American Public Power Association

Rate Design Options for Distributed Energy Resources

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Introduction

Distributed Energy Resources (DER), especially rooftop solar photovoltaic (PV) systems, are significantly changing the way customers use energy and, as a result, having a noticeable impact on electricity sales. Customer-sited generation in particular creates a unique challenge for utilities. Customers not only generate a portion of their electric power needs, but they are also able to supply excess power to the grid.

Under most utility tariffs, this excess supply is netted against the customer's consumption, lowering a customer's monthly electricity bill. This arrangement, known as net energy metering (NEM), not only impacts utility revenues, but it often creates a cost shift to non-net metered customers who must make up the shortfall if the utility is to fully cover costs.

These changes have spurred utilities to explore and implement new rate designs to more equitably recover costs from customers. Public power utilities in particular have been at the forefront of innovative rate design. Some utilities have made wholesale changes to their tariff structures, while others have made changes that apply only to new DER customers. The changes offer potential benefits to utilities and customers, but also pose unique challenges. Some of these rate design options may not work, given a utility's specific circumstances.

This paper examines different rate design options public power utilities should consider in adapting to the new environment of DER technologies and changing customer preferences.

- The first section looks at how cost of service (COS) analysis is done, and the balancing of interests that goes into establishing electric rates. It explores how increased DER penetration impacts solar and non-solar customers, and how this in turn affects COS studies and revenue requirements.
- The second section shows how different rate design options impact rate recovery as well as customer bills.
- The third section takes a more detailed look at different rate options, and explores the pros and cons of each.
- The fourth section discusses how a utility's specific demographics may affect the likelihood of greater DER penetration, as well as what rate designs may make more sense given those demographics.
- The final section offers suggestions on how utilities might approach rate tariff revisions and what they should do to inform and educate the public about new rate designs.

The rate designs in this paper are not exhaustive. There may be fundamentally different approaches worth considering. No one approach is deemed here to be the "best" design, especially given the variety of public power utilities.

The purpose of this paper is to explain how DERs present a challenge to traditional COS analysis and rate design, and to give utilities an opportunity to develop innovative rate designs that equitably recover costs, while balancing competing public policy goals and customer expectations. The American Public Power Association encourages utilities to adapt and combine different elements of these general designs to address their unique circumstances.

Rate Fundamentals

Cost of Service Analysis

Utility rates for both community-owned and investor-owned utilities are designed to yield revenues equal to a utility's total COS, which includes all capital and operating costs incurred by a utility to provide service to its customers.[1] If revenues exceed the COS, customers are paying too much. On the other hand, revenues below COS create an untenable situation in which at least one service provider (e.g., the utility, its contractors or its power suppliers) is being undercompensated and thus suffering losses.

Ideally, revenues would exactly match COS, but it can be difficult to achieve this outcome because rates are usually set prior to the sales and billing periods, with forward looking rates designed to match projected revenues with estimated costs. Costs and revenues will fluctuate, to different degrees, with the level of sales and mismatches will likely occur.[2] Non material mismatches are of no great concern, but material mismatches must be addressed in some manner.

Actual costs and revenues routinely differ from estimated levels for various reasons, including weather, customer load and usage patterns, and macroeconomic factors but the impacts are often relatively small. Of perhaps greater concern, DER, including generation technologies (e.g., solar PV), energy efficiency (EE) and demand management programs,[3] can cause cost and revenues to depart significantly from the levels underlying utility rate structures, by displacing potentially significant amounts of utility production and sales.

1 COS for investor-owned utilities includes a return on capital, or profit, to equity investors which is not included in the COS of not-for-profit public power utilities, although the cost of service for public power utilities does typical include a margin above expenses and depreciation for a variety of purposes including, maintenance of financial coverages, payments in lieu of taxes, transfers to municipalities and operating reserves.

2 In some, but not all, cases the mismatches will be mitigated by devices such as true-up mechanisms or power cost adjustment clauses.

3 There is no single definition of DER, but in some cases, like the New York Reforming the Energy Vision (REV) initiative, DER subsumes both supply and demand resources.

4 In this example, the allocation of fixed costs remains the same in the pre and post DER cases. In practice, the fixed cost allocations might change as kWh sales change.

Table I

Hypothetical Utility	Basic Inputs
Total kWh	10,000
Variable Production Cost $/kWh	$0.040
Fixed Cost $$$	$600
Variable Cost $$$	$400
Total Cost $$$	$1,000

DER Revenue Impacts

Supply-side DERs and demand-side DERs often have similar financial impacts on electric utilities. In both situations utility production and sales are displaced. DER customers can realize lower electric bills and perhaps lower overall costs for energy services. Utilities may see lower total COS, but revenue losses will often exceed cost savings, leading to weakened financial performance, higher electric rates and cross-customer subsidization. Societal, customer and utility interests may not always be aligned

Consider the following hypothetical example. Assume a utility, initially with no DERs, with annual sales of 10,000 kWh, fixed costs of $600 and variable production costs of $.04/kWh. Assume further that there are two customers, each of whom consumes 5,000 kWh annually and that fixed costs are allocated equally, $300 to each customer. Table I below shows the basic inputs and Table II shows sales (Column 2), fixed cost (Column 3), variable cost (Column 4), total cost of service (Column 5), average rate (column 6) and total customer bills/utility revenue for each customer and for the total utility. As shown on Table II, under this scenario, the utility cost of service (COS) is $1,000, with a COS for each customer of $500. The customer bill (utility revenue) for each customer is $500 and total utility revenue is equal to the total utility COS of $1,000.

