Modernizing Distribution Rate Design

PREPARED FOR

ATCO

PREPARED BY
Ahmad Faruqui
Ryan Hledik
Long Lam

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THE Brattle GROUP

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Executive Summary

Principles of Rate Design

This report was developed by Brattle on behalf of ATCO as part of the company's input to Modules 2 and 3 (known as the "combined module") of the Alberta Utilities Commission's (AUC) Distribution Inquiry (DI).

The purpose of the report is to identify rate design options that could better accommodate customer adoption of emerging energy technologies such as smart thermostats, digitally-communicative appliances, rooftop solar panels, battery storage, other forms of on-site generation, and battery-powered electric vehicles. This report is not intended to endorse one rate design solution over another. Rather, this report provides an overview of other utilities' current or proposed rate modernization initiatives, and highlights important rate design principles for moving ahead with pricing modernization in Alberta as new energy technologies are adopted. While the examples presented in this report focus on electricity rates, the same economic concepts also largely apply to rate design for natural gas distribution.

Cost-causation is the fundamental principle of rate design. In other words, the pricing of electricity should reflect the economic cost of providing electricity to customers. This principle is particularly relevant in addressing the opportunities and challenges that arise when customers adopt new energy technology. Cost-based rates should lead to improvements in equity and fairness in cost recovery, removing unintended subsidies embedded in the rate design, while also promoting efficiency in the use of the electric grid. Cost-based rates are likely to contribute to reduced distribution costs in the long run, by encouraging customers to use electricity more efficiently, as well as to make informed investment decisions when siting and designing distributed energy resources (DERs).

With cost-causation as an overarching rate design principle, **customer considerations** may lead to the deliberate deployment of rate designs that are not entirely cost-based. A practical consideration in this regard is the extent to which the rate is simple and easy for the customer to understand. The tradeoff between cost-causation and simplicity is an inherent tension in rate design; this tension will become more apparent as the technical barriers to offering more complex rate design (such as metering) are removed. When moving toward cost-based rates, other considerations include customer acceptance and the distribution of bill changes among customers.

Options for Modernizing Distribution Rates

There are many options for moving toward more cost-reflective distribution rates, depending on how the AUC and industry stakeholders choose to manage the tension between cost-causation and simplicity. Highlights of these opportunities for each of the three common types of charges (variable, demand, and fixed) are:

Variable charge: Where distribution costs are collected through variable charges (*i.e.*, cents per kilowatt-hour charges), cost-reflectivity can be improved if the charge is made to be time-varying. That could include a static time-of-use (TOU) rate, or dynamic options such as critical peak pricing (CPP) or at the extreme even hourly or sub-hourly real-time pricing (RTP). Another possibility is a rebate for reductions in usage during times of distribution capacity shortages (known as a peak time rebate, or PTR). Thus far, there has been relatively little innovation in variable distribution charges in the industry, even though the idea has been entertained in several U.S. jurisdictions and also in Australia and New Zealand. Additionally, some vertically integrated utilities with TOU rates have indicated that their distribution costs are being collected on a time-varying basis under these rates, in recognition of the fact that distribution capacity is largely a peak demand-driven cost.

There has been significantly more innovation in variable charge design on the generation side of the bill. A number of utilities have collected generation costs through dynamic pricing rates, such as Baltimore Gas & Electric and Pepco in Maryland (PTR), Oklahoma Gas & Electric (CPP), and Commonwealth Edison (RTP). These rates were introduced to reduce utility costs through demand response, in some cases leveraging the presence of smart thermostats and in-home energy information displays and therefore enhancing the customer's ability to respond to the dynamic price signals.

Demand charge: Demand charges (dollars-per-kilowatt charges) are a common method of distribution cost recovery, particularly among larger customers where the necessary metering infrastructure is already in place. There are many ways to design a demand charge, and design decisions regarding the move toward more cost-reflective rates will depend on the nature of the distribution costs being recovered through the demand charge. At a high level, demand charges that collect costs that are further downstream (*i.e.*, closer to the customer, such as line drop costs) will be based on metrics that more closely align with the maximum demand of the individual customer. Demand charges that collect upstream costs (*i.e.*, further from the customer, such as distribution substation costs) will be based on metrics that more closely relate to the coincident peak demand of the distribution system. Many utilities—including in Alberta—already have demand charges for large customers. In the U.S., there are at least 67 instances in which residential demand charges are being offered to residential customers. Arizona Public Service (APS) has more than 20 percent of its residential customers enrolled in a voluntary rate with a demand charge.

Fixed charge: Fixed charges are common to most utility distribution rates. At a minimum, they collect costs that do not vary with usage or demand, such as metering and billing costs. Additionally, in some cases fixed charges are used to collect "embedded" costs (*i.e.*, the sunk cost of prior investments in the distribution system). The Ontario Energy Board (OEB) recently approved a transition toward collecting a higher share of distribution costs through a fixed charge, partially due to concerns about under-recovery of sunk investment costs through volumetric rates. Advantages of fixed charges include simplicity and bill stability for the customer, though they do not include an actionable price signal that encourages electricity consumption during lower-cost hours of the day.

These principles and rate design options should continue to be evaluated as energy technologies emerge, and as the nature of the customer's interaction with the grid evolves. New technological developments emphasize the need to re-evaluate the price signals and incentives provided to customers on a regular basis.

Transitioning to Modernized Rate Design

In addition to deciding the specific elements of the rate design, there will be a number of accompanying issues to consider. For example, should rate design be used to promote the province's policy objectives? Should separate rates or rate classes be created to target individual technologies, or instead should rates be modernized for all customers? How will the transition to the modernized rates be rolled out to customers? And, in addition to the distribution charge, will the other elements of the retail rate (*i.e.*, transmission and generation-related charges) be modernized as well?

Rates are not merely a blunt tool for recovering costs. They provide customers with proper price signals that enable adoption of the emerging energy technologies that are most beneficial to the grid, while still fully recovering the costs that they impose on the grid from those customers. Ultimately, this alignment of customer incentives with the optimal operation of the power grid will reduce costs for all customers. Given the rapid pace of technological change, it is important to modernize rates in a proactive rather than reactive manner. Next steps in modernizing Alberta's electricity and gas rates could include developing commonly understood rate design principles and objectives, establishing a list of the most attractive alternative rate designs that satisfy those objectives, and conducting market research and pilots to evaluate the likely impacts of the new rates before rolling them out at scale.

I. Introduction

The emergence of distributed energy technologies will change the way ATCO's customers interact with its distribution network. Smart thermostats and appliances, for instance, will enable customers to respond to price signals in ways that were not previously possible. Electric vehicles (EVs) will introduce a large load that will place new demands on the distribution system, but which can also be incentivized to be shifted to off-peak hours or to alternative locations (*e.g.*, home versus workplace charging) when the system is not constrained. Additionally, both residential customers and large customers are increasingly serving their own power needs through a variety of behind-the-meter generation technologies including backup generators, rooftop solar panels, battery storage, requiring that utilities accommodate two-way flows on the distribution system and revisit the compensation mechanisms for customer energy exports to the grid. Parallel to these behind-the-meter developments, upgrading the meter itself with digital two-way communications capability can help provide the infrastructure necessary to modernize ATCO's rate designs.

The purpose of this report is to identify rate design options that could better accommodate customer adoption of emerging energy technologies such as smart thermostats, LED lights, digitally-communicative appliances, rooftop solar panels, battery storage, other forms of on-site generation, and battery-powered electric vehicles. Brattle developed the report on behalf of ATCO as part of the company's input to Modules 2 and 3 of the Alberta Utilities Commission's (AUC's) Distribution Inquiry (DI).

Our report takes a forward-looking view on rate design, and considers opportunities to modernize rates specifically with respect to challenges associated with new technologies that are expected to emerge over the next several years. Modernized distribution rate design will align customer investment and electricity consumption decisions with the operational requirements of the power system. Given the pace of change in consumer technologies that has been observed in the energy sector in the past few years, it is important to address rate design in a proactive rather than reactive manner.

We focus primarily on distribution rates for residential customers, but also address issues associated with rate design for large customers that have adopted on-site generation. Further, while the examples presented in this report are focused on electricity rates, the same economic concepts largely also apply to rate design for natural gas distribution. Our report discusses rate designs that do not require smart meters, as well as rates that would require a metering upgrade; where relevant, we have highlighted this distinction.

II. The Need for Cost-Reflective Rates

What is the Objective of Rate Design?

The literature on principles of rate design, such as Professor James Bonbright's *Principles of Utility Rates*, has recommended adherence to the overarching principle of **cost-causation** in rate design. In other words, the pricing of electricity or natural gas should reflect the economic cost of providing electricity or natural gas to customers. A cost-based rate should lead to achievement of the following associated objectives:

- *Equity:* Cost-based rates minimize cross-subsidies between all types of customers, with each customer's bill reflecting the cost that the customer imposes on the distribution system. In the context of emerging technologies, this is a particularly important consideration given that certain segments of customers may be more or less able to adopt the technologies than other customer segments.

- *Reduced long-run distribution costs:* Cost-based price signals will provide customers with an incentive to align their consumption of electricity with the times of day when it is least expensive to produce and deliver. In the long run, this more-efficient use of the network will lead to lower costs through a reduced need for capacity upgrades. Emerging technologies such as smart thermostats and EV chargers will enable customers to respond to those price signals by automating response from large sources of discretionary load, thus providing greater improvements in system efficiency than have been observed historically through behavioral response to the price signals.

- *Efficient siting and design of distributed energy resources (DERs):* Cost-based pricing will lead to the adoption of the types of DERs that are most beneficial to the power system; it will also lead to design and operation of those DERs that minimizes system costs. In addition, cost-based pricing can potentially lead to the adoption of those resources in the locations of the grid where they are needed most (if price signals in the distribution rate vary by location).

With cost-causation as an overarching rate design principle, **customer considerations** may lead to the deliberate deployment of rate designs that are not perfectly cost-based. Relevant practical considerations in this regard include:

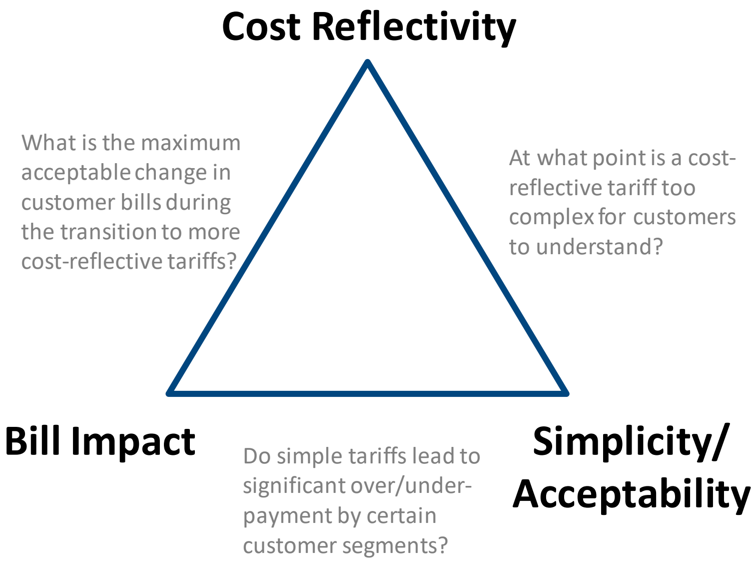
- *Simplicity / understandability:* For customers to be able to respond to new price signals, the rate design must be simple enough for the customer to understand. Adoption of automating technologies could temper this need to a degree, as those technologies could be programmed to respond according to the customer's preferences (*i.e.*, "set-it-and-forget-it").

- *Customer acceptance / perceived fairness:* Aside from the rate's understandability, customer willingness to accept the rate is another relevant concern. Customer perceptions of the rate's fairness are often a key consideration in this regard. A strong customer education and communications plan, and the provision of web-based tools, can help to mitigate these challenges.

