

# The Tariffs of Tomorrow



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TODAY, MOST AMERICAN RESIDENTIAL CUSTOMERS pay for electric service via tariffs that are structured as two-part rates consisting of a fixed monthly charge and a volumetric energy charge expressed in U.S. dollars per kilowatt-hour. The fixed-charge component generally comprises a small portion of the bill, which is dominated by the volumetric charge.

California's energy crisis in 2001–2002 triggered an important discussion about the need to better connect retail and wholesale markets. Since then, scores of pilot programs

have been carried out with time-varying rates. The empirical evidence shows that customers can understand and respond to incentives provided by new tariffs that convey the cost structure of electricity to customers. Additionally, smart meters now track the energy use of half of all U.S. residential customers, removing a major barrier to the deployment of modern tariffs.

The introduction of smart digital technologies, changing consumer tastes, and new state policies promoting renewable energy sources have cast doubt on the sustainability of the utility business model based on traditional two-part tariffs. This shift comes at a time when many utilities are making significant investments to modernize the grid and

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# Innovations in Rate Designs

integrate distributed energy resources (DERs). These capital investments, along with most other utility costs, do not vary with the volume of electricity consumed. They thus cannot accurately be reflected through a volumetric charge. This has resulted in large residential customers effectively subsidizing smaller customers, who, as a result of low energy usage, pay less relative to the costs they impose on the system. An additional limitation of flat volumetric charges is that they fail to capture the effects of temporal and seasonal variability, which result in peak periods that are more expensive to utilities than off-peak periods.

Consequently, a misalignment between utilities' cost and rate structures currently exists, particularly with respect to the residential class. In response to this challenge, many utilities are introducing innovative, cost-reflective tariffs better aligned with both their own needs and those of their customers. In short, utilities seek to develop the tariffs of tomorrow.

## The Principles of Rate Making

The same seminal principles that have guided rate design for decades should motivate regulatory designs of future tariffs. James Bonbright's principles for public utility rates, first published in 1961, have remained in place in spite of various technological advances and evolving industry trends. These principles continue to be widely accepted (see the "For Further Reading" section). As shown in Table 1, they can be distilled to five key criteria.

Economic efficiency means that the resources are not used to generate and deliver electricity in such a way that their reallocation will increase the total cost to consumers and producers, resulting in an overall increase in the total cost to society. In other words, no resources consumed in the delivery of electricity should be wasted through overinvestment and operating costs.

The second criterion, equity, refers to fairness among customers and between the utility and customers. Although rate design nearly always involves some degree of cross-subsidy, a utility should aim to remove unintentional subsidies between customer types. According to Bonbright, a natural way to achieve equity among customers with different load profiles and consumption values is through cost-reflective rates. Under such rates, customers who incur high costs for the system will pay proportionally higher amounts than low-cost customers.

Revenue stability refers to the utility's ability to recover its costs through a sufficient and predictable level of revenues. Bill stability, the fourth criterion, then stipulates that while the utility must recover its costs, ideally through cost-reflective rates, it must also protect customers from unmanageable fluctuations in their bills. Although new rates will nearly always result in bill increases for some customers, utilities can take steps to minimize seriously adverse and unexpected impacts, for instance by gradually implementing changes to rates.

Finally, customer satisfaction is needed for the successful implementation of any changes to the pricing structure. If not properly explained or rolled out, even simple rates can cause confusion and subsequently trigger a backlash from customers. Regulators and utility companies who anticipate such an adverse reaction from customers will resist implementing new rates.

## Rethinking Present-Day Rate Making

Underpinning all five key criteria is the principle of cost causation, which Bonbright considered the most important standard of reasonable rates. In the case of electricity, costs consist of three elements:

