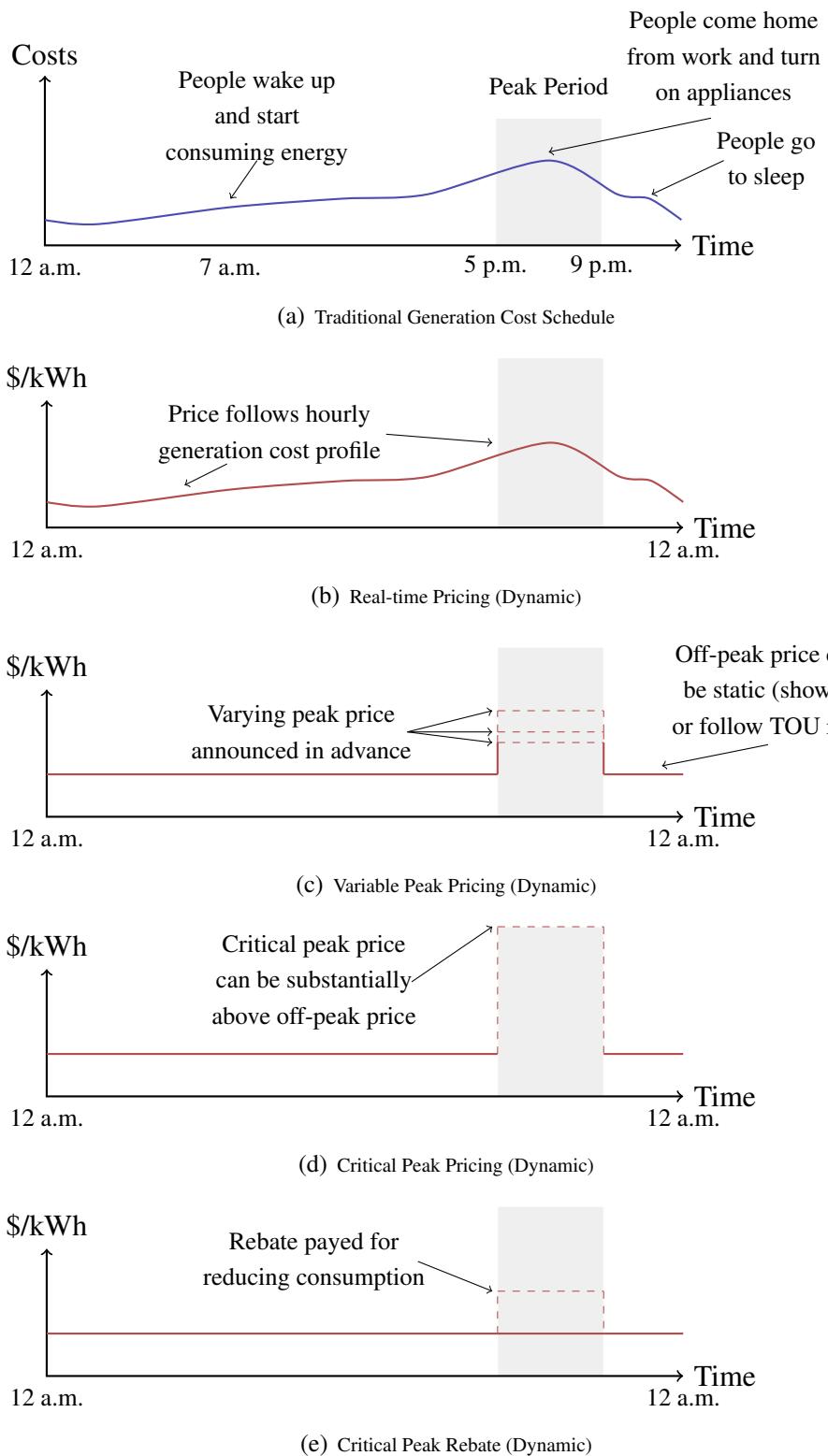


Figure 4.7: Retail Pricing Arrangements

NOTES: Diagrams based on information in US EIA (2017), and diagrams in EDF (2015) and IRENA (2015).

In 2015, once the roll-out was over 98% complete, the Victoria Auditor-General's Office (VAGO) released a report censuring the program, attributing the net costs in large part to the lack of adoption of dynamic pricing. Expected benefits from smart meters in the 2011 CBA were based on the assumption that 4% of consumers would be enrolled in a flexible tariff program by 2014. By 2015, however, only 0.27% had been enrolled (VAGO, 2015). Moreover, according to VAGO, two-thirds of consumers were “unaware of the link between their smart meter and saving money on their electricity bills.”



## 5. Current State of Deployment

This section surveys the extent of deployment of the major technologies impacting the retail electricity sector. Interval metering is the crucial enabling technology surveyed. Distributed solar is the major disruptive technology to the existing electricity retailing business model. Dynamic pricing is enabled by the deployment of interval metering, so we survey the current penetration of dynamic pricing plans, as well as other approaches to active demand-side participation in the wholesale market. Finally, we survey the current state of regulatory rules that allow third-party access to the distribution network.

### 5.1 Extent of Deployment of Interval Meters

*Interval, smart, or advanced* electricity meters are the essential first step necessary for active demand-side participation in the wholesale market for customers without loads that are controllable by the transmission or distribution network operator. Interval meters provide highly granular consumption data to both consumers and utilities—in many cases reporting usage statistics as often as every 15 minutes. In 2017, global investments in interval metering technology reached close to \$20 billion (a 300% increase over 2010) (IEA, 2019e).

In this section, we outline the progress and scale of advanced meter adoption in the US, Europe, Oceania and Asia, and Latin America. We use the terms *interval, smart, advanced*, and *Advanced Metering Infrastructure (AMI)* interchangeably throughout. While these types of meters are always required to have two-way communication capabilities, other specifications can differ across jurisdictions and many meters have even more advanced functionalities. We delve into those differences in our survey of grid modernization technologies in Section 6.1.

### 5.1.1 Deployment in the United States

As smart meters have gained popularity in the US, other metering technologies have declined in use. Figure 5.1 displays the historical adoption of advanced AMI, automated meter reading (AMR), and standard electricity meters from 2008 to 2019. While both AMI and AMR meters offer benefits over standard devices, AMR meters are limited to “one-way” communication (i.e., they only report usage statistics to the utility) (US EIA, 2015). AMI meters, on the other hand, measure consumption at least once an hour and transmit the data to both consumers and utilities each day (US EIA, 2019a). This feature is generally referred to as “two-way” communication or interoperability. AMR meter installations (red line) peaked in 2010 before slowly declining for most of the subsequent decade. The number of AMI meters (blue line) first surpassed AMR in 2013 at which point there were roughly 53.3 million AMI meters nationwide (38.7% of the market) (US EIA, 2020a). By the end of 2017, AMI meter installations exceeded the combined total of standard and AMR meters (purple line).

By the end of 2019, over 94.5 million AMI meters had been installed in the US. Nationwide, the market penetration rate of AMI meters reached 60.7%—up from 56.5% in 2018. Still, while AMI meters now make up more than half of all metering installations in the US, 26 states remain below 50% market penetration and twelve remain below 25% (US EIA, 2020a). Moreover, only about 50% of electricity sold in 2019 was metered with AMI meters. Figure 5.2 provides the individual market penetration rates for each state in 2019.<sup>1</sup> The District of Columbia has maintained the highest market penetration rates—over 99%—for the last four years of available data.

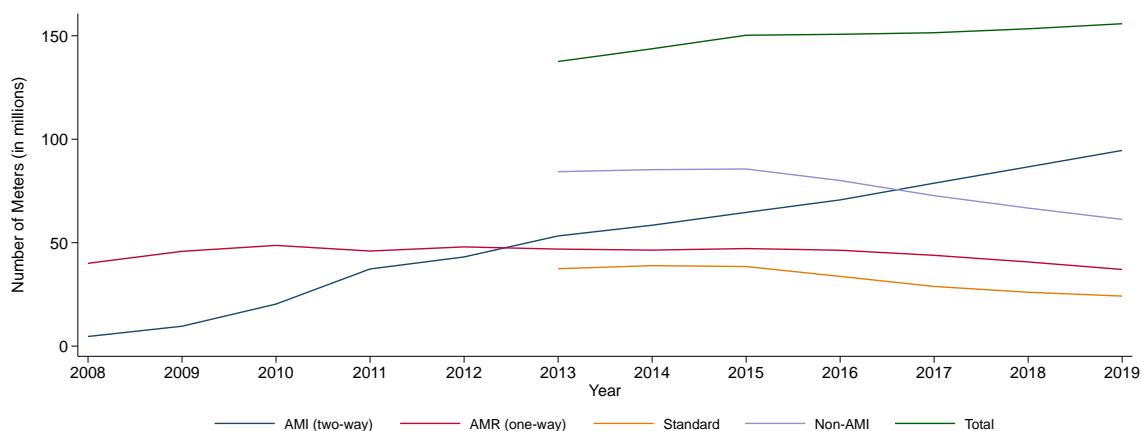


Figure 5.1: US Metering Infrastructure from 2008 - 2019

NOTES: This figure was produced using raw data from EIA's *Annual Electric Power Industry Report* (US EIA, 2020a). Non-AMI (purple line) meters is calculated to be the sum of AMR and standard meters. The total meter count (green line) includes AMI, AMR, and standard meters. Prior to 2013, EIA did not record the number of standard meters installed in the US. Consequently, total, standard, and non-AMI counts are omitted prior to 2013. Additionally, in 2008 and 2009, EIA recorded the number of customers with AMI rather than the actual number of meters installed.

<sup>1</sup>Unless otherwise noted, we include the District of Columbia in references to the states.

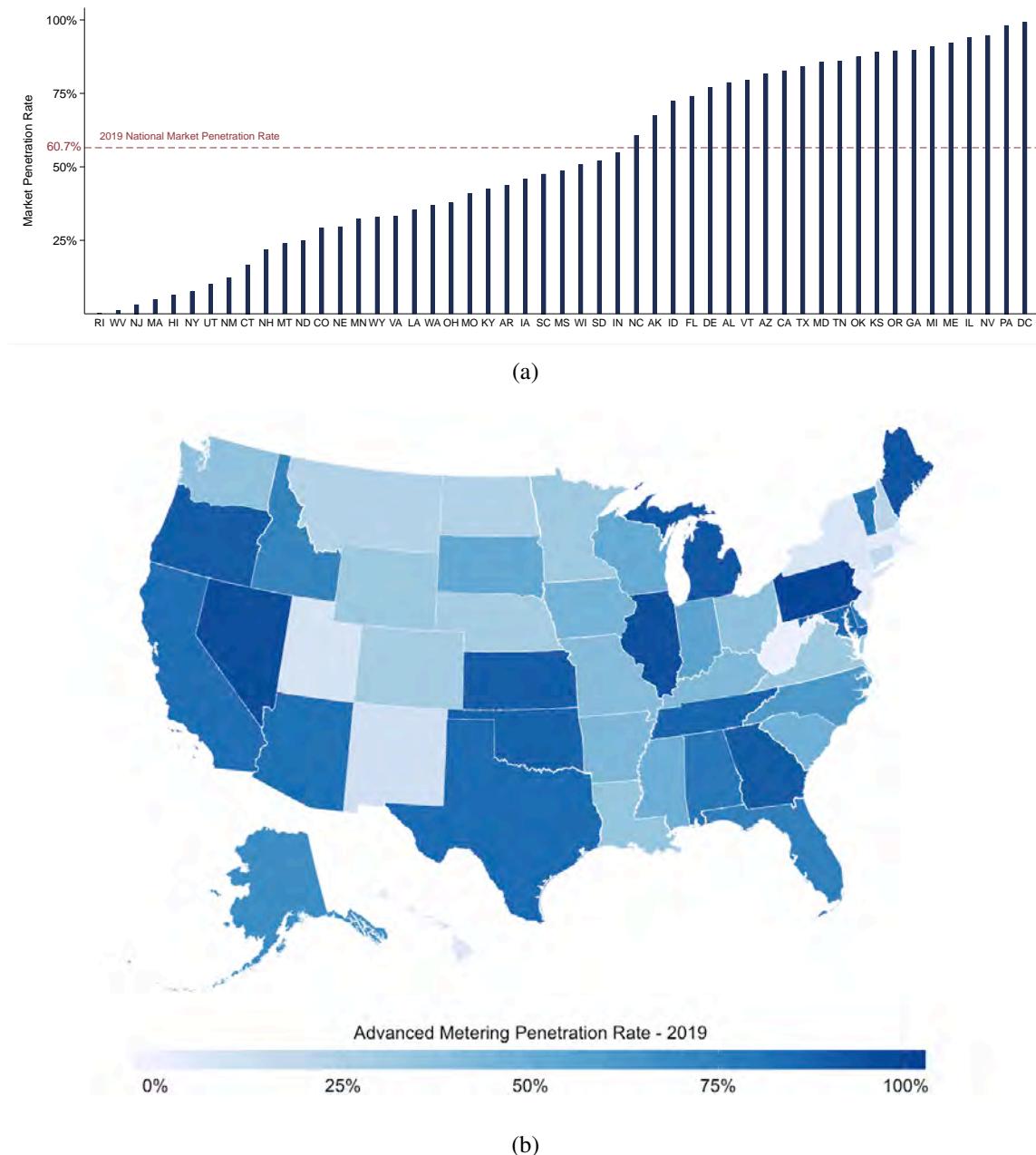


Figure 5.2: US State-level Advanced Meter Penetration in 2019

NOTES: The market penetration rate is calculated by dividing the number of AMI installations in a state by the total number of electricity meters in that state. The figures were produced using raw data from EIA's *Annual Electric Power Industry Report* (US EIA, 2020a).

The majority of all electricity meters are installed in the residential customer sector, regardless of metering technology (US EIA, 2020a). Residential meters are installed in private homes and apartment buildings where electricity is primarily used for space and water heating, air conditioning, lighting, refrigeration, cooking, and clothes drying. From 2013 to 2019, residential meters consistently made up 87-88% of all meters installed in the US. By 2019, there were almost 138 million electricity meters installed in the residential sector—83.5 million of which were advanced (US EIA, 2020a).

Nationally, the residential sector maintained the highest market penetration rates of any customer sector from 2013 to 2015 and regained this position in 2019. In 2016, the national market penetration rate in the transportation sector first surpassed the residential sector's (US EIA, 2020a). In both 2017 and 2018, four states sustained 100% market penetration in their transportation sectors—Michigan, North Carolina, New Jersey, and Wisconsin.<sup>2</sup> Meters installed in the transportation sector are used to record consumption for railroads and railways propelled by electricity (e.g., a metro system). While smart meter penetration tends to be high in the few states with metered transportation infrastructure, the majority of states have no meters of any type installed in their transportation sectors (US EIA, 2020a). It's important to note that the 'transportation sector' in this context is different in scope than the sector discussed in Section 2.5 and does not include smart meters connected to EV charging stations or household EV chargers. Those would instead be included in the commercial and residential sectors, respectively.

Figure 5.3 illustrates the raw growth in AMI meters and the changing market penetration rates in each customer sector. From 2008 to 2009, the number of customers with smart meters in the US increased by 107%. By the end of 2010, the count had more than doubled again (a 111% increase over 2009) (US EIA, 2020a). After a few more years of strong growth, the adoption of AMI meters settled at around 10% annual growth from 2014 to 2018. From 2018 to 2019, the country experienced 9.2% growth in AMI installations. The US Dept. of Energy (DOE) attributes the slowed growth in AMI adoption to the reluctance of some utilities to phase out AMR meters before absolutely necessary. AMR meters still make up about 24% of all metering infrastructure in the US and they provide a portion of the benefits offered by AMI meters (e.g., operational and maintenance savings). Still, Bloomberg New Energy Finance (BNEF) predicts that the US market for smart meters will continue to grow steadily, reaching a 93% market penetration rate by 2030 (US DOE, 2018).

The US saw large-scale federal funding efforts for smart meter adoption during the early 2010s after President Obama signed *The American Recovery and Reinvestment Act* with the intent of stimulating US economic growth. This piece of legislation provided \$4.5 billion for grid modernization projects under the terms of the Smart Grid Investment Grant (SGIG). As of 2011, over \$800 million of SGIG funding and \$1.1 billion in participant funding had gone toward advanced metering projects, allowing for the installation of over 7.4 million AMI meters in the 2 years since the program commenced.<sup>3</sup> By March of 2012, it was reported

<sup>2</sup>Arizona and Georgia reached 100% penetration in previous years but fell behind by 2018 with Arizona at 23% and Georgia at only 10%.

<sup>3</sup>SGIG award data are from <https://www.energy.gov/oe/information-center/recovery-act-smart-grid-investment-grant-swig-program>.

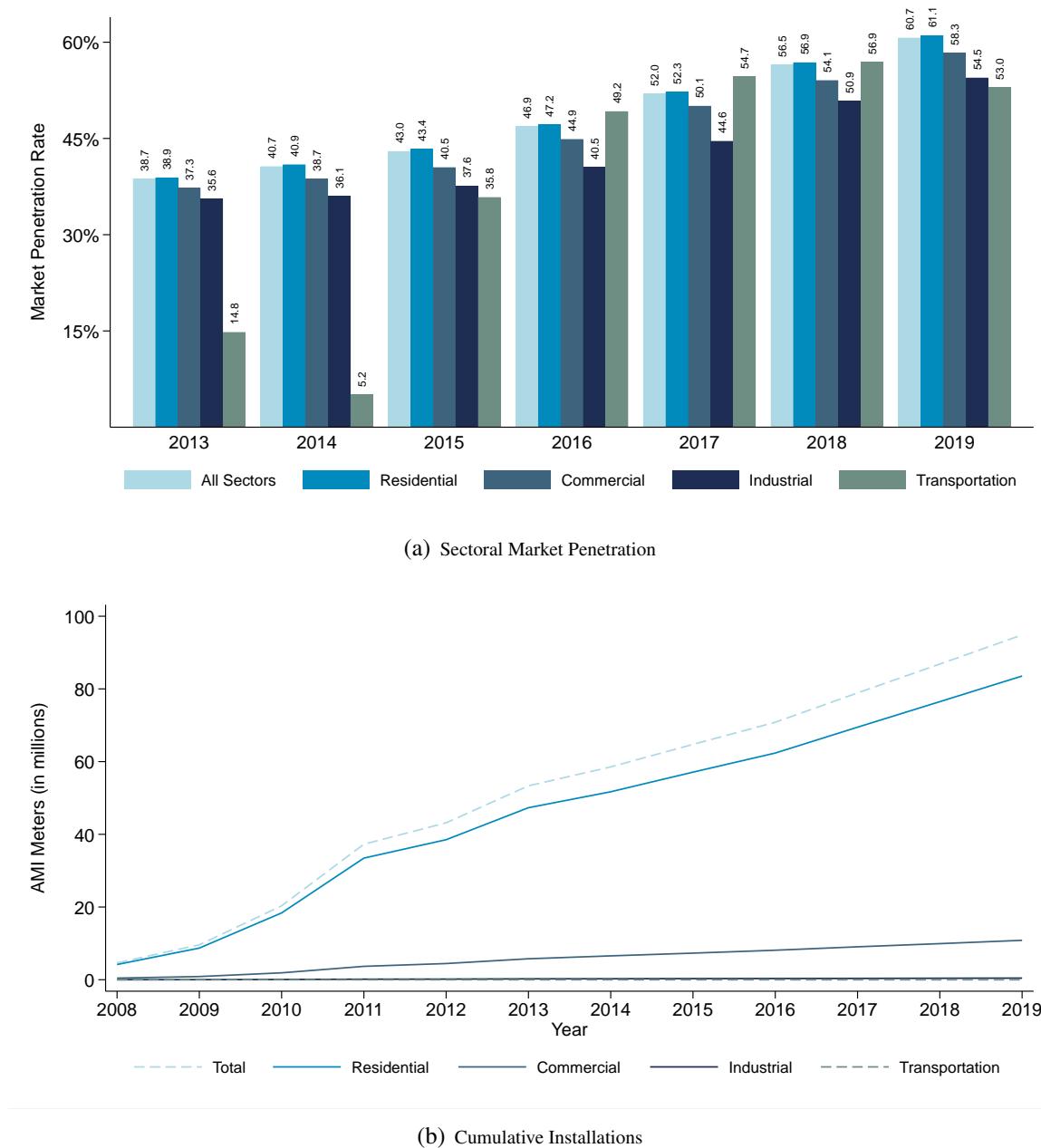


Figure 5.3: Adoption of Advanced Metering Infrastructure by US Customer Sector

NOTES: Panel (a) displays the market penetration rates for AMI meters in each end-use customer sector in addition to the total, nationwide market penetration rate. Panel (b) presents the cumulative count of AMI meters installed in the US in each end-use customer sector as well as the total number installed across all sectors. The figures were produced using raw data from EIA's *Annual Electric Power Industry Report* (US EIA, 2020a).

that 10.8 million AMI meters had been installed as part of SGIG projects (US DOE, 2012). The following year, DOE reported that 14.2 million AMI meters had been installed as part of SGIG projects and that total investment had reached over \$2.5 billion (US DOE, 2013). Data from EIA indicate that over 53.3 million AMI meters had been installed nationwide by the end of 2013 meaning that SGIG funded AMI meters made up about 27% of all installations. By 2016, SGIG funding had been responsible for 32% of AMI installations (US DOE, 2016a)

### 5.1.2 Deployment in Europe

In Europe, the widespread adoption of smart electricity meters was prompted by the 2009 Electricity Directive. Under Annex I of the Directive, all Member States of the European Union were instructed to carry out a cost-benefit analysis (CBA) to assess the feasibility of smart metering infrastructure. The Directive initially stipulated that any state with a positive CBA result must reach 80% market penetration by 2020.<sup>4</sup> The recast Electricity Directive, released in June 2019, updated the requirements for smart meter deployment. Member states of the EU must now reach 80% market penetration within seven years of a positive CBA result, or by 2024 in the Member States that had initiated deployment before July 2019.<sup>5</sup>

The most recent reports indicate that six Member States have reached at least 80% market penetration—Estonia, Finland, Italy, Malta, Spain, and Sweden (ACER and CEER, 2019; Tractabel, 2019). While Slovenia and Denmark have both reached over 50% market penetration, most of the remaining Member States are in the early stages of their roll-outs. Additionally, while not a Member State of the EU, Norway also reportedly surpassed 80% market penetration (ACER and CEER, 2019). Overall, about 34% of electricity meters in the EU were smart by the end of 2018. In June 2019, the consultancy Tractabel—in its report to the European Commission—predicted that only about 123 million of the initially proposed 226 million smart meters were to be installed by 2020. If this prediction was correct, the EU would have reached an overall penetration rate of about 42.5% by 2020 (Tractabel, 2019).

Figure 5.4 displays the 2018 market penetration rates in each of the EU Member States as reported in Tractabel (2019). While the overall roll-out of smart meters was not on track to meet its target by 2020, Tractabel still predicts substantial market penetration by 2024 (estimated at almost 84%). Moreover, Tractabel expects the market penetration rate to reach over 91% by 2030—only slightly less than BNEF’s prediction of 93% market penetration by 2030 in the US (Tractabel, 2019; US DOE, 2018). Tractabel expects that by 2030, the total investment in smart meters will have reached just over €40 billion.

While a number of Member States have reached their deployment target or are fast approaching it, there are several that have not completed a CBA or have reported a negative result. Additionally, some Member States’ initial CBAs have been overturned by more recent analyses (Austria and Luxembourg). Table A.1, in the appendix, provides the latest outcome of each country’s CBA and the latest estimated market penetration rates. Countries

<sup>4</sup>The 2009 Electricity Directive can be found here: <https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0072&from=EN>.

<sup>5</sup>The recast Electricity Directive can be found here: <https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019L0944&from=EN>.

reporting negative outcomes of their CBAs are required to conduct a new analysis every four years in order to keep up with technological change. By July 2018, Spain and Malta had still not completed a CBA, however, both countries are well above the 80% market penetration target (Tractabel, 2019).

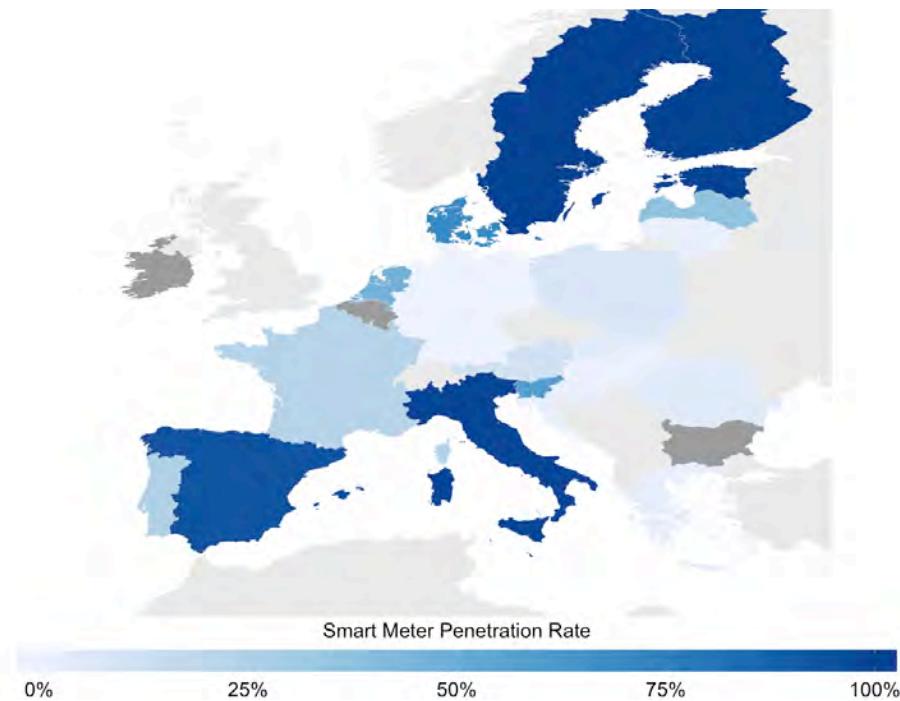


Figure 5.4: Adoption of Smart Meters in the European Union as of 2018

NOTES: This figure displays the market penetration rates for smart meters in the EU Member States as of 2018. Member States for which no data were available are shown in dark gray. Countries shown in light gray are not members of the EU. This figure was produced using the market penetration rates reported in Tractabel (2019).