- *Potential for large bill changes / volatility:* The extent to which the introduction of a new rate will lead to large bill changes for some customers has often been a point of concern in utility rate cases. The principle of "gradualism" is intended to address this concern. Bill volatility is also a consideration, as some customers may value predictability over bill savings opportunities.

Figure 1 summarizes the tradeoffs inherent in retail rate design.

Figure 1: Tradeoffs in Retail Rate Modernization



A. What is a Cost-Reflective Rate?

When providing customers with electricity, the incurred costs are generally divided into three categories: generation, transmission, and distribution. This paper is focused on rates designed to collect distribution costs. However, when modernizing rates, it will be important to consider the design of all charges on the bill. Customers typically react to their total bill, and with distribution charges representing only a portion of the bill, cost-reflectivity in generation and transmission charges will be similarly important.

Some elements of distribution costs are unrelated to customer electricity consumption or demand. These costs are entirely "fixed" on a per-customer basis and would include metering, billing, customer care, and connection/hookup costs. Other distribution costs are a function of peak demand. Depending on the type of distribution cost being recovered, the peak could be based on an individual customer's demand, local demand on the distribution system (*e.g.*, aggregate demand a neighborhood), or total demand across significant portions of the distribution system. The capacity of the distribution system must be built to serve each of these peak demands.

There is a time-related element to distribution system peak demand, with the peaks more likely to occur at certain times of day, days of the week, and seasons of the year. There is also a locational element. Some locations of the distribution system may have significant excess capacity, and therefore the ability to handle the addition of significant new load without the need for a capacity upgrade. Other locations may have capacity constraints, and therefore a higher marginal cost associated with demand growth.

A cost-based rate will present this basic cost structure to the customer. A precisely accurate pass-through of marginal distribution costs to customers is difficult or even infeasible to obtain, as this would require sub-hourly pricing at every location in the distribution system. However, as discussed later in this report, a variety of cost-based rate designs can approximate these dynamics with varying degrees of simplicity.

B. An Example

To illustrate the advantages of cost-based rate design in the context of emerging technology, consider the example of a customer who is considering purchasing an electric vehicle.

Many utilities, including those in Alberta, collect a majority of their revenues through a flat volumetric charge that is higher than the variable cost of providing power, and which does not reflect the time-varying or location-specific nature of power generation or delivery. With this rate design, the customer would be indifferent regarding when or where he or she charged the EV. As such, if the distribution grid was capacity constrained in the customer's neighborhood, plugging in during the evening hours could lead to the need for a transformer upgrade, raising costs for all customers. Yet, if the customer were to charge during other, less constrained times (*e.g.*, in the middle of the night) he or she would overpay relative to the actual cost of providing power during those times. Similar considerations might apply regarding the choice of home versus work as the location for charging (or, for that matter, discharging to the grid).

Alternatively, consider how the situation would change if the utility offered the option to enroll in a cost-reflective rate designed for customers with EVs. Through either a demand-based charge or a time-varying volumetric charge, that rate could convey to the customer the cost associated with charging during hours when the system is peaking. The customer could either choose to pay that higher cost, or delay charging until discounted hours of the day (typically achievable through a timer or remote control of the charger or vehicle). The availability of such a rate to residential customers may also vary by location, depending on the locational benefits of charging at the workplace (*e.g.*, if a downtown grid were more robust). In addition to allowing for higher utilization of the distribution system and avoiding the need for capacity upgrades, the fuel savings associated with the discounted off-peak price would improve the economics of the investment decision for customers considering switching to clean, electric transportation.

Similar benefits would apply for customers with other energy technologies. For instance, cost-based rates would incentivize investment in rooftop solar systems that are oriented to maximize output during times when it is most valuable to the system (typically facing west, so that output coincides with the system peak). An appropriate volumetric rate would also allow customers to make efficient decisions regarding investment in behind the meter generation, or, alternatively, if those resources would be better invested in energy efficiency. With the rise in smart appliances, a cost-based rate would also allow customers to unlock the automation features of those technologies by responding to price signals and reducing their bills.

III. Options for Modernizing Distribution Rate Design

Utility rate designs typically include up to three types of charges: volumetric, demand, and fixed charges. Volumetric charges are designed to reflect the variable components of costs of service over a billing period. In its simplest form, volumetric charge is flat, expressed in cents per kWh, and it is applied to total load served regardless of system conditions. On the other hand, as discussed above, time-varying rates can better align retail prices with underlying system costs.

Demand charges are designed with the goal of accurately capturing the long-run costs of capital investments on the distribution networks. Assessed by the maximum amount of power (in kW) that a customer draws within a defined time interval, demand charges help to directly link customers who drive system maintenance and capacity expansion with their costs.

Finally, fixed charges can help to recover non-variable costs of running a distribution system, such as billing and metering costs. Fixed charges are also sometimes considered to be representative of network costs in the short-run (*i.e.*, charges that are relevant for recovering the costs of sunk investments in the system). Fixed charges are different from demand charges in the sense that fixed charges do not vary based on the way the customer consumes electricity, while demand charges are a function of the customer's peak demand (which can be measured in a variety of ways). Fixed charges are typically represented as dollars-per-month or cents-per-day charges.

In practice, utility rate structures are typically a combination of these elements, with the specific design varying depending on the makeup and characteristics of customers served.[1] Regulations,

[1] In addition to most cost-based rate designs, there are other options available for incentivizing efficient use of distribution infrastructure, such as demand response programs and auctions to procure distribution services from DERs. For further discussion, see Ryan Hledik and Jim Lazar, "Distribution System Pricing with Distributed Energy Resources," prepared for Lawrence Berkeley National

policy goals, and technology adoption and development also play key roles in rate design. The following are examples of common rate structures as well as some emerging trends in this area.

A. Volumetric Charges

Volumetric charges are designed to recover the variable costs of service during a billing period and usually consist mostly of items related to fuel expenditures, but may sometimes include charges related to other costs, such as transmission and distribution. Customers are assessed volumetric charges every period (typically monthly) in accordance with their electricity consumption in that period.

Under a flat volumetric rate, customers pay the same rate for electricity distribution independent of system conditions at the time of consumption. With charges unchanged regardless of the levels of aggregate demand and system capacity, customers have neither the price signal nor the incentive to adjust their consumption level in accordance with their willingness to pay. Time-varying volumetric charges can help in better reflecting system needs, aligning customers' willingness to pay with real-time system conditions, though they require more advanced metering technology, which can measure energy consumption in specific time intervals.

Time-varying charges come in many forms; the most common is a time-of-use (TOU) rate with on-peak and off-peak periods.[2] Charges are higher on a predictable and daily basis during on-peak hours, signaling system scarcity, and are lower during other hours.

Alternatively, the timing and price level of peak periods may vary depending on coincidence with system peaks, a pricing structure known as critical peak pricing (CPP). Under the CPP design, the peak price would be significantly higher for the limited number of days during which the system load is the highest—typically 10 or 15 days out of the year. The peak time rebate (PTR) is similar to a CPP. Rather than charging customers a higher rate during peak events, PTR provides customers with a payment for reductions in consumption below a predetermined baseline. Real-time pricing (RTP), a more dynamic pricing option, provides customers with either an hourly or sub-hourly price. While each of these dynamic pricing options has been used by utilities to reflect variation in energy prices or the cost of generation capacity, they could also be applied at the distribution system level to reflect distribution system capacity constraints (though we are not aware of the utilization of this approach by any utility as of yet).

Relative to static TOU rates, dynamic rates allow the utility to respond with short notice to unexpected reliability- or price- driven events on the system. For example, as the amount of

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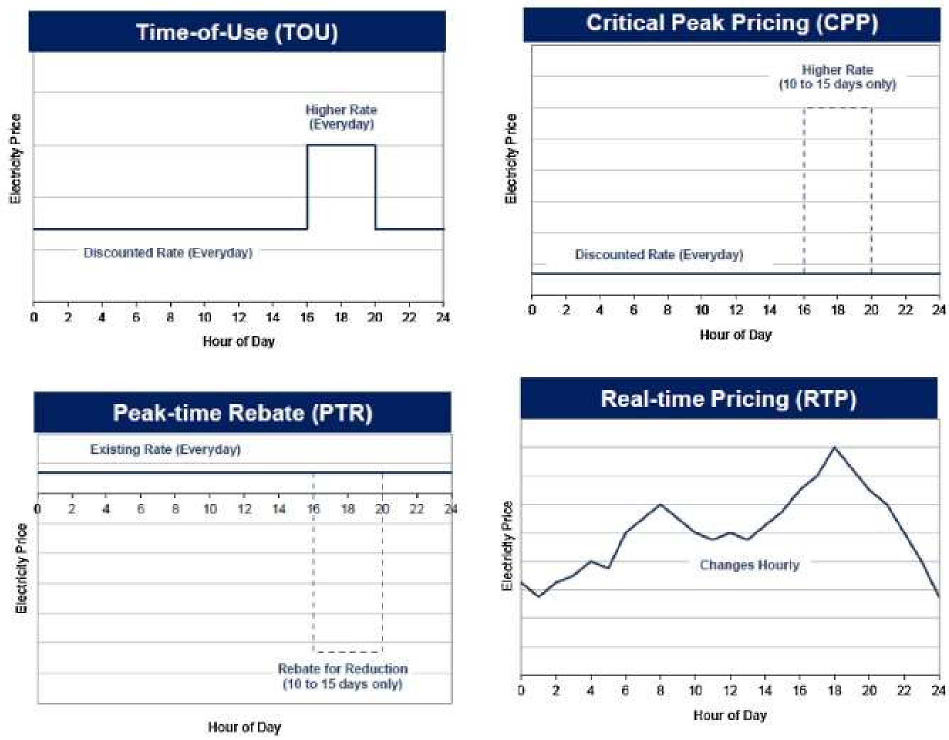
Laboratory's Future Electric Utility Regulation paper series, May 2016. https://emp.lbl.gov/sites/all/files/feur_4_20160518_fin-links2.pdf.

2 Roughly half of all investor-owned utilities in the U.S. offer residential TOU rates. For further discussion, see Ryan Hledik, Cody Warner, and Ahmad Faruqui, "Status of Residential Time-of-Use Rates in the U.S.," *Public Utilities Fortnightly*, November 2018. https://www.fortnightly.com/fortnightly/2018/11/status-residential-time-use-rates-us

intermittent generation from distributed energy resources increases, distribution system capacity constraints may become less predictable. In these instances, rate designs that can respond to actual system conditions (such as RTP or CPP) rather than reflect stable patterns (such as TOU) may become more valuable.

Figure 2 illustrates the design options for time-varying volumetric charges.

Figure 2: Illustrations of Different Time-Varying Rates



Beyond variation in price, variations in notification and locational pricing are also important considerations when designing time-varying volumetric charges. Customers can be notified of rates and applicable times anywhere from one day ahead to real time (for dynamic rates), or not at all (for fixed rates). Volumetric charges can also vary depending on location, a concept known as distribution locational marginal pricing. This concept is beginning to receive attention in the U.S., particularly in New York, where efforts are underway to facilitate the integration of DERs. Note that implementation of time-varying rates requires advanced metering capabilities and infrastructure, which provide utilities with granular customer information.