Tables III and IV depict outcomes after Customer A deploys a DER (in this case solar PV) with annual output of 2,000 kWh, but remains connected to the grid and continues to purchase 3,000 kWh of electricity from the utility.[4]

Table II

Customer Class	Sales kWh	Fixed Cost $$$	Variable Cost $$$	Total Cost $$$	Average Rate $/kWh	Customer Bill/Utility Revenue $$$
Customer A	5,000	$300	$200	**$500**	$0.10	**$500**
Customer B	5,000	$300	$200	**$500**	$0.10	**$500**
Total Utility	10,000	$600	$400	**$1,000**	$0.10	**$1,000**

Table III

Customer Class	Sales kWh	Fixed Cost $$$	Variable Cost $$$	Total Cost $$$	Average Rate $/kWh	Customer Bill/Utility Revenue $$$
Customer A (Solar)	3,000	$300	$120	$420	$0.10	$300
Customer B (Non-Solar)	5,000	$300	$200	**$500**	$0.10	**$500**
Total Utility	8,000	$600	$320	**$920**	$0.10	**$800**

Table IV

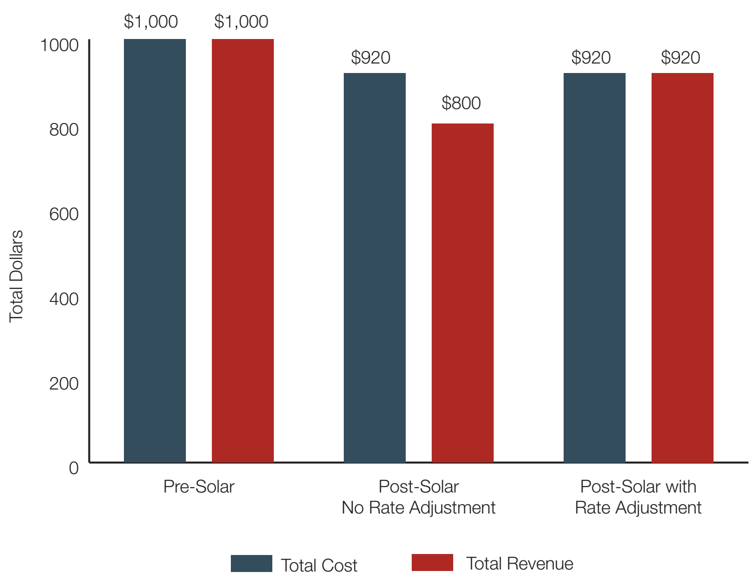
Customer Class	Sales kWh	Fixed Cost $$$	Variable Cost $$$	Total Cost $$$	Average Rate $/kWh	Customer Bill/Utility Revenue $$$
Customer A (Solar)	3,000	$300	$120	**$420**	$0.12	**$345**
Customer B (Non-solar)	5,000	$300	$200	**$500**	$0.12	**$575**
Total Utility	8,000	$600.00	$320.00	**$920**	$0.12	**$920**

Table III shows sales, costs, rates, and bills/revenues after deployment of the solar project but before any subsequent rate adjustments in response. One can see that total cost drops from $1,000 to $920. However, revenues drop from $1,000 to $800, so that revenues are no longer sufficient to cover the utility's total COS.

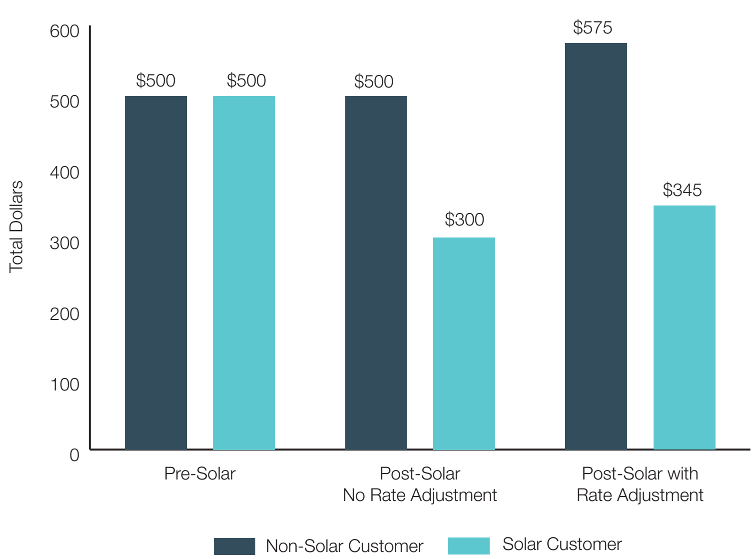
Obviously, the utility cannot continue to operate with persistent revenue shortfalls, so if sales are expected to remain at the lower level, rates will have to be adjusted upward to enable recovery of fixed and variable costs. As shown on Table IV, in this example, if sales are projected to remain at 8,000 kWh in subsequent rate years, while fixed and variable costs remain unchanged, the utility-average rate will have to rise to $.12/kWh to make total revenue equal to the total COS of $920.[5] As a result the solar customer's

5 In this particular case, the average rate is the same for both customers, but rate designs may result in different customer rates as long as the utility-wide average rate is $.12/kWh.