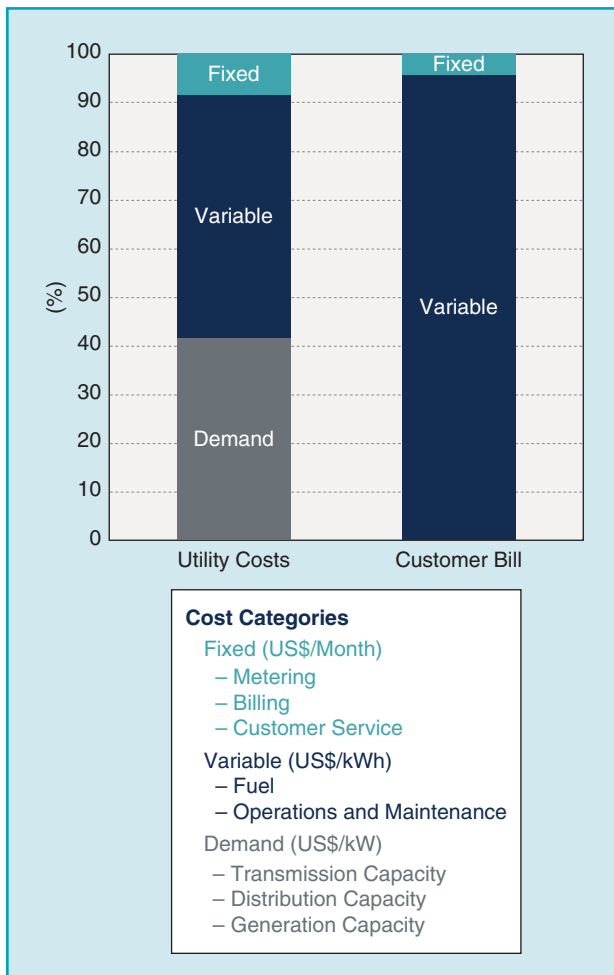
- ✓ a fixed cost for servicing the customer
- ✓ a capacity cost associated with the distribution grid, the transmission network, and the power plants
- ✓ an energy cost associated with the production of electricity.

Cost causation says that revenues should reflect these three costs. However, given the ubiquity of two-part tariffs for residential customers, this has historically not been the case. Instead, as typified in Figure 1, utilities employing two-part rates typically recover most of the costs of residential service on a volumetric basis. To achieve this, they build nonvariable fixed and capacity costs into the energy charge using assumptions about class load factors and applying them equally to all customers in the class.

As a result, a common violation of the equity principle occurs under two-part rates when "peaky" customers, who

**table 1. Bonbright's principles of rate making.**

Key Criterion	Bonbright Principle
1) Economic efficiency	<p>Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use</p> <p>Reflection of all of the present and future private and social costs and benefits occasioned by a service's provision (i.e., all internalities and externalities)</p> <p>Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns</p>
2) Equity	<p>Fairness of the specified rates in the apportionment of total costs of service among the different ratepayers to avoid arbitrariness and capriciousness and attain equity</p> <p>Avoidance of undue discrimination in rate relationships to be, if possible, compensatory</p>
3) Revenue stability	<p>Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety</p> <p>Revenue stability and predictability, with a minimum of unexpected changes that are seriously adverse to utility companies</p>
4) Bill stability	<p>Stability and predictability of the rates themselves, with a minimum of unexpected changes that are seriously adverse to utility customers and with a sense of historical continuity</p>
5) Customer satisfaction	<p>The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application</p> <p>Freedom from controversies as to proper interpretation</p>



**figure 1.** An illustrative misalignment between residential rates and costs.

consume more in high-cost hours, are subsidized by less peaky customers with a higher load factor. A customer with a low load factor may consume the same kilowatt-hours as a customer with a high load factor and thus pay the same bill under a two-part rate but impose much higher costs on the system.

The recent distributed generation (DG) expansion has further compounded inequity concerns by introducing a cross-subsidy from non-DG consumers to DG consumers (often referred to as *prosumers*, since they both produce and consume energy). Under net energy metering, available in 43 states, a utility credits prosumers for any generation they produce back into the grid. As a result, prosumers who produce as much as they consume can achieve very low energy bills, even as they continue to require grid services from the utility. Given that fixed infrastructure costs make up a large share of utility costs, this allows DG consumers to avoid paying for a key service that they continue to use. Meanwhile, non-DG consumers must then cover a disproportionate share of capacity costs through their own energy charges.

Under most current rate designs, this misalignment will only grow as DER penetration continues to develop, transforming the grid and the way in which customers interact with it. Dynamic pricing has been proposed as a means to address this misalignment, while also facilitating renewable penetration. This also comes at a time when states are adopting increasingly aggressive goals for their renewable portfolio standards, with the city of Washington, D.C., and the states of California and Hawaii all targeting 100% renewable energy within the next two to three decades. Although Bonbright's principles remain as relevant as ever, the world to which they apply is changing, and tariffs must now adapt to meet that change.