When conducting cost-benefit analyses, Member States generally consider not only the capital expenditures associated with smart metering devices, but also with investment in IT infrastructure, meter reading, network management, and customer service. Fewer than half of Member States consider the operating expenditures associated with revenue reduction and consumer engagement. The benefits considered include reductions in operating costs due to the advent of remote meter reading as well as the potential for active demand-side participation. The CBA results estimate the costs of smart metering to be between €38 and €546 per meter while the benefits range from €19 to €493 per meter (Tractabel, 2019).

### 5.1.3 Deployment in Australia, New Zealand, and Asia

Deployment of smart meters in Australia has occurred in two phases prompted by both state- and national-level regulations. The initial mandated adoption of smart electricity meters began in Victoria in 2009. An initial plan was drafted to replace all existing meters belonging to residential and small business consumers with advanced metering infrastructure by the

end of 2012. Before the program officially began, the deadline was extended to 2013 with the expectation that 2.6 million meters would need to be installed in order to meet the target. According to the Victoria Auditor-General's Office (VAGO), about 98.6% of the roll-out had been completed by June 2014 (VAGO, 2015).

As discussed in Section 4.3, Victoria's mandated roll-out has been subject to significant criticism, particularly from VAGO. While initial cost-benefit analyses estimated net benefits associated with the mass roll-out, revised estimates have indicated that Victorian consumers may have faced a net cost from the program. In 2011, the Victorian Department of Treasury and Finance commissioned Deloitte to provide a reassessment of the costs and benefits of the program. While Deloitte estimated that consumers would face a net cost of AU\$319 million as opposed to the previously estimated net benefit of AU\$775 million, Victoria maintained its plan and continued the roll-out (Deloitte, 2011). In 2015, VAGO released a report containing further criticism of the roll-out. The Victorian Auditor-General's Report found that metering costs between 2009 and 2015 were over 11% higher than originally forecast. Moreover, the report went on to state that the lifetime costs of the program were at risk of surpassing Deloitte's estimated net cost of AU\$319 million. VAGO largely attributed the expected increase in the net cost to the slow adoption of flexible tariffs which was inhibiting benefits realization. In 2016, the Australian Energy Regulator (AER) determined that Victorian energy distributors had overspent during the roll-out. Distributors were subsequently instructed to return over AU\$75 million to Victorian consumers (Australian Energy Regulator, 2016). As we argue in Section 7.3.3, the Australian wholesale electricity market design with some modifications could allow customers and retailers to realize substantial economic benefits from interval metering under the appropriate regulatory structure for default retail pricing in Victoria.

As of 2015, very few smart meters had been installed outside of Victoria, prompting the Australian Energy Market Commission (AEMC) to incorporate new rules into the existing National Electricity Rules (NER) and the National Energy Retail Rules (NERR) in order to catalyze and facilitate a competitive roll-out (Australian Energy Market Commission, 2015). Key differences exist between the Victorian and national programs. Namely, the introduction of meters in Victoria was mandated, meaning that all existing meters were replaced with AMI. Contrarily, the national program has a semi-competitive framework such that all new or replacement meters must be smart, but customers have a choice in whether to change out their existing meter. The national adoption began on December 1, 2017, and as of October 2018, roughly 29.9% of customers had smart meters (Delos Delta, 2018). Because Victoria had already mandated the adoption of smart meters prior to AEMC's ruling, the Amendments contain arrangements for the transition from the existing statewide AMI program to the national market-driven program.

New Zealand has abstained from mandating the roll-out of smart meters largely due to the speed at which advanced metering infrastructure has been adopted voluntarily. Indeed, New Zealand has one of the highest rates of market penetration of any country around the world, reportedly reaching over 73% in 2017 (Gunderson, 2017). While not legally binding, New Zealand's Electricity Authority does provide guidelines for the adoption of smart meters in order to "persuade and promote" the roll-out, "rather than to regulate" it

(New Zealand Electricity Authority, 2010).

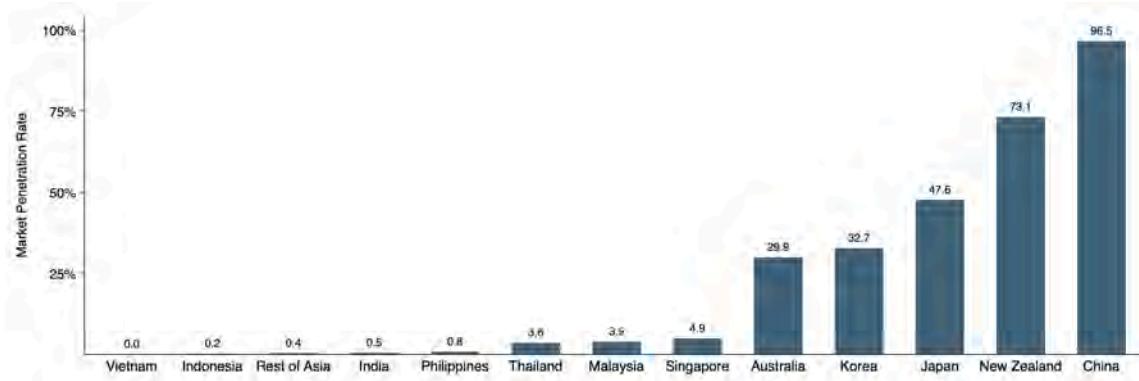


Figure 5.5: 2017 Market Penetration Rates for Smart Meters in Asia and Oceania

NOTES: This figure was produced using data reported in (Gunderson, 2017).

Most Asian countries have not begun widespread adoption of smart meters. According to the US Dept. of Commerce, the regional average market penetration rate is just 4% in spite of strong deployment in Korea, Japan, and China (Gunderson, 2019). Based on available estimates, China likely has the highest penetration rate outside of Europe (96.5% in 2017). Both of China's state-owned transmission operators have taken steps to ensure widespread adoption. According to the US Dept. of Commerce, both the State Grid Corporation of China and China Southern Power Grid Company planned to install 280 million more smart meters between 2017 and 2022. Further analysis from Research and Markets—an international market research distributor—predicts that the adoption will continue to grow at a rate of 3.5% annually through 2025 (Research and Markets, 2019a). Japan, currently at 47.8% market penetration, intends to finish installing smart meters by 2025 (Gunderson, 2017). Korea is similarly undertaking an effort to increase market penetration with KEPCO—the country's largest utility—selecting smart device supplier, Arm, to install 20 million smart metering devices (Business Wire, 2018).

In a number of developing countries, interval meter adoption has been driven by the desire to reduce losses from energy theft. Mexico, Brazil, India, and some Eastern European countries have pursued pilot installation programs for this purpose (Alejandro et al., 2014; Binz et al., 2019; Nielsen, 2012). India's Smart Grid Pilot Program intends to address this by spending \$60 million on the installation of smart meters. As of 2017, four pilot projects had already begun. The program also intends to improve reliability—a necessity in a country with over 550 million people with limited or no access to electricity (Gunderson, 2017).

While industry reports during the early part of the last decade predicted that India would have substantial smart meter adoption by 2021, the country largely remains in pilot mode. Still, despite the slower than expected growth, India has taken a number of steps to expand its smart grid and reduce electricity related losses (Alejandro et al., 2014). As of 2017, at least four pilot projects had commenced and the smart meter market penetration rate had reached 0.5% (Gunderson, 2017). In 2018, India was commissioning estimates from

meter providers in order to begin a larger roll-out on the order of 5 million units (Singh and Upadhyay, 2018; Rowlands-Rees, 2018).

### 5.1.4 Deployment in Latin America

Consistent and comprehensive information on the adoption of smart meters in Latin America is very limited. By all accounts, however, the region is in the very early stages of deployment. The US Dept. of Commerce reports that the regional average market penetration rate for Latin America and the Caribbean region was 5% in 2017 (Gunderson, 2019).

According to the US Dept. of Commerce, Mexico had the highest market penetration rate in the region at 10% in 2017. Additionally, NREL—in its 2019 investigation into Mexico’s smart grid—found that by the end of 2016 five AMI pilot programs had been completed and eleven more had commenced (Binz et al., 2019). NREL also indicates that the Mexican Federal Electric Commission (CFE) intended to install almost 4.7 million AMI meters between 2017 and 2021.<sup>6</sup> It also appears that one of CFE’s major justifications for adopting AMI is to reduce electricity losses due to theft (non-technical losses).

Brazil has also deployed smart meters in an effort to curtail illegal electricity consumption. In 2012, Bloomberg reported that 50,000 smart meters were installed in favelas in Rio de Janeiro. Prior to their installation, 80% of electricity was illegally tapped from the grid. Elster, the smart meter supplier, reported that theft dissipated afterwards. Of course this can’t be interpreted as causal, in part, because the pilot program was accompanied by an increased police presence (Nielsen, 2012). Although the country is largely still in pilot mode, Brazil’s energy regulator, Agência Nacional de Energia Elétrica (ANEEL), has taken a number of steps towards implementing a large scale roll-out. ANEEL had hoped to replace all metering infrastructure with smart meters by 2009, later delaying this goal to 2021 and then further abandoning the mandated replacement of existing meters (Alejandro et al., 2014). The US Dept. of Commerce reported that in 2017, only 3% of meters were advanced (Gunderson, 2019).

## 5.2 Extent of Deployment of Distributed Solar

According to IEA, the worldwide installed capacity of distributed solar generators reached 213 GW in 2018. For context, the total global solar capacity, including utility-scale installations, was about 496 GW in 2018 (IEA, 2019d). Figure 5.6, which provides the raw and per-capita, country-level adoption of distributed solar capacity, illustrates that almost all distributed solar capacity is installed in Europe, the Asia-Pacific region (largely Japan and Australia), China, and North America. According to IEA, commercial/industrial and residential installations in China, Japan, Germany, the US, and Italy alone accounted for 75% of worldwide installed capacity in 2018. IEA notes that all of these regions have strong policy incentives driving the adoption of distributed solar PV. Figure A.7, in the appendix,

<sup>6</sup>The Federal Electric Commission or Comisión Federal de Electricidad is the state-owned electric utility in Mexico.

provides per-capita, country-level capacities broken down by installation size (residential, commercial/industrial, and off-grid).

A number of different rate structures have been adopted around the world in order to compensate distributed generators for the energy they inject into the grid. These include buy-all, sell-all style arrangements in which distributed generators are required to inject all of their energy into the grid for a renumeration price; utilities are required to buy it. Owners of PV systems then buy energy from the utility at the retail rate. Buy-all, sell-all schemes are often referred to as ‘Feed-in Tariff’ or FIT schemes. These arrangements are used in a number of Asian countries, France, and Mexico (IEA, 2019d). Net metering policies—commonly found in the US—allow distributed PV owners to consume the energy they generate and sell any excess back into the grid for a credit on future energy bills. Finally, real-time self consumption arrangements allow customers to consume and sell excess generation but differ from net metering in that energy is sold for cash rather than a credit towards future bills. Real-time models perform energy accounting at least hourly. Most European countries use these types of arrangements (IEA, 2019d). Table 5.1 summarizes these compensation arrangements for distributed generation.

Table 5.1: Compensation Arrangements for Distributed Generation

Type	Description
Buy-all, Sell-all; Feed-in tariff	<ul style="list-style-type: none"> <li>PV owners sell all energy into grid at fixed renumeration price</li> <li>Renumeration price can be above, below, or equal to retail rate</li> <li>PV owners buy back electricity at retail rate</li> <li>Pre-set contract term</li> </ul>
Net Metering	<ul style="list-style-type: none"> <li>PV owners consume energy generated and get credit for excess</li> <li>Credit can be deducted from future bills</li> </ul>
Real-time Self Con- sumption	<ul style="list-style-type: none"> <li>PV owners consume energy generated and sell excess</li> <li>Energy accounting done hourly or more frequently</li> </ul>

**Notes:** Based on the definitions in IEA (2019d), US EIA (2017), and Aznar (2017).

In this section, we outline the extent of distributed solar adoption in the US, Europe, Oceania and Asia, and Latin America. Additionally, we discuss the drivers of distributed solar adoption and the potential trends that could develop in coming years. Throughout this section, we make reference to *residential, small-scale, commercial, industrial, off-grid, and utility-scale* solar installations. These terms are used to indicate both the size and purpose of distributed systems. These terms are not necessarily used consistently throughout the

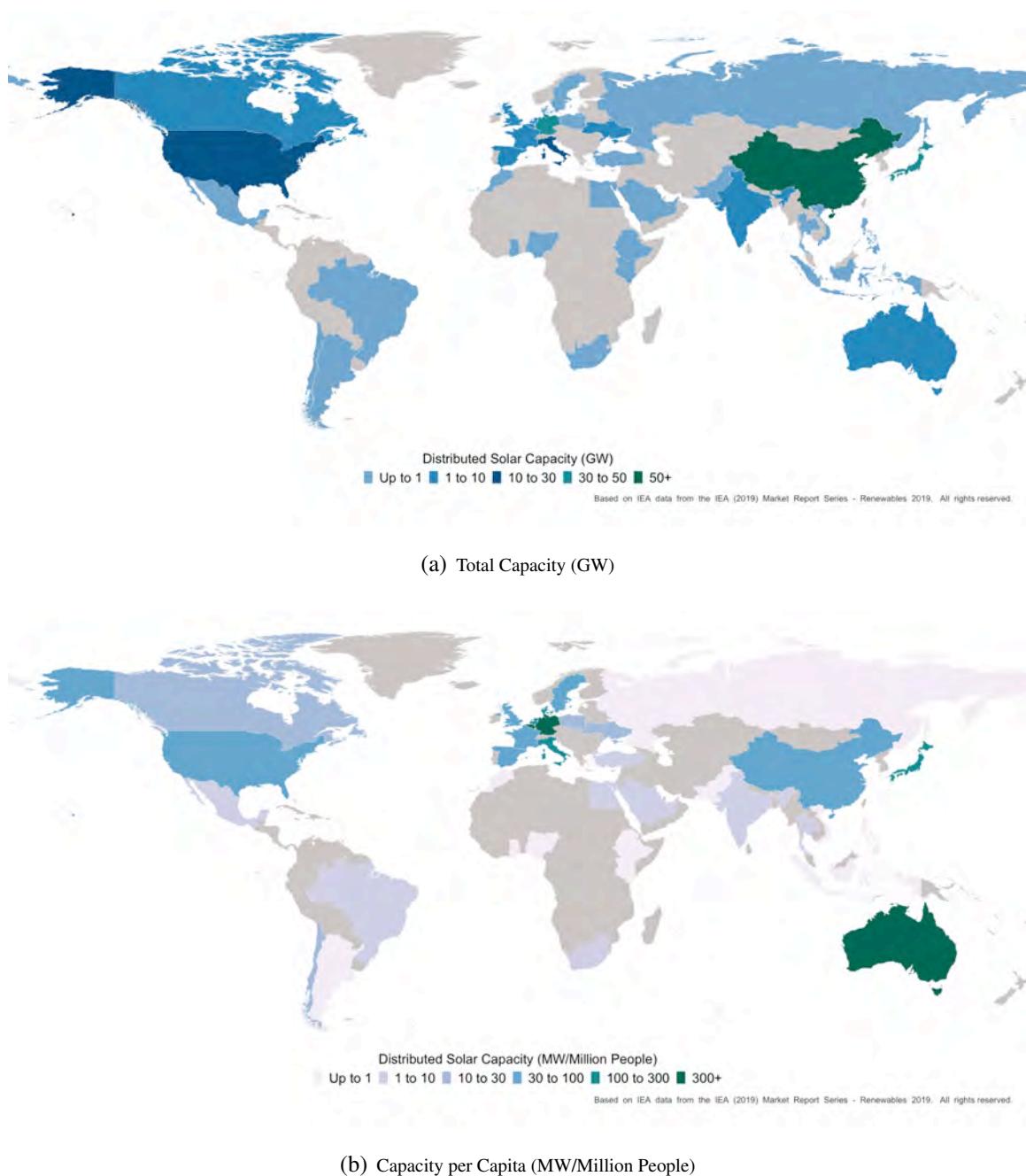


Figure 5.6: Global Distributed Solar Capacity per Capita in 2018

NOTES: Panel (a) displays raw distributed solar capacity in GW as of 2018. Panel (b) illustrates the global adoption of distributed solar capacity on a per-capita basis. We include the total residential, commercial/industrial, and off-grid capacities in our calculations (as defined by IEA). For per-capita values, we divided each country's total capacity by its 2018 population using data from United Nations (2020).

existing literature. We define each term in its own context within this report.

### 5.2.1 Deployment in the United States

As of October 2019, 45 states and the District of Columbia had adopted mandatory compensation rules for distributed generation, according to the Database of State Incentives for Renewables & Efficiency (DSIRE) (DSIRE, 2019). The majority of these policies require that excess generation be netted one-to-one against consumption. Six of these states, however, allow net excess generation to be credited to the customer at an avoided cost rate rather than the retail rate of electricity. Figure A.5 in the appendix provides DSIRE's breakdown of policy type by state.

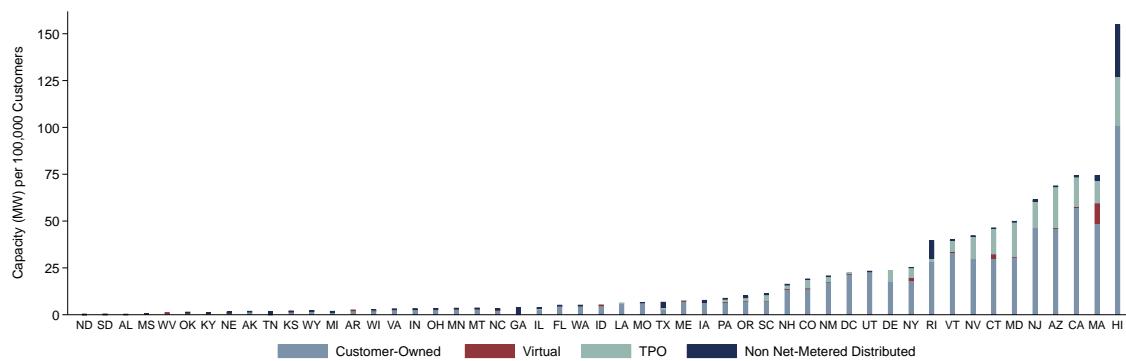


Figure 5.7: Types of Distributed PV Systems in the US in 2019

NOTES: This figure illustrates the total distributed solar PV capacity (in MW) per 100,000 customers in each state. Data are broken down by customer-owned, virtual, TPO, and non net-metered distributed solar PV, but omit short form respondents from the total customer counts in each state since they do not provide data on their net-metered capacity. These figures were produced using raw data from EIA's *Annual Electric Power Industry Report* (US EIA, 2020a).

There are several ownership arrangements for distributed Solar PV in the US (see Figure 5.7). Customer-owned, net-metered installations made up the majority of capacity at roughly 22.6 GW in 2019 (US EIA, 2020a). The capacity of these installations has more than doubled since 2015. Third-party Owned (TPO) solar arrangements have also grown in popularity throughout the US—by 2019, over 6.3 GW of capacity were installed under TPO agreements. A TPO solar installation generally involves a lease or Power Purchase Agreement (PPA) between a customer and an owner of the solar infrastructure. Customers sign on to benefit from the energy generated during a set period of time while avoiding the up-front expense of installing solar panels.<sup>7</sup>

There is also a growing market for “virtual” net-metered solar in the US (sometimes called “community solar”). These arrangements allow multiple customers to benefit from the generation of a remote or onsite solar installation. Customers may own a fraction of the installation’s capacity, and receive credit for the energy it generates. This is a solution for

<sup>7</sup>For more on third-party ownership of distributed solar PV systems, see <https://www.epa.gov/repowertoolbox/understanding-third-party-ownership-financing-structures-renewable-energy>.

consumers who do not own their home or lack the necessary space for onsite solar PV. There are only about 711 MW of virtual net-metered solar capacity in the US and over half of the capacity is located in Massachusetts (US EIA, 2020a). Lastly, the US has about 1.5 GW of non net-metered, distributed solar PV capacity. Over 60% of these installations are located in Texas, Georgia, California, and Hawaii (in decreasing order). Non-net-metered, distributed installations include systems that are less than 1 MW in size and are “installed at or near a customer’s site, or other sites within the system” (US EIA, 2017). These installations can be grid-connected and utility or customer-owned, but are not enrolled in any sort of net-metering arrangement.

Between 2015 and 2019, most net-metered, distributed capacity was added in California and New England. Indeed, by 2019, about 39.5% of US net-metered, distributed solar capacity was located in California (US EIA, 2020a). Hawaii, however, maintained the highest net-metered PV capacity per customer from 2015 to 2019, reaching a peak of 127 megawatts of capacity per 100,000 customers in 2019. Panel (a) of Figure 5.9 displays the state-level, net-metered distributed solar capacity per 100,000 customers for 2015 and 2018. The capacity per customer in Hawaii is 73% higher than that of the next highest state: California (US EIA, 2020a). While Hawaii has the most distributed capacity per customer and California has the most in total, Massachusetts sells the most energy back into the grid from distributed solar. Panel (b) of Figure 5.9 provides the actual sales (in GWh) into the grid from net-metered solar PV.

Other than state-level net metering rules, the US has a number of policies, incentives, and targets in place for the deployment of distributed energy resources. In 2019, New York passed a senate bill laying out a target of reaching 6 GW of distributed solar capacity by 2025 (New York State Senate, 2019). In 2019, the state had reached just over 2.1 GW (US EIA, 2020a). At the federal level, the US offered a 30% Solar Investment Tax Credit (ITC) from 2006 to 2019. As of this year, the Solar ITC has been ramped down to 26% and will be further curtailed to 22% in 2021 (US DOE, 2020c). From 2022 onward, only commercial installations will be eligible for a 10% credit (US DOE, 2020a).

Utility-scale solar in the US increased by close to 50% between 2016 and 2018.<sup>8</sup> The total utility-scale solar capacity in the US reached close to 30.5 GW in 2018. Figure 5.8 compares the utility-scale and distributed solar capacities per 100,000 customers in the ten states with the highest per-customer capacities.<sup>9</sup> The US Dept. of Energy (DOE) has endeavoured to increase solar competitiveness through its SunShot 2030 program. DOE reports that, between 2010 and 2017, the LCOE of utility-scale solar fell from \$0.28/kWh to just \$0.06/kWh (-78%). For comparison, the LCOEs for residential and commercial solar fell from \$0.52/kWh to \$0.16/kWh (-69%) and \$0.40/kWh to \$0.11/kWh (-72.5%), respectively (US DOE, 2017). These LCOEs are for installations in average climate regions and with no Investment Tax Credit (ITC) or other federal or state subsidies. The SunShot 2030 program’s ultimate goal is to reach a LCOE for utility-scale solar of \$0.03/kWh by 2030 and LCOEs for residential and commercial solar of \$0.05/kWh and \$0.04/kWh,

<sup>8</sup>EIA defines utility-scale installations to be those that are over 1 MW in capacity and are connected to the high-voltage grid. See <https://www.eia.gov/electricity/data/eia860/>.

<sup>9</sup>We omit utility-scale capacity that is part of a net-metering program from these calculations.

respectively.

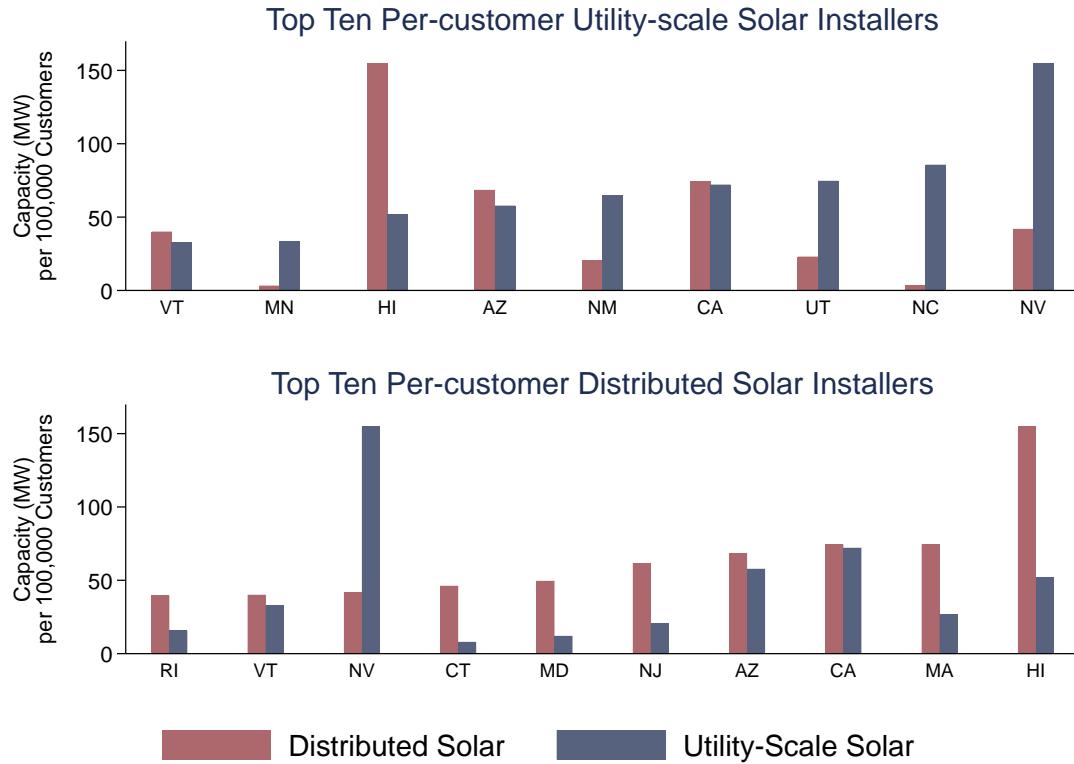


Figure 5.8: Top US Solar Installers in 2019

NOTES: This figure displays distributed and utility-scale solar capacities per 100,000 customers in the top ten states. Utility-scale solar includes all solar PV capacity reported on Form EIA-860 except for capacity enrolled in a net metering arrangement. Distributed solar capacity includes customer-owned, virtual net-metered, and TPO installations. The figure was produced using raw data from EIA's *Annual Electric Power Industry Report* and *Annual Electric Generator Report* (US EIA, 2020a,d).

