RATE DESIGN FOR A DER FUTURE

Designing rates to better integrate and value distributed energy resources

A 21st Century Electricity System Issue Brief

By Advanced Energy Economy

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ABOUT ADVANCED ENERGY ECONOMY

Advanced Energy Economy (AEE) is a national association of businesses and business leaders who are making the global energy system more secure, clean and affordable. Advanced energy encompasses a broad range of products and services that constitute the best available technologies for meeting energy needs today and tomorrow. AEE's mission is to transform public policy to enable rapid growth of advanced energy businesses. AEE and its State Partner organizations are active in 26 states across the country, representing roughly 1,000 companies and organizations in the advanced energy industry. Visit www.aee.net for more information.

ABOUT THIS ISSUE BRIEF

The U.S. utility sector has entered a period of foundational change not seen since the restructuring of the late 1990s. Change is being driven by new technologies, evolving customer needs and desires, environmental imperatives, and an increased focus on grid resiliency. With these developments come challenges, but also new opportunities to create an energy system that meets the changing expectations of consumers and society for the coming decades. We call this the *21st Century Electricity System:* a high-performing, customer-focused electricity system that is efficient, flexible, resilient, reliable, affordable, safe, secure, and clean. A successful transition to a 21st Century Electricity System requires careful consideration of a range of interrelated issues that will ultimately redefine the regulatory framework and utility business model while creating new opportunities for third-party providers and customers to contribute to the cost-effective management of the electricity grid by utilities.

To support this transition, Advanced Energy Economy (AEE) has prepared several issue briefs that are intended to be a resource for regulators, policymakers, and other interested parties as they tackle issues arising in the rapidly evolving electric power regulatory and business landscape.[1] This issue brief on **Rate Design for a DER Future** lays out the objectives and principles that should guide consideration of new rate design structures for better integrating and valuing distributed energy resources, describes the pros and cons of various rate design options, and makes recommendations on how to move toward a long-term framework that maximizes the benefits of distributed resources for customers and the electricity system as a whole.[2]

SUMMARY

The U.S. electricity system on which we all depend is changing, powered by technological innovations, increased use of distributed energy resources (DER)[3] on what has been traditionally a centralized power system, and changing customer needs and preferences in an increasingly connected world. If DER assets are properly integrated into the existing system, they have the potential to make the grid more efficient, flexible, resilient, reliable, and clean. One key element to this transition is developing rate designs that enable the equitable allocation of costs, properly compensate for the benefits that DER provides and charge DER customers for their use of the grid, and allow utilities to fairly recover the revenue required to maintain a system that provides safe, reliable, and universal service.

From among the suite of rate design options being considered and/or implemented for mass-market customers (residential and small commercial customers), AEE generally believes that rate structures should evolve toward time-varying rates (TVRs), which price electricity higher when customer demand on the system is higher, as well as tariffs that more precisely monetize the value of DER to the system. This will require utilities to deploy technology that allows them to adopt more granular and sophisticated rate structures that more closely align the costs of operating the grid with its use, while also enabling new distributed resources to contribute, by developing rates that encourage participation, including sending actionable price signals to customers. To this end, it is important to move toward a long-term framework that treats all customers fairly – those who make use of DERs and those who do not. Important principles to adhere to include:

- The concept of gradualism in transitioning from current rate designs to future ones, to give customers and DER providers time to adapt. This should include the adoption of rate pilots, where appropriate, to inform customer engagement.
- "Grandfathering" of rates for existing DER customers for a transition period that is long enough so as not to undermine investments made under existing rates.
- Providing information and energy management tools that allow customers to understand and effectively respond to the pricing signals they will be receiving.

Rate design is only one component of the changes needed to modernize our grid. Utilities must make foundational investments in enabling technology, such as advanced metering infrastructure and meter data management systems, before many of these more sophisticated rates can be implemented, including taking advantage of customer-side technologies such as smart thermostats. Other complementary regulatory changes, such as revenue decoupling, comprehensive benefit-cost analysis, and performance-based regulation, should also be considered as part of a package that can make new rate designs more effective at achieving the desired outcomes. Finally, any changes should include input from all stakeholders so that regulators can take into consideration the impact of the changes on all participants in the market.