## Proposing Tariffs of Tomorrow

Of course, tariffs have been slow to adapt in part because of technological limitations. As Bonbright recognized, cost-reflective rates require having the necessary metering infrastructure in place, and, for decades, this infrastructure was only available to large commercial and industrial customers. For residential and smaller commercial and industrial customers, it was less expensive and easier for utilities to simply bill metered kilowatt-hour usage, despite the resulting issue of fixed-cost recovery. However, the widespread deployment of smart meters is making it much more affordable to measure demand, even for residential customers. As this change progresses, the implementation of cost-reflective rate designs for all customers is becoming more accessible than ever before.

Given these advances, the tariffs of tomorrow are likely to consist of three parts corresponding to the three elements that comprise electricity costs: a fixed monthly charge, a time-varying energy charge, and a demand charge.

The fixed charge (sometimes referred to as a customer charge, service charge, or facilities charge) is expressed in dollars per month. It reflects the costs of servicing the customer, such as billing, metering, and customer service.

The time-varying energy charge, expressed in U.S. dollars per kilowatt-hour, recovers energy costs, either in the form of a simple time-of-use (TOU), critical peak pricing (CPP), variable peak pricing (VPP), or real-time pricing (RTP) rate. A simple TOU rate defines peak periods during which prices are higher than in off-peak periods and is currently the most common form of time-varying rate. However, programs like CPP, VPP, and RTP are considered purer forms of dynamic pricing in that they are based on actual market conditions and thereby a better signal of customer changes in the utility's costs.

The demand charge, expressed in dollars per kilowatt, recovers grid capacity costs, typically based on peak electricity consumption over a span of 15, 30, or 60 min. It may be either coincident or noncoincident. A coincident demand charge applies to a customer's peak electricity consumption at the time of the maximum system usage, whereas a noncoincident demand charge measures a customer's highest usage during the month, regardless of the time of day.

Some critics of noncoincident demand charges argue that they do not reflect the utility's cost structure, since they may not coincide with the capacity costs driving system peak and the need for new infrastructure where beneficiaries should pay. Many of these critics favor time-varying energy charges without any demand charges. However, these two charges are not at odds and can be offered simultaneously to supplement one another. While time-varying energy charges can dynamically recover energy costs and encourage load shifting, noncoincident demand charges for residential customers can recover distribution-related capacity costs and encourage overall greater efficiency. After all, customers expect electricity service whenever they need it, at any time of the day. As a result, a utility must build adequate infrastructure

to meet a customer's peak usage, regardless of when it occurs. However, a noncoincident demand charge effectively serves as a proxy for the localized cost of connecting a customer to the grid.

Another option for recovering the costs of the grid is to increase the fixed charge, but a fixed charge may not fully account for a customer's size or send price signals the way that both coincident and noncoincident demand charges can. The implementation of a demand charge further addresses the equity criterion by minimizing cross-subsidies from customers with high load factors to those with low load factors, who may have a low kilowatt-hour consumption but a high kilowatt demand that a volumetric rate cannot capture.

In terms of the cross-subsidy from non-DG consumers to DG consumers, one solution recognizes the unique features of the manner in which such customers interact with the grid, as exemplified by their load shapes, and to price electricity accordingly. Thus, utilities in a number of states are now asking their commissions for permission to establish a new class for prosumers and to price electricity to them in a manner that reflects the cost of serving electricity to them.

The creation of a separate class may discourage the adoption of rooftop solar and other DERs. Cost-based, three-part tariffs may also encourage the adoption of certain technologies like electric vehicles by enabling time-varying rates that give vehicle owners the option of charging vehicles during the less-expensive off-peak periods. Neither outcome is inherently wrong. Rather, regulators need to understand that a more advanced rate design requires a greater understanding of outcomes. Rate design is not always the place to incent technologies. Other policies outside of those applying to rates can do this, for instance, through tax credits, rebates, or renewable energy certificates.

## Obstacles to the Future

Undoubtedly, given the diversity of customer tastes and expectations, these new tariffs will not appeal to all residential customers. Risk-averse customers might resist the volatility of time-varying rates and the risk implicit in demand charges. Utilities can offer these customers rate options that better suit their risk profiles, while still incorporating the cost-reflective concepts underpinning the tariffs of tomorrow. Possible rate options are listed in Table 2.