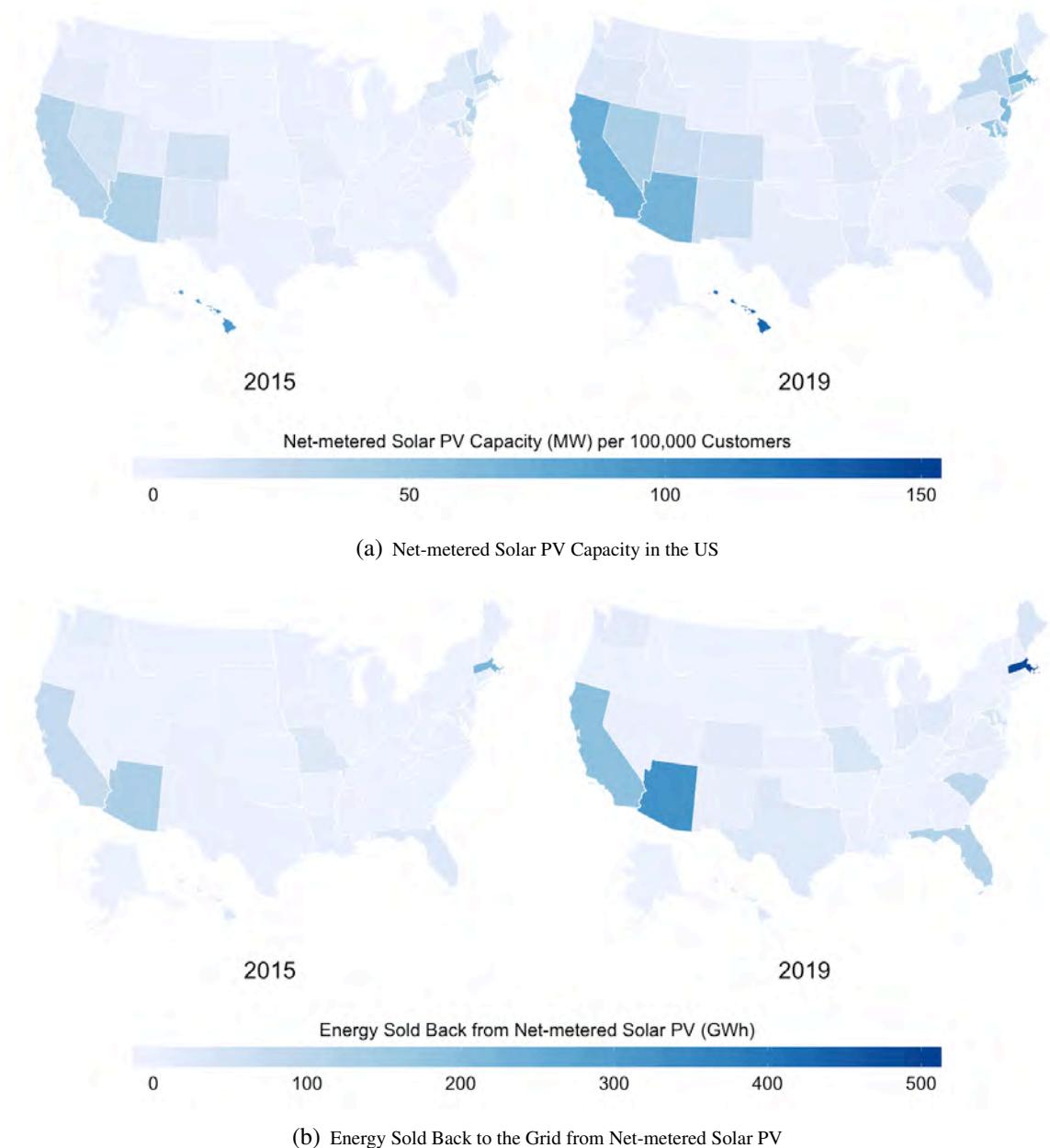


Figure 5.9: Net Metering Trends in the US

NOTES: Panel (a) illustrates the total net-metered solar PV capacity (in MW) per 100,000 customers in each state. For these calculations, we use the combined total of customer-owned, virtual, and TPO solar PV, but omit short form respondents from the total customer counts in each state since they do not provide data on their net-metered capacity. Panel (b) displays the energy sold back to the grid from customer-owned and virtual net-metered generators and from net-metered storage installations in each state. The figures were produced using raw data from EIA's *Annual Electric Power Industry Report* (US EIA, 2020a). EIA does not record the amount of energy sold back to the grid from TPO solar installations.

### 5.2.2 Deployment in Europe

Europe was an early adopter of distributed solar. Indeed, between 2006 and 2012 the majority of global distributed solar capacity was installed in Europe. While North America, China, and the Asia-Pacific region saw substantial growth after 2012, European countries still maintained close to 40% of the world's installed capacity in 2018—accumulating close to 80 GW of generating capacity—most of which was located in Germany and Italy (IEA, 2019d). Moreover, three of the top five, per-capita installers of distributed solar are members of the EU (Germany, Belgium and Italy) (IEA, 2019b; United Nations, 2020).

Europe's rapid rise to top installer is largely attributed to extremely generous tariff schemes between 2006 and 2012. European countries tend to use real-time self-consumption or net metering compensation schemes for distributed solar (IEA, 2019d). IEA expects, however, that the residential distributed solar market will expand under the influence of buy-all, sell-all schemes. Additionally, IEA notes that the current policy environment under the EU's most recent Renewable Energy Directive is set to encourage more self-consumption among distributed generators (IEA, 2019d).<sup>10</sup>

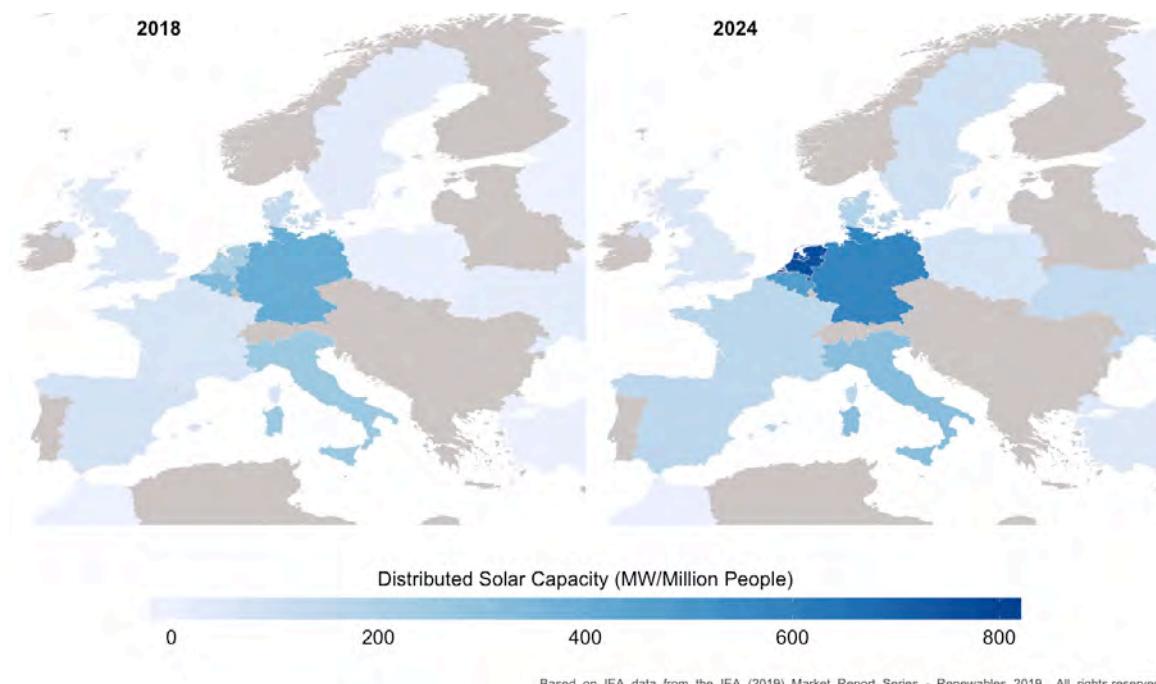


Figure 5.10: IEA Distributed Solar Forecast for Europe

NOTES: This figure illustrates the current and forecast, per-capita distributed solar capacity in Europe. We include the total residential, commercial/industrial, and off-grid capacities in our calculations. We divided each country's total capacity by its 2018 population and projected 2024 population using data from United Nations (2020).

IEA's forecast indicates that Europe could see an increase in distributed capacity of

<sup>10</sup>See Directive (EU) 2018/2001 at <https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018L2001&from=EN>.

about 63% between 2018 and 2024. While Germany is projected to remain the top installer in terms of raw capacity, the Netherlands is slated to become the top per-capita installer—not only in Europe, but globally. Figure 5.10, illustrates the forecast distributed solar capacity in Europe using capacity projections from IEA (2019b) and population projections from United Nations (2020).

In Panel (a) of Figure 5.11, we show the total (utility-scale and distributed) solar capacity development over the last decade in Europe. Germany is Europe's leading country in terms of installed solar power capacity in absolute terms as well as per-capita. While installed solar capacity was largely absent in Europe prior to 2008, the region experienced rapid growth until 2012 and has since experienced steadier growth rates. The early growth trends were partly driven by very generous subsidies and incentives provided by some European states. Many of these have since been revised and made less attractive. Much of this growth was experienced in Spain, Italy, Belgium, and Germany where these incentives were most generous (IEA, 2019d). Questions were eventually raised regarding the costs these incentives imposed on governments and consumers. Support schemes and tariffs were reduced significantly in many of these countries. In Panel (b) of Figure 5.11, we observe that during the period from 2014 to 2016 the majority of solar panels were installed in UK.

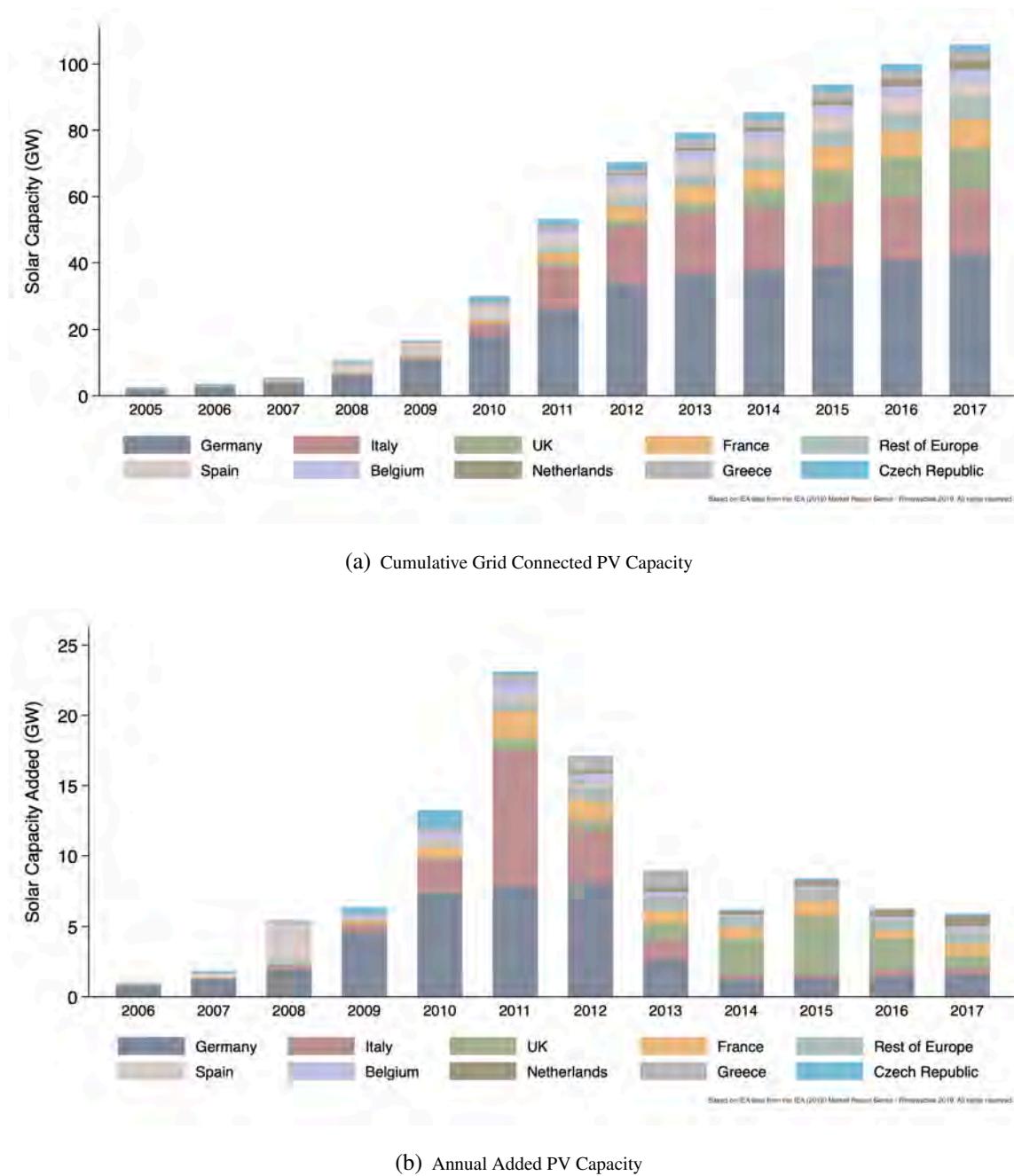


Figure 5.11: Adoption of Solar in Europe

NOTES: Panels (a) and (b) displays the cumulative total, grid-connected solar capacity in Europe from 2005 to 2017. Panel (b) displays the annual additions to each country's PV generating stock over from 2006 to 2017. The figures were produced with data from IEA (2019c).

### 5.2.3 Deployment in Australia, New Zealand, and Asia

According to the Australian Energy Regulator (AER), Australia receives more solar radiation per square meter than any other continent: 16 million TWh of solar radiation each year. Rooftop solar PV accounted for 3.4% of electricity generation in Australia's National Electricity Market (NEM) in 2017-18 (Australian Energy Regulator, 2018). In 2018, Australia had the most residential distributed solar capacity per capita of any country in the world (IEA, 2019d). IEA reports that federal rebates paid for up to 35% of system costs in 2018. Australia's Small-scale Renewable Energy Scheme (SRES) provides a financial incentive to residential installers of solar PV capacity.<sup>11</sup> The amount of compensation is based on the expected generation over a 15-year period or by 2030, when the scheme ends (Australian Clean Energy Regulator, 2018).

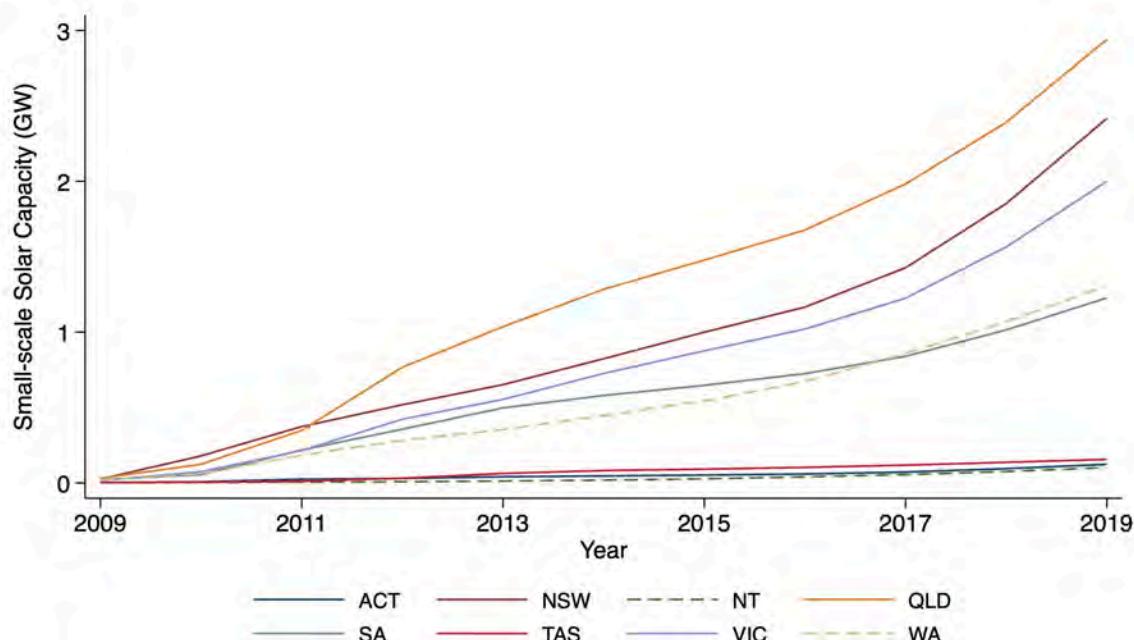


Figure 5.12: Australian Adoption of Small-scale Solar PV

NOTES: This figure provides the cumulative installed capacity of small-scale solar PV systems in each Australian state. This figure was produced using raw data from Australian Clean Energy Regulator (2020). The Northern Territory (NT) and Western Australia (WA) are each represented by a dashed line because they are not a part of the NEM.

Between 2010 and 2018, rooftop solar PV accounted for more than 30% of added renewable capacity in Australia's NEM (Australian Energy Regulator, 2018). Figure 5.12 displays the capacity of small-scale solar PV installations in each Australian territory and state from 2009 to 2019 (Australian Clean Energy Regulator, 2020). According to the data from Australian Clean Energy Regulator (2020), Australia had 8.2 GW of small-scale solar

<sup>11</sup>These 'small-scale' PV systems must be smaller than 100 kW in capacity and produce fewer than 250 MWh per year in order to qualify.

installed by the end of 2018, and 9.8 by the end of 2019. This contradicts IEA's report that by the end of 2018, Australia had less than 8 GW of total distributed capacity. Similarly, the total small-scale capacity reported by Australian Clean Energy Regulator (2020) in 2019 is larger than IEA's prediction for Australia's total distributed solar capacity for that year. In both Queensland (QLD) and Southern Australia (SA), over 30% of homes have installed PV systems (Australian Energy Regulator, 2018).

Australia's state governments regulate the availability of feed-in tariffs and net-metering arrangements. The Australian Capital Territory (ACT) passed the *Electricity Feed-in (Renewable Energy Premium) Act* in 2008 in order to establish a compensation scheme for small and medium distributed solar generators. The scheme applies to systems installed between March 1, 2009 and December 31, 2016. The program allows consumers to receive feed-in tariff payments for 20 years after system installation. The ACT tariff scheme offers payment for gross generation at a rate higher than market value (Australian Capital Territory Government, 2018). Consumers who missed the cut-off for enrollment in the scheme can still take part in net-metering programs though electricity retailers. Between 2015 and 2018, generators under the feed-in tariff scheme produced a total of 122.8 GWh of electricity and were paid an average of AUS\$380.88/MWh in feed-in tariffs. In addition to the 32.9 MW of capacity installed under the scheme, 42 MW were installed and billed under net-metering agreements with retailers.

Between 2013 and 2019, New Zealand's distributed solar capacity increased from just over 8 MW to about 114 MW (New Zealand Electricity Authority, 2020). While retailers in New Zealand are not required to purchase excess generation from these distributed generators, many do (New Zealand Electricity Authority, 2013). In 2019, rates generally ranged from NZ\$0.07 to NZ\$0.09 per kWh.<sup>12</sup> The majority of distributed solar capacity in New Zealand is made up of small-scale systems of up to 10 kW capacity. By the end of 2019, only about 18 MW of capacity were part of systems larger than 10 kW in size.

China's 13th Five Year Plan set a goal of reaching 60 GW of distributed solar capacity by 2020 (IEA, 2019d). By the end of 2018, just over 50 GW had been installed, primarily in the commercial and industrial sectors. IEA predicts that China's distributed solar capacity will increase by over 300% between 2018 and 2024 and that by then, Chinese installations will make up 40% of the global installed capacity. Additionally, by 2024, China will have moved up from being the 14th per-capita installer to the 12th per-capita installer based on IEA's capacity projections and population projections from the United Nations. According to the World Resources Institute, distributed solar in China is growing faster than utility-scale solar (Yuan et al., 2018). This capacity is mainly being installed in southeast Chinese provinces.

In 2011, the Japanese government passed legislation enforcing the availability of feed-in tariffs in the Japanese distributed energy generation market.<sup>13</sup> In 2018, Japan was the 4th largest per-capita installer and the only Asian country in the top ten. By 2024, Japan is projected to fall to fifth place, being surpassed by the Netherlands (IEA, 2019b; United

<sup>12</sup>See <https://www.mysolarquotes.co.nz/about-solar-power/residential/solar-power-buy-back-rates-nz/>.

<sup>13</sup>This piece of legislation is the *Act on Special Measures Concerning Procurement of Electricity from Renewable Energy Sources by Electricity Utilities*. The Act went into effect in 2012.

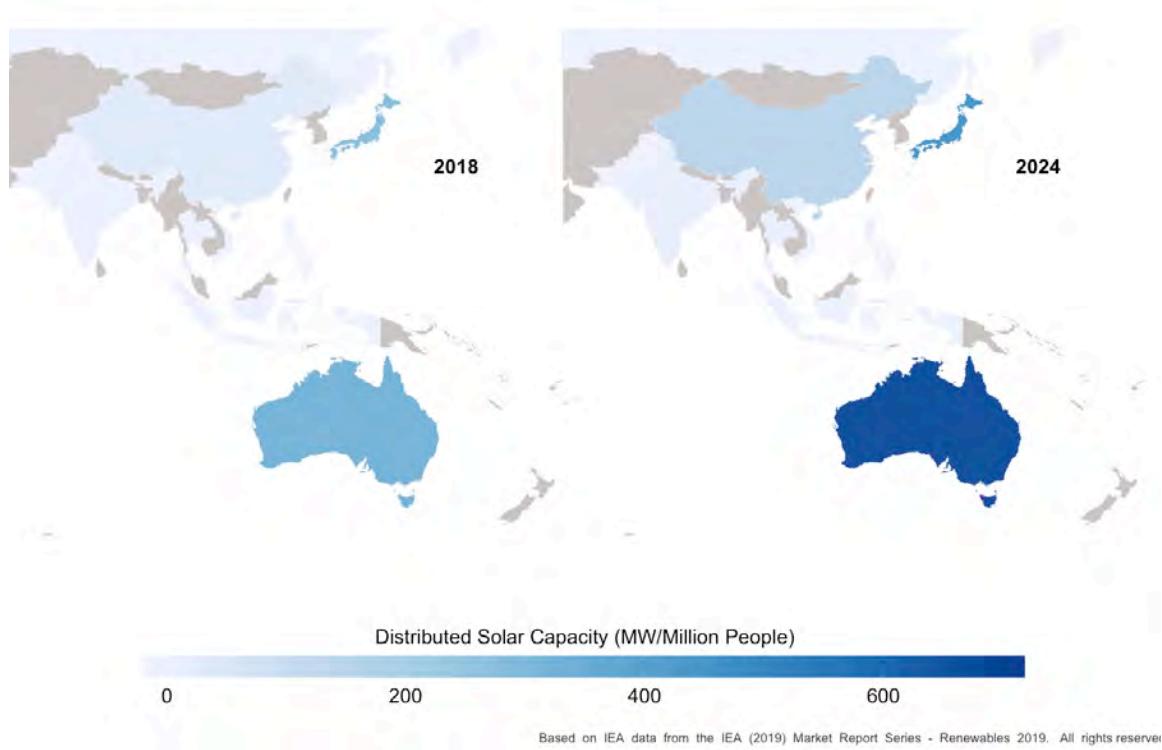


Figure 5.13: IEA Distributed Solar Forecast for Asia and Oceania

NOTES: This figure illustrates the current and forecast, per-capita distributed solar capacity in Asia and Oceania. We include the total residential, commercial/industrial, and off-grid capacities in our calculations. We divided each country's total capacity by its 2018 population and projected 2024 population using data from United Nations (2020). While New Zealand does have a small amount of distributed solar capacity, it is not included in IEA's data and forecast and so is omitted from this figure.

Nations, 2020). The remaining 5 GW or so of capacity in the Asia and Oceania regions comprises systems in India, Indonesia, Korea, Pakistan, the Philippines, Thailand, and Vietnam (IEA, 2019b).

#### 5.2.4 Deployment in Latin America

According to the National Renewable Energy Laboratory, Mexico has a goal of reaching 35% renewables by 2024 (Zinaman et al., 2018). As of June 2019, Mexico had installed just shy of 700 MW of distributed solar capacity (Zarco, 2019). This capacity makes up about 17% of Mexico's total installed solar capacity of 4 GW. Mexico's market for distributed solar is growing rapidly; it increased by 22% between December 2018 and June 2019 (Zarco, 2019). Consumers participating in Mexico's distributed solar market can be compensated through buy-all, sell-all, annual net metering, or real-time self consumption arrangements (IEA, 2019d)

Brazil's National Electric Power Agency (ANEEL) passed legislation in 2012 establish-

ing net metering rules for distributed generators.<sup>14</sup> The rules were most recently updated in 2015 and allow for customers to be compensated with credits to their electricity bill for energy produced beyond their own personal consumption. The credits last up to 60 months.<sup>15</sup> As of January 2020, Brazil had installed just over 2 GW of distributed solar generating capacity.<sup>16</sup> Brazil also has a 20% value-added tax exemption for small solar PV installations which has helped drive deployment (IEA, 2019d)

While the remaining Latin American countries have barely begun installing distributed solar, IEA forecasts that this could change dramatically over the course of the next four years. By 2024, Latin America could see residential distributed solar capacity increase by close to 600% due to new compensation policies in Argentina, Brazil, and Chile according to IEA's forecast (IEA, 2019d).

## 5.3 Extent of Adoption of Dynamic Pricing

The advent of high-resolution electricity consumption data—collected by smart meters—has paved the way for dynamic pricing programs around the globe. The wealth of information provided by smart meters allows customers to modify the timing and magnitude of their electricity usage and allows utilities to bill customers using tariffs based on this interval consumption data. We previously outlined the types of dynamic pricing plans that exist in Section 4.3. To reiterate: we do not consider TOU tariffs to be “dynamic” because, as discussed in Section 4.3.2, they are simply different fixed price tariffs assigned to different times of the day. Therefore, they cannot be used to manage the supply and demand balance in real-time because they do not vary with the hourly wholesale market price. Nevertheless, we discuss the adoption of TOU pricing as it is often touted as predecessor to dynamic pricing, although there limited empirical evidence in favor of this logic.

### 5.3.1 Adoption in the United States and Canada

The US has been experimenting with advanced tariff arrangements since the 1970s when time-of-use (TOU) pricing programs were adopted on a pilot basis after Congress passed the Public Utility Regulatory Policies Act (PURPA) in 1978 (US DOE, 2016a). At the time, however, the costs of the required smart meters were too high to justify large-scale adoption of dynamic pricing. Decades later, the first large-scale efforts to enroll customers in dynamic pricing programs were spurred by funding set aside by the The American Reinvestment and Recovery Act. The US Dept. of Energy used this opportunity to implement its Consumer Behavior Studies Program in which ten utilities worked with DOE to study the outcomes

<sup>14</sup>Normative Resolution No. 482, of April 17, 2012 (Updated in 2015) <http://www2.aneel.gov.br/cedoc/bren2012482.pdf>.