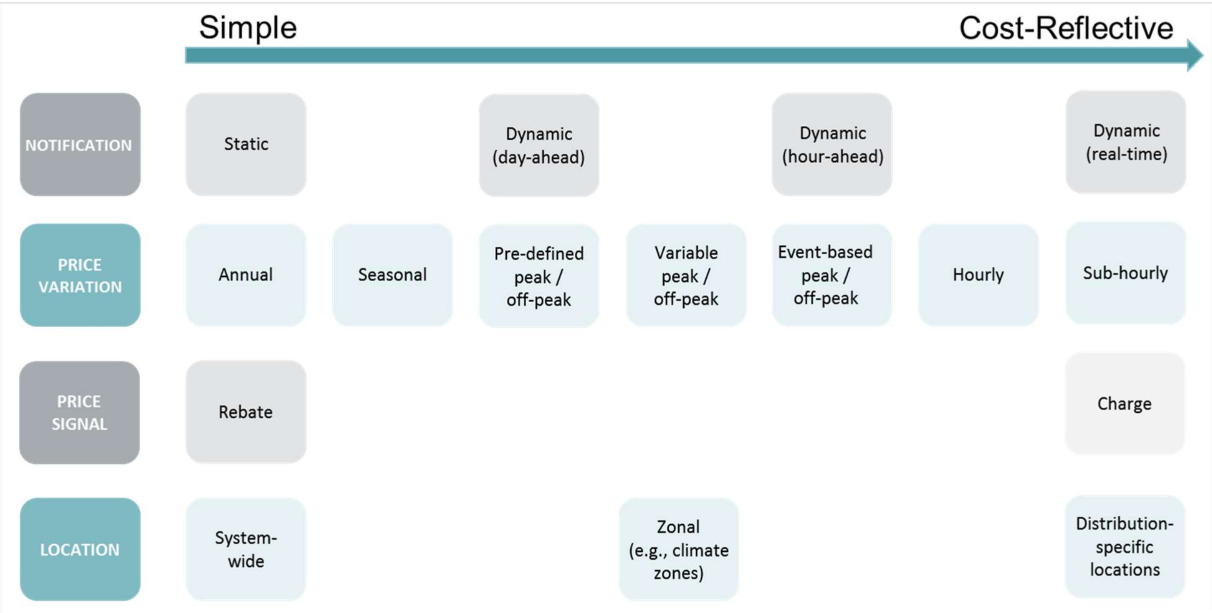
Time-varying rates offer the benefits of improving economic efficiency, increasing fairness in cost recovery, and providing customers with an opportunity for bill savings. Customers under dynamic pricing arrangements have the incentive to respond to price signals in a manner that is consistent with their willingness to pay, leading to an improvement in economic efficiency. This, in turn, results in improved equity in cost recovery; a customer with high willingness to pay incurs larger costs to the system through higher usage, thus should contribute more to cost recovery than one who uses the system less frequently. At the same time, customers can actively decide when and how much to consume electricity according to their own preferences and circumstances. Customers who wish to lower their electricity bills, for instance, can shift some of their consumption to off-peak hours.

Evaluations of pricing pilots and full-scale rate offerings have shown that customers do respond to price signals in time-varying rates.[3] Even in the absence of automating technologies (*e.g.*, smart thermostats or behind-the-meter generation), participants have demonstrated a significant level of behavioral response to the price signals, shifting load away from higher-priced hours. The presence of automating technologies increases the amount of price responsiveness; according to Brattle analysis of the pilot results, technology can often double the peak load reduction achieved through time-varying rates. While even behavioral response has been shown to be consistent and reliable when sufficient numbers of customers are enrolled in the time-varying rates, an important question from a distribution planning standpoint is whether automation of the price response should be a prerequisite for decisions to defer capacity upgrades in anticipation of price-based demand response.

As mentioned above, the provision of time-varying rates requires advanced metering technology. In cases where that metering technology has not yet been deployed, the value of time-varying rates and other benefits offered by the advanced meters should be evaluated against the cost of investing in the new metering infrastructure.

The range of options for designing volumetric charges is summarized in Figure 3.

Figure 3: Elements of Volumetric Charges



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3 *See* Ahmad Faruqui and Sanem Sergici, "Household Response to Dynamic Pricing of Electricity: A Survey of 15 Experiments," *Journal of Regulatory Economics* (2010) 38: 193. https://www.brattle.com/news-and-knowledge/publications/household-response-to-dynamic-pricing-of-electricity-a-survey-of-15-experiments

B. Demand Charges

Demand charges account for the maximum amount of power (measured in units of kW) that a customer draws within a defined time interval (ranging from instantaneous to hourly) during a given period. Designed to reflect the costs of capital investments on the distribution networks, demand charges are consistent with the long-run view of marginal capacity costs. Utilities build out distribution capacity to meet the highest demand at any moment, in any location. Demand charges can therefore help to link the drivers of new infrastructure needs with the actual costs.

Well-designed demand charges can help align prices with underlying cost-drivers, helping to enhance economic efficiency. As such, it is important for demand charges to convey accurately the cost structure of delivering electricity to customers, who in turn can make informed decisions about the level and timing of their consumption in accordance to their preferences and circumstances. By providing customers with an incentive to reduce their bills through demand management, demand charges present an opportunity for customers to save money.[4] Furthermore, directly linking customers to costs incurred on their behalf can also help to minimize issues of cross-subsidy, leading to an improved fairness in cost recovery.[5]

A number of factors are important when considering demand charges. Customers may be assessed a demand charge over all hours within a specified time period, typically a monthly billing cycle independent of system conditions. Peak demand measured in this way is called "non-coincident peak demand".[6] Alternatively, customers may pay a demand charge for their maximum demand during the window of the day when system demand is typically highest.[7] Customers may also pay for demand charges only during the specific hours when the system actually peaks. Variation in location is another important design element, where charges may be levied for the whole system or only for the zone or distribution system to which the customer is connected.

Another key element of demand charge design concerns the variability in customer demand. At the simplest level, the demand level may be determined in advance based on the capacity of the customer's physical infrastructure. In some European countries, such as Spain and Italy, residential customers commonly pay a capacity charge that effectively reflects the size of their connection to

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4 When faced with well-designed demand charges, residential consumers may have the incentive to buy smart digital technologies such as thermostats, load controllers, home energy management systems and smart appliances, along with batteries and other storage options.

5 It can be the case that one class of customers may pay more for their electricity than another class, even though the former class incurs a lower level of consumption.

6 ATCO Electric's rate structure currently contains this non-coincident peak design. For example, Residential customers pay a total demand charge of 40.72 cents per kW per day, which includes both transmission and distribution components.

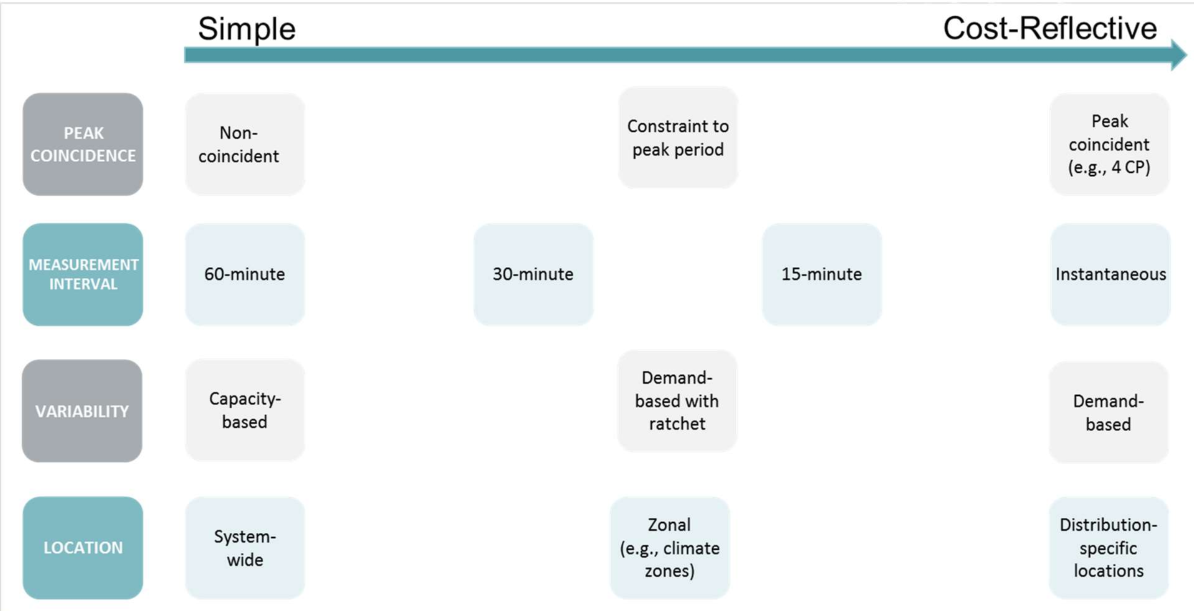
7 For example a four coincident peak ("4 CP") demand charge takes into account the share of a customer's maximum power consumption during the four system peaks over the billing period. The peak duration may be shorter than an hour (*e.g.*, 15 minutes).

the grid. When the customer's instantaneous demand exceeds this level, a circuit breaker flips and the customer must reduce demand before restoring power. Demand can also be determined *ex-post* based on the highest level of demand over a certain prior timeframe (a "ratchet") or on the customer's actual observed demand for that particular billing period (as discussed above).

Many jurisdictions, including Alberta, have used demand charges in various forms in both commercial and industrial rates for the better part of the last century. However, demand charges are less common for residential customers. To improve customer understanding of demand charges and their implications for electricity bills, utilities can present simple educational messages (*e.g.*, "avoid using your largest appliances simultaneously in order to save money on your bill"). Similar to time-varying volumetric charges, implementation of demand charges requires advanced metering capabilities and the supporting digital infrastructure.

Figure 4 summarizes the key design elements of demand charges.

Figure 4: Elements of Demand Charges



Fixed Charges

Fixed charges are designed to recover non-variable costs of running a distribution system. Also known as a customer charge, service charge, or monthly service charge, a fixed charge includes fixed customer costs such as metering, billing and customer assistance, but can sometimes cover fixed costs of distribution. The total costs are apportioned equally to the number of customers in the utility's service area, typically covering a small portion of distribution capacity costs. Proposals to increase the fixed charge have become increasingly common—one survey found active proposals to increase the residential customer fixed charge in at least 18 of the 50 U.S. states[8]

A variation of a higher fixed monthly charge is a minimum bill. A minimum bill is not a function of an individual customer's usage or demand, but ensures that every customer's bill will at least equal some pre-determined monthly amount. When using the distribution system, customers in principle impose a cost to the system, so a minimum bill guarantees the recovery of that amount on a regular basis.

Fixed charges are consistent with the short-run view of marginal capacity cost, reflecting the fixed nature of distribution system costs in the short run. Second, because fixed charges are already a feature of most electricity bills, customers can understand them easily, and can expect stability and predictability of monthly bills. Third, fixed charges can help to address emerging challenges associated with under-collection of costs from some customer types, such as solar PV customers. This is because, regardless of consumption level, customers have to pay fixed charges to cover a portion of the cost of the grid.

On the other hand, fixed charges have a number of limitations relating to equity and efficiency. Fixed charges, by definition, are unrelated to customers' actual usage of the distribution system. Small-use residential consumers and much larger customers are assessed the same charges, even though the two types of customer are responsible for substantially different costs. This mismatch in cost recovery tends to arise in a minimum bill design.[9] Furthermore, fixed charges do not change with the system conditions. Without such a pricing signal, customers do not know when to adjust their consumption patterns efficiently. As a result, certain rate designs with fixed charges may contradict policy goals. For instance, an increased fixed charge, coupled with a reduction in the unit charge, may reduce the incentive to invest in energy efficiency measures.

Figure 5 summarizes key elements of fixed charge design.