INTRODUCTION

The increased deployment of customer-sited DER and the success of demand-side management (DSM) programs in reducing load growth are transforming the U.S. electricity system, making the grid more efficient, flexible, resilient, reliable, and clean, while simultaneously giving customers greater choices and control over energy use and costs. Effective integration of these and other distributed resources and the continued success of DSM programs, such as energy efficiency and demand response, lead to a range of benefits; however, they can also pose challenges for utilities. Among these challenges is that, under traditional rate designs, growth of DERs can lead to reduced revenue collection from customers and a shift in how different customers contribute to system costs. While this is not unique to DER, this has led some utilities to look for new ways to recover their costs to maintain the electricity grid upon which we all rely and that take into account the different ways in which customers are using the grid. Distributed generation (DG) technologies, such as rooftop solar, use the grid in new ways and have become a major focus of rate design discussions and regulatory proceedings around the country. As DER technologies are adopted on a larger scale they will increasingly reveal weaknesses in the rate designs that utilities have traditionally used to recover their costs.

Traditional rate designs have been developed over many years and have served us well. Nevertheless, regulators, utilities, and other stakeholders are realizing that new rate structures are needed to better accommodate the changes taking place on the grid, and especially to better integrate and enable DER. Some changes to rate design and revenue recovery, such as revenue decoupling,[4] have been implemented in several states to address the overall level of cost recovery. But in order to maximize the value of DER for all customers while addressing concerns about the equitable allocation of costs for maintaining the electric distribution system, it will be necessary to consider more extensive changes. As DER deployment increases and as the grid becomes smarter, there is both a need and an opportunity to update rate designs to better meet the needs of utilities, customers, and energy suppliers.

This issue brief focuses on rate designs for residential and small commercial customers, also known as "mass-market" customers. Larger commercial and industrial customers, which use more sophisticated metering, already are served using more complex rate designs.

OBJECTIVES OF RATE DESIGN

Before getting into the details of the different rate design options, it is important to define what we mean by rate design and clearly outline the objectives of a modern rate design framework.

Rate design is the process of setting prices and price structures to be paid by customers so that utilities have a reasonable opportunity to recover their revenue requirement (costs plus allowed return). Other key objectives of rate design include fair allocation of costs across customer classes, and sending appropriate price signals to customers so that they consume energy efficiently and are motivated to act in ways that benefit themselves and the grid as a whole. The diverse objectives and requirements of different stakeholders – utilities, customers, policymakers, DER providers, and society as a whole – make setting rate designs that satisfy all parties difficult. The methodologies in use today have been developed over many decades using the technologies available in the past. For example, until recently mass-market customers have had only monthly usage meters. Nevertheless, as the U.S. electricity system evolves, and available technologies advance, rate designs need to follow suit in order to encourage the beneficial adoption of new technologies, like DER. This requires rate design to better incorporate the value of DER, as well as the value of services that utilities provide in integrating DER into the grid.

Below is a list of the traditional objectives that have been considered in setting rate designs, as well as a list of new objectives that should be considered going forward

Traditional Rate Design Objectives

- Ensure safe, reliable, affordable electricity service
- Enable utility cost recovery and revenue stability
- Ensure stable and affordable utility bills
- Equitably allocate costs to customer classes reflective of cost causation (without an "undue" level of cross subsidy)
- Promote economic efficiency
- Be simple, understandable, and transparent to customers
- Where changes to rates are contemplated, apply principles of gradualism and continuity
- Promote policy goals (e.g., environmental, energy diversity, power/data security, needs of low-income households)

Emerging Rate Design Objectives

- Provide customers with timely and granular information so that they can make informed decisions about how they meet their energy needs
- Send customers price signals, with greater differentiation to the extent that it is cost effective (e.g., temporal, locational, and customer type)
- Empower customers to take control of their energy usage and costs to benefit themselves and the grid
- Accommodate technologies and service options that take into account new ways that customers can respond to rates, including the use of customer-sited DER and new energy management technologies.

Given the range of objectives associated with rate design, the need is evident for a set of clear and concise principles that should be adhered to when making rate design decisions for a DER future. Good rate design is a complex task, and a well-suited rate design for one particular jurisdiction and one class of customers may vary significantly from what is suitable for others.

COMMON RATE DESIGN OPTIONS FOR MASS-MARKET CUSTOMERS

Today, a majority of residential and small commercial customers, known as "mass market" customers, are on simple flat-rate pricing, where most costs are collected on a set per-kilowatt-hour (kWh) basis, regardless of when consumption occurs. While there are benefits to such a straight-forward rate design for these customers – they are easy to understand and stable – AEE believes that ultimately, more sophisticated rate designs based on granular and precise price signals are needed to meet the emerging objectives of rate design and better achieve traditional rate design objectives. Regardless of what is ultimately adopted, rate design should fulfill its key functions of providing the utility's revenue requirement and balancing the needs of both active and passive mass-market customers, but should do so whenever possible in a way that is consistent with the emerging needs and opportunities associated with DER. For the rate design options discussed below, we identify some of the pros and cons of each and, if applicable, our recommendations on how they should be structured to be consistent with the above rate design principles.