From among these many options, the most risk-averse customers would likely go with a guaranteed bill, which is constant regardless of the volatility in their load profiles or their electricity prices. On the other hand, risk-taking customers would likely go with a RTP rate that, on average, would likely give them a lower average price. Each of these rate options presents a unique tradeoff between the bill savings that customers would experience and the risk that they would be exposed to in the form of bill volatility. When they are plotted out in the savings-risk space, they yield an "efficient pricing frontier."

**table 2. Rate-design options.**

Rate Design	Definition
GB	Customers pay the same bill every month, regardless of usage.
Flat rate	A uniform US\$/kWh rate is applied to all usage.
Demand charge	Customers are charged based on peak electricity consumption, typically over a span of 15, 30, or 60 min.
TOU	The day is divided into time periods, which define peak and off-peak hours. Prices are higher during the peak-period hours to reflect the higher cost of supplying energy during that period.
CPP	Customers pay higher prices during critical events when system costs are highest or the power grid is severely stressed.
IBR	Customers are charged a higher rate for each incremental block of consumption.
PTR	Customers are paid for load reductions on critical days, estimated relative to a forecast of what they would have otherwise consumed (their baseline).
VPP	During predefined peak periods, customers pay a rate that varies by utility to reflect the actual cost of electricity.
DSS	Customers subscribe to a kilowatt demand level based on the size of their connected load. If they exceed their subscribed level, they must reduce their demand to restore electrical service.
TE	Customers subscribe to a baseline load shape based on their typical usage patterns and then buy or sell deviations from their baseline.
RTP	Customers pay prices that vary by the hour to reflect the actual cost of electricity.

GB: guaranteed bill; IBR: inclining block rate; PTR: peak-time rebates; DSS: demand subscription service; TE: transactive energy.

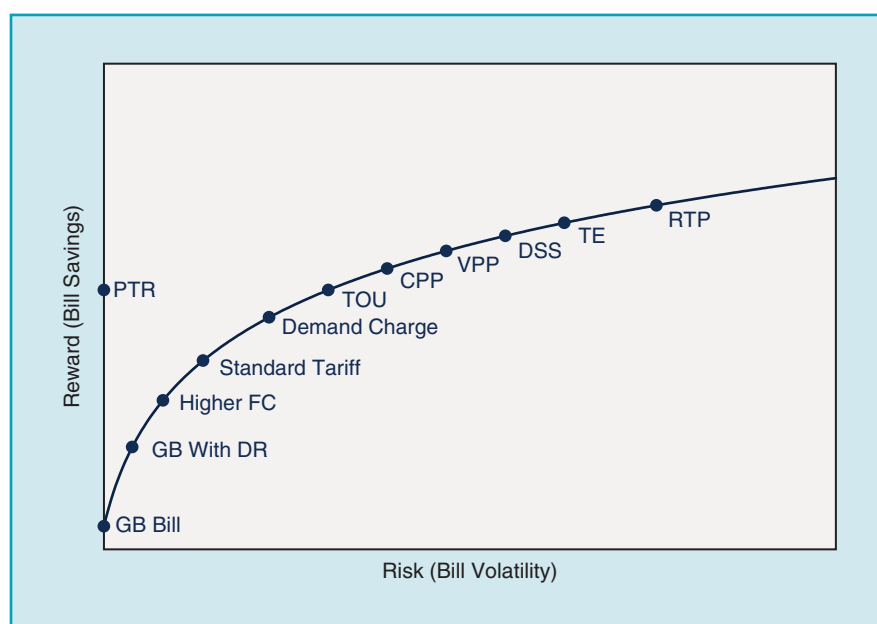
The efficient pricing frontier reflects Bonbright’s criterion of equity in that, while it is good to offer choices to customers, each rate must still recover the cost of serving each customer correctly to avoid creating intercustomer subsidies. As a result, to capture the impact of customer load volatility on wholesale prices, low-risk rates should yield lower potential savings than higher-risk rates that better reflect the time-varying cost of energy. For instance, the average price implicit in a standard tariff should be higher than the average price implicit in a TOU rate, under which a customer is

charged more in peak hours when the cost of energy is high. Figure 2 illustrates this tradeoff.

This tradeoff applies to all customers, including those who are disadvantaged or have a low income. In fact, low-income customers tend to have flatter load profiles and thus are likely to benefit from rates that charge higher prices in peak hours. On the other hand, critics of dynamic new rates argue that disadvantaged and low-income customers generally have more difficulty responding to new rates, either due to physical or flexibility constraints.