<sup>15</sup>See Chapter 3, Article 6, Section 1 of the resolution.

<sup>16</sup>Data accessed on January 23, 2020. Solar PV is denoted as UFV. See [http://www2.aneel.gov.br/scg/gd/GD\\_Fonte.asp](http://www2.aneel.gov.br/scg/gd/GD_Fonte.asp). It is unclear when the data was last updated but EIA reported on it in November 2019 at which time there were only about 1.57 GW of distributed solar capacity (<https://www.eia.gov/todayinenergy/detail.php?id=42035>).

of critical peak pricing, variable peak pricing, and critical peak rebate adoption (US DOE, 2016a).

Although SGIG funded projects began over a decade ago, the adoption of dynamic pricing is still in its infancy. Twenty-four states and the District of Columbia had enrolled fewer than 1% of their customers in either TOU or dynamic pricing by 2019. Nationwide, only about 7.1% of electricity customers were enrolled in these types of programs. The transportation sector had maintained the highest enrollment rate for advanced tariffs during most years between 2015 and 2019. However, the industrial sector experienced a large increase in enrollment from 7.8% in 2018 to over 18% in 2019—eclipsing the transportation sector’s rate of 15.7% (US EIA, 2020a). And while the residential sector has been a major adopter of advanced metering infrastructure, enrollment in TOU and dynamic pricing has remained low over the last four years of available data. Figure A.8, in the appendix, displays the state-level market penetration rates for 2015-2019 as well as the nationwide rates by customer sector. Only ten states had market penetration above the national rate. Maryland stands out as the major adopter of advanced tariffs with about 69% of customers enrolled in some type of advanced pricing program (including TOU) in 2019 (US EIA, 2020a). A major factor in the dismal rate of adoption of dynamic pricing programs is the lack of interval metering technology, but more important in regions with interval metering is the availability of an attractive default price option, as we discuss Section 7.2.

There were only nine utilities in the US offering residential real-time pricing in 2019 (down from 16 in 2015). One major utility offering residential RTP is Commonwealth Edison (ComEd), the largest electric utility in Illinois. ComED’s “Hourly Pricing” program follows the PJM real-time, hourly market prices, passing along these rates to customers with no markup.<sup>17</sup> Because the real-time hourly price is calculated to be the average of PJM’s twelve 5-minute prices during each hour, the price cannot be determined until after the hour has passed. Customers can instead use the PJM day-ahead hourly prices to set expectations for what their rate might be. RTP arrangements are much more widely available to commercial and industrial customers in the US with 63 utilities offering commercial RTP and 73 offering industrial RTP in 2019 (US EIA, 2020a).<sup>18</sup>

Variable peak pricing (VPP) was also relatively rare in the US in 2019 with only 6 utilities offering VPP rates to residential customers. The number of utilities offering industrial VPP plans fell from 14 to 11 between 2015 and 2018 before rising back to 14 in 2019 (US EIA, 2020a). Eversource, the largest energy provider in New England, has been offering a VPP rate program since 2008.<sup>19</sup> Under this program, off-peak prices are determined monthly and the variable on-peak prices are determined daily. Figure 5.14 illustrates how VPP prices vary over the course of a summer month like June.<sup>20</sup> In this example, the highest on-peak

<sup>17</sup>See <https://hourlypricing.comed.com/live-prices/>.

<sup>18</sup>These utility counts do not include short form respondents. See the appendix for more information.

<sup>19</sup>Eversource was previously called Connecticut Light and Power Company. See <https://www.eversource.com/clp/vpp/vpp.aspx>.

<sup>20</sup>Eversource’s VPP rider does not discuss in detail how these prices are determined, stating only that “replaces the fixed, monthly on-peak Generation Service charge from the Company’s TOD rates with a rate that varies daily according to the energy market.”

price during the month was 67% higher than the constant off-peak price of \$0.06311/kWh. The lowest on-peak price was 35% higher than the constant off-peak price.

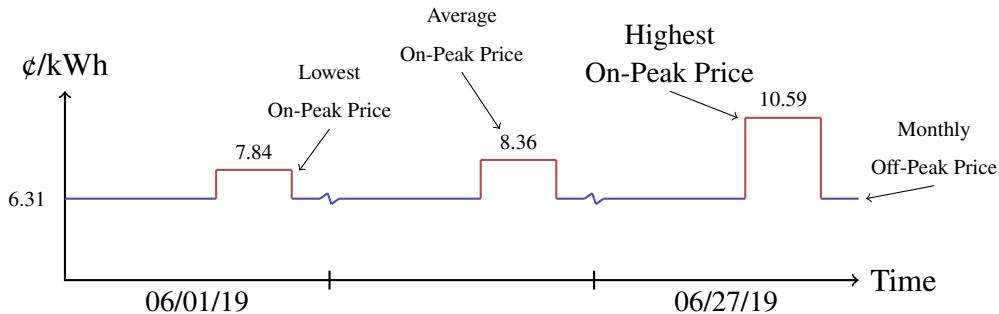


Figure 5.14: Eversource VPP Price Range in June 2019

NOTES: This figure illustrates Variable Peak Pricing using historical data from Eversource's program during June 2019. On-peak prices—shown in red—take place during the period from noon to 8 p.m. (Eversource, 2020).

Critical Peak Pricing (CPP) has seen increased availability recently. Like RTP plans, CPP arrangements are more commonly offered to commercial and industrial customers. Still, 31 utilities were offering residential CPP plans in 2019 and 15 offered residential CPR plans (US EIA, 2020a). Baltimore Gas and Electric (BGE) is one of the few utilities offering a CPR program. Customers enrolled in BGE's CPR plan receive alerts on a maximum of six critical peak days and are paid \$1.25 in credits towards their bill for each kilowatt hour reduced below their normal consumption between 1 p.m. and 7 p.m. (Baltimore Gas & Electric, 2019). San Diego Gas and Electric (SDG&E) offers a CPP pricing program to its customers in which the critical peak period is between 2 and 6 p.m. Under this program, a maximum of eighteen critical peak days can be declared per year.<sup>21</sup> The CPP period in this plan coincides with the on-peak period in SDG&E's TOU plan (4 to 9 p.m.) and so customers must be wary that they will be charged both the on-peak price and the CPP price during the period from 4 to 6 p.m., resulting in an extremely high price of consumption during this period. SDG&E allows customers to hedge against the risk of CPP events using a “Capacity Reservation” policy. Customers can reserve a desired amount of energy which will be set aside and unaffected by CPP prices on event days. For more information, Figure A.2 in the appendix provides information on the dynamic pricing initiatives undertaken by the US's largest utilities.

In 2012, Ontario became the first jurisdiction in North America to adopt time-of-use pricing as the default. Enrollment had reached 89% within four years of adoption (Faruqui et al., 2016). Beyond TOU pricing, there appears to little adoption of advanced tariffs by Canadian electric utilities. Board et al. (2007) describes the results of an early dynamic pricing experiment in the province.

<sup>21</sup>See <https://www.sdge.com/businesses/savings-center/energy-management-programs/demand-response/critical-peak-pricing>.

### 5.3.2 Adoption in Europe

Currently, electricity consumers in 16 European Member States can sign up for time-of-use contracts with intra-day, weekday, and weekend energy price differentiation. In eight Member States electricity consumers can choose real-time or hourly energy pricing. Dynamic tariffs that handle the operation of smart devices are available only in five Member States (see Figure 5.15). In order to induce more adoption of dynamic pricing, the EU's Clean Energy Package requires Member States to ensure customers have access to dynamic pricing (Hussain and Torres, 2019).

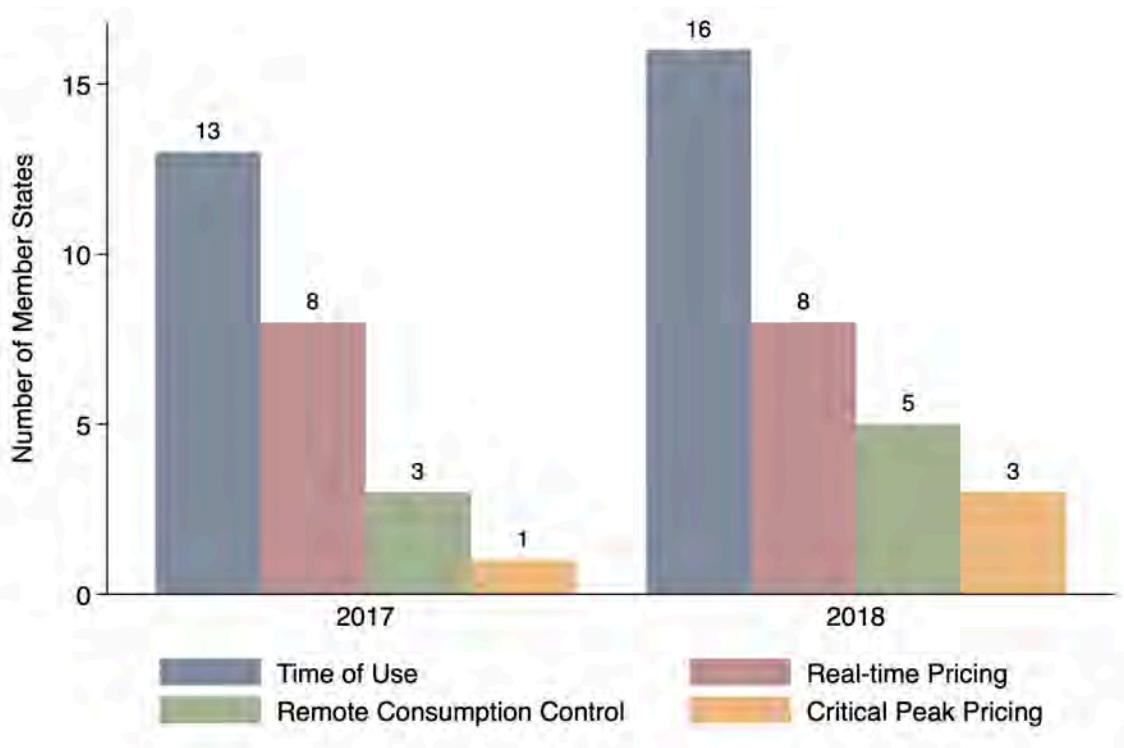


Figure 5.15: Adoption of Advanced Tariff Arrangements in Europe

NOTES: This figure displays the count of EU Member States with time of use pricing (TOU), real-time pricing (RTP), critical peak pricing (CPP), and remote consumption control arrangements. The figure was produced using information in ACER and CEER (2018) and ACER and CEER (2019).

The United Kingdom was an early adopter of real-time pricing for commercial and industrial customers during the initial Electricity Pool market design in the early 1990s. Midlands Electric, an electricity retailer, charged these customers the half-hourly pool price plus a dynamic transmission charge that was assessed on the average of the customer's demand during the three highest system peaks during the year. Patrick and Wolak (2001) estimates the half-hourly own-price and cross-price elasticities of demand for the sample of commercial and industrial customers on the Midlands electric real-time pricing plan. The authors find significant differences in the patterns of price responsiveness during the day and across hours of the day for different customers depending on their industry group. The

industry group with the largest price responsiveness was the local water and sewage utilities that typically had to use their pumps intensively once per day and would do so during the lowest priced half-hours of the day.

Although the Scandinavian countries have seen widespread smart-meter adoption, most customers are still on tariffs that vary monthly rather than intra-daily (Hussain and Torres, 2019). Spain and Italy, on the other hand, have adopted dynamic pricing as the default option. By 2019, nearly 40% of Spanish residential customers were on dynamic pricing plans Hussain and Torres (2019). Including commercial consumers, 75% of Spanish final energy consumption is priced dynamically (Boeve et al., 2018). A study by the Brattle Group identified that in the UK, a successful opt-in offering might attract only 20% of customers, whereas 80% or more of customers may remain enrolled in a dynamic pricing plan when deployed on an opt-out basis (Hledik et al., 2017).

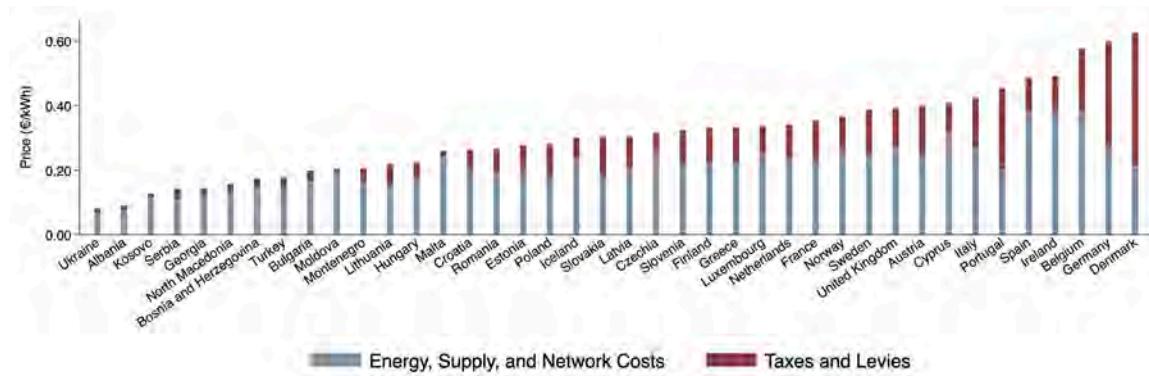


Figure 5.16: Average Electricity Prices for European Households in 2018

NOTES: This figure was produced using raw data from Eurostat (2020). We use the prices for households consuming between 2.5 MWh and 5 MWh per year.

As we illustrate in Figure 5.16, energy costs often make up a small portion of the actual retail price faced by consumers in Europe. Taxes and levies which finance state budgets and regulatory activities can make up large portions of energy charges (Boeve et al., 2018). The tax component is partially made up of an excise tax required of every Member State. This excise tax must be a minimum of €1/MWh for households and €0.50/MWh for other consumers. Historically, network costs have made up between 15% and 51% of the retail price faced by European households (Boeve et al., 2018).

Spain has adopted a novel approach to dealing with the challenges posed by the non-energy components of retail prices. Network costs and levies are aggregated in an “Access Tariff” component which is flexible and varies with the energy component. While commercial customers’ Access Tariff only varies on a time-of-use basis, residential customers benefit from dynamic, real-time variation in this charge.

### 5.3.3 Adoption in Australia, New Zealand, and Asia

Outside of Victoria, Australia’s smart meter deployment is still in the early stages, hampering efforts to adopt dynamic pricing programs at a large scale. Still, the Power of Choice program

that initiated the national smart meter roll-out in 2017 has prompted a number of utilities to begin experimenting with non-traditional electricity tariffs. In 2018, most Australian customers were still enrolled in a standard electricity pricing plan composed of daily supply and flat usage charges. Under Australia's Power of Choice reforms, distributors are now required to offer customers pricing plans that better reflect costs. TOU and CPP both meet this requirement. As of 2018, most networks were offering advanced tariff programs on an opt-in basis and only 12% of small customers were enrolled. Most of those enrolled were participating in TOU rather than dynamic pricing (Australian Energy Regulator, 2018). AER reported that most consumers with access to opt-in programs were not electing to adopt the new pricing plans. As we note in Section 7.2, this outcome could be due to the level of the fixed Victoria Default Offer Price.<sup>22</sup>

New Zealand has one of the highest market penetration rates for smart metering infrastructure (73.1% in 2017) and thus has substantial potential for dynamic electricity pricing. Over the course of the last decade, New Zealand's Electricity Authority has researched and encouraged advanced and dynamic pricing programs and about 75% of distributors have begun offering time-of-use arrangements (New Zealand Electricity Authority, 2019). However, the Electricity Authority notes that many distributors are considering time-of-use plans to be a sufficient and are abstaining from looking into dynamic pricing schemes. The Authority is encouraging distributors to explore other forms of efficient pricing.

China began experimenting with flexible tariffs as early as 2010 (Kang and Jia, 2011). Because the commercial and industrial sectors consumed such a large portion of China's energy (70% in 2011), TOU pricing was first introduced for those end-uses. (Kang and Jia, 2011) reported that an industrial TOU scheme in southern China consisted of peak, flat (off-peak), and valley (super off-peak) prices where the valley price was about 68% lower than the peak price and about 48% lower than the off-peak price. Residential customers have also gained access to these types of advanced tariff arrangements. More recently, China has adopted TOU pricing programs specifically for electric vehicle charging (Hover and Sandalow, 2019).

#### 5.3.4 Adoption in Latin America

The slow adoption of interval meters in Latin America has hindered the region's ability to adopt dynamic pricing programs. While Mexico's energy market has been liberalized with the introduction of the Wholesale Electricity Market, there does not appear to be much adoption of dynamic pricing. The Federal Electricity Commission (Comisión Federal de Electricidad) offers no dynamic pricing programs for its customers. Time-of-use plans with base, intermediate, and peak rates are offered to some customers, primarily those in the industrial sector with large demand.<sup>23</sup> Additionally, some of these plan vary by region based on average summer temperature. Similarly, the most flexible tariff in Brazil is a time-of use-tariff that differentiates between three different demand period categories (peak,

<sup>22</sup>See <https://www.esc.vic.gov.au/electricity-and-gas/prices-tariffs-and-benchmarks/victorian-default-offer>.

<sup>23</sup>See <https://app.cfe.mx/Applicaciones/CCFE/Tarifas/TarifasCRENegocio/Negocio.aspx>.

intermediate, and off-peak). The peak, intermediate, and off-peak hours are approved by ANEEL – the Brazilian national energy agency – in the periodic tariff reviews of each distributor, which take place every five years on average.<sup>24</sup> Currently, there are public consultations discussing the introduction of more flexible tariffs and net metering.

## 5.4 Extent of Adoption of Demand Response Programs

Demand response programs encourage temporary reductions—lasting minutes to hours—in consumer electricity demand at the prompting of the utility or grid operator.<sup>25</sup> Generally, consumers enrolled in demand response programs are rewarded with a financial incentive when they reduce their energy use during peak-demand periods. In this sense, demand response is similar to a critical peak rebate pricing program. In the US, 7.1% of customers were enrolled in a demand response program in 2019—up from 6.4% in 2018. (US EIA, 2020a). Figure 5.17 displays the state-level and national trends in US adoption of demand response.

Southern California Edison's (SCE) demand residential demand response program is designed for load management during the summer and is specifically engineered to allow SCE to remotely turn off the customer's A/C unit.<sup>26</sup> Customers can also add the option to override demand response events. Under this plan, SCE is allowed to shut off the customer's A/C unit for up to six hours per day. Customers are compensated based on the "Connected Tonnage" of their A/C unit.<sup>27</sup> Customers can earn between \$0.066 and \$0.262 per connected ton of central air conditioning depending upon how much control over their system they give to SCE.<sup>28</sup>

The amount of reported energy savings from demand response programs nationwide increased from 1.25 TWh to 1.46 TWh between 2015 and 2019 (US EIA, 2020a). Additionally, EIA reports data on the potential and actual peak demand savings from demand response in the US. The potential savings for each utility refer to the total demand savings that could occur if all demand response were called at the time of the system peak hour. The actual peak demand savings is the demand reduction actually achieved by demand response activities at the time of each utility's annual system peak hour. Between 2015 and 2019, the potential savings declined from about 33 GW to 31 GW. In 2019, 36.5% of potential peak demand savings were achieved (a decline from 40% achievement in 2018) (US EIA, 2020a).

According to IEA (2019e), global demand response capacity expanded by 4% in 2018.

<sup>24</sup>See <https://www.aneel.gov.br/tarifa-branca>.

<sup>25</sup>See <http://project-respond.eu/demand-side-management-vs-demand-response/>.

<sup>26</sup>See <https://www.sce.com/residential/rebates-savings/summer-discount-plan>.

<sup>27</sup>SCE's definition of Connected Tonnage: "Connected Tonnage is determined by dividing the central air conditioning unit's power (in watts) by a conversion factor of 1400 watts/ton, and multiplying by the Power Factor, then adding 0.09 for rounding purposes. The central air conditioning unit's power is determined by multiplying the voltage (VOLT) and electric current (amperage or AMP) based on the information on the faceplate of the central air conditioning unit." See: [https://library.sce.com/content/dam/sce-doclib/public/regulatory/tariff/electric/schedules/residential-rates/ELECTRIC\\_SCHEDULES\\_D-SDP.pdf](https://library.sce.com/content/dam/sce-doclib/public/regulatory/tariff/electric/schedules/residential-rates/ELECTRIC_SCHEDULES_D-SDP.pdf).

<sup>28</sup>SCE estimates that these savings can accumulate to between \$35 and \$140 per year.

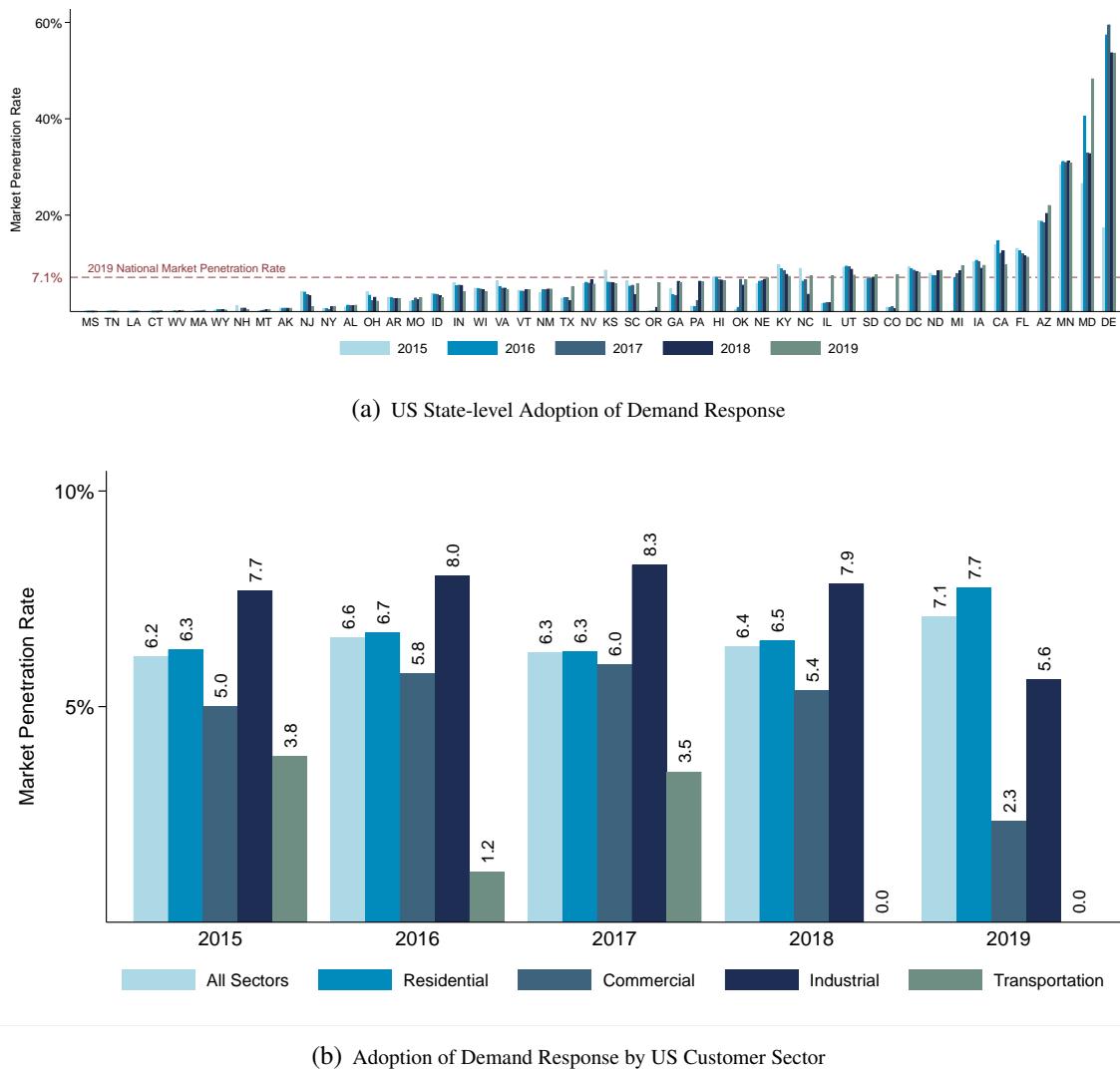


Figure 5.17: Adoption of Demand Response Programs in the US

NOTES: Panel (a) of this figure presents the market penetration rate for demand response programs across all sectors in each state from 2015 to 2019. Panel (b) displays the market penetration rates for dynamic pricing in each end-use customer sector in addition to the total, nationwide market penetration rate. Both panels of the figure were produced using raw data from EIA's *Annual Electric Power Industry Report* (US EIA, 2020a). We define market penetration to be the number of customers enrolled in demand response in each state/sector divided by the number of customers in that state or sector/sector.

IEA notes that the potential flexibility that could be provided by demand response for EV charging is currently untapped and could provide up to 2 GW of demand response capacity globally.



## 6. Technologies Providing Distribution Network Services

### 6.1 Interval metering systems

The main benefit of interval meters is the ability to measure electricity consumption on an hourly or short-term time interval basis during the billing cycle. This allows the electricity retailer to measure and price energy flows to and from the consumer at that level of temporal granularity. A number of other features of interval meters are often offered—and at times required—in markets around the world. In this section we highlight some of the other beneficial qualities that smart meters use to modernize the grid.

#### 6.1.1 Technology Specifications

In the US, smart meters are often integrated with or feature a Home Area Network (HAN), Direct Load Control (DLC), or Daily Digital Access (DDA). Figure 6.1 illustrates the adoption trends for these features from 2015 to 2019. A HAN is a combination of software and hardware components that work in tandem to allow the smart meter to communicate with devices throughout a user's residence. DLC is a type of demand response arrangement allowing the grid operator to remotely and instantaneously shut off devices consuming energy. This allows the operator to manage network load without having to rely on customers reacting to price signals. Finally, DDA provides consumers with a means of accessing daily usage data, often through a web portal (US EIA, 2017). DDA is by far the most common of these features to be adopted by US consumers, reaching over 33% market penetration in 2019. DLC and HAN adoption are far less common but have still gained traction over the last four years of available data.