FIXED CHARGES

Many utilities have recently proposed increasing the fixed charge component of their rates to lock in recovery of a larger portion of their costs and reduce their risk in today's changing environment. Traditionally, fixed charges have been low, typically under $10 per month for residential customers, and were designed mainly to recover direct customer costs, such as metering, billing, customer service, and the cost to connect the customer to the distribution grid. The majority of costs are then allocated to the variable (per kWh) portion of the bill. Some utilities are now trying to update their calculations of these fixed elements to reflect current costs while others are seeking to expand the definition of direct customer costs, usually to cover past investments for certain assets that are recovered in rates but that were made to serve customers that have now reduced their usage. While these costs should be recovered by the utility, in AEE's view, increasing the fixed charge is not the preferred option. Nevertheless, to the extent that direct customer costs have changed, regulators should consider having that reflected in the fixed customer charge, without expanding the definition of what constitutes a fixed cost. The objective should be to keep fixed charges low but have them fairly represent current costs. As discussed below, increased fixed charges can have significant impacts for customers.

Cost Shift vs. Revenue Shift

There is considerable debate over whether or not there is actual or significant cost shifting from DG customers to non-DG customers, especially after the benefits of DG are included. DG companies and others have argued that when all costs and benefits are fully taken into account, DG customers are providing benefits that exceed their cost of utility service and therefore there is zero or minimal cost shift. To understand if any significant cost shift exists requires a comprehensive valuation of both the benefits and costs of DG on the system, which could include temporal or locational value. As such, AEE prefers using the term *revenue shift*. Under most existing rate designs, a shift in the collection of the revenue requirement does occur regardless of the valuation of costs and benefits, as DG customers reduce their kWh purchases. But a revenue shift and a cost shift are not the same.

Increasing the fixed charge necessarily decreases the variable component of a customer's bill, leaving total revenue collection unchanged. Although the per-kWh rate is lower, the utility gets a more stable and predictable revenue stream and customers see bills with lower fluctuations from month to month. Proponents of higher fixed charges argue that they are fairer than the way rates are typically structured because the majority of a utility's costs are fixed. They also contend that because DG customers consume less energy from the grid, they do not pay their fair share to utilize and maintain the grid, resulting in a cost shift to non-DG customers.

The drawback of increasing fixed charges is that it focuses on utility revenue collection and does not adequately balance the other goals of rate design, including the customer's ability to manage their usage based on price signals. Higher fixed charges that lead to lower per-kWh rates will impact customers who have already invested in energy efficiency measures by reducing their bill savings, lengthening the payback period for energy efficiency investments. For the same reason, these types of rate design changes will likely discourage future energy efficiency investments. The impact is similar for customers who invest in DG technologies. Higher fixed charges cut into the benefit they receive from reduced electricity purchases, and reduces the value to them of exported generation.

Higher fixed charges also are widely considered to disproportionately affect low-income customers, who on average tend to use fewer kWh than other customers, although utilities can consider changes to their low-income programs to mitigate these impacts. Nonetheless, this has resulted in controversy and stiff opposition from various stakeholder groups, with regulators often denying utility requests for fixed charge increases or approving only modest increases.[5] Consider the following example, based on a recent proposal from Kansas City Power & Light.[6] Increasing the fixed charge for residential customers from $9 per month to $25 per month, with a corresponding decrease in the per-kWh charge would have the following impact: Customers who consume 1,250 kWh per month would see virtually no change in their monthly bill, while low-usage customers who consume only 250 kWh per month would see their bill rise by nearly 40%; high usage customers (>1,250 kWh/month) would see their bills go down.

An Alternative to Fixed Charges: Minimum Bills

As an alternative to increasing fixed charges, a minimum bill, properly designed, can provide utilities with a baseline level of revenue recovery while ensuring that all customers contribute some amount for their use of the distribution system. As the name implies, a minimum bill is structured such that customers are required to pay at least a certain amount every month regardless of their level of usage. But unlike higher fixed charges, a minimum bill does not reduce the per-kWh rate of a customer's bill. If set at an appropriate level, it can reduce the potential revenue shift, because DG customers would not be able to net-meter below the minimum bill. Alternatively, they might choose to install a smaller system. A minimum bill is also easy to understand and would require minimal customer education to implement. However, the specific level of the minimum bill is important. If set too high it can reduce the portion of the bill that customers can control, reducing their incentive for doing so.