Graph I
Total Cost vs. Total Revenue



Graph II
Customer Bills With and Without Solar



(Customer A) bill is now $345, lower than before he/she installed the solar project, but higher than it would have been if the rates did not adjust. The bill for the non-solar customer (Customer B) rises to $575, which is higher than it was before Customer A installed the PV system.

So, the solar customer benefits[6], but if the utility is to be made whole, the non-solar customer will have to pay more. If the non-solar customer is held harmless, the utility will fail to recover its COS, which is an unsustainable situation.

These outcomes are summarized on Graphs I and II. Graph I compares total cost and total revenue, before the solar project, after the project but before any rate adjustment, and then after the project with the rate adjustment.

6 So long as bill reduction exceeds cost of facility.

Billing and Revenue Impacts of Different Rate Designs

Some rate structures are more effective than others at matching costs and revenues when sales, costs and revenues fluctuate. A utility's rate design and ratemaking practices will have an impact on the results.

Rate structures vary in complexity. Most revenue is collected through simple two-part tariffs that rely primarily on a small service charge and a single volumetric ($/kWh) charge. Meanwhile, other utilities employ complicated multi-part tariffs exhibiting several fixed and variable charges. Regardless of the complexity, mismatches between costs and revenues will be driven in large part by the relationship between the fixed and variable rate components and the utility's fixed and variable costs.

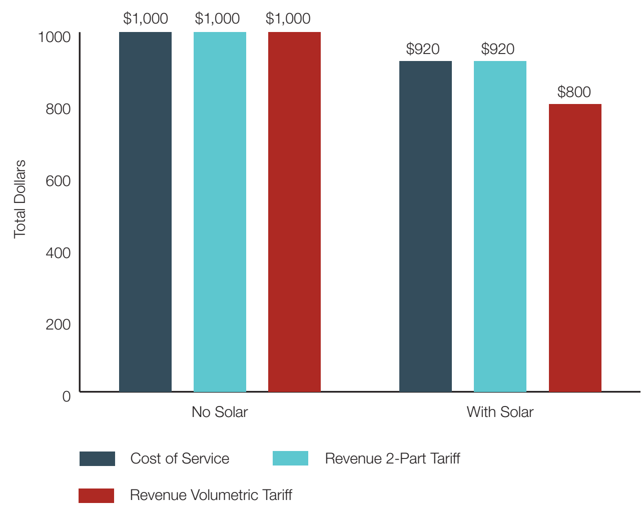
The following three graphs illustrate the differing rate impacts for DER and non-DER customers under two alternative approaches to rate design. The alternative approaches include a two-part tariff with a fixed charge to recover fixed cost and variable (volumetric) charge equal to actual variable cost, and a one-part tariff with single volumetric charge to recover all costs, fixed and variable, which is initially set to fully recover all costs at the level of sales. The analysis is based on rate making practices that are "typical" in broad strokes. In practice, there are many variations around and between these broad approaches, which will yield varying results, but the fundamental principles are the same.[7] The next section will examine more specific rate designs, but for present purposes we will use these broad approaches.

Graph III shows total cost (red) and total revenue under a two-part tariff (blue) and one-part tariff (green), before Customer A deploys the solar project (left 3 bars) and after DER deployment (right 3 bars). As shown on the Graph, in the pre-solar case, revenue under both tariff structures is equal to total cost. However, in the post-solar case, while revenue under the two-part tariff falls to a level equal to the new lower COS, revenue under the one-part tariff drops below the COS, which is unsustainable.

Graph IV shows the rate impacts on both the solar and non-solar customers for the pre and post DER cases, and Graph V shows the associated bill impacts. On each graph there are four pairs of bars which show the impacts on non-solar customer (green) and solar customer (blue), in four cases: pre-solar; post-solar under a two-part tariff, with all fixed costs recovered through a fixed rate component; post-solar with a one-part, volumetric tariff recovering all costs; and a hybrid[8] case in which some, but not all, fixed costs are recovered through a fixed rate component.

Referring to Graph IV, one can see that average rates before the solar project are the same for both customers. Turning to the three post-solar cases; under the two-part tariff, the average rate for the non-solar customer remains unchanged, while the rate for the solar customer rises. Under the one-part tariff, average rates for both customers rise but the rate increase for the solar customer is less severe. Finally, under the hybrid case, both customers see increases in their average rates, relative to the pre-solar case, but the magnitudes are different than in the other cases.