The European Commission (EC) has recommended ten common minimum functional requirements that every smart metering system for electricity should fulfil. These functionalities are listed in Figure 6.1. Functionalities (a) and (b) are directly related to the customers and make their consumption data available (at a rate of at least 15 minutes) to them and to

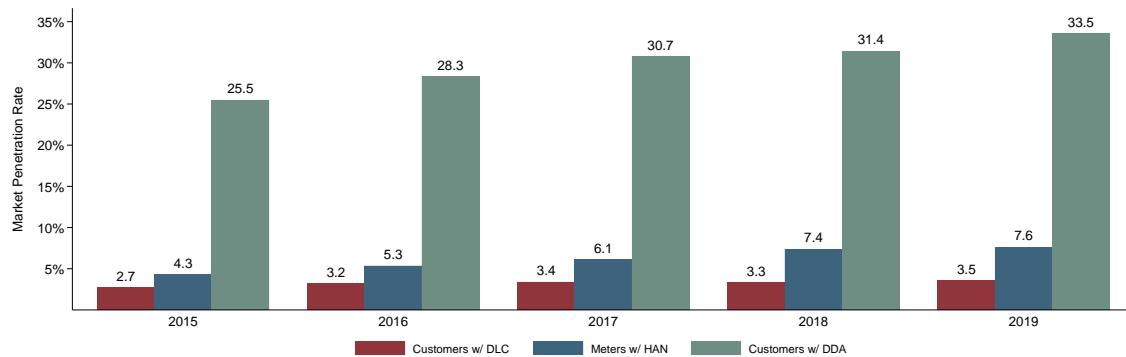


Figure 6.1: Smart Grid Technologies in US Homes

NOTES: This figure displays the market penetration rates for Home Area Network (HAN) enabled meters, customers with Direct Load Control (DLC), and customers with Daily Digital Access (DDA) to energy usage data through a web portal. This figure was produced using raw data from EIA's *Annual Electric Power Industry Report* (US EIA, 2020a).

energy service providers, if they choose so. This kind of information update is absolutely necessary for the consumer to efficiently manage his consumption, and also for the network as a whole. This is similar to Daily Digital Access in the US. Both of these functionalities in conjunction with functionality (f) support advanced pricing structures (e.g, dynamic pricing) and may achieve energy efficiencies and save cost by reducing the peaks in energy demand. Most Member States have implemented requirements for secure data collection and support for advanced tariff systems (ACER and CEER, 2019). Reporting intervals also differ across the Member States, though the majority require a maximum interval of 15 minutes. The remaining States allow 30 minute and hour-long reporting intervals (ACER and CEER, 2019). Only six states allow the consumer to choose their own timing interval.

In Australia, the National Electricity Rules and National Energy Retail Rules declare the set of features that smart meters must be able to perform (Australian Energy Market Commission, 2015). Requirements include but are not limited to remote disconnection, reconnection, and meter reading services. AEMC chose not to prescribe an exhaustive list of requirements in order to maintain a level of competition—stipulating that “consumers and those other parties will be better placed to determine the services they want and are willing to pay for” (Australian Energy Market Commission, 2015).

The hardware lifespan for smart meters is generally between 10 and 20 years which means that a number of countries are already preparing to roll-out second generation smart meters over the coming decade (Rowlands-Rees, 2018). Over the next decade, BNEF predicts that investment in smart meters will transition away from government-led roll-outs and towards replacement and improvement of existing metering infrastructure. In 2030, BNEF estimates that up to \$12.2 billion will be spent on replacing the first generation of smart meters installed around the globe (Rowlands-Rees, 2018). The investment required will depend on whether new meters gain added functionalities, resulting in little overall change in hardware cost, or whether functionalities will remain the same and the cost will just continue to decline.

Table 6.1: Smart Meter Functionalities in the EU

Relevance	Requirements
Consumer	<ul style="list-style-type: none"> <li>a) Provide readings directly to the consumer and/ or any 3rd party</li> <li>b) Update readings frequently enough to use energy saving schemes</li> </ul>
Metering Operator	<ul style="list-style-type: none"> <li>c) Allow remote reading by the operator</li> <li>d) Provide two-way communication for maintenance and control</li> <li>e) Allow frequent enough readings for networking planning</li> </ul>
Commercial Aspects of Supply	<ul style="list-style-type: none"> <li>f) Support advanced tariff system</li> <li>g) Remote ON/OFF control supply and/or flow of power limitation</li> </ul>
Security - Data Protection	<ul style="list-style-type: none"> <li>h) Provide secure data communications</li> <li>i) Fraud prevention and detection</li> </ul>
Distributed Generation	<ul style="list-style-type: none"> <li>j) Provide import/export and reactive metering</li> </ul>

**Notes:** This table is a reproduction of the information found in Figure 27 in Tractabel (2019).

### 6.1.2 Customer Data Privacy

While smart meters collect large amounts of detailed information regarding customers' electricity consumption, these data are often underutilized due to the high costs of maintaining customer data privacy (Douris, 2017). In an effort to prevent these data from being misused or shared without customer consent, several states in the US have implemented policies to ensure data privacy. Additionally, as discussed in Table 6.1, secure data communication is one of the key smart metering functionalities recommended by the EU (Tractabel, 2019). In 2018, seventeen Member States had implemented legal requirements for secure data communication for smart metering infrastructure (ACER and CEER, 2019).

Data collected by smart meters can be used to surveil customers by matching personal information like addresses and names to real-time consumption data. Because many individual appliances have uniquely identifiable load profiles, consumption data can be used to see what types of devices are being used within a residence (Asghar et al., 2017; Douris, 2017). Eom and Wolak (2020) use hourly consumption data for small commercial customers in South Korea and the results of a customer-level survey of appliance holdings to recover appliance-level load profiles, appliance-level load responses to facing a dynamic price tariff, and appliance-level load responses to a critical peak event day. Eom and Wolak (2020) find that the major source price response of small commercial customers is what they call the

reconfiguration effect of being placed on a dynamic pricing plan rather than the response to a specific critical peak event day, because of the difficulty of temporarily adjusting work schedules in these small businesses.

Law enforcement officers have used such data to identify electricity consumption patterns that coincide with the types of special lighting, fans, and ventilators used for indoor marijuana cultivation. Data showing unique consumption signatures from these devices can be enough to obtain a search warrant (Douris, 2017; Durkay and Freeman, 2016). Other concerns include the possibility of data being acquired by hackers in order to commit identity theft, burglary, stalking or other crimes (Douris, 2017). For example, having access to consumption data can allow a criminal to identify when residents are typically home which would make burglary or stalking much easier. Similarly, load profiles can be used to identify commercial activities, potentially easing attempts to steal proprietary information or commit other forms of corporate espionage (Douris, 2017).

In 2015, the US Dept. of Energy (DOE) released a voluntary code of conduct known as DataGuard, with guidelines for data privacy in the era of interval meters. The voluntary program is intended to be used by both utilities and third-parties as they navigate new data privacy challenges posed by these new technologies. DataGuard is based upon five tenets of security, recommending that: (1) customers be given clear and conspicuous notice about privacy related policies, (2) customers should have some control over the access to their data with the ability to authorize disclosure to third-parties and revoke consent for said disclosure, (3) customers should have access to their own data, (4) data should be accurate and secured against unauthorized access, and (5), firms should engage in some form of self enforcement to encourage compliance (US DOE, 2015).

DOE also aided in the creation of the industry-led data portal, Green Button Connect, which allows customers, utilities, and third-parties to securely access energy data. In 2018, the Green Button Alliance—a non-profit aiming to foster adoption of the Green Button Connect platform—became one of the first members of the DataGuard program. Because Green Button Connect follows the security principles outlined by DataGuard, it is a commonly used portal through which utilities can safely share data with customers and third parties (Green Button Alliance, 2018). While DOE has only issued voluntary recommendations for how consumer data should be used, the American Council for an Energy-Efficient Economy (ACEEE) reports that many states have implemented some sort of regulation addressing privacy concerns and third-party access (ACEEE, 2019).

Data collected by California utilities are kept secure under several pieces of legislation. Decision 14-05-016, which was passed by the Public Utilities Commission in 2014, dictates a set of rules for providing third parties access to customer data while protecting privacy (California Public Utilities Commission, 2014). These rules provide comprehensive and rigorous protocols that utilities must follow in order to aggregate and anonymize data securely. Any information that is obtained by smart meters and that can be “can reasonably be used to identify an individual, family, household, residence, or non-residential customer,” cannot be released to a third-party without consent of the individual it pertains to (California Public Utilities Commission, 2014). However, if utilities follow the Decision’s rules for aggregating and anonymizing data, information can be distributed to third-parties for particular uses.

including academic research and government projects. For example, when aggregating residential customer data over a census block group, data must be stripped of all personal identifying information and the census block group must contain more than fifteen customers and no customer can account for more than 20% of the energy consumed in the group over the course of a month. These requirements vary depending on the level at which customer data are grouped (e.g. zip codes).<sup>1</sup>

The Texas Utilities Code dictates that all data collected by electricity meters belong to the customer (Texas Utilities Code, 2014).<sup>2</sup> Utilities can only share customer data with affiliated corporations or third-parties if the information is directly necessary to provide electricity service to the customer or with the customer's consent. All customers in Texas have access to their own data through an online portal called Smart Meter Texas (SMT) (Douris, 2017). SMT makes use of the Green Button Connect data platform in order to provide customers with a secure data retrieval experience.

In the cases where states do have relevant usage data policies in place, regulations are fairly similar. Generally, aggregated customer data can be shared with third-parties without customer consent (ACEEE, 2019). In a similar manner to California's regulations, aggregation protocols generally dictate a minimum number of customer accounts to be included as well as the maximum portion of energy that can come from a single account. More granular, individual data can be shared with third-parties if customer consent is given. These types of regulations do not prevent data from being distributed in the case that state or Federal law requires it be shared (e.g. with law enforcement).

While the EU has been carrying out mandated smart meter roll-outs for the better part of the last decade, regulations for smart meter data privacy were only more recently solidified in the recast Electricity Directive of June 2019 (Riemann, Robert, 2019). After years of research and policy recommendations from the European Data Protection Supervisor and the Data Protection Working Party, the recast Directive determined that data collected by smart meters should be required to meet the standards set by Regulation (EU) 2016/679 of the European Parliament (the General Data Protection Regulation) (Riemann, Robert, 2019). These regulations pertain to all personal data belonging to individuals in the EU, not just detailed electricity usage information. By default, customer data are not to be shared without consent, under the regulation.

## 6.2 Network Monitoring Systems

Advancements in network monitoring have saved US distributors millions of dollars in operations and switching costs (US DOE, 2016b). These technologies are largely made possible by smart sensors that record real-time data and transmit it to the distribution network

<sup>1</sup>Additional information can be found California Public Utilities Code Chapter 5.8380-8381.

<sup>2</sup>Texas Utilities Code Chapter 39.107(b) reads: "All meter data, including all data generated, provided, or otherwise made available, by advanced meters and meter information networks, shall belong to a customer, including data used to calculate charges for service, historical load data, and any other proprietary customer information. A customer may authorize its data to be provided to one or more retail electric providers under rules and charges established by the commission."

operator. The costs associated with these smart sensors have fallen substantially, allowing automation technologies to be incorporated into distribution networks. The US Dept. of Energy orchestrated over 60 pilot programs between 2009 and 2016 in order to test the effectiveness of new distribution automation technologies. These projects were largely funded through Smart Grid Investment Grant (SGIG) allocations set aside in *The American Recovery and Reinvestment Act of 2009*.<sup>3</sup>

Smart devices referred to as fault location, isolation, and service restoration (FLISR) technologies are used to quickly and effectively resolve issues arising from faults in a distribution network or to proactively avert faults entirely. If there is a fault in the distribution network, a remote sensor will detect and locate the abnormal voltage or current. Subsequently, automated feeder switches will isolate the fault by opening upstream and downstream of its location. Once the fault is isolated, the system can restore service to impacted customers by diverting energy to intact feeders. These actions happen autonomously and rapidly (often in under a minute), greatly shortening the duration and extent of power outages (US DOE, 2016b).

Distribution automation can also be administered in an effort to reduce strain on capital assets like sensitive electronic equipment by monitoring and controlling voltage and reactive power (US DOE, 2016b). Automated voltage controls can reduce line losses, peak demand, outage costs, energy bills, and need for labor, and improve power factors, reliability and energy savings. Thirty-eight of the SGIG recipient utilities used conservation voltage reduction (CVR), a voltage reduction technique relying on smart sensors and feeders, to achieve peak demand reductions ranging from 1% to 3% (US DOE, 2016b).

Another key benefit of advanced monitoring and control devices is the ability to proactively identify distribution equipment that is in poor health. Smart sensors collecting data on temperatures, oil and water levels, or system pressures can report real-time data to grid operators and work in tandem with diagnostic software to determine whether preventative maintenance is needed (US DOE, 2016b). During the SGIG project period, Florida Power & Light Company (FPL) installed smart monitoring devices on transformers in its distribution network and subsequently identified a serious potential transformer fault. FPL proactively replaced the unit, avoiding over \$1 million in restoration costs and preventing 15,000 customers from losing power (US DOE, 2016b).

The advent of distributed generation equipment has increased the need for automated distribution monitoring and control. Distributed energy resources are being adopted rapidly and are predicted to continue growing immensely during the coming decades. Distributed solar, electric vehicles, and other innovative energy solutions all need to be integrated into existing distribution systems in a low cost manner in order to maintain cost-competitiveness (US DOE, 2016b).

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<sup>3</sup>US DOE (2016b) provides an extensive review of SGIG projects that involved distribution automation.

### 6.3 Automated Load Shifting Technologies

Innovation in “smart” appliances will be key for dynamic pricing to take off. Such appliances will allow users to extract the most of the potential savings without the hassle of constantly monitoring electricity prices and adapting load.

While upfront costs of smart appliances may be high, they have the potential to pay off rapidly, depending on their energy consumption. A promising candidate is the electric heat pump. In the UK, a three member team of the government-backed Energy Systems Catapult, Daikin, and Passiv Systems, designed a fuel switching technology for heat pumps. If the price for electricity is low the technology can automatically change from gas to electricity (Hussain and Torres, 2019).

Many durable goods may also be retrofitted and, in conjunction with digital technology, be converted to smart devices. For example the start-up company Ecopush, has developed an application that lets customers outfit their home appliances with the ability to be controlled by Amazon’s Alexa virtual assistant. Commands such as “Alexa, turn on my dish washer when it’s cheapest/greenest/right now” allow consumers to incorporate their environmental preferences into their energy use (Hussain and Torres, 2019).

The company Myenergi followed a similar path and created an app that allows customers to charge their electric car or run household appliances either from the grid or from their own distributed generating system, depending on the price at the time (Hussain and Torres, 2019)

For retailers it may be interesting to team up with tech-companies as electricity may be bundled with other goods and services. For example, energy suppliers partnering and technology providers can partner up in order to offer discounts on smart, remotely controllable devices like intelligent thermostats. Bundling has also been used to incentivize the adoption of larger purchases like battery storage systems or even electric vehicles. In Sweden, for instance, firms have offered new TOU customers a bundled product incorporating electric vehicle leases with discounted charging station prices (Hussain and Torres, 2019).

Other examples of bundling include combining EV leasing with discounts at EV charging stations when signing a TOU tariff contract with the respective supplier. This strategy is in use in Sweden as noted by Hussain and Torres (2019).

### 6.4 Distributed Energy Resource Management Systems

Because distributed solar energy resources provide intermittent power to the grid, advanced management solutions are necessary for maintaining grid reliability and realizing maximum benefits from these types of generators. DERMS have been developed in an effort to aid utilities as they navigate the transition to a world with increasing adoption of distributed generation.<sup>4</sup> In many ways, a DERMS is similar to or incorporates aspects of the distribution automation technologies discussed in Section 6.2. Like distribution automation systems, a DERMS comprises software and smart hardware working in unison to forecast and control

<sup>4</sup>In brief, a DERMS is used to “monitor (in near real time), control, forecast, schedule, and optimize” distributed energy resources (OATI, 2016).

grid connected generation and storage assets (AutoGrid, 2019). These technologies are a necessity because, in their absence, the grid can experience unwanted and potentially dangerous events such as abnormal voltage profiles, damages to infrastructure, and other complications that are avoidable with DERMS (OATI, 2020b)

DERMS solutions have been developed by several firms and are currently being administered in grids around the world. Common features include forecasting, load and voltage management, and the integration of electric vehicles as sources and sinks for energy. These features often rely on artificial intelligence in order to optimize their functionalities. Another common offering across DERMS solutions is the creation of a virtual power plant, which is essentially a centralized way of operating a collection of distributed energy resources as one large asset (Wolf, 2020).

OATI, an energy technologies firm serving much of the North American energy sector, offers a DERMS that is in use by utilities in North Carolina, Tennessee, and other markets. The North Carolina Electric Membership Corporation (NCEMC)—a power supplier for 25 of the 26 electric cooperatives (over 2.5 million people) in the state—adopted OATI’s DERMS solution in 2019. According to net metering data from EIA’s *Annual Electric Power Industry Report*, members of NCEMC had about 11.6 MW of distributed solar generating capacity in 2018 (including customer-owned and virtual capacity) (US EIA, 2020a). NCEMC’s adoption of OATI’s DERMS includes cloud-based computing for new and existing demand-side management operations along with a proprietary microgrid management system. OATI’s microgrid controller is capable of optimizing local distributed generation and providing load prioritization and ancillary services to the grid (OATI, 2020a). In the southeastern US, 128 utilities belonging to the Seven States Power Corporation—a nonprofit organized by the Tennessee Valley Public Power Association—are also able to benefit from OATI’s DERMS solutions (OATI, 2018). By the end of 2019, at least seven utilities—spread across Alabama, Georgia, and Tennessee—had signed letters of intent to begin implementing the DERMS solution (Seven States Power Corp., 2019)

AutoGrid Systems is another firm providing DERMS solutions to utilities around the world. As of June 2019, AutoGrid had contracted more than 5 GW of distributed energy resources around the world (AutoGrid, 2019). AutoGrid’s DERMS has been used by Dutch utility, Eneco, in order to manage 100 MW of customer-owned Combined Heat and Power (CHP) balancing capacity.<sup>5</sup> Additionally, AutoGrid announced in June 2019 that it will be working with Japan to create the world’s largest storage-virtual power plant in the world. The first stage of this partnership is for AutoGrid to use its Demand Response Optimization and Management System (DROMS) to aggregate demand response resources into assets that can be sold into capacity markets. This phase was set to begin by the end of 2019. The second phase is the full introduction of the DERMS including the aggregation of distributed solar, storage, CHP, and EV batteries into a virtual power plant.<sup>6</sup>

The growing market for electric vehicles has posed new challenges and opportunities for DERMS suppliers. EnergyHub, another DERMS provider, recently began a project with

<sup>5</sup>See <https://www.auto-grid.com/news/2895-2/>.

<sup>6</sup>See <https://www.prnewswire.com/news-releases/autogrid-announces-major-virtual-power-plant-agreement-with-japans-eneres-co-ltd-300869173.html>.

Baltimore Gas and Electric (BGE) to help the city prepare for the large number of EVs expected to be adopted by 2025. The EnergyHub DERMS will allow BGE customers to participate in TOU rates for EV charging without having to have an additional meter installed. The customer's own charging equipment will be sufficient to collect charging data. The hope is that this will remove what was previously a barrier to program enrollment (Bleiberg, 2020). While increased adoption creates new stresses for grid infrastructure and load management, the bi-directional charging abilities of EVs allow them to act as both sources and sinks of electricity which can be advantageous for utilities needing to balance flows in the presence of intermittent renewables. ENGIE, a major European energy technology firm, offers a DERMS solution that incorporates Vehicle-2-Grid (V2G) technology. This program allows fleets of parked EVs to be used to stabilize the electrical grid and can incentivize the self-consumption of distributed renewables.<sup>7</sup> Revenue made from selling this energy into the grid is split between ENGIE and the battery owners.

## 6.5 Services Aiding Customer Participation in Wholesale Markets

Whereas DERMSs and automated load management systems are generally marketed as resources for energy suppliers and distributors, there are a number of companies offering demand-side services in order to help individual customers manage their energy consumption. A key component of these types of services is the disaggregation of consumer-level energy usage data. Disaggregation provides consumers with device-level energy consumption data rather than the household- or building-level data that are commonly provided by electric utilities. Itemized consumption data has the key advantage of allowing consumers to identify *which* of their devices are using the most energy, and *when*. They can then adapt their energy usage, responding to price-signals from their utility, in a manner that most suits their personal needs.

Bidgely, a Silicon Valley firm, has been honing the disaggregation approach for the last decade. Their approach leverages advancements in machine learning and artificial intelligence to provide customers with a variety of metrics with which to assess their own energy consumption. Historically, the absence of granular smart-meter data or has hindered disaggregation attempts by customers and utilities. However, advancements in machine learning have allowed Bidgely to extend disaggregation services to customers who do not have advanced metering infrastructure. Using a vast quantity of smart metering data, Bidgely determines the predictive relationship between household characteristics and itemized energy usage.<sup>8</sup> By comparing a home without a smart meter to a similar home with a smart meter (a “matched peer” approach), they are able to scale some of the disaggregation benefits of smart meters to homes that do not have them. So while a customer without a smart meter may not be able to directly participate in the wholesale market through dynamic pricing, they can make more informed choices about how they use their appliances and the effects these

<sup>7</sup>See <https://innovation.engie.com/en/distributed-energy-resources-management-system>.

<sup>8</sup>See <https://www.bidgely.com/wp-content/uploads/2018/03/Introduction-to-Universal-Disaggregation.pdf>.

behaviors might have. According to Bidgely's website, at least 15 million homes around the world are enrolled in Bidgely services. While the cost of smart sensors has fallen markedly (as we show in Figure 2.1), there may still be some customers for whom these devices are prohibitively expensive. Bidgely's innovative method of "universal disaggregation" allows customers to reap some of the benefits of smart sensors without the installation cost.

Stem is another firm leveraging advancements in artificial intelligence in an effort to help consumers, businesses, and utilities best utilize the full range of options offered by distributed energy resources. In particular, Stem's "Athena" AI software is designed to help owners of distributed storage manage their system so that it can "reduce peak demand charges while reserving power in the battery for backup during an outage" or to aid owners of PV and storage systems "shift energy output to maximize revenue through participation in wholesale energy markets." Stem's software helps these storage systems make intelligent, real-time decisions regarding when to store energy, and when to deploy it. This system is programmed to take into account rate structures, weather forecasts, price signals, and market participation rules when making decisions.<sup>9</sup>

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<sup>9</sup>See white paper available at <https://www.stem.com/technology/>.



## 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 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.<sup>1</sup> 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.

<sup>1</sup>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.<sup>2</sup> 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  $\mathbf{E}(P_r(h))$ .

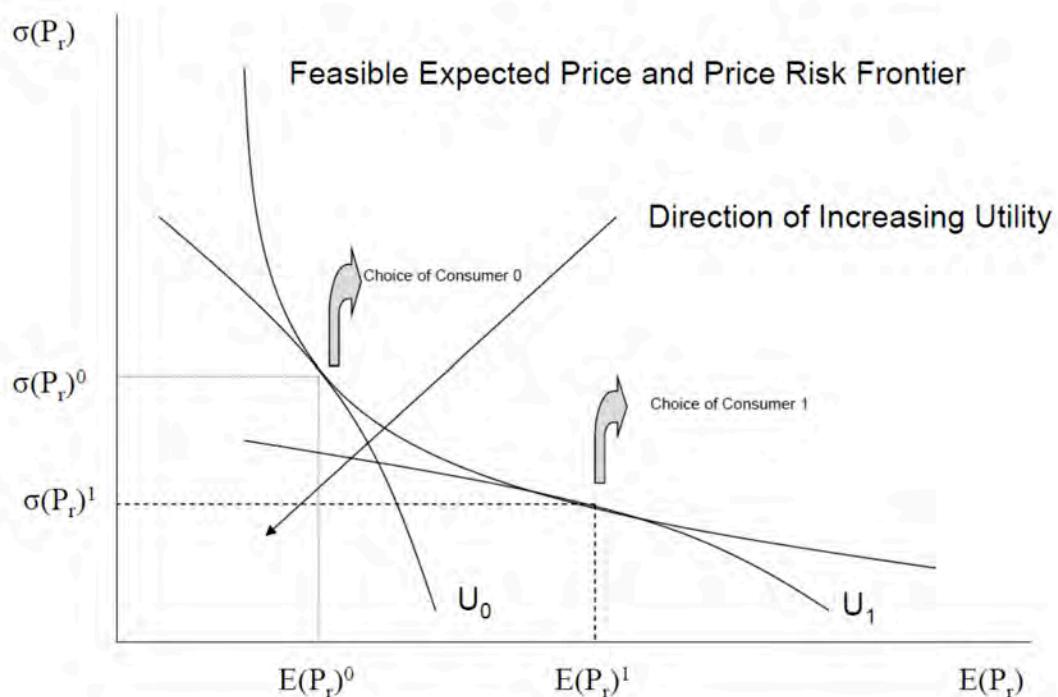


Figure 7.1: Expected Retail Price ( $\mathbf{E}(P_r)$ ) and Standard Deviation of Retail Price ( $\sigma(P_r)$ ) Frontier

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

<sup>2</sup>This means that consumers prefer a lower mean hourly price and a lower standard deviation of the hourly price.