DEMAND CHARGES

A rate design commonly used with large commercial and industrial (C&I) customers, but not traditionally used for mass-market customers due in part to historic metering limitations, is a demand charge. Demand charges are calculated by multiplying per-kilowatt (kW) rates by measured demand, so that customers are charged in part based on their peak usage for a given time interval. Demand charges are intended to better align revenue collection with utility costs, because the utility builds its system to meet its peak demand – both the generation system peak and the local distribution system peak,[7] which typically occurs during a few hours of the year (e.g., hot, humid days when air conditioning usage spikes). By charging customers for their maximum demand (kW),[8] as well as total consumption over time (kWh), customers are encouraged to spread their usage as much as possible, reducing the capacity needs of the system, and therefore overall system costs. Demand charges can be structured in different ways, such as being limited to certain time periods, or based on an average of the top few demands in a month (e.g., 3-5) rather than relying on a single maximum demand. Regardless of the specific design they are generally intended to reflect either a customer's individual peak demand or their demand at the time that the system peak occurs, as described below.

Non-coincident demand charges are typically based on an individual customer's highest demand during each billing cycle. Demand charges may only apply during certain times of the day or year, or vary depending on the season.[9] While these charges are assessed without regard to the relationship between the individual customer's demand peak and demand on the system overall, for large commercial and industrial (C&I) customers – who have long been subject to this type of demand charge – their individual peaks often coincide roughly with the local distribution peak, such that the customer's demand aligns with costs borne by the utility.

While a non-coincident demand charge may make sense for large C&I customers, it may not make sense for mass-market customers because their individual peaks rarely match up with local or system peaks. Residential customers in particular have a wide variety of load profiles,[10] such that residential usage overall tends to have a smoothing effect on total demand, with different customers peaking at different times. As a result, charging for the non-coincident peak demand of a residential customer must be carefully considered to avoid unfairly allocating costs to these customers, because their individual demand peak may not be a good indicator of their contribution to utility costs. However, non-coincident peaks may be a better indicator of distribution system costs. Analysis would be needed to determine if this is the case before implementing such charges with mass-market customers.

Coincident-peak demand charges are based on an individual customer's demand during the overall system peak, regardless of their non-coincident individual peak. Coincident peak demand charges often align more closely with system costs and can more directly incent customers to reduce their usage when it would benefit the system overall. However, if the demand charge is set coincident with the overall system peak, it will not be effective at lowering distribution costs if the local distribution peak occurs at a different time than the system peak. Thus, an alternative coincident-peak demand charge could be based on the local distribution peak. In either case, the objective is similar: incentivize customers to reduce their demand when it matters most.

However, demand charges may be difficult for mass-market customers to understand as they move from paying for energy on a volumetric basis, as the introduction of a rate based on peak demand can be confusing and non-intuitive. Also, coincident-peak demand charges are difficult to implement without advanced metering infrastructure and a robust customer communication and education program. Since the system peak in a particular time period is not known until after the fact, customers may have to deploy new technologies such as smart thermostats or alternatively actively manage (or have a third party actively manage) their demand during multiple time periods (with warnings from utilities or grid operators that a period of high demand is expected) to successfully manage or reduce demand during the system peak. Alternatively, demand charges focused on pre-defined peak periods run the risk of simply shifting the peak to other hours, rather than encouraging more efficient use of the system in all hours. Rather the benefits of a potential demand charge are maximized if the demand charge is effective at reducing system peak demand regardless of when it occurs.

In order for customers to respond to demand charges, whether non-coincident or coincident, they need access to their usage data, they need to have the knowledge to interpret their data, and they must have the ability to take action to manage their usage. New customer engagement tools may be needed to help customers know their peak usage during the peak pricing periods, including real-time usage alerts to help customers, either actively or passively with the use of technologies, to manage their peak period usage; though this structure would encourage or enable third parties to provide such management services.