Graph III
Cost of Service vs. Revenue

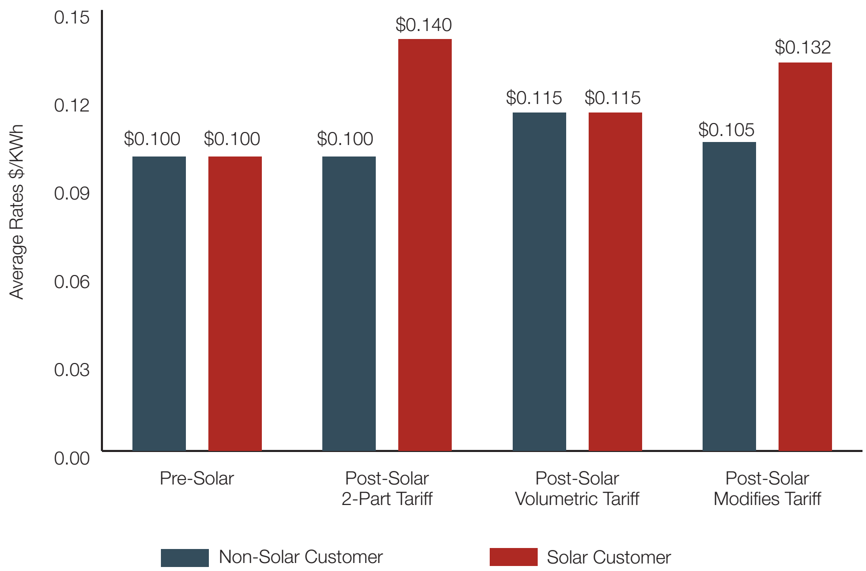


7 These results are supported by the tables in the Appendix

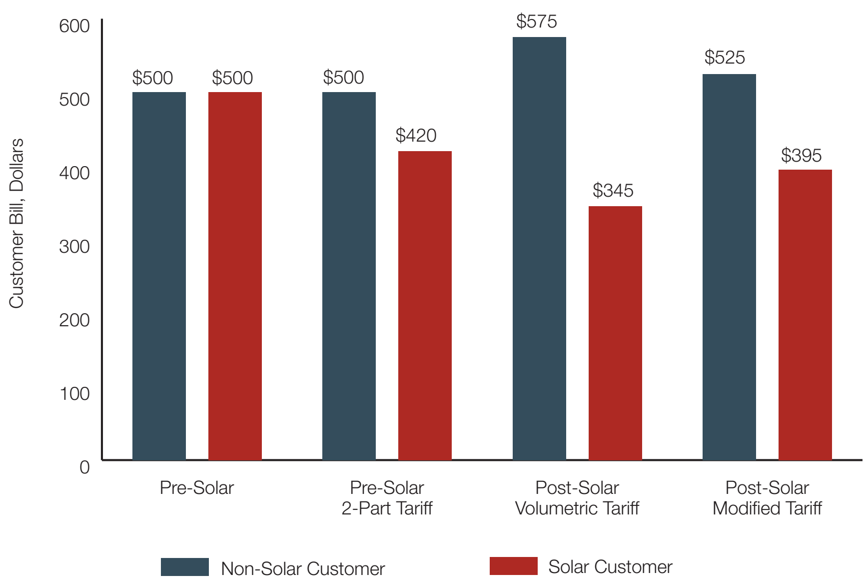
8 In this case, two-thirds of the fixed costs are recovered through fixed charges, with each customer paying one half of the fixed costs. This is just one of many combinations of total proportion of fixed costs recovered with fixed charges and allocation of fixed costs among customers that could arise.

Billing and Revenue Impacts of Different Rate Designs

Graph IV
Rate Impacts



Graph V
Bill Impacts



The rate impacts should be considered along with the bill impacts shown on Graph V. The same four cases are depicted, and again, bills are the same for both customers in the pre-solar case. Turning to the post-solar cases: under the two-part tariff, the average rate rises for the solar customer, but his/her bill declines, while both rates and bills remain unchanged for the non-solar customer. Under the one-part tariff, rates to both customers rise, but while the DER customer's bill declines the non-solar customer's bill increases. In the hybrid cases, rates rise for both customers, but the solar customer's bill is less than the pre-solar case while the non-solar customer sees a bill increase.

The retail rate impacts associated with DERs, including solar PV, can have important consequences. The cross-customer subsidies are inefficient and can compromise customer satisfaction, including resentment over the "reverse Robin Hood" effect. Also, higher rates will likely encourage more DER, which leads to yet higher rates and even greater incentives for customer installed DER, known as the utility death spiral. Impacts vary significantly with the level of DER penetration.

Rate Design Options

In light of the challenges associated with increased DER penetration, utilities have begun mulling their rate design options. This section will explore some of the broad categories of rate design utilities have already implemented or are currently investigating.

Many of the rate options considered here would make sense even without DERs. Advanced metering and other technologies have broadened the options for utility managers. For example, analog meters designed simply to measure the aggregate amount of electricity consumed at a residence often lack the capability of measuring residential peak demand. Residential demand charges have traditionally not been included in rate tariffs as much because they were not technologically feasible as through conscious rate design choices. Similarly, advanced meters enable utilities to determine precisely how much and when customers consume electricity, thus making time-varying or time-of-use rates possible to implement.