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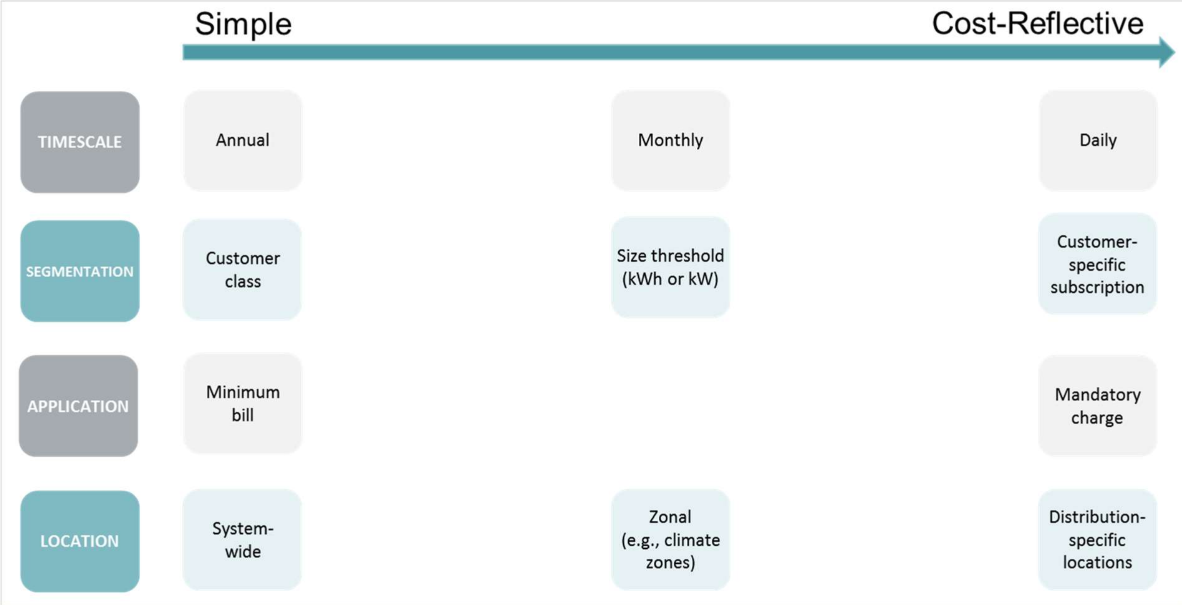
8 Benjamin Inskeep, *et al.,* "The 50 States of Solar," prepared by the NC Clean Energy Technology Center and Meister Consultants Group," Q3 2015. https://nccleantech.ncsu.edu/our-work/policy/the-50-states-reports/

9 A tiered minimum bill that increases with the level of consumption may address this issue.

Figure 5: Elements of Fixed Charges



C. Combining the Charges into Rate Offerings

Rate offerings typically feature a combination of the above rate design elements in order to maximize their relative advantages. The specific design also depends on existing regulations and policies, as well as the states of the utility's technology and infrastructure. Some of the common distribution rate design options currently being implemented by utilities include:

- **Flat volumetric charge with modest fixed charge.** Most common for residential customers, this two-part rate structure includes a monthly fixed fee and a volumetric charge of energy consumed. Because fixed charges can be a very small share of a typical customer's bill, the costs may not be distributed equitably between high- and low-demand customers.
- **Large fixed charge with modest flat volumetric charge.** This approach makes the bill simpler and more predictable for both the customers and the distributor, while also providing regulators with information about the costs of service for different distributors in the region. The flat volumetric charge acts as a guardrail, ensuring that customers still have an incentive to moderate their energy consumption. The Ontario Energy Board is transitioning all residential customers to this rate structure (see Hydro One case study below).
- **TOU energy charge with modest fixed charge.** Relative to large fixed charges and flat volumetric rates above, TOU rates can help customers save money (by shifting their consumption to lower-priced periods) and help distribution utilities lower investment costs (by deferring investments in grid infrastructure). With increasing renewable penetration, TOU rates can shift customers' demand to hours when renewable generation is most abundant, creating more opportunities for bill savings. At the same time, utilities can still collect fixed charges to cover fixed costs such as metering. California is moving all residential customers to TOU rates (see PG&E case study below).

- **Demand charge with modest fixed charge.** Demand charges correspond with the long-term need for investments into the distribution system. Based on a customer's peak demand every month, demand charges are often assessed for large commercial and industrial customers who have the ability and technology to measure and control their demand levels. However, the increasing deployment of smart meters makes the implementation of this rate structure more feasible for residential customers.
  U.S. utilities have considered introducing mandatory demand charges for their residential customers to ensure equity and efficiency in the pricing of electricity. As many as 67 demand charges are being offered to residential customers in the U.S., primarily by investor-owned utilities as well as cooperatives and municipal utilities. These programs also incorporate various rate elements that we discussed above, with 35 percent offering TOU rates, 44 percent seasonal rates, and 62 percent peak coincident rates (see Appendix). More utilities continue to propose demand charges on an opt-in basis rather than as either a default rate or a mandatory rate. With increasing rooftop solar adoption, a few utilities have proposed demand charges for these customers, citing cross-subsidy concerns.[10]

Beyond the common rate design options above, we observe several emerging options, including:

- **Fixed bill coupled with peak time rebate (PTR), energy efficiency, or demand response programs.** This option offers customers an easy-to-read electricity bill with high levels of bill stability, which in turn provides the distributor with predictable revenue every month. When set at an appropriate level, the fixed charge recovers system costs from all customers equally, including those who would otherwise pay less by offsetting their demand with their own energy resources. Peak time rebate, or energy efficiency or demand response programs help achieve or comply with energy policy goals by offering customers incentives to use electricity only at economically efficient times.

- **Critical peak pricing with fixed charge.** The CPP component reflects the cost of capacity during the (seasonal) system peak. The time and duration of peak events are either predetermined (similar to TOU) or variable, based on the system needs in real time. For example, Oklahoma Gas and Electric (OG&E) offers variable peak pricing for a number of

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[10] Westar Energy (now Evergy) in Kansas has a three-part in place for solar customers. Westar's proposal was appealed by the solar industry before the Court of Appeals in Kansas, which upheld the Kansas Commission's decision. It is currently under review at the Supreme Court in Kansas. Investor-owned utility Arizona Public Service offers a similar structure, giving its rooftop solar customers a choice between three time-of-use rates, two of which have demand charges. It also has a grid access charge for solar customers. Nevada Energy and Northwestern Energy (Montana) have made similar proposals. Among municipal utilities, the Salt River Project (SRP) in Arizona provides a noticeable example. SRP initially mandated three-part rate for its solar customers but now provides them a choice of staying with the demand charge or choosing a time-of-use rate. There is a higher fixed charge.

service classes.[11] The utility's residential customers within this rate structure have a fixed customer charge and seasonal on/off-peak variable charges. OG&E notifies customers of the on-peak prices the day before. The rate was introduced in part to encourage demand response and, as a result, reduce the utility's infrastructure investment costs.

- **Locationally varying real-time prices.** Rates with this structure vary depending on a customer's location within the distribution system, presenting a solution to integrate high levels of DERs. The locationally-varying rates signal where in this system load reductions or DER installations are most valuable. The New York distribution utility Con Edison offers a demand response tariff that offers two different incentive payments depending on the location of customers on the distribution system, with higher financial incentives available for those customers in locations with capacity constraints.[12] The goal is to encourage demand response to be adopted where it is needed most, relieving local capacity constraints. Aside from this example, however, the concept of locationally-varying retail rates or demand response incentives is an emerging area of industry interest, and is not yet commonly implemented.

Rate Design for Large Customers

Large commercial and industrial customers typically account for a significant share of electricity demand, playing an important role in defining the needs of the power system. For instance, industrial customers make up the largest share of ATCO Electric's demand, making up 69 percent of the company's delivered electricity in 2018.[13] To recover costs that large customers impose on the system, utilities often rely on demand charges in addition to fixed and/or volumetric charges. Depending on the makeup of the customer class, demand charges may be further divided into different tiers. Alternatively, utilities may use a demand ratchet structure that charges the customer based on their highest demand during a particular time period, typically several months or even a year.

Large customers increasingly rely on self-generation as a way to offset their electricity charges. This trend is expected to continue in light of recent technological developments and as a means for reducing bills by avoiding demand-based charges. Commercial and industrial customers can offset both their energy and wires costs through self-generation, historically through adoption of

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[11] Oklahoma Gas and Electric Company, "Residential Variable Peak Pricing," 06/19/2018. https://www.oge.com/wps/wcm/connect/c41a1720-bb78-4316-b829-a348a29fd1b5/3.50+-+R-VPP+Stamped+Approved.pdf?MOD=AJPERES&CACHEID=ROOTWORKSPACE-c41a1720-bb78-4316-b829-a348a29fd1b5-mhatJaA

[12] ConEdison, "2020 Demand Response Forum," 2/18/2020. https://www.coned.com/-/media/files/coned/documents/save-energy-money/rebates-incentives-tax-credits/smart-usage-rewards/demand-response-forum.pdf

[13] ATCO Electric's Module 1 filing. For comparison, 9 percent of ATCO Electric's delivered electricity in the same year was for residential customers.

of combined heat and power (CHP). For example, there were more than 80 GW of CHP as of 2017 installed in the U.S. at more than 4,400 sites around the country.[14] More recently, interests in self-generation have renewed as costs of behind-the-meter generation technologies (including backup generators, rooftop solar panels, and battery storage systems) continue to decline. The trend toward self-generation could accelerate in areas where customers have the added incentives to defer wires costs (when their transmission and distribution charges depend on the level of consumption, *i.e.*, demand charges).

Self-generating customers may reduce their grid usage level, but their connection to the grid still requires sufficient generation, transmission, and distribution capacity. Utilities are still obliged to provide both backup power during unplanned generator outages, and supplemental power at times when onsite generation does not meet energy needs. Furthermore, utilities incur delivery costs. Unless rates charged to self-generating customers fully recover these costs, the utility will pass these costs to other customers, creating issues of cross-subsidy.

Well-designed standby rates can help ensure that capacity is there when needed, at the same time eliminating cross-subsidies. Levied on "partial requirements" customers, standby rates may include one of or a combination of volumetric, demand, and fixed charges.[15] Standby rates apply to customers as long as they are connected to the grid.

An exit fee is another mechanism that can help to mitigate cost under-recovery from self-generation customers that leave the system. A large customer's decision to leave the system means that the remaining customers must pay for the remaining assets, even though those assets were developed to serve the departing customer. The size of the impact depends on the timing: the effects are much larger when exit occurs before most of the investments are fully recovered. This issue is particularly important for areas with low load growth, where it may require some time to replace the lost load. An exit fee imposed on the departing load ensures that costs allocated to that customer are partially if not fully recovered.

14 U.S. Department of Energy, "More than 550 Megawatts of New Combined Heat and Power Capacity Added in United States, Puerto Rico, and Virgin Islands," Office of Energy Efficiency & Renewable Energy," August 13, 2018. https://www.energy.gov/eere/amo/articles/more-550-megawatts-new-combined-heat-and-power-capacity-added-united-states-puerto

15 A capacity reservation charge ($/kW) for the capacity the utility must always have available may be billed separately from a demand charge for the capacity actually supplied during a billing cycle. A maintenance capacity charge ($/kW) for the capacity supplied during scheduled outage may be billed separately.

IV. Case Studies Illustrating the Rate Design Options

Utilities across North America are at widely varying stages of their transition to modern rate designs. The design of some utility rates has remained virtually unchanged for decades, whereas other utilities have recently introduced a number of innovative options. Thus far, most of the innovation in rate design has been driven by utilities with AMI, and has been implemented for a bundled rate or for the generation portion of the rate.

For example, Baltimore Gas & Electric and Pepco, in Maryland, both introduced PTR as the default rate option for residential customers following completion of the utilities' respective AMI deployments. The resulting load reductions are sold into the PJM capacity market, reducing the utilities' capacity costs accordingly. In Illinois, Commonwealth Edison offers residential customers a voluntary RTP rate, which passes through hourly variation in wholesale energy market prices. Oklahoma Gas & Electric has reached 20 percent enrollment in a critical peak pricing rate which was introduced to leverage the demand response capabilities of smart thermostats and reduce generation capacity costs as a result. Arizona Public Service (APS) has achieved a similar 20 percent enrollment rate in a voluntary residential demand rate offering. APS views demand rates as a cost-based solution for recovering costs from customers with rooftop solar.