In addition, demand charges may reduce the incentive for energy efficiency outside of the peak hours, which may impact state policy goals, by reducing volumetric rates and thus the amount of money that customers can save by reducing their overall energy usage. Finally, it is noteworthy that demand charges reduce the value proposition for non-dispatchable DG (e.g., rooftop solar), as customers would also pay for their demand should they use energy during the peak period when their solar panels are not generating enough energy to cover their usage, such as on a cloudy day or in the evening. For customers with solar, demand charges could also provide a strong incentive to adopt energy storage or to install west-facing panels, because it would encourage the customer to actively manage peak period usage.

Because of the challenges associated with demand charges for mass-market customers, some stakeholders are concerned about their adoption and the potential impacts, especially during the transition and educational period.

Targeted demand charges might provide a middle ground. A demand charge that only applies during clearly articulated periods known in advance (e.g., a few hours every weekday afternoon during the summer, similar to a time-of-use rate) could provide value to the system while sending better price signals to customers. A targeted demand charge implemented for just a certain subset of sophisticated customers could be an option that would begin to move towards a more sophisticated rate design that better aligns rates with costs while giving customers the information they need to manage their bills during those peak periods. Again, this structure would open up the market for third-party companies to provide services (e.g., demand response or behavioral analytics) to assist customers in managing their bills. It would also encourage the use of emerging technologies, such as energy storage.

TIME VARYING RATES

Broadly speaking, AEE believes that time-varying rates (TVRs), based on kWh usage and/or kW demand, are the preferred long-term option for modern rate design. TVRs can take many forms but they generally work by pricing electricity higher at times when demand on the system is high, incenting customers to reduce their electricity use when it is the most expensive to generate or when there are capacity constraints on the system. This reduces stress on the power grid and lowers wholesale energy and capacity costs by reducing the need for inefficient and costly peaking plants. TVRs can also allow engaged customers to capture the benefits of managing their electricity usage. In states that allow customer choice of energy supplier, the utility could be the platform for data necessary for TVR products, with customers and their designated third parties getting access to this data. This would allow for the greatest array of products and the most customer choice. In states without retail competition, customers should also have access to their data.[11] TVRs may be also used in conjunction with demand rates. For example, TVRs could apply to electricity supply charges, while demand-rates may be deployed for delivery charges. This hybrid approach may be considered as an option in certain areas.

TVRs come in four general categories, as shown in the table below:

Time Varying Rate Categories

Structure	Definition
Time-of-Use (TOU)	The most basic pricing scheme, which consists of a tiered pricing structure with pre-defined peak and off-peak time periods
Critical Peak Pricing (CPP)	Traditional flat-rate volumetric pricing coupled with higher rates during peak demand events that are announced in advance
Peak Time Rebate (PTR)	Essentially the inverse of a CPP: a flat rate coupled with a rebate when customers reduce their usage during a peak demand event.
Real Time Pricing (RTP)	The most sophisticated pricing scheme, with hourly prices determined by day-ahead market prices or real-time spot market prices.

TVRs can be designed with a variety of time intervals, such as long versus short peak periods, and large versus small differentials between peak and off-peak rates. Experience has shown that rate structures with shorter on-peak periods and larger differentials between on- and off-peak rates are more effective at peak demand reduction.[12] At the same time, the impact of different TVR designs on different types of distributed generation should also be considered, and it could be possible for utilities to offer different options from which customers can choose to best meet their needs.

Although AEE supports TVRs as the preferred long-term option, how TVR is implemented is important. As with other rate designs, successful adoption and implementation depends on investment in advanced metering and other infrastructure, which will take time. Furthermore, effective customer education and engagement is critical to the success of TVR. Customers must understand their default rates and any available options if they are to make educated choices about how to best manage their electricity bills under TVR. A lack of customer education and engagement can lead to low levels of customer response, which can frustrate the goals of TVR deployment. Customers should have access to analyses showing them how their bills would likely change under different rate options, based on their historical energy usage patterns. Ideally, customers should also be able to see how their bills would change under different rate structures if they were to shift a given percent of their usage to different times.

Opt-in vs. Opt-out

One question to consider is whether TVRs enabled with advanced metering functionality should be opt-in or opt-out. Customers who voluntarily sign up for new rates are inherently more engaged than the average consumer and therefore more likely to achieve higher levels of load shifting in response to the new rate than customers who are defaulted into one. Voluntary TVRs can also be designed with higher pricing differentials between time periods, since the risk of significant negative impacts to vulnerable customers is reduced, if not eliminated entirely. The natural trade-off in rolling out new rates on a voluntary basis is scale. Most opt-in TVR programs attract a very small percentage of residential customers; however, with the right mix of customer education and marketing, this can be improved.