These options, and others under consideration, may be better suited to aligning rates and utility costs, regardless of DER penetration. Multi-part rates can send price signals to customers that may induce them to consume electricity more efficiently. If customers do respond as intended to these price signals, this will mitigate the need for new capital investments in generation, distribution, and transmission infrastructure. Customers may also benefit from lower off-peak prices or, in the case of demand charges, maintaining a more even load curve, thus avoiding higher demand charges while saving money through lower energy or variable rates.

At the same time, these rates could diminish the economic incentives for customers to pursue DERs. Some rate designs, including those with higher fixed charges, could also reduce customer incentives for greater energy efficiency. In constructing new rate tariffs, utilities will have to balance between the desire for secure revenue recovery and promoting energy efficiency and/or renewable resources. Though not necessarily within the purview of rate analysts, some of these rate options may be politically sensitive, and utility decision-makers will undoubtedly have to weigh all considerations before changing their current rate design.

The options provided below are not meant to be completely exhaustive. Further, as will be discussed in the next section, some options may not be viable for certain utilities based on their size, location, metering capabilities, and other considerations. It also goes without saying that all rate designs involve trade-offs between competing goals. As Scott Rubin puts it:

> It is worth remembering that there is no "perfect" rate design. The rate design process involves developing averages and groupings for thousands, or even millions of customers. No rate design will exactly capture the actual cost to serve an individual customer, but the goal is to have a rate design that treats all customers fairly within the confines of the averaging and grouping process.[9]

It is worth keeping Rubin's point in mind when evaluating these options. There is no absolutely right rate for all utilities, and for individual utilities no rate will perfectly accommodate or satisfy each individual customer. Therefore, the key task is to develop a rate that works most effectively within the context of the needs of both your utility and your customers.

Residential Demand Charges

Historically, demand charges have been applied only to large commercial and industrial customers. As mentioned above, this has been due, at least in part, to metering constraints. The combination of new metering technologies as well as the growth in the number of net metered customers has increased utility interest in developing residential demand charges.

A demand charge assigns a cost to the customer for the relative strain the individual customer places on system resources.[10] A customer with a more variable demand — one that fluctuates throughout the day — places more

9 Scott J. Rubin, "Moving Toward Demand-Based Residential Rates," Electricity Journal Volume 28, Issue 9 (2015), 64.

10 American Public Power Association, Rate Design for Distributed Generation: Net Metering Alternatives June 2015, 10.

strain on the system than a customer with flatter demand. Demand charges are designed to reflect the cost associated with meeting customer demand, and can be used to incent customers to flatten their loads or even to reduce their load during utility system peak periods.

Several public power utilities, including Lakeland Electric in Florida, have implemented residential demand charges for customers who have installed rooftop solar.[11] Utilities such as Arizona Public Service Company have established system-wide, opt-in demand charges.[12] Other utilities are either investigating or close to implementing system-wide demand charges.

Demand charges can be based on several different criteria. A paper published by the Rocky Mountain Institute walks through the different options. First, demand charges could be either *ex post* or *ex ante*. Most U.S. demand charges are ex post, meaning they are based on peak demand in a previous billing cycle.[13]

From there, the utility must determine if the demand charge will be based on each customer's peak during the billing period (non-coincident with the utility system peak demand) or based only on the customer's peak demand during the time of the system's peak (coincident peak demand).[14] Utilities size their systems based on peak demand, therefore it would make sense to base billing demand on the individual customer's contribution to system peak. Doing so may incent off-peak usage, which in turn flattens the utility's load profile and puts less strain on the system.

The next consideration is the duration of the peak. The measurement may be instantaneous, meaning peak demand is measured at the exact moment of the customer's peak, or it can be based on an interval of some given length (15 minutes, 30 minutes, or more).[15] Once the peak is determined, the demand charge can either be based on a single peak or on the average of two or more of the customer's peak loads in each billing period.[16]

The next consideration is whether to develop a seasonal demand charge, or to set one single charge for the entire year. Utilities may develop bi-seasonal charges with distinct rates for summer and winter seasons, for example, or they could even implement multi-seasonal demand charge rates for three or more seasons.[17]

One final consideration is whether the demand charge should be ratcheted. In a non-ratcheted demand charge, the billing demand is based on the current billing month. A ratcheted demand charge is based on the customer's highest peak over some historic period, which could be several months or even the entire previous year. In some cases, the ratchet may be based only on the customer peak established during the summer months. Whatever interval is chosen, that will set the billing demand going forward for some period of time.[18]

Each of these options has pros and cons both for the utility and the customer. A ratcheted demand based on summer-time peak could reduce incentives to reduce energy usage (once a new peak billing demand has been established, incentives to manage load are reduced). In contrast, a ratchet based on a rolling average of several consecutive months could provide an incentive for customers to manage

11 See ibid for a detailed examination of Lakeland's demand charge.

12 APS's rate schedule ECT-2, residential service time-of-use with demand charge, can be found at https://www.aps.com/library/rates/ect-2.pdf. Approximately 11 percent of APS residential customers are served under this tariff. For more information, see powerpoint presentation, Residential Demand Rates: APS Case Study available at https://www.hks.harvard.edu/hepg/Papers/2015/June%202015/Grabel%20Panel%201.pdf.