Such apprehension about customer reactions largely explains why the adoption of smart rates has not kept up with the adoption of smart meters. As important as economic efficiency may be, it remains only one of Bonbright’s key criteria, and concerns about customer satisfaction can immediately halt any changes to the pricing structure. However, as described in more detail later in this article, protections can be applied for vulnerable customers to mitigate risk and ease the transition.

Another concern surrounding three-part tariffs is that, by reducing the volumetric portion of customers’ bills, they may discourage energy efficiency. However, cost-reflective tariffs are the best way to simultaneously promote equity



**figure 2.** Efficient pricing frontier. FC: fixed charge.



between customers as well as economic efficiency in the use of scarce capital and fuel resources. Most of the tension between energy efficiency and rate design stems from the recovery of fixed costs, which is best addressed through separate financial mechanisms such as revenue decoupling or lost-revenue adjustment mechanisms. Such mechanisms protect utilities from fluctuations in sales, either by completely breaking the link between revenue and sales or allowing utilities to recover lost revenues resulting specifically from energy-efficiency programs.

## Case Studies

Despite concerns about customer response, several utilities have already begun offering dynamic rate options with promising initial results. In Maryland, for example, the three largest utilities (Pepco, Delmarva Power, and Baltimore Gas and Electric) have each implemented peak-time rebates as the default tariff to all their customers. These programs have resulted not only in peak load reductions for the utility but also customer savings and satisfaction.

Figure 3 illustrates the results of 332 TOU, CPP, and PTR pricing experiments. Some of the 332 experiments had very high peak-to-off-peak ratios and could not be included in the figure. These results further support the idea of customer peak-load reductions in response to higher peak-to-off-peak price ratios. Some experiments provided a pure price signal to customers, whereas others included enabling technologies, such as smart thermostats, with the pricing signal.

Around 14% of all U.S. utilities, including roughly half of all investor-owned utilities, now offer a residential TOU rate. Among these TOU rates, 6% now also include a demand charge on top of the time-varying volumetric charge. Although adoption rates for dynamic tariffs remain low, the successes of a few utilities show promise for customer willingness to adopt future tariffs.

The Arizona Public Service (APS) has adopted TOU and demand charges. Approximately 57% of APS's residential customers are enrolled in TOU rates, and 20% of these customers also pay a demand charge. To ease the transition since it first implemented demand charges in 1989, APS made a significant commitment to providing customers with information on the various rate options. Ultimately, this resulted in a rate-comparison tool that customers either could use on their own or with the assistance of a customer service representative. Additionally, APS began to provide customers with an annual analysis of their usage, energy savings recommendations, and a rate recommendation if they would benefit from switching. The company also provides rate comparisons for customers who contact the call center. As APS began rolling out more advanced metering to all customers, the rate-comparison tool was modified to reflect an analysis of actual load data. Over the years, APS has not marketed any particular rate option to its customers. Instead, it has provided them—through the rate-comparison tool—the

information they need to make an informed decision about what rates are best for them.

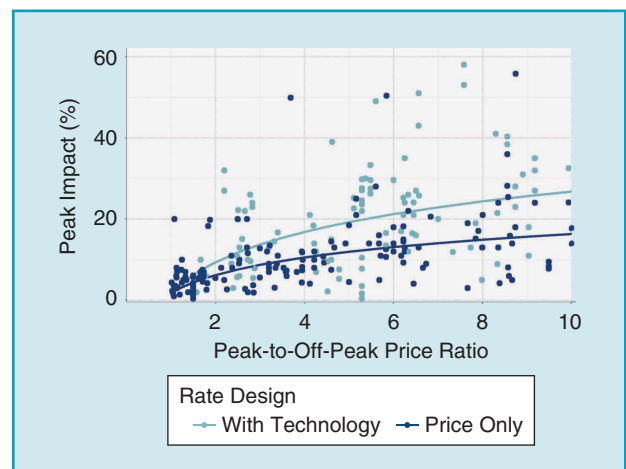
APS is not alone in introducing demand charges for residential customers. At least 51 demand charges are now being offered in 22 states by 43 utilities. Demand charges tend to be disproportionately prevalent among cooperatives, which are owned by the customers and thus have an additional responsibility to guarantee equity among members. Some cooperatives have even implemented mandatory demand charges for certain customers. For example, the Salt River Project has mandatory demand charges for customers with rooftop solar panels.