Some utilities consider opt-in the preferred approach, as it is seen as being potentially more customer friendly. However, the Sacramento Municipal Utility District's (SMUD) *SmartSacramento Project,* which included the rollout of 617,000 smart meters, found that opt-out was more successful and more equitable by applying to all customers. Under the project, the number of customers under opt-out enrollment (93%) was about 3.5 times higher than for opt-in (24%). While peak period demand reductions per customer were higher under opt-in programs, the larger number of customers enrolled made opt-out more cost effective.[13]

Beyond opt-in vs. opt out, regulators can also consider whether TVRs should become mandatory for all customers or only for certain highly-engaged customers (sometimes called "prosumers") seeking to actively manage their usage in response to price signals.

Baltimore Gas and Electric's PTR program is an example of successful customer engagement: Utilizing mass-market education campaigns, as well as personalized pre- and post-event communications, BGE was able to achieve high levels of customer response for their opt-out PTR program.[14] It is important for customers to have load management tools and information at their disposal in order for them to effectively respond to price signals and manage their energy bills. For mass-market customers, this should include the use of automation (e.g., smart thermostats) and third parties to help them manage energy use (which would require third-party access to customer data) to take best advantage of TVR.

SUCCESSORS TO NET ENERGY METERING (NEM)

Net energy metering (NEM), under largely volumetric rate designs, provides compensation for DG, often at the full retail rate, for electricity that is exported to the grid.[15] NEM is accomplished by subtracting from customer usage any electricity generated by the customer and also compensating the customer for any power produced in excess of their usage as measured by their meter. This essentially allows DG customers to bank the excess electricity they generate, in many cases at the full retail rate, and get credited for it on their bills when their DG systems are not generating enough to fully offset their electricity use. At the end of a billing period, the customer is either charged for the net consumption or credited for the net exports.[16]

While NEM does not send precise price signals, it is simple to implement and easy for customers to understand. That has made it very effective at supporting DG adoption. However, as described above with respect to the issues of cost shift and revenue shift, in states with higher levels of DG penetration, NEM raises issues with respect to utility revenue collection and potential distribution cost allocation, as revenue recovery is shifted onto non-NEM customers.[17]

Thus, as the number of NEM customers increases, efforts are underway in various jurisdictions to develop alternative rate designs and successor NEM tariffs for DG customers. The aforementioned rate designs all indirectly affect NEM compensation to varying degrees,[18] but it is also appropriate to consider direct changes to NEM that could be more sustainable in the long term. In states where DG penetration is low, it may be appropriate to continue traditional NEM rates to facilitate DG deployment, with a transition to new rate designs based on time, DG penetration, or other factors. In states where DG deployment is rising and as meters are becoming more advanced, AEE believes it makes sense to consider more nuanced and sophisticated net metering policies, consistent with the principles of continuity and gradualism.

Successors to NEM should more precisely monetize the value of DG to the system, achieve desired behavior changes/outcomes related to electricity use, and also fairly compensate the utility for the service it provides to DG customers in their use of the grid. Moreover, it is also appropriate to consider changes to NEM compensation that can apply to all DER, and not just DG, to encourage beneficial integration of DG with other DER technologies (e.g., solar plus storage, or combined heat and power plus demand management). Different DERs have different operating characteristics, different load profiles, and ultimately different impacts on the distribution grid. NEM frameworks that are structured to account more precisely for the value that DER provides to the system – both locational and temporal – would effectively address concerns about impacts on non-DER customers without depriving DER customers and the system as a whole of the value they bring.

One potential framework, based on a "value stack," is being implemented in New York, on an interim basis, primarily for the burgeoning community solar market there and certain behind-the-meter projects that are already on demand-based rates (NEM remains unchanged for residential and small commercial customers).[19] This approach compensates exported energy (netted hourly instead of monthly) based on several price components rather than simply the retail rate. Specifically, the value is based on the utility's avoided costs plus other DER values, including wholesale energy and capacity, distribution, and environmental values. It also includes a transitional charge designed to decline over time as DG deployment rises. AEE supports the direction being taken, and is continuing to promote the evolution of this approach so that electricity that is produced and consumed behind the meter is valued similarly to exported electricity (as we proposed in comments submitted in the Value of DER proceeding in New York).[20]

CONCLUSION: A PATH FORWARD

Making changes to rate design is an essential element of modernizing the electricity system. Yet it cannot be considered in a vacuum, as it is only one piece of a larger puzzle, and any modifications need to be considered in the context of other changes in utility operations and regulation.