13 James Sherwood et al., A Review of Alternative Rate Designs: Industry experience with time-based and demand charge rates for mass market customers (Rocky Mountain Institute, May 2016), 50. Paper available at http://www.rmi.org/alternative_rate_designs. Ex ante demand charges are available in countries such as France and Italy. Customers choose their level of peak capacity, and are billed based on the level they have chosen. If they exceed the pre-determined limit, they are either tripped off of service or their rate increases.

14 Ibid., p. 58.

15i Ibid., p. 61

16 Ibid., p. 64

17 Ibid., p. 66.

18 Ibid., p. 69.

19 Ibid., p. 71.

energy usage and thereby reduce their rolling average.[19] A ratchet provides more revenue stability for the utility, but may be viewed as punitive by some customers.[20]

The duration and occurrence of the billing demand are very important considerations. A billing demand based on an instantaneous or brief (15 minute) interval could penalize customers who experience a momentary and anomalous increase in demand. A longer interval, as well as multiple intervals, mitigates the penalty associated with sudden sharp increases in energy usage.

However the demand charge is structured, there are pros and cons for the fundamental concept, outlined below.

Pros

One of the most important features of a demand charge for the utility is that it sends a price signal to customers to avoid usage patterns requiring increased utility capital investment in long-lived assets to increase system capacity. Demand charges also allow the utility to set energy charges that are closer to its actual economic costs, while recovering fixed costs from those that impose the greatest capacity costs on the utility. From a customer perspective, unlike higher fixed charges (discussed below), a customer has greater flexibility in avoiding higher bills by either reducing demand or moving energy usage to off-peak hours if the billing demand is based on system peak hours. In this way a demand charge acts as a version of demand response, providing fiscal incentives to customers to change their consumption patterns to the benefit of both the utility and the customer.

In the context of distributed generation, demand charges help mitigate the problem of cross-customer subsidies. Residential customers with rooftop PV systems may not be using any electricity from the grid during the early afternoon, and in fact may be net exporters of generation. As the day progresses and as their rooftop generation diminishes, they begin taking more electricity from the grid. In many situations they are becoming net consumers of electricity just at the time of the system's peak in early evening hours, thus compounding the stress on the overall system. This can lead to something like the California duck curve phenomenon where the distribution utility must ramp up production to meet additional demand and compensate for lost solar generation.[21]

Cons

The drawbacks associated with residential demand charges mainly concern the inability of customers to adapt to an unfamiliar rate element. A consumer advocate could see these along with higher fixed charges, as "blunt instruments" which may leave many ratepayers worse off.[22] Consumer advocates Janee Breisemeister and Barbara Alexander cite a presentation by David Springe detailing the concerns consumers and consumer advocates have with demand charges including:

- Residential customers are unfamiliar with the concept of demand, and are used to measuring energy usage in kWh, not kWs.
- Residential customers aren't as able as large commercial or industrial customers to control peak usage.
- Bills will be higher for low-use customers, who tend to also be low-income.
- Smart meters (AMI) measure kWh, not kWs.
- Demand charges, especially if they are NCP, penalize residential demand that is not coincident with the system peak.
- It is difficult to calculate the correct kW billing determinant.[23]

Jim Lazar, among others, has expressed more techni-

20 Jim Lazar and Wilson Gonzalez. Smart Rate Design for a Smart Future (Montpelier, VT: Regulatory Assistance Project, 2015), 38. Available at http://www.raponline.org/document/download/id/7680.

21 See for example California IS Fast Fact, accessed at https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

22 Residential Consumers and the Electric Utility of the Future. Prepared by Janee Briesemeister with the assistance of Barbara R. Alexander for the American Public Power Association (2016), p.14

23 Ibid. p. 16. See also David Spinge, Customer Concerns with Implementing Demand Rates, presentation for NASUCA and NARUC Conferences, November 2015, available at http://nasuca.org/event/2015-nasuca-annual-meeting/.

cal reservations about demand charges. He notes that the only portion of the distribution system sized to individual customer demand are line transformers, and they constitute only a small percentage of the cost of service. He also adds that residential customers have highly diverse demand profiles, using power at different times of the day. Smaller customers contribute less to system coincident peak even though they have a higher share of NCP. He also echoes the concerns of consumer advocates that residential customers have a poor understanding of demand charges and may not be able to adapt.[24]

Lazar is more bluntly critical of demand charges in another paper, referring to them as "obsolete." He states they unfairly treat customers who use capacity for only a few hours the same as customers who use the same level of capacity at all hours. He views hourly pricing based on time-of-use rates as "much more granular and precise in recovering these costs than monthly demand charges."[25]