Successful dynamic pricing case studies are often supported by smart technologies. In 2012, Oklahoma Gas and Electric (OG&E) rolled out its SmartHours program, a time-based program offered to residential customers on an opt-in basis. As part of the program, the utility offers its customers the option to install smart thermostats, which will adjust in response to price signals according to customers' programmed preferences. However, customers also maintain full control, so they can override these settings and choose not to respond to OG&E's alerts. A fifth of the utility's customers have signed up for SmartHours and achieved significant savings on their electric bills.

ComEd has similarly partnered with Nest, a smart thermostat provider, for its AC Cycling Program. Under this program, ComEd offers customers a US\$100 rebate to purchase and install a Nest thermostat, which it can then control during a maximum of 10 peak events each summer. The program runs from June through September, and customers receive a US\$10 bill credit for each month of participation. The smart thermostat is designed to reduce energy usage while maintaining a comfortable temperature, but if customers start to feel too warm, they can manually override it at any time.

## Transitioning in the Digital Age

Increasingly widespread advancements in technology are integral to empowering and informing customers about their



**figure 3.** Price responsiveness under dynamic pricing experiments.

power-supply choices. Many customers today are likely to have not only smart meters but also smart digital appliances, thermostats, and digital apps to track and optimize their own usage patterns. In the age of constant connectivity and the Internet of Things, newer generations of customers are already well equipped to embrace this shift and adapt to more open and responsive two-way communication. In fact, many of these customers have already embraced modern pricing designs in other aspects of their life. They encounter dynamic pricing every day, from airlines and hotels to concerts and movies, and they understand how to interpret and respond to surge pricing from ride sharing apps like Uber.

The success of all these designs is in, large part, predicated on their transparency and simplicity and in the manner in which they are clearly conveyed to customers. However, there is no reason utilities cannot likewise communicate their prices and offer more transparent bills that minimize unnecessary line items and unclear calculations. Even relatively complex tariffs can be made simple to customers, especially with the profusion of modern-day technologies. With such technologies, customers can respond to dynamic rates and achieve savings without constant monitoring. For example, smart thermostats can automatically adjust home temperatures with minimal programming, and utilities can send messages and text alerts to prepare customers for peak events.

Utilities can also use these same tools and technologies to understand and fulfill their customers' needs, for instance, through pilot programs and experimental studies, which can help predict customer response. To minimize adverse reactions at the beginning of the transition, utilities can also progressively ease customers from their old rates to the new ones through initial bill protections or transition rates.

Any change in rates will invariably cause some customer bills to go up and others to go down. The change in bills will depend on each customer's energy consumption, load factor, and load shape as well as the structure of the new rate. For example, a customer with a very high load factor would likely see a lower bill on a TOU energy rate compared to a flat rate, whereas a customer with a very low load factor would likely see a higher bill with the new cost-reflective tariff, especially if peak coincides with times of peak system energy prices. Customers with low kilowatt demand would see lower overall bills with the introduction of a demand charge, while customers with low kilowatt demand and a high load factor would see a lower bill with a demand charge offered in combination with a TOU energy rate. As a result, while most bills would not change substantially, this may not be the case for all customers.

Customers whose bills do go up substantially under three-part tariffs will likely complain, and if their complaints are picked up by the media, the move toward new tariffs could come to a standstill. Thus, implementing more efficient, cost-based tariff reform always requires serious consideration of customer satisfaction and education. However, given all of the changes and technological advancements currently

sweeping the industry, this should not be a reason to resist progress and maintain an outdated status quo.

Instead, to balance these challenges and ease the transition, utilities should first analyze customer bill effects to better mitigate these impacts and anticipate customer reactions. Before even implementing the three-part tariff, utilities and regulators can calculate expected bill changes for a representative sample of customers, assuming existing load profiles. These results should be plotted in the form of a propeller chart identifying which customers will see higher bills and which will see lower bills. The utility can then analyze the sociodemographic and regional characteristics of those with significantly higher bills and understand the degree to which this impact affects all users.

Next, utilities can carry out simulations to predict and incorporate customer responses. Models, such as the Price Response Impact Simulation Model, which was initially developed to quantify the impact of TOU and dynamic pricing in California's 2003–2004 statewide pricing pilot, can perform a bill-impact analysis that allows for a certain amount of demand response. The adverse bill impacts under the new three-part tariffs should be lower than they were without demand response, as customers shift their usage between periods in response to new average and relative prices.