Examples of innovation in distribution rate design are more limited. As is discussed later in this section, some utilities, such as those in Ontario, have recently increased the share of distribution costs recovered through a fixed charge, asserting that it aligns with the fixed nature of distribution investment in the short run. Other utilities have collected distribution costs through a TOU charge, though it was rolled into a TOU charge that recovers other system costs as well.

Perhaps the most significant example of TOU charges for distribution comes from Vector, a distribution utility in New Zealand. Starting in April of this year, Vector will introduce a two-part TOU rate structure for residential customers, featuring daily fixed charge with volumetric charges that vary with the time of electricity consumption. This rate structure will enable customers to reduce their electricity bills by shifting usage from peak to off-peak periods.

In the remainder of this section, we provide the details of a few utility distribution rate options that illustrate some of the rate design concepts discussed earlier in this report.

A. Canadian Utilities

1. Hydro One

Hydro One Networks is an electric distribution utility serving rural and urban areas of Ontario, Canada. The Ontario Energy Board (OEB) regulates Hydro One as well as 61 other local distribution companies (LDCs) located in the province.

Currently, Hydro One's residential delivery rates include both volumetric and fixed charges.[16] Distribution charges and transmission charges are assessed on a per kWh basis, whereas the service charge and the smart meter charge collection (on behalf of the Independent Electricity System Operator (IESO)) are fixed. These charges vary depending on the density of the service area, with generally higher charges for customers in low-density areas. For example, the monthly service charge is $33.57 in urban high-density areas, and $46.02 in low-density areas. The corresponding distribution volumetric charges are 0.30 cents/kWh and 2.96 cents/kWh.

Customers can also opt for a seasonal rate if their dwellings (*e.g.*, cottages and camps) do not qualify as year-round. Additionally, there is an adjustment factor to account for line losses.

Per the OEB's ruling, distribution rates for residential customers will transition from a blend of volumetric and fixed charges to an all-fixed monthly distribution charge over the next three to seven years.[17] Once the transition is complete, delivery charges will consist of a fixed distribution charge ($ per month), retail transmission rates (cents per kWh), and an adjustment for line losses. According to Hydro One, fixed distribution rates represent "a fairer and more transparent way to recover costs related to distribution."

The OEB considered transitioning distribution charges to a flat lump-sum amount, but was unable to find much support for that idea during stakeholder meetings.

General Service, or non-residential, customers are also billed according to the previously mentioned density zones. The customer's average monthly demand determines whether they belong to "energy-billed" (less than 50 kW) and "demand-billed" (above 50 kW) rate structure. "Demand-billed" GS customers have a flat fixed charge ($ per month) as well as demand charges for transmission and distribution costs. Smaller "energy-billed" GS customers pay fixed service and smart metering charges, but pay their transmission and distribution charges on a volumetric (per kWh) basis.

2. Hydro-Québec

Hydro-Québec Distribution operates distribution lines and serves customers throughout Québec, Canada. The majority of its customers fall into one of the following rate classes: Domestic, Small Power, Medium Power, Large Power, Off-grid systems, and Lighting.[18] Within each of these larger classifications, there are sub-classifications and options including net-metering options for customer-generators, running of new equipment and equipment testing, and interruptible options. Hydro-Québec also offers a flat rate option which is applicable to contracts for general use when

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16 HydroOne, "Rates and Billing." https://www.hydroone.com/rates-and-billing

17 HydroOne, "Moving to Fixed Distribution Rates." https://www.hydroone.com/rates-and-billing/rates-and-charges/fixed-distribution-rates

18 Hydro Quebec, "2019 Electricity Rates, Effective April 1, 2019." (2019 Electricity Rates) http://www.hydroquebec.com/data/documents-donnees/pdf/electricity-rates.pdf

Hydro-Québec decides not to meter consumption. This is a flat rate per kilowatt (kW) of billing demand, which is determined based on the installed capacity in kilowatts, or by metering tests.

The standard rate for Residential customers (demand below 65 kW) consists of a fixed charge and an inclining two-tier volumetric charge. Residential customers with higher demand have an alternative rate structure that includes an inclining two-tiered volumetric charge and a seasonal demand charge applied to kWs of billing demand in excess of 50 kW. The billing demand for this rate structure equals the maximum power demand during the consumption period in question, but never less than the minimum billing demand.[19]

The standard rate for Small Power Customers is similar to the one for Residential customers, featuring a fixed charge, a volumetric charge, and a demand charge. The demand charge is applied only when demand exceeds 50 kW, but it is not seasonal. The Medium Power rate requires a minimum demand of 50 kW, and consists of a demand charge and two-tier declining variable charge. The Large Power standard rate applies to an annual contract whose minimum billing demand is 5,000 kilowatts or more and which is principally related to an industrial activity. This rate does not have a fixed charge, but consists of a demand charge and an energy charge. Notably, "Flex" options, which offer peak time rebates, are also available for eligible Small and Medium Power Customers. For reduction in consumption during system critical peak events, the customer receives a credit for reduction in energy consumption.

B. Australia and New Zealand Utility

1. SA Power Networks

Serving around 1.7 million customers in South Australia, SA Power Networks (SAPN) has recently undertaken efforts to reform its rate structures so they will better reflect the costs of delivering electricity to customers. A significant share of SAPN customers have adopted solar PV panels; over 30 percent of residential customers have installed rooftop solar.[20] All of the company's large businesses have interval meters; one quarter have solar PV panels. Nearly 20 percent of residential and small business customers have interval meters.

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[19] The minimum billing demand is "equal to 65 percent of the maximum power demand during a consumption period that falls wholly in the winter period included in the 12 consecutive monthly periods ending at the end of the consumption period in question." 2019 Electricity Rates, p. 16.

[20] SA Power Networks, "Attachment 17, Tariff Structure Statement Part B – Explanatory Statement," 12/10/2019. https://www.aer.gov.au/system/files/SAPN%20-%20Revised%20Proposal%20-%20Attachment%2017%20-%20Tariff%20Structure%20Statement%20Part%20B%20-%20Explanatory%20Statement%20-%20December%202019_0.pdf. The Australian Energy Regulator in its draft decision approved the SAPN's proposed rate structures to be effective in July 2020. The final decision is expected in April of this year.

To manage customer demand more effectively, SAPN has recently proposed offering TOU rates on a default (opt-out) basis for residential customers from July 2020.[21] The network is experiencing a new pattern of load peaks and troughs owing to the increase in the adoption of solar PV panels, whose peak generation does not necessarily coincide with periods of highest loads on the network. Residential customers with interval meters receive a TOU rate (expressed in cents per kWh) that is structured in a way that accounts for variable generation and variable demand. During daytime hours with high solar PV output (between 10AM and 3PM), the "solar sponge" rate is 25 percent of the standard rate offered customers without interval meters. The rate is 50 percent of the standard rate for off-peak consumption between 1 AM and 6 AM, providing incentives for EV owners to charge their vehicles overnight. For the rest of the time, the tariff is 125 percent of the standard rate. [22] Both standard and TOU customers are assessed a small fixed charge.

A three-part 'prosumer' rate is optionally available for residential customers with interval meters with the appetite for a demand-based price signal. In this rate structure, the volumetric rate (in cents per kWh) are significantly lower than the standard TOU rate. The monthly demand charge is estimated using the average demand over a four-hour window (from 5 PM to 9PM). The summer demand is the highest day in each of the 5 months of summer (November to March). This rate structure accommodates customers who want to discharge energy storage systems during peak periods.

In addition to the standard rate, a TOU rate with the same peak/off-peak window is also available for small business customers. For customers with demand of less than 120 kVA, the default rate is the TOU tariff, though they can opt in to the "TOU with Demand" rate. Their peak volumetric rate is 50 percent higher than the standard rate. For small businesses with demand greater than 120 kVA, the default rate is the TOU with any time maximum demand rate (maximum 30-minute interval, rolling 12-month reset).

Large business customers are assigned to one of three rate classes depending on their voltage levels. Measured in summer over the four-hour window, a peak demand charge is expected to cover about 30 percent of the bill. Customers located in the Central Business District (CBD) have a longer, six-hour window (from 11 AM to 5 PM), and their demand charge is higher. This is because the effect of solar generation in the CBD is low – commercial loads in this area are significant, but there is not a lot of suitable roof space for solar PV development. Additionally, SAPN levies fixed and volumetric charges on these customers as well.

Overall, SAPN's innovative rate designs appropriately align consumers' decisions and behaviors with the system needs. By providing incentives for variation in demand and variable generation, the tariffs remain technology-neutral, encouraging the development of emerging technologies.

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21 *Ibid.*

22 The retailer pays this fee though it is not obligated to pass it through to customers.

2. Vector

Vector is the distribution utility that serves Auckland, the largest city in the country. After many months of deliberations and conversations with the Electricity Authority, the electricity market regulator, Vector made the decision to restructure its flat distribution charge as a TOU charge for all residential customers, effective April 2020.[23] The mandatory TOU charges will vary by size of usage. For low users, the charge during the off-peak period will be $.0621/kWh and during the peak period will be $0.1542/kWh. For standard users, the off-peak charge will be $.0229/kWh and the peak charge will be $.1150/kWh. Thus, the ratio between the two periods will be higher for standard users compared to low users. The peak period runs from 7 AM to 11 AM and from 5 PM to 9 PM Monday to Friday. All other hours are off-peak hours. It will be up to the retailers whether to pass through these time-of-use delivery charges to retail customers or to bundle them into some other types of charges.

Vector has also recently completed a trial of a peak-time rebate offering to retail customers. The trial was carried out jointly with a retailer, Mercury.[24]

C. U.S. Utilities

1. Consolidated Edison

Consolidated Edison's (ConEd) electric system serves 3.4 million customers in New York City's five boroughs, as well as in Westchester County.[25] ConEd's standard Residential delivery rate consists of a fixed charge and a variable charge. In the summer months only, the variable charge is two-tiered, with increasing charges for higher blocks. Residential customers also have a voluntary time-of-day optional rate with a higher fixed charge and on-peak/off-peak variable charges through the year.[26] A specific multi-dwelling space-heating rate is available for residents of multi-dwelling units in which the use of electricity meets space heating demands.

ConEd introduced a smart energy plan very recently, which includes demand charges for distribution service. According to information on the company's website, the delivery portion of

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23 Vector, "Electricity Prices Effective from 1 April 2020." https://www.vector.co.nz/personal/electricity/pricing/electricity-prices-2020

24 Energy Networks Association, "Distribution Pricing Reform-a roadmap of overall progress." May 2018. http://www.electricity.org.nz/.

25 Consolidated Edison Company of New York, Inc. , "Company History and Statistical Information." https://www.coned.com/en/about-us/corporate-facts

26 Consolidated Edison Company of New York, Inc., Schedule for Electricity Service," Leaf No. 388. https://www.coned.com/_external/cerates/documents/elecPSC10/electric-tariff.pdf. The variable charge is seasonal for a subgroup of customers.

the bill is based on how efficiently the customer uses the grid.[27] The company says that the difference between the standard delivery rate and the Smart Energy Plan is akin to the difference between a car's odometer and speedometer readings. While a car's odometer measures the number of miles traveled, its speedometer indicates the speed at a specific moment. The price of using the grid differs between the peak (noon to 8 pm on weekdays) and off-peak (all other hours) periods. During the peak period in the summer months, charge for demand is $19.66/kW; it is $15.13/kW during the winter. The year-round off-peak charge is $7.64/kW.

ConEd advises customers using this plan to stagger device use, and to avoid running them all simultaneously. ConEd says customers can save even more money by running devices during the off-peak period.