Because residential demand charges have been implemented in so few places, studies regarding customer response is limited. Ryan Hledik notes that the few experimental pilots that have been conducted have shown customers do respond to demand charges, though he further observes that two of the pilots are old and the third is in a unique climate, and that the sample sizes are small.[26] Nevertheless these pilots show significant customer response. He further explains that demand rates can work if customers are price-sensitive and will respond to rate changes, the rate design provides an opportunity for customers to save money, and the rate design is actionable — in other words, the customer has to know what actions to take to reduce usage.[27]

Hledik adds that customers don't need to know the precise period of peak demand, but must know generally how to avoid simultaneously using electricity-intensive appliances. If customers stagger using high-consumption appliances (dryer, oven, stove, etc.) at different times, they can avoid being hit with a high demand charge.[28]

Public power utilities may want to consider adoption of demand charges for customer classes that impose atypically higher costs on the utility and are able to manage their usage to reduce loads during system peak periods.

Demand charges are thus fraught with complications, some of which are not necessarily related strictly to cost of service analysis. That is not to suggest that residential demand charges cannot or should not be considered, but these considerations must be thought through carefully before moving ahead with this option.

Public power utilities may want to consider adoption of demand charges for customer classes that impose atypically higher costs on the utility and are able to manage their usage to reduce loads during system peak periods. Demand charges can also be used in combination with other rate design changes, such as fixed charges and time-of-use rates.

Increased Fixed Charges

A typical residential utility bill has two components: a fixed, monthly customer charge, and an energy charge (or variable charge) based on the amount of kWh a customer consumes during a billing cycle. Customer charges tend to be fairly small — usually around $8 to $10 per month. An average residential monthly bill is just over $100; thus over 90 percent of utility revenue from a typical residential customer is recovered through variable energy charges. As discussed earlier in this paper, while fixed costs can range anywhere from

24 Lazar and Gonzalez, Smart Rate Design, p. 51.

25 Ryan Hledik and Jim Lazar. Distribution System Pricing with Distributed Energy Resources (Lawrence Berkeley National Laboratory, May 2016), p. 55

26 Ryan Hledik. Rolling Out Residential Demand Charges, presented to EUCI Residential Demand Charges Summit, May 2015, p. 7.

27 Ibid., p. 8.

28 Ibid., p. 10.

20 to 60 percent of a utility's cost of service, most utilities recover their fixed costs through variable charges.

Utilities, including public power utilities, have begun implementing — or have investigated implementing — higher fixed monthly customer charges. Attempts to increase fixed charges have been resisted by consumer advocates and even state regulators, especially when the utility seeks a significant increase in the charge.[29] However, some utilities have been able to adopt higher charges. For example, Sacramento Municipal Utility District in California was able to implement a higher monthly charge, phased in over five years, while lowering its energy charge.[30] Several public power utilities in Wisconsin, including the City of Whitehall, also received approval for a moderate increase in the customer charge.[31]

Los Angeles Department of Water and Power received City Council approval for a fixed charge that is a hybrid of a customer charge and a demand charge called the Power Access Charge (PAC). The PAC is a monthly fixed charge based on the customer's highest monthly level of energy use in the previous year, and is also based on the residential zone the customer lives in (the zone is based on climate). For example, a zone 1 customer whose highest monthly usage between April 2015 and April 2016 was 700 kWh would be placed in tier 2. Each zone has three tiers based on usage, with the PAC being higher as the tiers increase. Each October LADWP will re-examine a residential customer's profile, and customers may be placed in different tiers based on their highest usage over the previous year.[32]

Pros

Whether tiered or flat for all customers, an increased customer charge has several benefits. It provides a better match between costs and revenues, thus mitigating the impacts of intra-class subsidies. It also provides a steadier stream of revenue for the utility, and helps guarantee that DER customers pay at least some share of their utility's fixed costs. Customer charges are also much simpler to administer, and unlike demand charges, most customers are at least familiar with the concept.

Cons

Consumer advocates dislike high customer charges as much, if not more, than demand charges. Demand charges provide customers with an opportunity, if they conserve energy usage at the right time, to avoid higher bills, but customers can take no action to reduce their customer charge. And though there is not a perfect correlation between low energy use customers and low-income customers — and in some service territories, studies show an almost inverse relationship — generally speaking in the United States, low-income customers tend to be low-use.[33] Since higher customer charges disproportionately affect low-use customers, they concomitantly may harm low-income customers. Briesemeister and Alexander cite analysis conducted by Synapse Energy showing a customer charge increase from $9 to $25

29 See for example the debate in Missouri: http://www.utilitydive.com/news/utilities-solar-advocates-at-odds-over-missouri-net-metering-bill/386351/; the controversy of APS's proposal in Arizona: Michael Copley. "Demand charge under APS rooftop solar proposal would add up to $80 in monthly fees." SNL: Electric Utility Report, July 15, 2013; the Idaho PUC rejecting a customer charge increase: Idaho Public Utilities Commission. "Most of Idaho net metering proposals denied." Case No. IPC-E-12-27, Order No. 32846, July 3, 2013; Louisiana PSC rejecting a customer charge increase: Amanda H. Miller. "Louisiana PSC upholds net metering." Clean Energy Authority, July 1, 2013. Accessed at: http://www.cleanenergyauthority.com/solar-energy-news/louisaana-psc-upholds-net-metering-070113.; and the discussion around Wisconsin utilities increasing their fixed charge: http://www.midwestenergynews.com/2014/11/11/wisconsin-fixed-charge-decision-a-sign-of-more-to-come/.