ENABLING TECHNOLOGY AND ACCESS TO DATA

More sophisticated rate designs require certain enabling technologies to be effectively implemented. The first prerequisite is advanced metering functionality (AMF), which includes not only the meters themselves, but also the two-way communications infrastructure, the back-office management systems, and the consumer engagement platform to provide alerts and other information to customers. AMF allows near-real-time energy tracking, load forecasting, and two-way communication between the utility and the end-user, which are critical to the development of more sophisticated rate designs.[21] Also, mass-market customers can benefit from the services of third parties to manage their energy use and properly respond to price signals. However, in order to do this, third parties must have timely access to the data that AMF provides.[22] The customer's acceptance and adoption of more sophisticated rates will also be facilitated through energy management technologies like smart thermostats, which can provide an automated response to dynamic rates. Such technologies can help translate market needs into customer response and more easily implement and scale new features that require integration between the utility systems and end user devices. Utilities have an important role to play in incentivizing the deployment of connected devices with these automation capabilities, such as through energy efficiency and demand management programs.

PILOTS, CUSTOMER EDUCATION, AND GRADUALISM

AEE strongly supports the principle of gradualism when implementing rate design reforms, to moderate their impact on both customers and third parties. Pilots and demonstration projects should be conducted before wider implementation is contemplated, as they are an integral tool at regulators' disposal to gather data and experience, test the effects of new rate designs, and identify the best way to proceed. However, pilots should not be used to delay the introduction of products that are already proven and working based on the experience of other states or utilities. Given the rapid pace of development of the DER market, pilots should include reasonable timelines for moving successful rate designs into general use. Pilots should also not interfere with competitive options in jurisdictions with retail access.

Another way to roll out new rate designs is through opt-in tariffs. Opt-in tariffs allow testing of new rate designs with voluntary participants before making changes to default rates. Some utilities have shown that opt-in rate designs can act as more than a test bed, and ultimately achieve high adoption rates. For example, Arizona Public Service (APS) has enrolled over 50% of its customers in an opt-in TOU rate.[23] To accelerate the adoption of opt-in rate designs, regulators also should consider requiring utilities to shadow bill, or offer a guarantee that customers will be better off than before. For example, in its Smart Time Pricing pilot, Philadelphia Electric Co. (PECO) guaranteed it would refund the difference if customers ended up paying more on the TOU rate than they would have on the flat rate. PECO ended up writing only 13 checks, ranging from $1 to $19, and totaling just over $100 in reimbursements in a pilot involving nearly 5,000 customers.[24]

Opt-out rates should be evaluated as well to determine customer reaction and adoption and differences in cost to implement, as opt-out rate designs are less costly to implement and may achieve greater value overall. Where regulators have decided to pursue default TVRs, AEE recommends the use of opt-out pilots that include a relatively large group of customers so that statistically significant conclusions can be drawn about how the overall customer base is likely to respond to the new default rates.

New rate structures (even if limited in scope and application) could require DER providers to quickly create new pricing structures and product offerings in order to guarantee savings for their customers. Therefore, it is also essential for third parties to get a preview of rate changes well in advance in order to model savings appropriately and develop new offerings.

OPEN, COLLABORATIVE REGULATORY PROCESSES

Through experience in several jurisdictions, we have learned that stakeholder collaboration is one of the most important tools for making sure new rate designs succeed. Therefore, we recommend that, to the greatest extent possible, regulators hold open and collaborative proceedings – or workshops, which can be even less formal – to gather information and generate new ideas. This allows regulators to take wide-ranging input and reduce barriers to participation, particularly for stakeholders with limited resources, for whom participation in adjudicated proceedings is difficult. In addition, such open forums (unlike rate cases) can help regulators understand all the options at their disposal and gather input from all parties to understand their views and the potential effects of new rate designs.

New technologies, changing consumer preferences, and the growth in customer-sited DER are fundamentally changing how customers interact with the grid and how utilities recover their revenue requirements. As DER deployment and use increase, DER can play a positive role in transforming our electric system to make it more flexible, resilient, and clean. Therefore, it is imperative to design rates that can better accommodate and integrate DER and send more accurate price signals to customers so that their choices lead to beneficial outcomes for all customers.