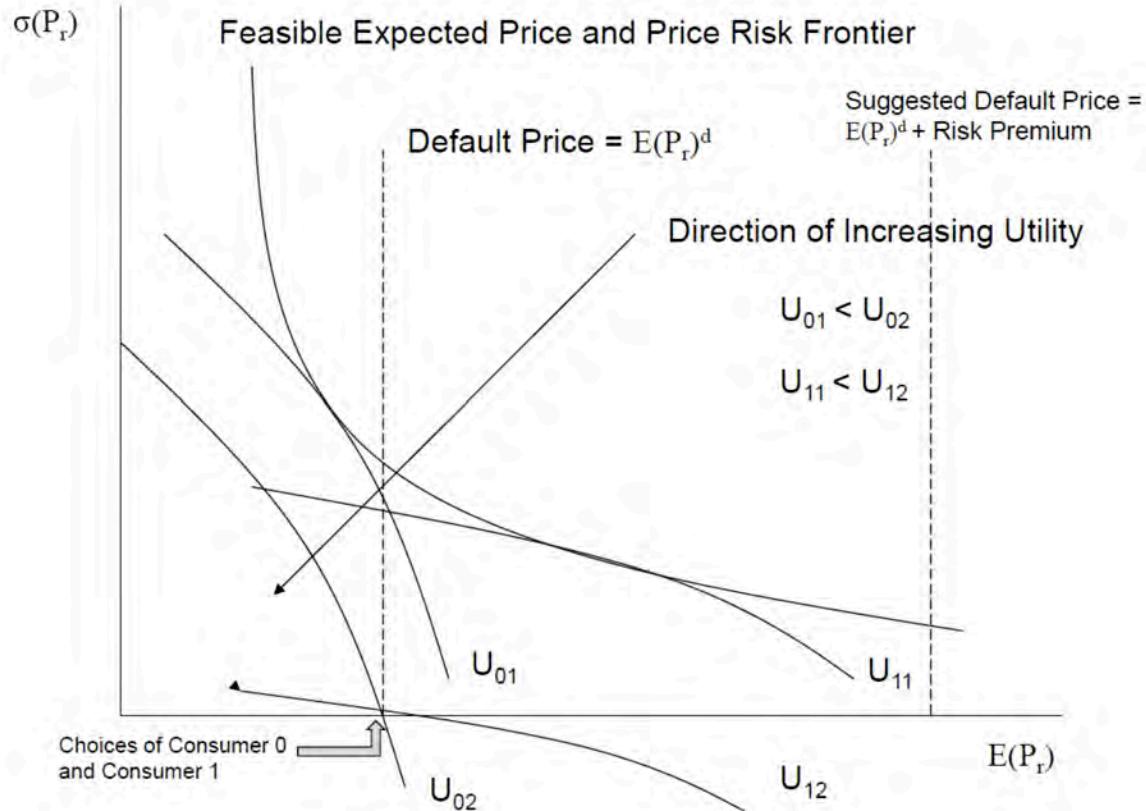


Figure 7.2: Consumer Choices with Default Rate Set at Average Wholesale Price and Suggested Default Fixed Price

pricing plan choice. For customer 0 this process yields the point  $(E(P_r)^0, \sigma(P_r)^0)$  and for customer 1 the point  $(E(P_r)^1, \sigma(P_r)^1)$ . 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  $E(P_r)$  on the *Feasible Expected Price and Price Risk 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,  $E(P_r)^d$ , was set that eliminated all price risk faced by these two consumers. Because  $U_{01} < U_{02}$  (the utility level of indifference curve  $U_{01}$  is greater than the utility level of indifference curve  $U_{02}$ ) and  $U_{11} < U_{12}$ , both consumers would achieve a higher level of utility by choosing  $E(P_r)^d$  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  $E(P_r)^d$  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  $E(P_r)^d$  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  $\$55.84 = 30 \text{ days/month} \times 24 \text{ kWh} \times 0.04 \text{ \$/kWh} + 24 \text{ days/month} \times 16 \text{ kWh} \times 0.06 \text{ \$/kWh} + 20 \text{ days/month} \times 2 \text{ kWh} \times 0.10 \text{ \$/kWh}$  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.

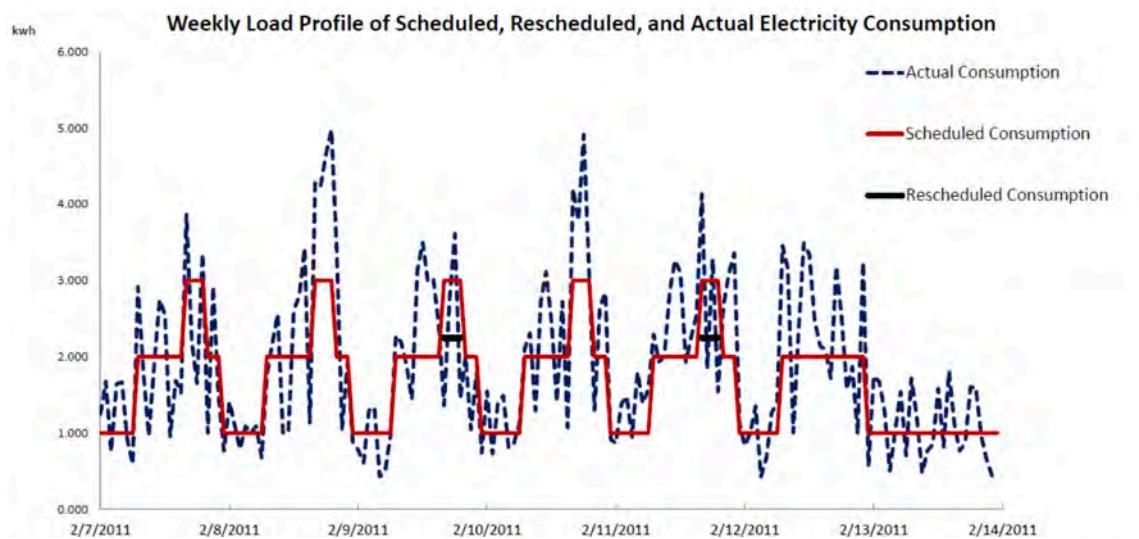


Figure 7.3: Cell Phone Plan Approach to Dynamic Retail Electricity Pricing

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 be 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:

$$PR_1 \times D_1(PR_1) + PR_2 \times D_2(PR_2) = PW_1 \times D_1(PR_1) + PW_2 \times D_2(PR_2), \quad (7.1)$$

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 retailer's 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

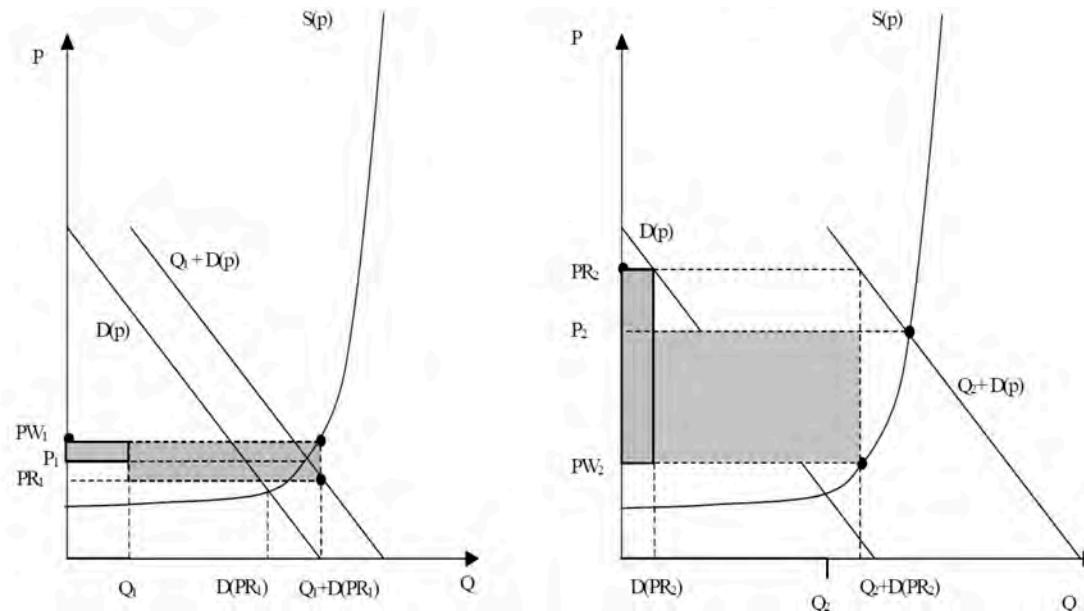


Figure 7.4: Using Dynamic Pricing Customers to Benefit Fixed Price Customers

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<sup>3</sup> 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

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<sup>3</sup> $1.03 = 13.5 \text{ kWh} \times \$0.10/\text{kWh} - (14 \text{ kWh}/0.90) \times \$0.02/\text{kWh}$

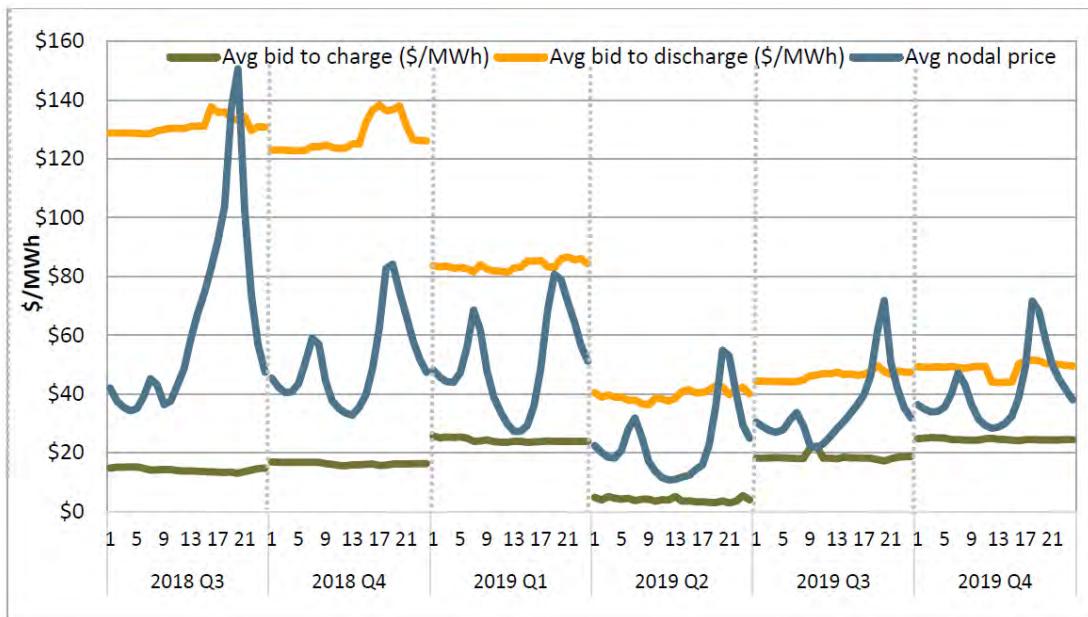


Figure 7.5: Buy (Bid to Charge) and Sell (Bid to Discharge) Prices for Grid-Connected Storage Capacity in California

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.

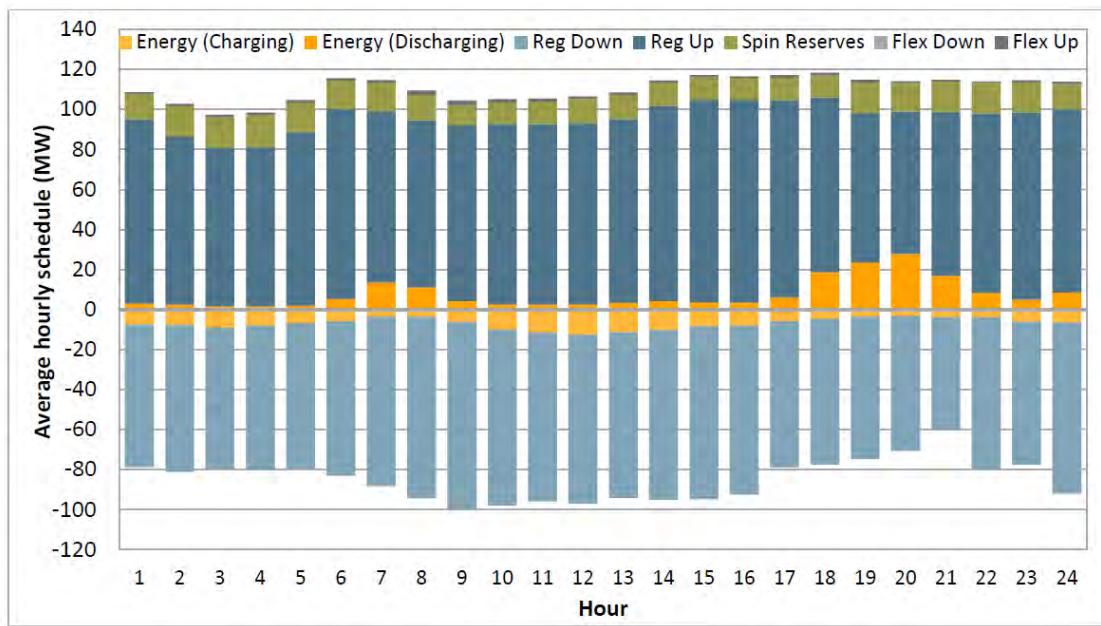


Figure 7.6: Products Sold by Grid-Connected Storage Capacity in California

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

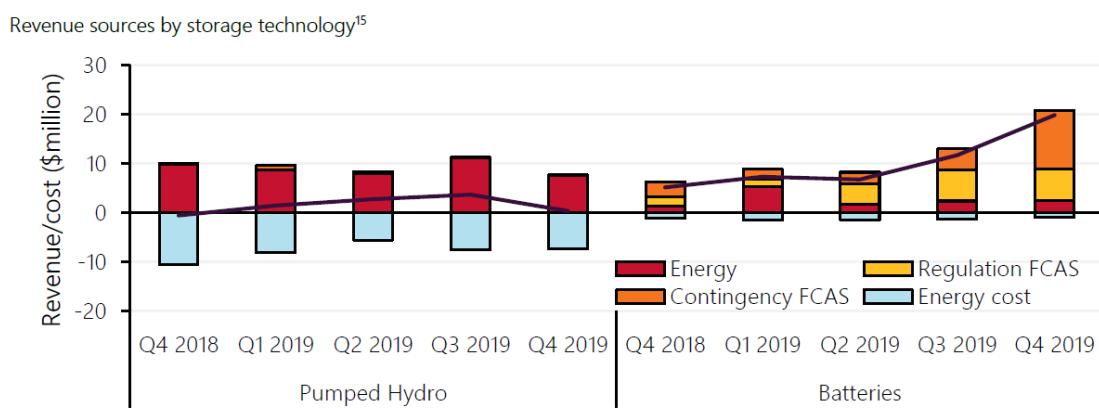


Figure 7.7: Products Sold by Grid-Connected Storage Capacity in California

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 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 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.<sup>4</sup> 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 been 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.

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<sup>4</sup>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 transmission 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 were 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.<sup>5</sup>

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

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<sup>5</sup>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 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.



## 8. Directions for Future Research

There are a number of directions for future research for both the reactive and forward-looking looking approaches to the future of electricity retailing. Topics applying to both possible futures are: (1) the technical and financial viability of direct load-control approaches to demand response using WiFi enabled plugs and in-house routers, (2) mechanisms for valuing storage for its ability to avoid distribution network upgrades while still allowing it to participate in energy and ancillary services markets, (3) mechanisms for allowing remote-controlled distribution network-connected resources such as solar PV capacity, storage, high-speed vehicle charging, and electric heating and cooling to provide ancillary services to the wholesale market.

Topics unique to the forward-looking future are: (1) spatial and temporal pricing of distribution network services, (2) methods for communicating dynamic pricing information to customers in a salient and actionable manner, (3) bundling strategies for retailers providing low-carbon energy solutions to customers.

### 8.1 Technical and Financial Viability of Direct Load Control

Although the technologies exist for retailers to provide direct load control services to customers through their in-home WiFi systems and smart plugs and switches, it is unclear what conditions are necessary for these services to be financially viable. If a retailer has direct load control over a significant amount of demand, it can use to these resources to reduce its demand when the economics favor it.

As noted in Section 7.3.3, a multi-settlement wholesale market with an high offer cap and no capacity payment mechanism is the ideal wholesale market design to derive the greatest value from these distribution network controllable loads. The day-ahead market provides more predictable hourly prices that retailers can use to schedule these load reductions against. The lack of a capacity payment mechanism increases the likelihood of within-day variation

in wholesale prices that support these actions. Finally, a higher offer cap on the short-term market implies a higher potential upside in terms of the magnitude of within-day price differences that retailers can exploit with these technologies.

## **8.2 Regulated Non-Wires Alternatives and Unregulated Services**

It is well known that distribution network installed storage devices can substitute for distribution network upgrades. However, it also the case that these devices can earn additional revenues from providing buying and selling energy or selling ancillary services. This has created a very difficult set of circumstances for regulators of how to compensate for the regulated services that distributed storage devices provide and still allow them to sell market-based services.

A number of jurisdictions in the US have ongoing proceedings that are attempting to resolve this issue. A set of principles are necessary to govern the behavior of these partially regulated resources that guards against the storage owner leveraging its regulated actions to benefit its competitive market sales. These principles must also allow the storage owner sufficient flexibility to earn market revenues in order to minimize the regulated revenues necessary for its financial viability.

## **8.3 Financial Viability of DERMS Investments**

In regions with ambitious renewable energy, electricity vehicle and electric space heating goals, investments Distributed Energy Resource Management Systems (DERMS) are likely to be necessary to achieve these goals at least cost to electricity consumers. This will require the development of frameworks for regulatory cost/benefit assessments to determine whether these investments should be made.

Again, the design of the wholesale market will again play an important role in this decision-making process. Multi-settlement LMP markets without capacity payment mechanisms and high offer caps are likely to be the wholesale market designs that favor these investments.

## **8.4 Spatial and Temporal Pricing of Distribution Networks**

Spatial and temporal pricing of the distribution network is potentially lucrative area for forward-looking retail sector in regions with wholesale markets with high offer caps and no capacity payment mechanism. This research would build a realistic mathematical model of a representative distribution network in order to study alternative approaches to pricing distribution network services to achieve more efficient investment decisions by households in distributed solar and load-management technologies and to maximize the opportunities for third-parties to provide value-added distribution network services that improve system reliability and reduce total distribution network costs.

This research could proceed in three phases. The first phase would compile detailed data on the technical characteristics and operating behavior of a representative distribution

network territory. The second phase would use this information to construct a mathematical model of this distribution network that is able to replicate the actual power flows in the distribution network under a range of system conditions with an acceptable level of accuracy. The third phase would use this mathematical model to simulate the operation and pricing of this distribution network under a range of pricing and operating protocols. This phase would also identify potential value-added distribution network services and analyze alternative approaches to pricing them to capture the operating costs and system reliability benefits of these distribution network services.

The resulting network pricing model could be used to determine benefits and costs of different approaches to pricing distribution network access to retailers and third-parties buying and selling wholesale market services and distribution network services.

## 8.5 Adapting Customers to Manage Wholesale Price Volatility

Increasing the energy cognizance of electricity consumers is a first step in adapting final consumers to managing wholesale price risk. A emphasized numerous times throughout this report, the default price all customers with interval meters face must be the real-time hourly price. This simply means that all retailers must pay the real-time hourly price for the actual hourly consumption of all customers with interval meters that they serve. If there is regulated default fixed delivered wholesale energy price, this price must be set significantly higher than the annual average wholesale energy price for the reasons discussed in Section 7.2.

With these initial conditions in place, there may still be a need to increase the energy cognizance of electricity consumers. Different from other goods and service, consumers do not directly consume a kWh. Instead they consume minutes or hours of energy services using an energy-consuming capital equipment such as a light bulb, air conditioner, heater, cell phone, television, computer electricity. Few consumers understand how much these energy services costs. Consequently, there is scope for informing consumers of the costs of commonly used energy services.

A simple economic model can explain the issue. Let  $S_t = (s_{1t}, s_{2t}, \dots, s_{Kt})'$  equal the  $K$ -dimensional vector of energy services demanded by the household during billing cycle  $t$ , where  $s_{kt}$  is the household's demand for services from electricity-consuming appliance  $k$  in hours-of-use during the billing cycle. Let  $E_t$  equal the household's consumption of electricity during billing cycle  $t$ . It is related to  $S_t$  through the following "electricity production function,"  $E_t = \sum_{k=1}^K A_{kt} s_{kt} + \varepsilon_t$ , where  $A_{kt}$  is the average kilowatt-hours of energy consumed by an hour of use of appliance  $k$  during billing cycle  $t$  and  $\varepsilon_t$  accounts for variation on the weather and other background conditions during the billing cycle. Let  $p(E)$  equal the price schedule faced by the consumer. For example,  $p(E) = F + c(E)$ , where  $F$  is the monthly fixed charge and  $c$  is the monthly average marginal cost of grid-supplied electricity. In terms of this notation, the household's monthly bill is equal to:

$$Bill(S_t) = \int_0^{[\sum_{k=1}^K A_{kt} s_{kt} + \varepsilon_t]} p(x) dx$$

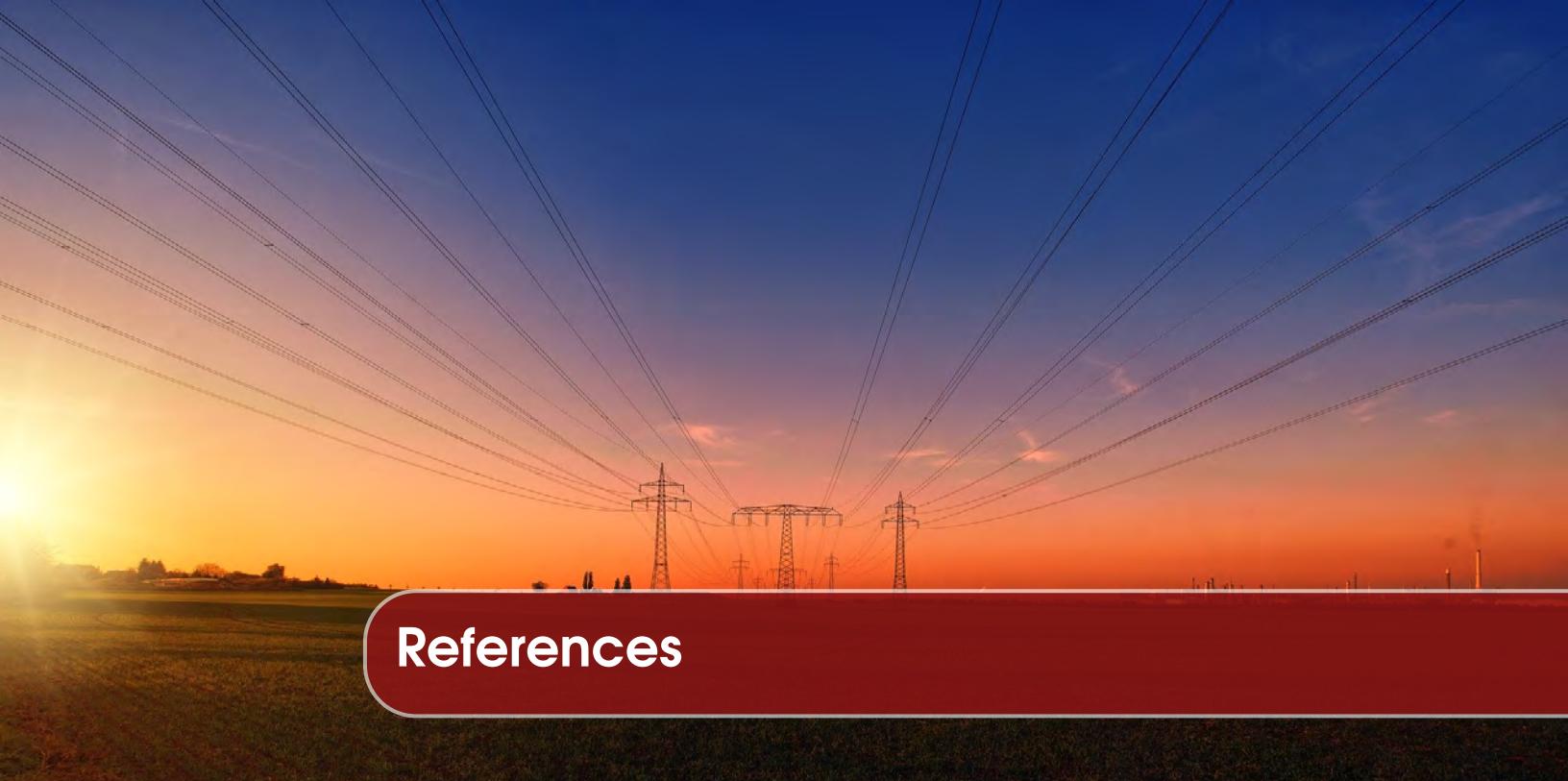
Let  $E^* = \sum_{k=1}^K A_k^* s_k^*$  equal the household's typical electricity consumption during a billing cycle,  $S_t^*$  the vector of typical hours of use of the  $K$  electricity consuming appliances by the household, and  $A_k^*$  if the typical rate that kilowatt-hours are consumed for an hour of use of appliance  $k$ . In terms of this notation, teaching the households how  $Bill(S_t)$  is determined and the values of  $\frac{\partial Bill(S_t^*)}{\partial s_k^*}$  for the major electricity-consuming appliances owned by the customers can create more sophisticated customers willing to manage wholesale price risk.

## 8.6 Bundling Strategies for Low Carbon Energy Solutions

In the forward-looking future when all customers have interval meters, the distribution network is efficiently priced, all customers are charged the hourly real-time price for their actual production, and there is either no or an extremely high regulated fixed default price, electricity retailing is no longer simply selling grid-supplied electricity. Retailers are now energy service providers providing different attributes of energy services that consumers demand.

They can sell solar panels, batteries, load-flexibility devices, high-speed vehicle chargers, electric heating systems. They can craft the combination of technologies that provide the set of energy service attribute that the customer want and price these to customers. They can offer attractive deals to high demand customers with flexible demands and use these customers as discussed in Section 7.2.4 to reduce the cost of serving other customers.

Retailers can also offer direct load control services and manage all wholesale price risk associated with serving that customer in exchange for a fixed monthly bill, as long as the customer's monthly consumption remains within certain bounds and the customer agrees to have certain automated response technologies installed and used by the retailer. Alternatively, the retailer could allow the customer to manage some of this wholesale price risk using cell phone messages or customer-initiated demand response applications and share saving with the customer.