Standard service contract for Small General Service customers includes a fixed charge and a seasonal variable component, wherein the rate is higher in the summer months (June to September). Under specified conditions, a customer with unmetered service would have a smaller fixed charge.[28]

The standard Large General Service rate has a variable charge and a seasonal tiered demand charge.[29] Variable and demand charges are divided into two rates, based on whether the company is providing low or high voltage service. Under certain conditions specified in Rate II of ConEd Service Classification No. 9 for large customers, time-of-day rates are mandatory.

2. Pacific Gas & Electric

Pacific Gas & Electric (PG&E) is a full-service utility that provides electricity to approximately 5.4 million electric customers across central and northern California, with over 100,000 circuit miles of electric distribution lines.[30]

Pursuant to a recent order by the California Public Utilities Commission, PG&E is transitioning residential customers from tiered rate structure to TOU structure.[31] The tiered structure has no fixed charge and an increasing tiered variable charge, which depends on a tier boundary (termed

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27 Consolidated Edison Company of New York, Inc., "Smart Energy Plan." https://www.coned.com/en/accounts-billing/small-business-smart-energy.

28 "Where the Customer's only utilization equipment consists of warning lights, electric signs or the like, having a total rated capacity of less than 10 kW and an estimated use of less than 3,000 kWh per month and such equipment has a definitely determinable demand, and is operated on a fixed schedule, the Company may supply unmetered service." *Ibid.* at 26, Leaf No. 63

29 *Ibid.* at 26, Leaf No. 445

30 Pacific Gas and Electric Company, "Company Profile." https://www.pge.com/en_US/about-pge/company-information/profile/profile.page.

31 California Public Utilities Commission, "Residential Rate Reform / R.12-06-013." https://www.cpuc.ca.gov/General.aspx?id=12154

"Baseline Quantity").[32] The baseline depends on the season, as well as the customer's specific service territory. Under the new TOU structure, residential customers can select an option with on/off peak hours for every day of the year. Alternatively, customers can select an option with on/off peak hours for only business days. In the second option, prices are lower for off-peak hours and non-summer months (October through May). Note that under the Net Energy Metering Rules 2.0 provisions, PG&E, along with San Diego Gas & Electric, and Southern California Edison, have mandatory time-of-use rates for solar customers.[33]

PG&E is one of several utilities that collect distribution costs on a time-varying basis through a residential TOU rate offering. A survey of 12 large utility residential TOU rate offerings found that 58% (7 of 12) collected distribution costs through the TOU rate. While these rates typically have been offered for many years, and were not introduced in response to the adoption of a specific energy technology, they demonstrate industry precedent for time-varying distribution charges. Table 1 summarizes the survey.

Table 1: Survey of Costs Recovered Through Utility Residential TOU Rates

	Name of Investor-Owned Utility	State	Residential Customers	Costs Recovered under TOU Rate		
				Generation	Transmission	Distribution
[1]	Potomac Electric Power Company	MD	496,347	✓	-	-
[2]	Jersey Central Power & Light Company	NJ	977,420	✓	-	✓
[3]	Arizona Public Service Company	AZ	1,046,989	✓	-	✓
[4]	NSTAR Electric Company	MA	1,063,565	-	✓	✓
[5]	Connecticut Light & Power Company	CT	1,117,897	✓	-	-
[6]	Baltimore Gas & Electric Company	MD	1,132,934	✓	-	-
[7]	San Diego Gas & Electric Company	CA	1,266,249	✓	-	-
[8]	Ohio Power Company	OH	1,276,363	✓	-	✓
[9]	Consumers Energy Co	MI	1,577,087	✓	-	-
[10]	Virginia Electric & Power Company	VA	2,150,818	✓	-	✓
[11]	Southern California Edison Company	CA	4,381,511	✓	-	✓
[12]	Pacific Gas & Electric Company	CA	4,749,486	✓	-	✓
Average			**1,769,722**	**92%**	**8%**	**58%**

Note: Extracted from Ryan Hledik, Cody Warner, and Ahmad Faruqui, "Time-of-Use Rates in the U.S.," *Public Utilities Fortnightly*, November 2018.

32 Pacific Gas and Electric Company, "Electric Schedule E-1, Residential Services," Sheet No. 1 https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-1.pdf

33 EnergySage, "California Net Metering: Everything You Need to Know About NEM 2.0." https://news.energysage.com/net-metering-2-0-in-california-everything-you-need-to-know/

The standard rate for Small General Service distribution customers is a two-part rate with a fixed charge and a seasonal variable charge.[34] The fixed charge is larger for poly-phase service as compared to single-phase service. Small General Service customers also have a TOU option under which distribution volumetric charges differ based on peak period and seasonality.

PG&E defines three standard distribution rates for demand loads for Medium General Service (with demand between 75 and 499 kilowatts). The rate structure consists of a fixed charge, seasonal variable charge, and a seasonal TOU demand charge broken up for secondary, primary, and transmission voltages.[35] The summer period is split by peak, part-peak, and off-peak hours, while the winter period is split by peak, off-peak, and super off-peak.

3. Commonwealth Edison

Commonwealth Edison (ComEd) is the largest electric utility in Illinois, providing electric service across the northern part of the state to approximately 70% of the state's population, or 4 million customers.[36] Illinois has retail choice, but also allows utilities to offer default service. ComEd divides its customers by electric service, which includes full-service retail customers, and delivery service, which applies to customers who elect to receive energy from a retail electric supplier, but utilize delivery on ComEd's distribution network.[37]

Residential customers may fall under one of four rates, depending on whether or not they reside in a single or multi-dwelling residence, and whether they use only electric space heating devices. The residential delivery rate consists of a fixed charge—including charges for metering services—and a variable charge.[38]

ComEd specifies a Watt-hour delivery class for which no metering equipment or only watt-hour metering equipment is installed at the retail customer's premises. It also specifies a railroad delivery class and three lighting delivery classes based on whether or not ComEd installs or furnishes the light, and when the light operates.[39]

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34 Pacific Gas and Electric Company, "Electric Schedule, A-1, Small General Service," p. 4. https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_A-1.pdf

35 Pacific Gas and Electric Company, "Electric Schedule –B-10, Medium General Demand-Metered Service," p. 2. https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_B-10.pdf

36 Commonwealth Edison Company, "Company Information." https://www.comed.com/AboutUs/Pages/CompanyInformation.aspx

37 Commonwealth Edison Company, "Schedule of Rates for Electric Service." https://www.comed.com/SiteCollectionDocuments/MyAccount/MyBillUsage/CurrentRates/Ratebook.pdf

38 *Ibid.*, 13th Revised Informational Sheet No. 24

39 *Ibid.*, Original Sheet No. 135-138

For General Delivery Service, ComEd identifies five low-voltage delivery classes distinguished by the size of the customer's highest thirty-minute interval demand in the past 12 months. These rates are composed of a fixed charge, which includes the customer charge and metering charge, and a demand charge, which differs depending on whether service is delivered at secondary or primary voltage.[40] ComEd also identifies a High Voltage Delivery class, which follows the same structure as the low voltage classes, but includes an additional two-tier demand charge for high voltage distribution facilities and transformers.

Utilities like ComEd have explored the possibility of introducing demand charges into the residential distribution rate at various times, though cases where formal proposals have been made and then accepted by the regulator are fairly rare. In general, moving towards three-part rates for residential customers, even when the appropriate metering infrastructure exists to measure demand, has proven to be difficult. Multiple concerns have been voiced, including that customers will not understand demand, that they will not know how to manage their demand, and that demand charges will raise bills for vulnerable customers.

Also note that ComEd offers a real-time energy pricing program for its residential customers. The utility passes on the price of electricity at cost, which fluctuates based on wholesale market conditions. Customers can elect to receive hourly pricing alerts, which are sent out when prices are expected by the utility to be high. Customers can switch back the standard fixed-price rate at any time.[41] Separately, ComEd is offering a pilot TOU program that features three separate rates for different times of the day, with the lowest rate for off-peak hours (10 PM to 6 AM), highest rate during 'super peak' hours (2 PM to 7 PM), and a peak rate for the remaining hours.[42] Specific pricing information will be available in May of this year.

V. Important Decisions when Transitioning to Cost-Reflective Rates

In addition to rate design considerations, a number of other decisions must be made when transitioning to more cost-reflective rate designs. The importance of many of these decisions is amplified when rates are deployed in an environment with high adoption of emerging, distributed energy technologies.

Should rates be used to promote policy objectives?

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40 *Ibid.*, 13th Revised Informational Sheet No. 25-28. Illinois Electricity Distribution Tax Charge is a per kWh charge applies for every rate class.

41 Commonwealth Edison Company, "Hourly Pricing." https://hourlypricing.comed.com/faqs/. Regardless of their rate structures, all customers are required the pay the same delivery service charges.

42 Commonwealth Edison Company, "Rate TOUPP Residential Time of Use Pricing Pilot," 10/18/2019. https://www.comed.com/SiteCollectionDocuments/MyAccount/MyBillUsage/CurrentRates/75_Rate_RTOUPP.pdf

As discussed throughout this report, rates should accurately reflect costs in order to promote equity and economic efficiency. Policy goals vary from one province to the next, and may include, for example, promoting clean energy. Specific policy goals such as these are ideally accomplished through initiatives independent of rate design, in order to avoid distorting the incentives that customers have to make economically efficient decisions.

In addition to the distribution rate, will transmission and generation rates be modernized as well?

This paper has focused specifically on options for modernizing distribution rates. However, transmission and generation charges also make up a significant share of the customer's total bill. In most cases, the total bill drives customer decisions. Therefore, the structure of the non-distribution charges will be similarly important for incentivizing beneficial energy technology adoption decisions. In fact, as was discussed earlier in this paper, much of the recent innovation in utility rate design has focused on generation charges (both energy and capacity). It will be important to think comprehensively about all aspects of the customer's bill when developing a rate modernization strategy in Alberta.

Should rates reflect embedded or marginal costs?

Embedded costs represent the costs of prior investments which the utility must continue to recover through rates. Marginal costs are a forward-looking representation of the incremental costs of adding new load to the system. Price signals that reflect marginal costs ensure the most efficient allocation of distribution system resources, and provide customers with an incentive to consume electricity in a way that will reduce costs in the long run. At the same time, however, rates must be set such that utilities fully recover their embedded costs. For example, it is important for rates to continue to recover the costs of historical investments in transformer capacity, even if there is sufficient capacity on the system on a forward-looking basis.

In the rate design process, it is important to be clear about the distinction between embedded and marginal costs, and to set prices accordingly. In particular, given the rapidly changing landscape of energy costs, this may require a new cost of service study to address gaps in the methodology of prior studies.

Will AMI be deployed, thus expanding the range of possible rate options?

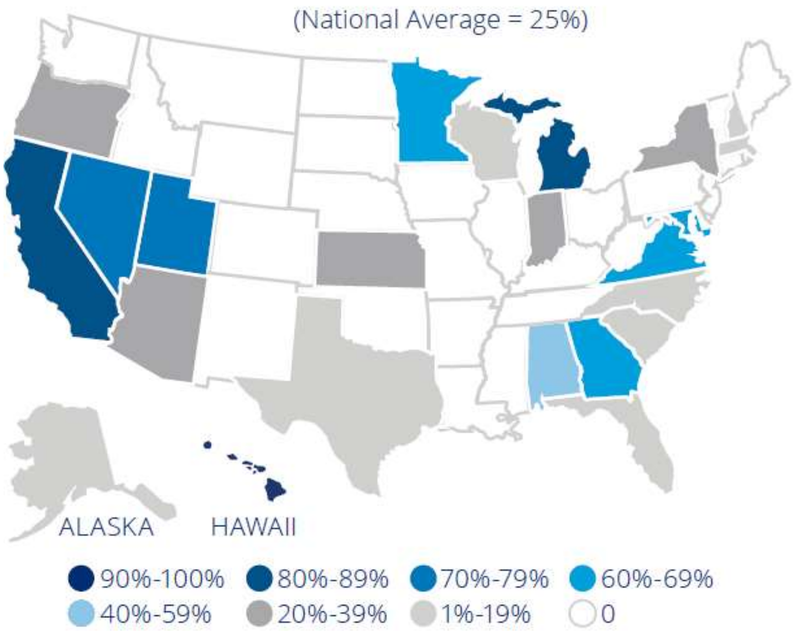
There has been continued growth in adoption of advanced meters in the world over the past decade as utilities replace legacy metering systems and modernize their power grids. The deployment of smart meters can lead to both operational and demand side management benefits. Utilities can may be able to reduce meter reading costs as well as costs related to disconnects and reconnects or identifying theft, at the same time implementing new rate designs due to the availability of more granular and more frequent consumption data.