ADDITIONAL RESOURCES

Resource	Link
National Association of Regulatory Utility Commissioners Rate Design and Distributed Energy Resources Compensation Manual	https://www.naruc.org/rate-design/
"A Review of Alternative Rate Designs" by Rocky Mountain Institute	https://rmi.org/insights/reports/review-alternative-rate-designs/
"Smart Rate Design for a Smart Future" by Regulatory Assistance Project	http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf
"Designing Tariffs for Distributed Generation Customers" by Regulatory Assistance Project	http://www.raponline.org/wp-content/uploads/2016/05/rap-madri-designingtariffsfordgcustomers-final.pdf
"Teaching the Duck to Fly" by Regulatory Assistance Project	http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-teachingducktofly-2014-jan.pdf
"Lessons from Nevada's Net Energy Metering Reforms" by R Street	http://www.rstreet.org/wp-content/uploads/2016/03/59.pdf

END NOTES

[1] http://info.aee.net/21ces-issue-briefs
[2] Advanced Energy Economy (AEE) is comprised of a diverse membership. As such, the information contained herein may not represent the position of all AEE members.
[3] DER is defined broadly to include distributed generation of all types, demand response, energy efficiency, energy storage, electric vehicles and the associated charging infrastructure, and microgrids.
[4] Revenue decoupling has been adopted in some form in at least 14 states. Source: AEE PowerSuite.
[5] For example, See Appendix B in *Caught in a Fix*, Synapse Energy Economics, Prepared for Consumers Union, February 9, 2016.
[6] Missouri Public Service Commission Docket ER-2014-0370, adapted from the report *Caught in a Fix*, Synapse Energy Economics, Prepared for Consumers Union, February 9, 2016.
[7] Some rates can have separate demand charges for generation and distribution (which can occur at different times), but for the purposes of this issue brief we address peak demand more generally.
[8] Demand charges may be based on hourly or sub-hourly intervals (e.g., average usage over a 15-minute interval)
[9] For example, demand charges often are higher (or may only apply) during weekday hours in the summer.
[10] California Public Utilities Commission Decision 14-12-080, Application for PG&E for 2013 Rate Design Window
[11] See our Issue Brief on Access to Data for more information.
[12] "Time Varying and Dynamic Rate Design," prepared by Ahmed Faruqui, Brattle, for the Regulatory Assistance Project, July 12, 2012. http://www.raponline.org/wp-content/uploads/2016/05/rap-faruquihledikpalmer-timevaryingdynamicratedesign-2012-jul-23.pdf
[13] https://www.smartgrid.gov/files/CBS_interim_program_impact_report_FINAL.pdf
[14] In 2015, BGE deployed PTR to over 1 million residential customers and achieved a participation rate of 78% and an average peak demand reduction of 16.2%. See: Prepared Direct Testimony of William B. Pino on Behalf of Baltimore Gas and Electric Company in Case 9406. 6 November 2015.
[15] Generation that is consumed behind the meter offsets retail purchases at the applicable retail rate.
[16] Rules vary with respect to how long credits can be carried forward and at what rate they are valued if there is a payout (e.g., retail vs. wholesale rates). In some jurisdictions, the banked amount disappears when an account is closed rather than being automatically paid to the customer.
[17] This is primarily an issue when NEM is credited at the full retail rate. In some jurisdictions, some technologies are credited at rates below the full retail rate, such as the wholesale rate.
[18] This is because any increase in the fixed charge or demand charge component of a bill must be accompanied by a proportional reduction in the per kWh portion of the bill. This reduces the net metering credit, effectively lowering the level of DER compensation. Alternatively, TVR does not reduce the net metering credit but it does change its value by making the credit more or less valuable depending on the set per kWh rate at different times.
[19] New York Public Service Commission Value of DER Phase I decision in Case 15-E-0751, March 9, 2017.
[20] AEE Institute Filing in Case 15-E-0751, April 18, 2016. http://info.aee.net/hubfs/21CES/AEEI-ACENY-NECEC_LMPD_Comments_04-18-2016.pdf
[21] For more details see our Issue Brief on Advanced Metering, available at http://info.aee.net/21ces-issue-briefs
[22] For more details, including the terms under which the data is provided to customers and third parties, see our issue brief on Access to Data, available at http://info.aee.net/21ces-issue-briefs
[23] Ryan Randazzo, "Arizona leads California on time-of-use electricity plans," The Arizona Republic (May 26, 2015). http://www.usatoday.com/story/money/2015/05/26/arizona-california-time-of-use-electricity/27985581/.
[24] "PECO Smart Time Pricing Pilot Final Report," prepared by Nexant for PECO Energy Company. Filed in proceeding P-2012-2297304 on April 28, 2015, before the Pennsylvania PUC.