If the adverse bill impacts are still significant for a certain group of customers, utilities can take several approaches to ease their transition. These include the following:

- ✓ *Gradualism*: Roll out the new rates gradually for each rate-design element to preserve bill stability, for instance, by gradually ramping up the peak price of a new TOU rate.
- ✓ *Bill protection*: Provide these customers with bill protection in the first year and then gradually phase it out over three to four years
- ✓ *Protections for vulnerable customers*: Make the three-part rate optional for vulnerable customers, while making it mandatory for the largest customers and the default rate design for all other customers. Alternatively, offer customers who are vulnerable or will experience adverse bill impacts financial assistance for a defined period of time.
- ✓ *Enabling technologies*: Install enabling technologies, such as smart thermostats, on customers' premises that allow them to more easily respond to price signals under the new tariffs.
- ✓ *Two-staged rollout*: Structure the rate into two stages. Under the first stage, charge customers the current rate, if their usage resembles their historical usage over a given reference period. Under the second stage, charge customers the new tariffs for any deviations from their historical usage.

Utilities can also prepare for the rollout by conducting focus groups with customers to test possible education and marketing campaigns and gauge customer understanding of the new tariffs. Based on their findings, utilities can then

make appropriate modifications in language (and possibly in the rate-design parameters, such as the magnitude of the demand charge and the charges for energy by TOU as well as the duration and temporal location of the peak period) to make the new tariffs more understandable to customers.

To better test customer acceptance and the amount of demand response to the new tariffs, utilities can conduct additional pilots. Pilots should be designed on scientific principles of experimental design that would preserve the internal and external validity of the results, allowing them to be extrapolated to the population of customers and applied to different prices than the ones being tested. Randomized controls, randomized encouragement, and matching controls are different ways of preserving pilot validity.

Given these pilot results, the utility must then decide on the rollout strategy and whether it should be mandatory, default, or opt in. As a point of reference, Fort Collins rolled out TOU energy rates to all its residential customers on a mandatory basis as of 1 October 2018. Also, as of 1 October 2018, the Sacramento Municipal Utilities District began rolling out time-of-use energy rates with a US\$20-per-month service charge on a default basis in California. In Ontario, Canada, TOU rates have been rolled out as the default tariff for energy supply since 2007 (which means that customers can opt out of the rate). At this point, only 10% have opted out. The distribution tariff is a flat bill. Finally, the utility must track the deployment of the new tariffs, survey customers for feedback, set up social media sites and monitor the conversation, and make any necessary modifications to the rate design.

## Conclusions

TOU rates were first tested in the United States in the late 1970s. Fourteen pilots showed that customers accepted such rates and responded to the price signals in a fairly predictable fashion. The tests were motivated by the energy crisis of the 1970s and the passage of the Public Utilities Policies Act in the United States under the Carter administration, which put the spotlight on TOU rates.

But not much happened, since smart meters were lacking, and other priorities surfaced. Most notably, there was a newfound interest in restructuring the electricity industry and offering customers a retail choice of energy suppliers. Tariff reform was put on the back burner.

The California energy crisis of 2001–2002 put the focus back on tariff reform, along with advanced metering and demand response. Hundreds of pilots were carried out in the United States and abroad showing that customers accepted such rates and responded in a fairly predictable pattern. Smart-meter deployments began in earnest and now encompass half of the residential population. Modern tariffs, however, touch fewer than 5% of customers.

Progress is stymied because of the fear of the unknown and by a concern that rate reform will harm low-income

customers, customers with disabilities, and senior citizens. Customer backlash remains a primary concern. Secondary concerns relate to the inability of several billing systems to handle the new tariffs.

The way forward is to conduct pilot programs where none have been done to deploy the new tariffs, which could be offered with temporary bill protection. Additionally, they should be accompanied with customer-education and marketing campaigns to ease the transition.

Ultimately, these three-part rates provide a favorable option as the default tariff to maximize economic efficiency and inter-customer equity. They can be paired with alternative designs that would be offered only on an opt-in basis.

There are signs of change. Technological advancements have already cleared some of the major barriers to tariff reform. With slowing sales and growing DER penetration, the day is not far off when the tariffs of tomorrow will become the tariffs of today.

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