Should separate rates/classes be created for specific technologies?

In some cases, utilities have designed rates specifically to address the characteristics of a given technology. Those technology-specific rates include features that account for the operational characteristics of the applicable technology, both to ensure fair cost recovery and to incentivize any flexibility in load that the technology may offer. Alternatively, if existing rates have to be modified to accommodate a specific class of customers, it may be the case that rates need to be modernized for the class as a whole.

A common example of technology-specific rate design is the recent introduction of TOU rates for home EV charging. In the U.S. alone, at least 50 utilities offer a residential rate geared toward EV charging; most were introduced within the past few years.[43] A map summarizing EV TOU rate deployment is show in Figure 6.

Figure 6: Percent of Residential Customers in Each State with Access to Time-varying EV rates



Source: The Brattle Group and SEPA, "Residential Electric Vehicle Rates That Work," November 2019.

In the vast majority of cases, the rates are TOU rates that encourage charging during off-peak hours in order to lessen the strain on the distribution system and to reduce generation costs. Utilities also indicate that the rates were introduced to provide an incentive for EV adoption (*i.e.*, to reduce customer fuel costs through the discounted off-peak rate). One important consideration that arises in this context, as well as in the context of technology-specific rates more broadly, is whether the

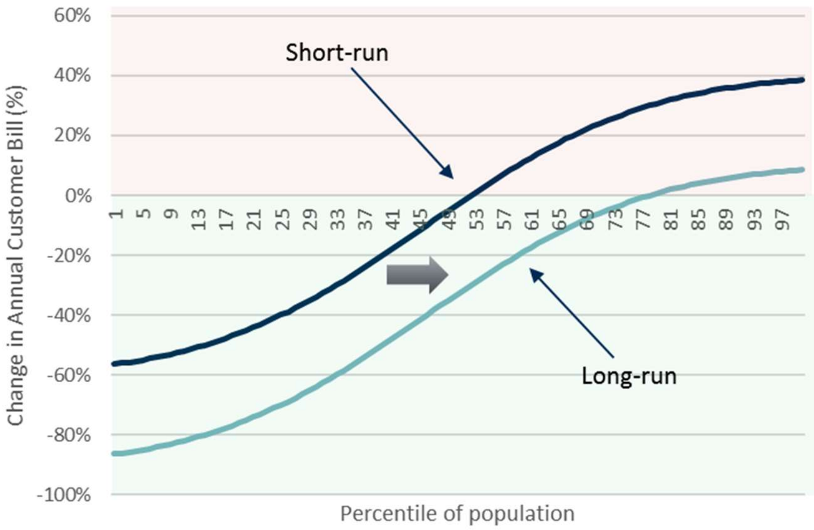
[43] Erika Meyers, Jacob Hargrave, Richard Farinas, Ryan Hledik, and Lauren Burke, "Residential Electric Vehicle Rates that Work," prepared for the Smart Electric Power Alliance, November 2019. https://sepapower.org/resource/residential-electric-vehicle-time-varying-rates-that-work-attributes-that-increase-enrollment/

rate should apply only to the load from the EV, or to the entire household load of the participation customer. The former requires a second meter and therefore comes at an additional cost, while the latter may present an adoption barrier if the customer does not want to subject his/her entire home to the TOU rate. From an implementation standpoint, there are also important considerations around what marketing and outreach messages will resonate with the subset of customers that have adopted the technology.

What tools will be offered facilitate the transition to cost-reflective rates?

When transitioning to a more economically efficient tariff structure, some of the benefits such as network cost reductions, will only be realized in the long run. However, the impacts to customers are more immediate. Some common stakeholder concerns associated with changes in tariffs include the potential for higher customer bills, for certain customers; inequity associated with moving away from status quo (both perceived and real); and impediments to adoption of preferred technology (such as rooftop solar). It is important to communicate to customers the needs and benefits related to transition. For example, customers may face higher costs in the short run, but overall costs will be lower in the long run (see Figure 7). Tools to communicate this key information include online rate comparison calculators, gradual transition to the new rates, customer education campaigns and outreach, among others.

Figure 7: Illustrative Example of Long-Run Customer Bill Savings



VI. Conclusions

Rates are not just a tool for recovering costs. They can also provide customers with incentives to invest in innovative new technologies that can help them manage their costs while also being beneficial to the power grid. Ultimately, this alignment of customer incentives with the optimal operation of the power grid will reduce costs for all customers. Given the rapid pace of technological change, it is important to modernize rates in a proactive rather than reactive manner.

As next steps in the modernization of Alberta's electricity and gas rate design, the AUC may wish to consider the following:

1. *Define ratemaking objectives for the province.* This report has identified a number of important decisions that must be made when transitioning to new rate designs. Defining a commonly shared set of principles will provide guidance for those decisions.

2. *Identify the most attractive rate designs.* This report effectively provides a menu of the various options that are available for modernizing rate design. These options each have their relative advantages and disadvantages. A scorecard-based approach could be used to summarize how each rate design is likely to perform against the established ratemaking principles and reduce the list of rate options to a feasible set.

3. *Conduct bill impact analysis.* Upon establishing a relevant list of rate designs, bill impact analysis will help to identify the consumers with bill reductions and consumers with bill increases under the new rates. In addition to addressing the overall magnitude of changes in consumer bills, this analysis is also helpful in determining other important but sometimes overlooked factors, such as month-to-month bill volatility. As smart meters are deployed, this analysis can be conducted with increasing degrees of sophistication and insight.

4. *Assess customer understanding of the rates through market research.* Concerns are often voiced that customers cannot understand new tariff structures. Focus groups and surveys can test this hypothesis, and results can assist in devising creative solutions. For instance, focus groups will help to determine the relative effectiveness of different educational and marketing messages with customers. Through survey-based conjoint analysis, the relative attractiveness of different tariff designs could be measured. OG&E in Oklahoma used both techniques to fine tune its offering of dynamic pricing tariffs, which have now been adopted by one out of five residential customers.

5. *Assess consumer response to new tariff designs through empirical analysis.* It also will be important to develop a better understanding of consumer response to new tariff designs. If consumers are able to shift load, they can reduce their bills under certain tariff structures. Well-designed scientific experiments or pilots would offer the advantage of testing new tariff designs in a "live" but controlled setting. The pilots would be designed to mimic a full-scale rate offering. Given the potential opportunities that some of the new tariff designs will create for behind-the-meter demand-reducing technologies such as smart appliances and energy storage, it would be useful to include various technology offerings as treatments in the pilot.

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Appendix: Survey of Residential Demand Charges