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## A. Additional Figures

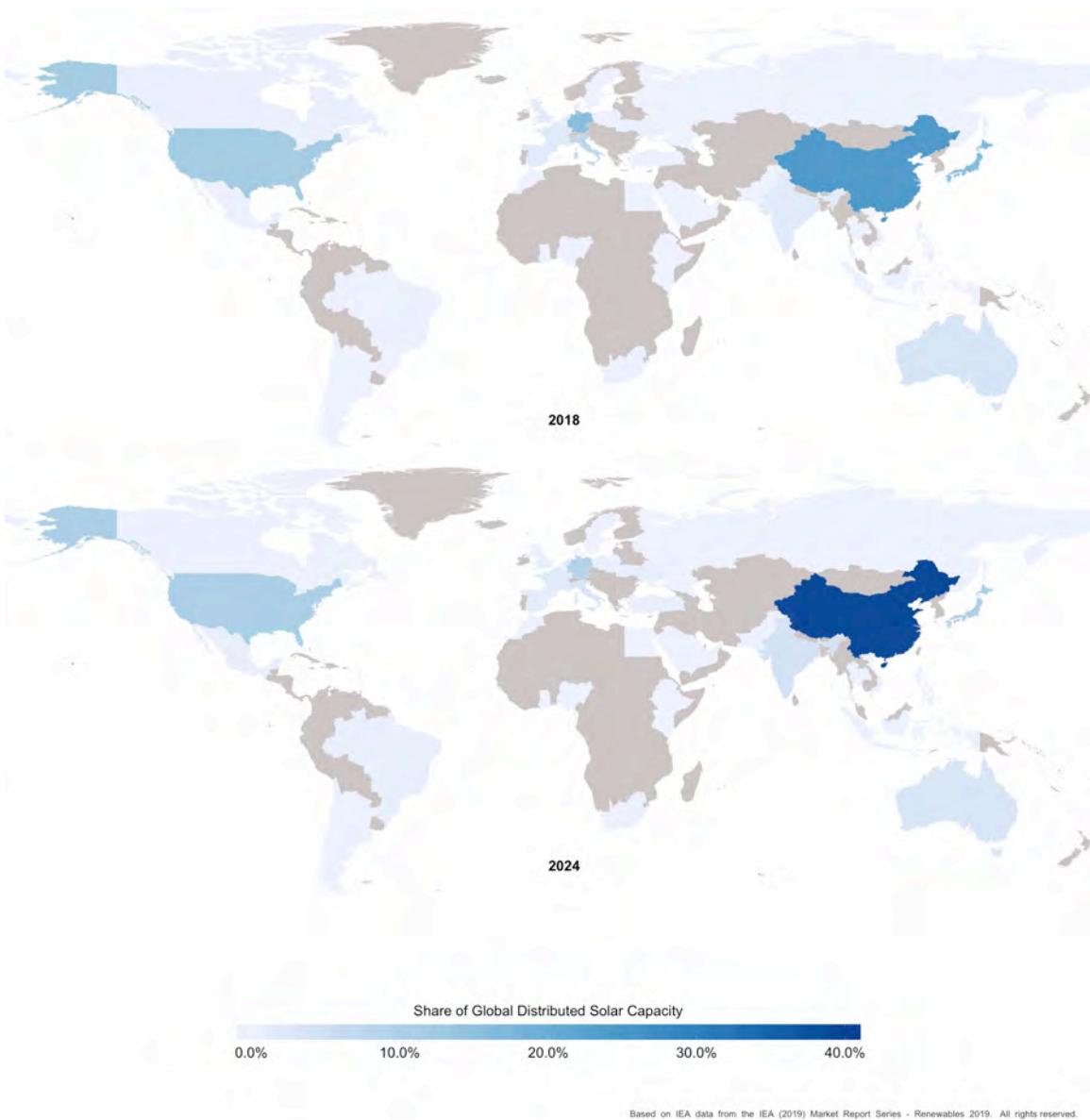


Figure A.1: Country-level Shares of Global Distributed Solar Capacity

NOTES: This figure illustrates the global adoption of distributed solar capacity as of 2024 as forecast by IEA. We include the total residential, commercial/industrial, and off-grid capacities in our calculations.

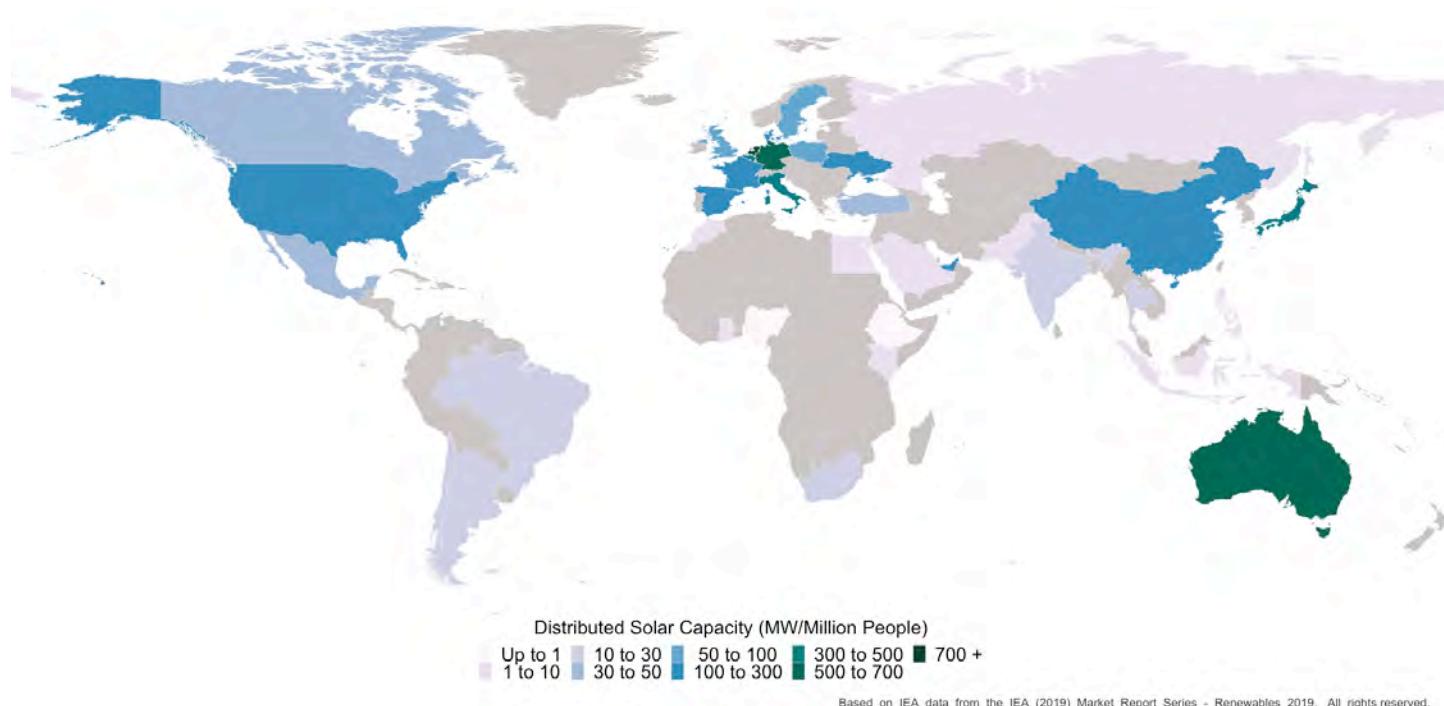
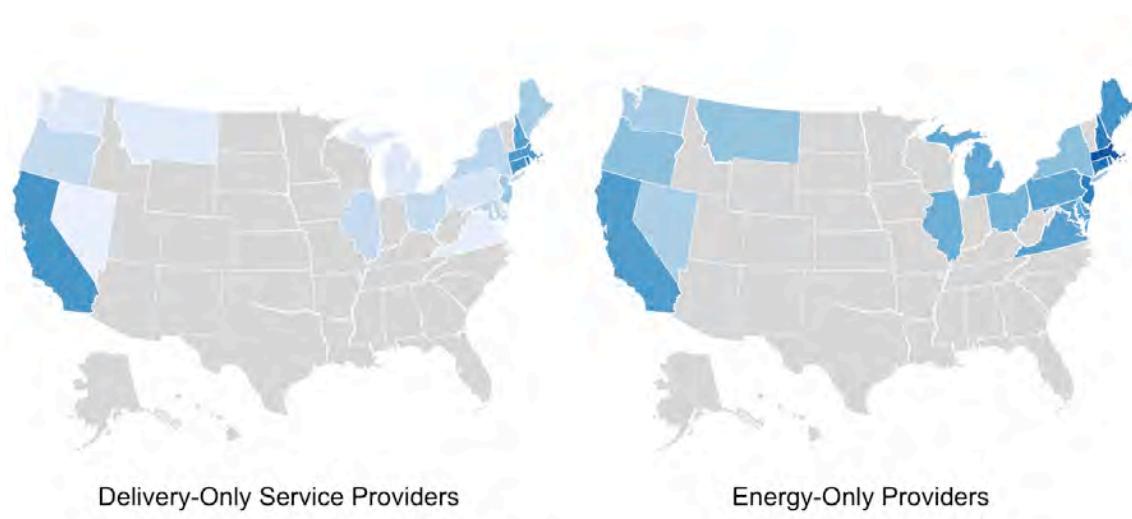
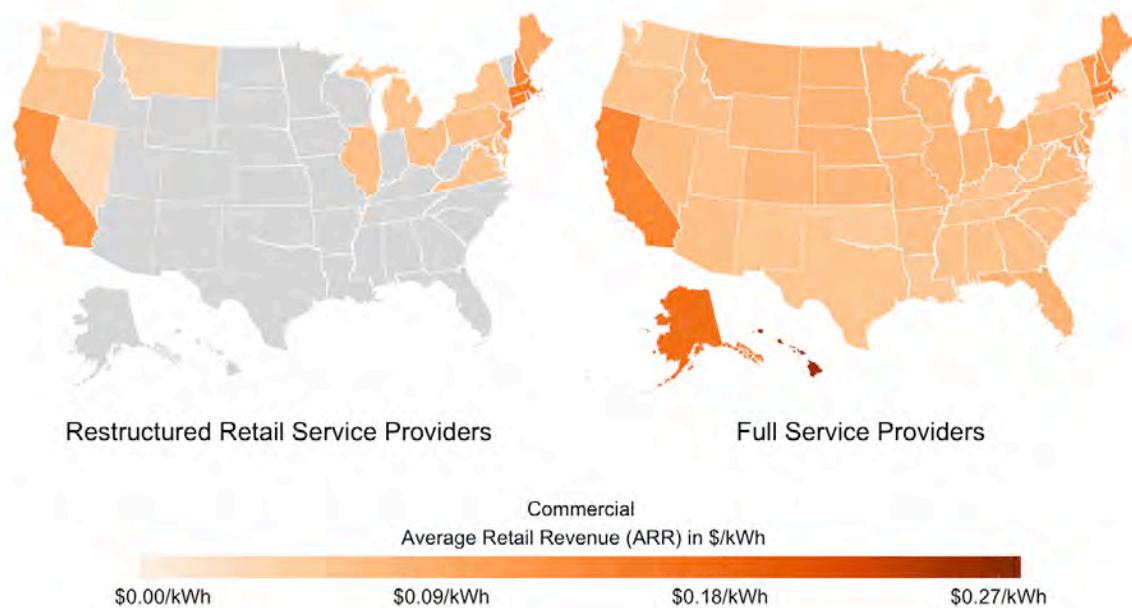


Figure A.2: IEA Distributed Solar Capacity per Capita Forecast for 2024

NOTES: This figure illustrates the global, per-capita distributed solar capacity as of 2024 as forecast by the IEA. We include the total residential, commercial/industrial, and off-grid capacities in our calculations. We divided each country's total capacity by its 2018 population and projected 2024 population using data from United Nations (2020).



(a) Delivery-Only vs Energy-Only Average Retail Revenues



(b) Restructured vs Full-service (bundled) Average Retail Revenues

Figure A.3: 2019 Industrial Average Retail Revenues in the US

NOTES: These maps display the Average Retail Revenue (ARR) in each state. Prices are displayed by provider type. The restructured retail service price is the sum of delivery- and energy-only service prices. The figures were produced using data from (US EIA, 2020c). While Washington does not have a formal restructured market, the state does have a small amount of retail competition for commercial and industrial customers.

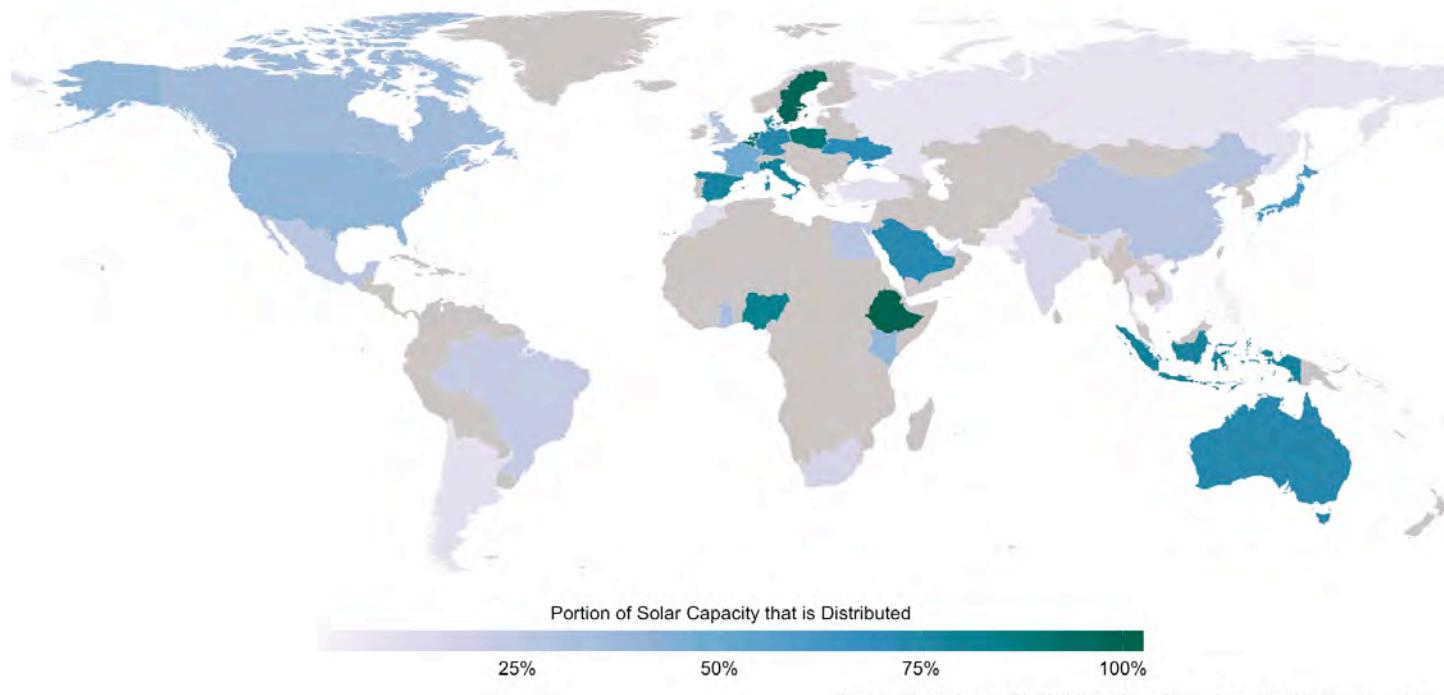


Figure A.4: Distributed Solar Market Shares in 2018

NOTES: This figure displays the market share that distributed solar held in 2018 in countries around the globe. Distributed capacity includes residential, commercial/industrial, and off-grid installations as defined in IEA (2019d). The remaining capacity in each country is utility-scale solar. We divide the amount of distributed capacity by the sum of distributed and utility-scale in order to calculate the market penetration rate.

Table A.1: Status of European Smart Meter Roll-out as of July 2018

Country	Smart Meter Market Penetration	Latest CBA Outcome
Austria	11.8%	Negative
Belgium	-	Positive/Inconclusive
Bulgaria	-	Negative
Croatia	2.3%	Positive
Cyprus	0%	Inconclusive
Czech Republic	-	Negative
Denmark	69.1%	Positive
Estonia	98.9%	Positive
Finland	99.8%	Positive
France	22.2%	Positive
Germany	0%	Negative
Greece	2.6%	Positive
Hungary	1.0%	Pending
Ireland	-	Positive
Italy	98.5%	Positive
Latvia	36.3%	Positive
Lithuania	2.4%	Inconclusive
Luxembourg	25.2%	Negative
Malta	97.3%	No CBA
Netherlands	46.5%	Positive
Poland	8.3%	Positive
Portugal	25%	Positive
Romania	4.8%	Positive
Slovakia	5.1%	Inconclusive
Slovenia	58.2%	Positive
Spain	93.1 %	No CBA
Sweden	100.0%	Positive
United Kingdom	19.9%	Positive

**Notes:** The information in this table is derived from Tractabel (2019). Market penetration rates for smart meters are found on page 52 of the report; CBA outcomes are found on pages 29 and 30. For market penetration rates, a '-' indicates that no data were available.

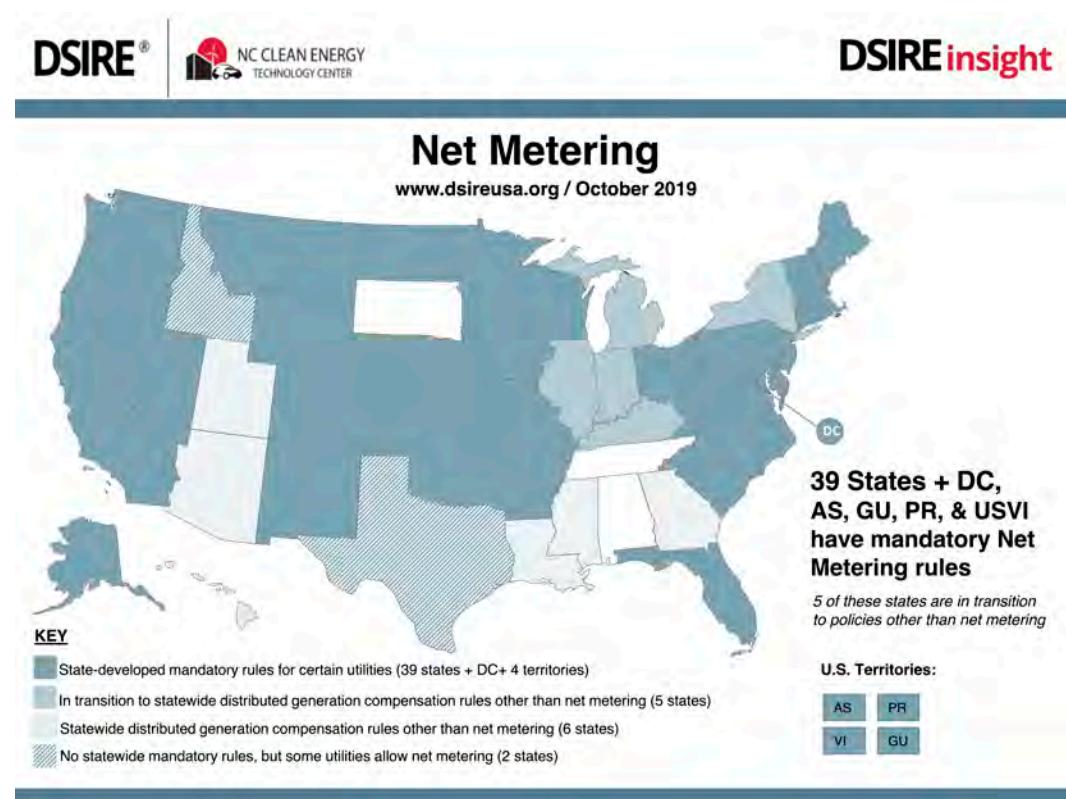


Figure A.5: Net Metering policy Adoption in the US

NOTES: This figure is from the Database of State Incentives for Renewables and Efficiency (DSIRE) (DSIRE, 2019). The figure, which was last updated in October of 2019, details the statewide net metering policies that have been adopted across the US. The figure indicates that 39 states and Washington, D.C. currently have statewide net metering policies, but that five of these states are transitioning towards other types of distributed generation compensation rules. The differences in these types of policies are largely attributable to different compensation rates for customers selling energy into the grid (e.g. avoided cost rates).

Country/ state/ province	Buy-all, sell- all model	Net metering		Real-time self-consumption models	
		Energy accounting	Remuneration of grid exports beyond energy accounting	Energy accounting	Remuneration of grid exports
China	Y	N	N/A	Y – real time	Value-based
New York (USA)	N	N	N/A	Y – real time	Value-based
California (USA)	N	Y – annual	Value-based	N	N/A
Germany		N	N/A	Y – real time	Value-based
Japan	Y	N	N/A	Y – real time	Value-based
Australia	N	N	N/A	Y – real time	Value-based
France	Y	N	N/A	Y – real time	Value-based
Spain	N	N	N/A	Y – real time	Wholesale or value-based
Turkey	N	Y – monthly	Value-based	N	N/A
Flanders (Belgium)		Y – annual	Value-based	Y	Zero- to wholesale price
Netherlands	N	Y – annual	Retail	N	N/A
United Kingdom	N	N	N/A	Y	Value-based
Maharashtra (India)	N	Y – annual	Value-based	N	N/A
Telangana (India)	N	Y – biannual	Value-based	N	N/A
Israel	Y	Y – monthly	Value-based	N	N/A
Viet Nam	Y	N	N/A	N	N/A
Chinese Taipei	Y	N	N/A	N	N/A
Sweden	N	N	N/A	Y – real time	Value-based
Denmark	N	N	N/A	Y – real time	Value-based
Italy	N	N	N/A	Y	Value-based
Indonesia	N	N	N/A	N	N/A
Thailand	N	Y – annual	Value-based	N	N/A
Philippines	N	Y – monthly	Wholesale	N	N/A
Mexico	Y	Y – annual	Value-based	Y	Wholesale

Figure A.6: Policies for Compensation of Distributed Generation

SOURCE: IEA (2019) Renewables 2019. All rights reserved.

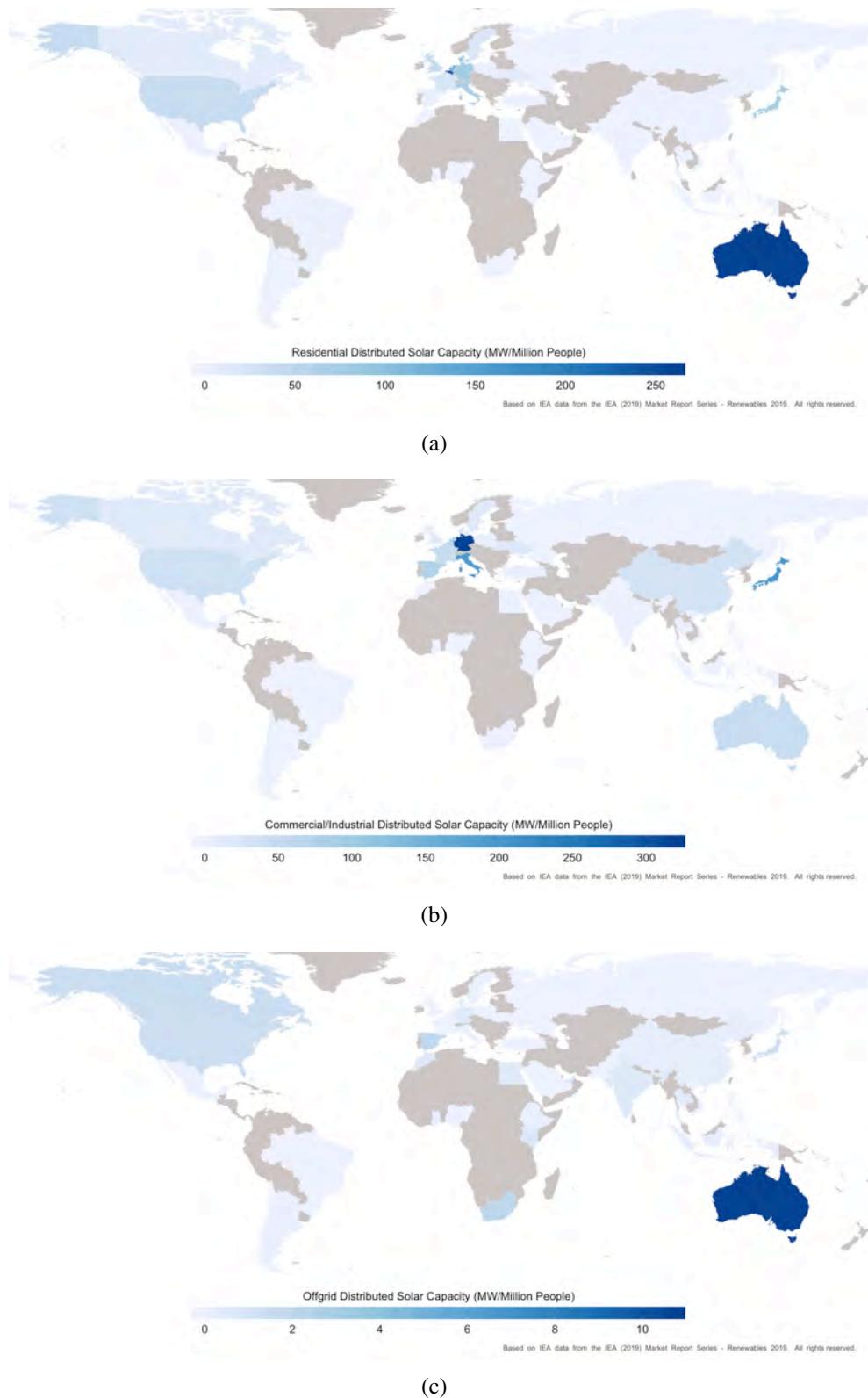
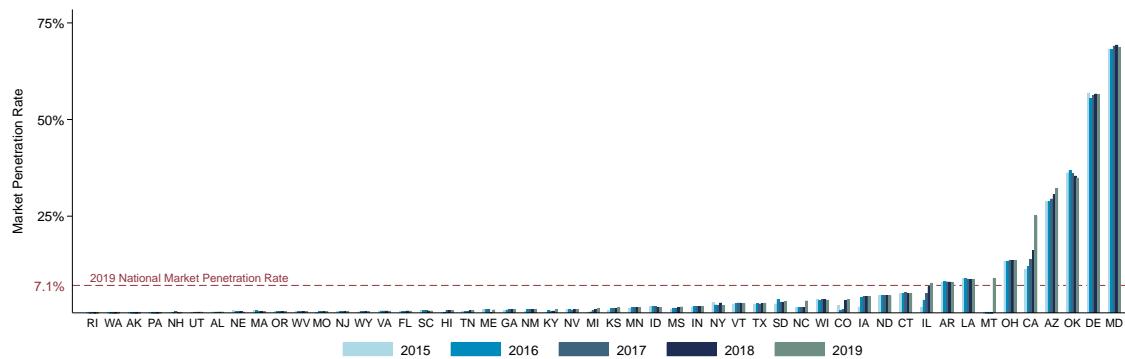
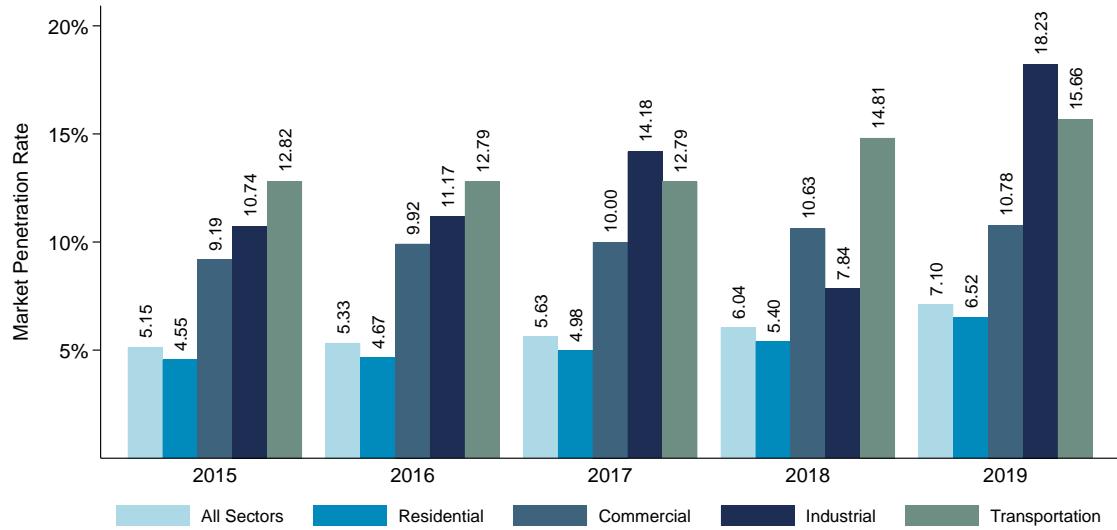


Figure A.7: Distributed Solar Capacity per Capita in 2018 by Installation Size

NOTES: Panel (a) displays the installed distributed solar capacity made up of installations of less than 10 kW in size (residential). Panel (b) displays the installed distributed solar capacity made up of installations of between 10 kW and 1 MW in size (commercial/industrial). Panel (3) displays the installed distributed solar capacity made up of installations of between 8 W and 100 kW and are not connected to a large-scale grid.



(a) US State-level Adoption of Dynamic Pricing



(b) Adoption of Dynamic Pricing by US Customer Sector

Figure A.8: Adoption of Dynamic Pricing Programs in the US

NOTES: Panel (a) of this figure presents the market penetration rate for dynamic pricing programs across all sectors in each state from 2015 to 2018. Panel (b) displays the market penetration rates for dynamic pricing in each end-use customer sector in addition to the total, nationwide market penetration rate. Both panels of the figure were produced using raw data from EIA's *Annual Electric Power Industry Report* (US EIA, 2020a). We define market penetration to be the number of customers enrolled in dynamic pricing in each state (or sector) divided by the number of customers in that state or sector.

Table A.2: Major US Utilities and Dynamic Pricing

Utility	Balancing Authority	State	RTP		VPP		CPP		CPR		EV Specific Rate Plan
			R	B	R	B	R	B	R	B	
Florida Power & Light Co (FPL)	FPL	FL	No	No	No						
Southern California Edison Co. (SCE)	CAISO	CA	No	Yes	No	No	No	Yes	No	No	Yes
Pacific Gas & Electric Co. (PG&E)	CAISO	CA	No	No	No	No	Yes	Yes	No	No	Yes
Consolidated Edison Co-NY Inc (ConEd)	NYISO	NY	No	Yes	No	No	No	No	No	No	Yes
Commonwealth Edison Co. (ComEd)	PJM	IL	Yes	Yes	No	No	No	No	Yes	No	No
Georgia Power Co.	SOCO	GA	No	Yes	No	No	No	No	No	No	Yes
Virginia Electric & Power Co. (Dominion)	PJM	VA	No	Yes	No	Yes	No	Yes	No	No	Yes
DTE Electric Company	MISO	MI	No	No	No	No	Yes	Yes	No	No	Yes
Duke Energy Carolinas, LLC	Duke Energy Carolinas	NC	No	Yes	Yes	Yes	Yes	Yes	No	No	No
Public Service Elec & Gas Co. (PSEG)	PJM	NJ	No	No	No						

**Notes:** The ten utilities included in this table had the ten highest customer counts in 2018 according to data from EIA (US EIA, 2020a). They are presented in descending order. 'R' denotes residential and 'B' denotes business. Information in this table is based on tariff and rate schedules provided on each individual utility's website.

## **B. Data and Methodology**

Throughout this report, we make use of rich, comprehensive datasets from the US Energy Information Administration, the US Department of Energy, the US Department of Transportation, the International Energy Agency, Bloomberg, and several other organizations. In this section, we document each of these datasets and explain the methodology we used to produce figures and statistics from them.

## B.1 Data from the US Energy Information Administration

The US Energy Information Administration (EIA) collects detailed annual data from all firms participating in the generation, transmission, distribution, and sale of electricity in the US and its territories.<sup>1</sup> These data are collected on Forms EIA-861 and EIA-861S. The information provided to EIA on these forms makes up the *Annual Electric Power Industry Report*. All data are publicly available on EIA’s website and can be retrieved for all years from 1990 through 2019.<sup>2</sup> Form EIA-861S – referred to as the “Short Form” – is used by utilities with annual retail sales of 100 GWh or less in the prior year. Exceptions to this threshold apply to unbundled retailers (delivery-only or energy-only providers), firms aggregated under the Tennessee Valley Authority (TVA) or WPPI Energy, and firms that are part of EIA’s statistically chosen sample of monthly data providers. Utilities meeting one of the exceptions must fill out Form EIA-861. Short Form respondents must fill out Form EIA-861 at least once every eight years in order for EIA to maintain accurate records. The complete documentation and instructions for each form are included with each year’s dataset.

The datasets associated with Forms EIA-861 and EIA-861S include annual data regarding a multitude of aspects of the US electric power sector. Table B.1 outlines the sections of the forms that we are primarily concerned with.

Not all information collected on Form EIA-861 is also collected on the Short Form. Short Form respondents do not report the number of standard electricity meters they have installed – only the count of automated meter reading (AMR) and advanced metering infrastructure (AMI) meters. AMI is the term EIA uses to refer to smart meters. Additionally, Short Form respondents are asked whether they offer net metering, but do not report how much net-metered capacity they have. For dynamic pricing programs, Short Form respondents only report the number of customers they have enrolled in some type of time-based tariff. Unlike respondents of Form EIA-861, they do not specifically report whether or not they offer TOU, RTP, VPP, CPP, or CPR pricing. Because of these shortcomings of Form EIA-861S, data reported on the Short Form is generally omitted from our calculations in order to maintain consistency when calculating statistics like market penetration rates or other comparisons of program or technology adoption. Any exceptions will be noted in this section. In 2019, all respondents, even those who would normally fill out the short form, were required to fill out the long form. In order to maintain the most consistent understanding of the data across different years, we omit short form respondents from the 2019 data where they were

<sup>1</sup>For the purpose of this report, we are not concerned with the territories.

<sup>2</sup>Earlier years do not include as much information as later years. See <https://www.eia.gov/electricity/data/eia861/>.

omitted in previous years. That is to say, even though short form respondents provided more complete information in 2019 (such as standard meter counts or net-metered capacity), we omit them anywhere that short form respondents previously did not report such data. Short form respondents' customers made up less than 0.9% of all customers in 2019 and their sales (in MWh) made up less than 0.7% of electricity sales.

Table B.1: Forms EIA-861 and EIA-861S Data Locations

Topic	Location	
	EIA-861	EIA-861S
Smart Meters	Schedule 6, Part D	Schedule 6, Part D
Distributed Generation	Schedule 7, Part A; Schedule 7, Part B	Schedule 7, Part A
Dynamic Pricing	Schedule 6, Part C	Schedule 6, Part C
Demand Response	Schedule 6, Part B	Schedule 6, Parts A & B
Sales, Revenues, and Customers	Schedule 4, Parts A-D	Schedule 4, Part A

**Notes:** Each of these sections are described in detail in the instructions for both forms. The instructions are included in the download file for each year available at <https://www.eia.gov/electricity/data/eia861/>. Additionally, we use EIA's Average Retail Revenue data which are calculated using the revenues and sales reported in Schedule 4.

For the most part, the data provided by Forms EIA-861 and EIA-861S are reported by end-use customer sector. These sectors include residential, commercial, industrial, and transportation. The following are EIA's definitions of the customer sectors. The residential sector includes private households and apartment buildings where energy is consumed primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking, and clothes drying. The commercial sector includes nonmanufacturing business establishments such as hotels and motels, restaurants, wholesale businesses, retail stores, health, social, and educational institutions, public street and highway lighting, municipalities, and divisions or agencies of states and federal governments under special contracts or agreements, and other utility departments, as defined by the pertinent regulatory agency and/or electric utility. The industrial sector includes manufacturing, construction, mining, agriculture, fishing, and forestry establishments. The transportation sector includes railroads and railways.

### B.1.1 Advanced Metering

In Section 5.1, we use the advanced metering data from Form EIA-861 in order to calculate historical trends in smart meter adoption and market penetration at the national and state levels. In order to calculate market penetration rates, we use the following equation.

$$\text{Smart Meter Market Penetration (\%)} = \frac{\text{AMI Meters}}{\text{AMI Meters} + \text{Standard Meters} + \text{AMR Meters}} \times 100$$

This rate can be calculated at the end-use sector level for individual states or nationwide. The numerator and denominator are just qualified to include only the count of meters in each state or sector. Since data are reported at the utility level, we aggregate the meter counts to the state level first.

Because Short Form respondents do not supply their count of standard meters, including their count of AMI and AMR meters in this calculation would inflate our market penetration estimates. For some context, in 2019 there were only about 264,000 smart meters installed by Short Form respondents. These make up roughly 0.3% of all smart meters installed in the US. So, in order to maintain consistency, our market penetration rates are based only on meter counts reported by respondents of Form EIA-861. Depending on the actual number of standard meters installed by Short Form respondents, actual market penetration rates could potentially be slightly higher or lower. This methodology applies to calculations used to produce Figures 5.1, 5.2, and 5.3 Panel (a). Additionally, with regards to Figure 5.1, EIA did not collect the count of standard meters prior to 2013 so the total, non-AMI, and standard counts are only shown from 2013 to 2018. Also, in 2008 and 2009, EIA recorded the number of customers with AMI rather than the actual number of smart meters. The difference is likely small since most customers, particularly those in the residential sector, tend to only have one meter. Lastly, since Panel (b) of Figure 5.3 illustrates only the raw growth in AMI meters, we do include the smart meters installed by Short Form respondents.

Figure 6.1, which displays the adoption of Direct Load Control (DLC), Home Area Networks (HAN), and Daily Digital Access (DDA), was also produced using data from the advanced metering data recorded on Form EIA-861. Because Short Form respondents do not report the number of meters equipped with a HAN or the number of customers they have with DLC or DDA, we omit them from these calculations. The market penetration rate for HAN is calculated to be the percent of total meters that are HAN equipped. The market penetration rates for DLC and DDA are calculated as the percent of all electricity customers that have DLC and DDA, respectively. Customer counts are calculated using EIA's recommended protocol. We describe this process below in Section B.1.2

### B.1.2 Dynamic Pricing

In Sections 4.3 and 5.3, we refer to statistics that were calculated using the dynamic pricing data provided by Form EIA-861 and EIA-861S respondents. Short Form respondents report the number of customers they have enrolled in some type of time-based rate program including Time-of-Use, Real Time Pricing, Variable Peak Pricing, Critical Peak Pricing, or Critical Peak Rebate. That is, they report how many are enrolled in any one of these types, but not the number enrolled for each individual type of program. However, Short Form respondents do not report which of these types of programs they offer. It is important to note that while EIA considers TOU plans to be “dynamic”, we do not in this report. While respondents of EIA-861 do report which types of programs they offer, they do not

report the number of customers on each individual type of program. Because of this, we can only calculate the percentage of customers enrolled in some type of advanced tariff program, rather than the percentage enrolled in any one type of program. Since Short Form respondents do report the number of customers they have enrolled in advanced tariffs, we do include them in our market penetration rate calculations. For these calculations we use the following equation.

$$\text{Advanced Tariff Market Penetration (\%)} = \frac{\text{Customers Enrolled in a Time-Based Rate}}{\text{Total Customers}} \times 100$$

The market penetration rate can be calculated for individual states and sectors by qualifying the numerator and denominator to include only the customers that belong to each state or sector. Since data are reported at the utility level, we aggregate the enrolled customer counts to the state level first. Figure A.8 was produced using these steps.

Total customer counts for each state and sector are recorded on both Forms EIA-861 and EIA-861S. These are provided in the ultimate customer sales dataset. We followed EIA's protocol for aggregating customer counts, sales, and revenues. In order to aggregate customer counts to the state level, we took the sum of customers reported by full-service (bundled) providers, energy-only providers, and retail energy providers and power marketers. Customers belonging to delivery-only providers are omitted in order to avoid double-counting customers who are already reported by energy-only providers. Some of our calculations require us to omit Short Form respondents in order to accurately estimate market penetration rates. In these cases, we use the same protocol but also omit customers that belong to Short Form respondents by using EIA's indicator within the dataset.<sup>3</sup>

### B.1.3 Distributed Solar

To calculate many of the US statistics provided in Section 5.2, we use the net metering and non net-metered distributed generator data reported on Form EIA-861. The Short Form has not historically recorded detailed net metering or distributed generation data. Form EIA-861 collects extensive data on all net-metered distributed solar systems including installed capacity, number of systems, storage capacity and number of storage systems, virtual net-metered (community solar) capacity and customer counts, and the energy sold back into the grid from net-metered capacity. These data are reported at the utility level. Additionally, respondents report the capacity of any Third-party Owned (TPO) solar systems, and the number of customers enrolled in TPO solar net metering. In a separate schedule of Form EIA-861, respondents report the amount of distributed solar capacity they have installed that is not a part of a net metering program (non net-metered distributed).

We used these data to produce Figure 5.7, which shows the state level composition of distributed solar generating system types (customer owned, virtual, TPO, and non net-metered). Using the state-level counts of electricity customers (described above), we calculated the capacity per 100,000 customers in each state and for each type of solar

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<sup>3</sup>Within the dataset, to omit short form respondents, observations where both the "Part" value is "A" and the "Utility Number" value is "99999" are dropped.

system. Because Short Form respondents do not report the capacity of their net-metered solar systems, we omit their customers from the customer counts.

We also used these data to produce Figures 5.8 and 5.9. In Figure 5.9, Panel (a) was produced using the sum of all net-metered distributed solar generating capacity at the state level. Capacities were divided by each state's total electricity customer count while omitting Short Form respondents. Panel (b) shows the total energy sold back to the grid from net metering programs in each state. EIA does not record the amount of energy sold back by TPO solar systems so the values shown in this panel are based solely on energy sold back from customer-owned and virtual generating systems, and from net-metered storage systems.

Figure 5.8 uses data from both Form EIA-861 and from Form EIA-860. The latter is the form used to collect data for EIA's *Annual Electric Generator Report*.<sup>4</sup> Form EIA-860 collects the total capacity of all grid-connected generators with at least 1 MW of capacity. Data are recorded by EIA at the utility level so we calculate the sum of solar photovoltaic capacity for each state. Some of this capacity is enrolled in net metering programs. We omitted from values in the figure. Figure 5.8 presents these utility-scale solar capacities in tandem with the distributed solar capacities which were calculated using the methodology above. We divide capacities by state-level customer counts in order to display capacity per 100,000 customers.

#### B.1.4 Demand Response

EIA records a number of details about the demand response programs that are used by utilities in the US. Respondents of Form EIA-861 report the number of customers they have enrolled in demand response programs, the energy savings from those programs, the potential and actual peak demand savings associated with demand response, and the amount spent on incentives and other costs of demand response programs. They also report the number of grid-connected demand side management water heaters they installed during the calendar year. Similar to our market penetration calculations for advanced tariffs, we use the following equation to calculate demand response market penetration rates.

$$\text{Demand Response Market Penetration (\%)} = \frac{\text{Customers Enrolled in a Demand Response}}{\text{Total Customers}} \times 100$$

Since Short Form respondents do not report the number of customers they have enrolled in demand response, we omit their customers from the total customer count when calculating market penetration. Both panels of Figure 5.17 were produced using this methodology.

#### B.1.5 Retail Price Data

In our discussion of US retail electricity price trends in Section 4.1, we use Average Retail Revenue (ARR) statistics calculated from Form EIA-861 and EIA-861S data. These data can be generated straight from the raw Form EIA-861 datasets or can be retrieved directly

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<sup>4</sup>These data can be retrieved here: <https://www.eia.gov/electricity/data/eia860/>.

from EIA with the ARR calculations already completed at the state and national levels for years dating back to the 1990s.<sup>5</sup> Average Retail Revenue is calculated in the following manner.

$$\text{Annual Average Retail Revenue (\$/kWh)} = \frac{\text{Revenue from Retail Sales (\$)}}{\text{Retail Energy Sales (kWh)}}$$

Using Average Retail Revenue allows us to estimate the average price during the year accounting for the fact that retail electricity prices can fluctuate hourly, daily, or seasonally. EIA calculates these statistics for full-service (unbundled) energy providers, delivery-only providers, and energy-supply only providers. Delivery-only and energy-only providers operate in restructured retail markets in 20 states and D.C. as illustrated in Figure 4.1. Additionally, these data from EIA are used to produce Figures 4.2, 4.3, 4.4, 4.5, and A.3.

## B.2 Data from Bloomberg

Some of data referenced in our report were not publicly available and instead were accessed through the Bloomberg Terminal.

### B.2.1 Technology Prices

Figures 2.1 and 2.2 display historical prices for lithium-ion batteries and solar generating hardware. The global lithium-ion battery prices shown in Figure 2.1 were reported by Bloomberg New Energy Finance (BNEF). The ticker for this index is IBWWST and the prices were calculated by BNEF using primary research and data from third-parties. The Photovoltaic-grade Polysilicon prices were also reported by BNEF. The ticker for this index is SSPFPSNO and the data are available on the Solar Energy Equipment Dashboard of the Bloomberg Terminal. Figure 2.1 also displays the historical prices for smart sensors, however these prices were reported by Business Insider Intelligence and were retrieved from Microsoft Dynamics 365 (2018).

Figure 2.2, which displays historical price trends for solar wafers, cells, and modules, was also produced using data from the Solar Energy Equipment Dashboard. These prices are from the Bloomberg New Energy Finance (BNEF) Solar Spot Price Index. Table B.2 provides the specifications for the materials associated with each price.

### B.2.2 Global Electric Vehicle Trends

Figure 2.10, which provides historical trends in electric vehicle adoption, also uses data retrieved from the Bloomberg Terminal. Country-level lithium-ion battery demand data for EVs are reported by BNEF and are the result of primary research and data from third-parties. BNEF calculates and reports country-level EV energy consumption similarly.

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<sup>5</sup>See Average retail price of electricity to ultimate customers: Annual retail price by sector, by state, by provider at <https://www.eia.gov/electricity/data.php>.

Table B.2: BNEF Solar Component Specifications

Component	Specifications	
	Monocrystalline	Poly/Multicrystalline
Solar Wafer	<ul style="list-style-type: none"> <li>• 156mm (6") side</li> <li>• 200mm diameter</li> <li>• 180-200 micron thickness</li> </ul>	<ul style="list-style-type: none"> <li>• Square wafer</li> <li>• 156mm (6") side</li> <li>• 180-200 micron thickness</li> </ul>
Solar Cell	<ul style="list-style-type: none"> <li>• 125mm or 156mm side</li> <li>• 165mm or 200mm diameter</li> <li>• 180-200 micron thickness</li> </ul>	<ul style="list-style-type: none"> <li>• 156mm side</li> <li>• 180-200 micron thickness</li> </ul>
Solar Module	<ul style="list-style-type: none"> <li>• Laminated framing</li> <li>• At least 40 cells per module</li> </ul>	<ul style="list-style-type: none"> <li>• Laminated framing</li> <li>• At least 40 cells per module</li> </ul>

**Notes:** These specifications are based on the security descriptions provided in the Bloomberg Terminal.

### B.3 Calculations with IEA's *Renewables 2019* Data

Much of our discussion of the global adoption of distributed solar is based on detailed data and forecasts from the International Energy Agency (IEA). IEA's most recent annual report on the state of the global renewables market—*Renewables 2019 Analysis and Forecast to 2024* (“*Renewables 2019*”)—provides an extensive discussion of the history of distributed generation and the direction that the market is expected to progress over the next four years. Neither the report, nor the raw data it is based on, are publicly available.

The raw data associated with *Renewables 2019* provide the 2018 off-grid, residential, and commercial/industrial distributed solar generating capacities at the global level as well as for 41 individual countries and seven world regions (IEA, 2019b). *Renewables 2019* defines off-grid installations to be those with capacity between 8 W and 100 kW that are a part of a household or small commercial system or miniature grid. Residential systems include those that have a capacity of up to 10 kW, are grid connected, and are installed on rooftops. Commercial and industrial systems include those that have a capacity between 10 kW and 1 MW, are grid connected, and are ground-mounted or installed on rooftops. IEA notes that there are some exceptions in cases where installations larger than 1 MW still qualify as distributed commercial/industrial because they are used for self-consumption (IEA, 2019d). Additionally, the *Renewables 2019* dataset includes the total solar capacity (including distributed) for each of these countries and world regions. Using the total solar

capacities and the distributed capacities, we calculate the total utility-scale capacity for each country in the following manner.

$$\text{Utility-scale PV Capacity} = \text{Total PV} - (\text{Off-grid} + \text{Residential} + \text{Commercial})$$

In addition to providing the actual 2018 capacities, IEA has forecast country-level distributed solar capacities out through 2024. IEA provides two forecast scenarios: a main case and an accelerated case. We use the main case for our estimates of capacity statistics in 2024. The main case forecast is based on current market trends and is revised annually. IEA's accelerated case is based on assumptions that governments will address policy and regulatory uncertainties, high investment risks in developing countries, and system integration of solar (IEA, 2019d).

We use the raw capacity data to produce Figures 2.8, 5.6 Panel (a), A.1 and A.4. For Figure A.1, we calculated the percent of the global distributed solar capacity installed in each country by dividing the country's sum of off-grid, residential, and commercial/industrial capacity by the global capacity. For 2024, we use IEA's main case projection of capacity in each country. Similarly, for Figure A.4, we divide each country's total distributed capacity by the total solar capacity to determine what percent of total capacity is distributed.

For Figures 2.7, 5.6 Panel (b), 5.10, 5.13, A.2, and A.7, we calculated capacities at the per-capita level for each country. We retrieved population statistics from the United Nations (UN) Department of Economic and Social Affairs (United Nations, 2020).<sup>6</sup> We use the UN's World Population Prospects 2019 dataset which provides historical populations from 1950 to 2020 as well as country level population forecasts through 2100. For the projected 2024 population, we use the Medium Fertility Variant forecast. The UN uses probabilistic projections based on the historical variability of changes in fertility while also taking into account uncertainty about future changes. The Medium Fertility Variant scenario is based on the median of several thousand trajectories of the probabilistic model.<sup>7</sup>

## B.4 Electric Vehicle Trends in the United States

In our discussion of electric vehicle adoption in the US, we make use of detailed data from the US Dept. of Energy and Dept. of Transportation in tandem with EV registration data provided by the Alliance of Automobile Manufacturers. Panel (a) of Figure 2.9 displays the count of operating EV charging stations in each state between 2010 and 2019. These data are from the Dept. of Energy's Alternative Fuels Data Center Station Locator. Most of these data are available publicly through the Alternative Fuels Data Center Station Locator website.<sup>8</sup> However, the online database does not have the opening date of operation for every station. In order to retrieve opening dates, we received data directly from Dept. of Energy's Office of Energy Efficiency and Renewable Energy's Vehicle Technologies Office. The Vehicle Technologies Office notes that some of the open dates provided to us were

<sup>6</sup>See <https://population.un.org/wpp/>.

<sup>7</sup>For more on these forecasting methods, visit <https://population.un.org/wpp/DefinitionOfProjectionVariants/>.

<sup>8</sup>See <https://afdc.energy.gov/stations/#/find/nearest>.

estimated based on assumptions and that the set of stations included in the data only includes active stations and does not include stations that have previously opened and closed. So, in our calculations of how many stations were open by the end of each year, it is certainly possible that there were more in a given year but that they have since closed. Hence, our calculations should be treated as estimates. The charging station data we received from the Vehicle Technologies Office were current as of November 14, 2019. These data include both public and private charging stations but we omit the count of private charging stations from each state's total count. In these data, each individual charger or outlet at a station is indicated as a separate observation. Using the unique equipment identification number assigned to each individual station, we are able to make sure we do not double count outlets as multiple stations.

Using these data, Panel (a) of Figure 2.9 displays the number of stations operating at the end of each year from 2010 through 2018. For 2019, the figure displays the number of stations operating as of November 14. Panel (b) makes use of these data as well, in addition to traffic volume trends reported by the Dept. of Transportation. The Dept. of Transportation's Office of Highway Policy Information maintains a database of monthly Vehicle Miles Travelled for every month dating back to at least 2002.<sup>9</sup> Vehicle miles travelled (VMT) is a measure of traffic volume and is calculated by multiplying the length of a roadway by the number of vehicles that use it. We calculate annual averages of monthly VMT for the years from 2010 to 2018. For 2019, we calculated the average for January through November since our charging stations data are only current through November 14. We divide the number of public charging stations in each state at the end of each year (or November for 2019) by the annual average monthly VMT for that year.

Panel (c) makes use of comprehensive historical data from the Alliance of Automobile Manufacturers (Auto Alliance). These data include the number of battery electric vehicles (BEVs) and plug-in hybrid electric vehicles registered in each state from January of 2011 to June of 2019. Auto Alliance compiled these data using information provided by IHS Markit and Hedges & Co.—two market research agencies. Importantly, these data keep track of vehicles that are registered in one state but that are later re-registered in a different state.<sup>10</sup> Because of this, we are not concerned about double counting vehicles that move across state lines. These data are publicly available from Auto Alliance's Advanced Technology Vehicle Sales Dashboard.<sup>11</sup> To produce Panel (c) of Figure 2.9, we used the count of charging stations installed through June of 2019 in order to maintain consistency with the time-scale of the Auto Alliance dataset.

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<sup>9</sup>See [https://www.fhwa.dot.gov/policyinformation/travel\\_monitoring/tvt.cfm](https://www.fhwa.dot.gov/policyinformation/travel_monitoring/tvt.cfm).

<sup>10</sup>Based on personal communications with the Alliance of Automobile Manufacturers

<sup>11</sup>See <https://autoalliance.org/energy-environment/advanced-technology-vehicle-sales-dashboard/>.