Summary of Residential Three-Part Tariffs

#	Utility	Utility Ownership	State	Residential Customers Served	Fixed charge ($/month)	Demand Charge ($/kW-month)		Timing of demand measurement	Demand interval	Combined with Energy TOU?	Applicable Residential Customer Segment	Mandatory or Voluntary	Docket No.
						Summer	Winter						
[1]	Alabama Power	Investor Owned	AL	1,273,526	14.50	1.50	1.50	Any time	15 min	Yes	All	Voluntary	U-5024
[2]	Alaska Electric Light and Power	Investor Owned	AK	14,707	11.13	6.51	10.76	Any time	Unknown	No	All	Voluntary	
[3]	Albemarle Electric Membership Corp	Cooperative	NC	11,796	27.00	13.50	13.50	Peak Coincident	15 min	Yes	All	Voluntary	EC-66
[4]	Alliant Energy	Investor Owned	IA	403,726	13.00	19.06	12.73	Peak Coincident	60 min	Yes	All	Voluntary	
[5]	Alliant Energy	Investor Owned	WI	413,571	15.04	3.00	3.00	Peak Coincident	60 min	Yes	All	Voluntary	Order 6680-UR-120
[6]	Arizona Public Service	Investor Owned	AZ	1,100,816	13.02	8.40	8.40	Peak Coincident	60 min	Yes	All	Voluntary	5914
[7]	Arizona Public Service	Investor Owned	AZ	1,100,816	13.02	17.44	12.24	Peak Coincident	60 min	Yes	All	Voluntary	5915
[8]	Black Hills Power	Investor Owned	SD	56,835	17.00	7.90	7.90	Any time	15 min	No	All	Voluntary	EL 18-029
[9]	Black Hills Power	Investor Owned	WY	2,021	15.50	8.25	8.25	Any time	15 min	No	All	Voluntary	
[10]	Butler Rural Electric Cooperative	Cooperative	KS	6,682	31.00	5.10	5.10	Peak Coincident	60 min	No	All	Mandatory	
[11]	Butte Electric Cooperative	Cooperative	SD	5,143	45.00	9.50	9.50	Unknown	Unknown	No	All	Voluntary	
[12]	Carteret-Craven Electric Cooperative	Cooperative	NC	36,439	30.00	11.95	9.95	Peak Coincident	15 min	No	All	Voluntary	EC-55
[13]	Central Electric Membership Corp	Cooperative	NC	20,496	34.00	8.55	7.50	Peak Coincident	15 min	Yes	All	Voluntary	
[14]	City of Fort Collins Utilities	Municipal	CO	65,303	6.16	2.60	2.60	Any time	Unknown	No	All	Voluntary	
[15]	City of Glasgow	Municipal	KY	5,567	33.57	12.17	11.16	Peak Coincident	30 min	Yes	All	Voluntary	
[16]	City of Kinston	Municipal	NC	9,954	14.95	9.35	9.35	Peak Coincident	15 min	No	All	Voluntary	
[17]	City of Longmont	Municipal	CO	37,326	16.60	5.75	5.75	Any time	15 min	No	All	Voluntary	O-2016-61
[18]	City of Templeton	Municipal	MA	3,500	3.75	8.00	8.00	Any time	15 min	No	All*	Mandatory	
[19]	Cobb Electric Membership Corporation	Cooperative	GA	185,848	28.00	5.55	5.55	Peak Coincident	60 min	No	All	Voluntary	
[20]	Consolidated Edison	Investor Owned	NY	2,934,275	0.00	19.66	15.13	Peak Coincident	Unknown	No	All	Voluntary	
[21]	Dakota Electric Association	Cooperative	MN	99,341	12.00	14.70	11.10	Any time	15 min	No	All	Voluntary	E-111/GR-19-478
[22]	Dominion Energy	Investor Owned	NC	102,865	16.31	9.62	5.64	Peak Coincident	30 min	Yes	All	Voluntary	E-22
[23]	Dominion Energy	Investor Owned	VA	2,220,797	11.28	5.36	3.72	Peak Coincident	30 min	Yes	All	Voluntary	
[24]	Duke Energy Carolinas, LLC	Investor Owned	NC	1,719,715	14.00	7.83	3.92	Peak Coincident	30 min	Yes	All	Voluntary	E-7
[25]	Duke Energy Carolinas, LLC	Investor Owned	SC	495,483	13.09	8.81	4.33	Peak Coincident	30 min	Yes	All	Voluntary	2019-3-E
[26]	Edgecombe-Martin County EMC	Cooperative	NC	10,269	31.00	8.75	8.00	Peak Coincident	Unknown	No	All	Voluntary	
[27]	Flathead Electric Cooperative	Cooperative	MT	55,402	23.71	0.26	0.26	Peak Coincident	60 min	No	All	Mandatory	
[28]	Fort Morgan	Municipal	CO	4,987	8.17	10.22	10.22	Unknown	Unknown	No	All	Voluntary	
[29]	Georgia Power	Investor Owned	GA	2,204,911	10.00	6.64	6.64	Any time	30 min	Yes	All	Voluntary	
[30]	Kentucky Utilities Company	Investor Owned	KY	431,614	16.17	8.90	8.90	Peak Coincident	15 min	No	All	Voluntary	
[31]	Lakeland Electric	Municipal	FL	109,044	11.00	6.00	6.00	Peak Coincident	30 min	No	All	Voluntary	
[32]	Lincoln Electric Cooperative	Cooperative	MT	5,215	42.84	1.25	1.25	Any time	15 min	No	All	Voluntary	
[33]	Louisville Gas and Electric	Investor Owned	KY	362,112	13.73	7.62	7.62	Peak Coincident	15 min	No	All	Voluntary	
[34]	Loveland Electric	Municipal	CO	32,450	24.93	10.30	7.75	Any time	15 min	No	All	Voluntary	
[35]	Mid-Carolina Electric Cooperative	Cooperative	SC	51,985	28.98	12.00	12.00	Peak Coincident	60 min	No	All	Mandatory	
[36]	Midwest Energy Inc	Cooperative	KS	29,706	27.00	6.50	6.50	Any time	15 min	No	All	Voluntary	
[37]	Midwest Energy Inc	Cooperative	KS	29,706	24.00	5.50	5.50	Any time	30 min	No	All	Voluntary	
[38]	NV Energy (Nevada Power)	Investor Owned	NV	825,227	10.25	0.22 (daily)	0.06 (daily)	Peak Coincident	15 min	No	All	Voluntary	
[39]	NV Energy (Nevada Power)	Investor Owned	NV	825,227	12.25	0.80 (daily)	0.32 (daily)	Peak Coincident	15 min	Yes	All	Voluntary	
[40]	NV Energy (SPP)	Investor Owned	NV	299,602	10.25	0.31 (daily)	0.05 (daily)	Peak Coincident	15 min	No	All	Voluntary	
[41]	NV Energy (SPP)	Investor Owned	NV	299,602	15.25	0.31 (daily)	0.05 (daily)	Peak Coincident	15 min	Yes	All	Voluntary	
[42]	Oklahoma Gas and Electric Company	Investor Owned	AR	55,912	9.75	1.00	1.00	Any time	15 min	No	All	Voluntary	
[43]	Otter Tail Power Company	Investor Owned	MN	48,497	11.00	8.00	8.00	Any time	60 min	No	All	Voluntary	E017/M-18-380
[44]	Otter Tail Power Company	Investor Owned	ND	45,754	20.10	8.00	8.00	Any time	60 min	No	All	Voluntary	PU-17-398/PU-18-106
[45]	Otter Tail Power Company	Investor Owned	SD	8,741	15.00	8.00	8.00	Any time	60 min	No	All	Voluntary	EL18-031
[46]	PacifiCorp	Investor Owned	OR	509,553	13.30	2.20	2.20	Unknown	Unknown	No	All	Voluntary	
[47]	Pee Dee Electric Membership Cooperative	Cooperative	SC	28,749	34.40	8.50	7.00	Peak Coincident	Unknown	Yes	All	Voluntary	
[48]	Platte-Clay Electric Cooperative	Cooperative	MO	21,729	25.38	2.50	2.50	Peak Coincident	60 min	No	All	Mandatory	
[49]	Progress Energy Carolinas	Investor Owned	NC	1,203,058	16.85	4.88	3.90	Peak Coincident	15 min	Yes	All	Voluntary	
[50]	Progress Energy Carolinas	Investor Owned	SC	136,802	14.63	5.66	4.35	Peak Coincident	15 min	Yes	All	Voluntary	2019-262-E
[51]	Salt River Project	Political Subdivision	AZ	956,645	32.44	11.13	4.54	Peak Coincident	30 min	Yes	NEM Only	Voluntary	
[52]	Salt River Project	Political Subdivision	AZ	956,645	32.44	21.94	8.13	Peak Coincident	30 min*	Yes	NEM Only	Voluntary	
[53]	Santee Cooper Electric Cooperative	Cooperative	SC	33,206	50.00	6.00	6.00	Peak Coincident	30 min	Yes	NEM only	Mandatory	
[54]	Smithfield	Municipal	NC	3,251	17.00	5.93	5.93	Peak Coincident	15 min	Yes	All	Voluntary	
[55]	South Carolina Electric & Gas Company	Investor Owned	SC	625,021	13.00	10.50	7.50	Peak Coincident	15 min	Yes	All	Voluntary	
[56]	Sun River Electric Cooperative	Cooperative	MT	4,480	30.00	6.00	6.00	Unknown	Unknown	No	All	Mandatory	
[57]	Swanton Village Electric Department	Municipal	VT	3,259	26.57	6.77	6.77	Any time	15 min	No	All*	Mandatory	
[58]	Tideland Electric Member Corp	Cooperative	NC	20,207	31.00	10.35	9.40	Peak Coincident	15 min	No	All	Voluntary	

Summary of Residential Three-Part Tariffs

#	Utility	Utility Ownership	State	Residential Customers Served	Fixed charge ($/month)	Demand Charge ($/kW-month) Summer	Demand Charge ($/kW-month) Winter	Timing of demand measurement	Demand interval	Combined with Energy TOU?	Applicable Residential Customer Segment	Mandatory or Voluntary	Docket No.
[59]	Tri-County Electric Cooperative	Cooperative	FL	16,560	23.00	7.00	7.00	Any time	15 min	No	All	Voluntary	
[60]	Traverse Electric Cooperative, Inc.	Cooperative	MN	1,892	76.00	18.65	18.65	Peak Coincident	Unknown	No	All	Voluntary	
[61]	Tucson Electric Power	Investor Owned	AZ	385,414	10.00	8.85	8.85	Peak Coincident	60 min	Yes	All	Voluntary	
[62]	Tucson Electric Power	Investor Owned	AZ	385,414	10.00	8.85	8.85	Peak Coincident	60 min	No	All	Voluntary	
[63]	Vigilante Electric Cooperative	Cooperative	MT	8,572	28.00	0.50 per KVA	0.50 per KVA	Any time	Unknown	No	All*	Mandatory	
[64]	Westar Energy	Investor Owned	KS	330,847	16.50	6.91	2.13	Any time	30 min	No	All	Voluntary	18-WSEE-328
[65]	Westar Energy	Investor Owned	KS	330,847	14.50	9.00	3.00	Peak Coincident	60 min	No	NEM Only	Mandatory	18-WSEE-328
[66]	Westar Energy	Investor Owned	KS	330,847	14.50	9.00	3.00	Peak Coincident	60 min	No	All	Voluntary	18-WSEE-328
[67]	Xcel Energy (PSCo)	Investor Owned	CO	1,262,866	19.31	10.08	7.76	Any time	15 min	No	All	Voluntary	
[68]	Xcel Energy (PSCo)	Investor Owned	CO	1,262,866	6.54	13.38	10.46	Peak Coincident	60 min	No	All	Voluntary	

Sources: Utility tariffs as of January 2020 (except for Butler Rural Electric Cooperative, City of Fort Collins Utilities, and Traverse Electric Cooperative, which were last updated on September 2018), and EIA Form 861 from 2018 (for Utility ownership and Residential Customers Served columns).

Notes:

For some utilities, the monthly fixed charge has been calculated by multiplying a daily charge by 30.5.
When the utility offered different basic service charges for single-phase and three-phase services, the single-phase service charge was selected.

[2]: Mandatory if customer consumes more than 5,000 kWh per month for three consecutive months or has a recorded peak demand of 20 KW for three consecutive months.
[3]: This rate also includes a "maximum billing demand" of 2.25 kW in addition to the on-peak billing demand. The maximum billing demand kW is the maximum kW demand registered by the consumer for any consecutive 15 min period during the billing month.
[4]: Only offered on a pilot basis. The billing demand is the sum of the highest hourly demand during on-peak hours of the current month plus 50% of the amount by which the highest hourly demand during the off-peak hours exceeds the highest on-peak demand.
[6]-[7]: The monthly fixed charge is a daily basic service charge multiplied by 30.5 days.
[8]-[9]: Available for customer with a minimum usage of 1,000 kWh per month on average.
[18]: *The demand charge only applies to demand measured in excess of 10 kW.
[20]: Customers on this rate also pay a year-round off-peak demand charge of $7.64/kW.
[21]: Available to residential members with at least 5 kW of qualifying off-peak loads.
[23]: Demand charge is the sum of the distribution demand charge and the generation demand charge. The distribution demand charge is $1.515/kW and the generation demand charge is $3.842/kW for the summer and $2.203/kW for the winter.
[34]: The demand rate is closed to new customers after December 31, 2014.
[36]: Midwest Energy Residential Demand Rate Service (RESD). The demand charge is based on the greater of the highest average 15 minute kW demand measured during the period for which the bill is rendered, and 80% of the average 15 minute maximum demand for the last three summer months.
[37]: Midwest Peak Management Electric Service (WSPA). The demand charge is based on the greater of the highest average 30 minute kW demand measured during the period for which the bill is rendered, and 80% of the average 30 minute maximum demand for the last three summer months.
[38]-[41]: The billing demand is calculated as the sum of the customer's daily 15-min maximum demand during the billing period.
[38]: This rate (Schedule ORS-DDP) also includes a $0.15/kW daily facilities charge in addition to the demand charges in the table.
[40]: This rate (Schedule OD-1 DDP) also includes a $0.16/kW daily facilities charge in addition to the demand charges in the table.
[43]-[45]: Demand is measured as the maximum winter demand for the most recent 12 months.
[46]: The demand charge is only applicable to three-phase customers.
[48]: Billing demand is the greater of the current month actual demand or 50% of peak demand established in the preceding eleven months.
[51]: Customers below 200 amps pay a fixed charge of $32.44 per month and customers above 200 amps pay $45.44 per month. Demand charges vary across three seasons: Winter, Summer (May, June, September, and October), and On-Peak Summer (July and August). The summer demand charges shown here apply for the On-Peak Summer period. The (on-peak) summer demand charge is $7.89 for up to 3kW of demand, $14.37 for the next 7kW, and $27.28 for over 10kW. The winter demand charge is $3.49 for up to 3kW, $5.58 for the next 7kW, and $9.57 over 10kW.
[52]: Customers below 200 amps pay a fixed charge of $32.44 per month and customers above 200 amps pay $45.44 per month. Demand charges vary across three seasons: Winter, Summer (May, June, September, and October), and On-Peak Summer (July and August). The summer demand charges shown here apply for the On-Peak Summer period. The Summer period demand charge is $19.29/kW. *The billing demand in each billing cycle is the average of the daily maximum 30-min integrated kW demands occurring during the on-peak periods of that billing cycle.
[57]: The demand charge is based on the greater of the measured demand for the current month and 85% of the highest recorded demand established during the preceding eleven months. *The rate is mandatory for all residential customers with monthly consumption equal to or greater than 1,800 kWh or 8 kW for each of two consecutive months.
[58]: The basic service charge is calculated as the average of the overhead service charge ($30/month) and the underground service charge ($32/month).
[61]-[62]: Tuscon Electric Power Residential Peak Demand and Demand Time-of-Use. The demand charge is $8.85/kW for the first 7kW and $12.85/kW for any additional kWs.
[63]: *The demand charge applies only to KVA greater than 15 KVA.
[64]: Westar Restricted Peak Management Electric Service. Not available to new customers since 2006.
[65]: Westar Residential Standard Distributed Generation.
[66]: Westar Residential Peak Efficiency.
[67]: Xcel Energy Residential Demand Service (Schedule RD).
[68]: Xcel Energy Residential Demand-Time Differentiated Rates Service (Schedule RD-TDR).

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