30 For more information about SMUD's system infrastructure fixed charge, see https://www.smud.org/en/about-smud/company-information/document-library/documents/GM-Rate-Report-Addendum-2-06-16-11.pdf.

31 See APPA, Rate Design for Distributed Generation, for more details.

32 LADWP's residential tariff and explanation of the PAC can be accessed at https://www.ladwp.com/ladwp/faces/ladwp/residential/r-customerservices/r-cs-understandingyourrates/r-cs-ur-electricrates?_adf.ctrl-state=wy8isb9vg_4&_afrLoop=428364220010586.

33 See, for example, research conducted by the National Consumer Law Center at http://www.nclc.org/energy-utilities-communications/utility-rate-design.html/. Higher income customers can have lower electricity usage due to factors such as investment in energy-efficient housing and appliances or greater reliance on natural gas for space heating, as compared to low-income customers who may rent less energy efficient housing. This pattern is an exception to general positive correlations between energy usage and income.

would lead to a 40 percent bill increase for a low-use customer (250 kWh/month).[34]

Lazar and Gonzalez elaborate on the problems with higher fixed charges from a rate design perspective:

> High fixed charges as part of a straight fixed variable (SVF) design can stabilize utility revenues in the near term and are easy to administer. This approach, however, deviates from long-established rate design principles holding that only customer-specific costs — those that actually change with the number of customer served — properly belong in fixed monthly fees. It also deviates from accepted economic theory of pricing on the basis of long-run marginal costs.[35]

Some analysts argue that higher customer charges may provide a disincentive for energy efficiency, especially since they are usually paired with lower variable energy charges. Furthermore, they could make adding rooftop solar an uneconomic proposition for many customers.[36]

Tiered customer charges — those based on the highest monthly usage in a given year — may be a good option for utilities considering demand charges but for whom adopting demand charges is not a viable option due to practical considerations, such as the lack of appropriate metering technology. However, these will only partially recover lost revenue from DER customers whose maximum usage may fall to very low levels.

34 Breisemeister, Residential Consumers, p. 16, citing Synapse Energy Economics, Caught in a Fix, The Problem with Utility Fixed Charges, http://consumersunion.org/wp-content/uploads/2016/02/Caught-in-aFix-FINAL-REPORT-20160208-2.pdf.

35 Lazar and Gonzalez, Smart Rate Design, p. 48. SVF rate design assigns higher fixed customer charges meant to fully recover fixed costs, while lowering the energy or variable rate component.

36 Galen Barbose, et al. On the Path to SunShot: Utility Regulatory and Business Model Reforms for Addressing the Financial Impacts of Distributed Solar on Utilities. (Golden, CO: National Renewable Energy laboratory, 2016), p. 36. Available at http://www.nrel.gov/docs/fy16osti/65670.pdf.

Minimum Bills

Minimum bills are an alternative to higher customer charges. This guarantees that a customer's bill never falls below a certain threshold. So if a DER customer has a negative net usage — meaning their excess generation was greater than the amount of electricity consumed from the utility — they would still have to pay some monthly minimum amount that would cover customer-related costs and at least some share of utility fixed costs incurred to serve the customer.

New Braunfels Utilities in Texas has a minimum bill mechanism. The monthly minimum has been established as the "Customer Charge plus any special charges or adjustments."[37]

Pros

Minimum bills may impact bill savings for all customers, including DER customers, less than customer charges. Generally speaking, volumetric rates are unaffected by minimum bills, thus the value for offset consumption and electric generation remains the same. Further, the minimum bill mechanism may rarely or never be triggered, especially if a DER customer does not oversize his system.[38]

Minimum bills thus will not impact most customers, and would theoretically not deter energy efficiency efforts as much as higher fixed charges. As Lazar and Gonzalez explain, "the key is to set the minimum bill at a level that guarantees the utility a certain level of revenue it can count on, while not penalizing the vast majority of customers."[39]

Cons

While minimum bills guarantee at least a minimum threshold of revenue recovery, they might not fully capture the cost of serving DER customers, thus leaving at least some intra-class subsidy in place. Minimum bills also provide a perverse incentive for "free electricity" usage for very low-use customers.

37 New Braunsfels Electric Rates, accessed at http://www.nbutexas.com/Portals/11/pdf/Residential%20Electric%20Rates_new%20format_2015.pdf/

38 Barbose et al, On the Path the SunShot, p. 36.

39 Lazar and Gonzalez, Smart Rate Design, p. 48.

Buy-All, Sell-All

The buy-all, sell-all approach refers broadly to metering and rate design alternatives where the customer's DER output and energy consumption are metered and paid for separately by the utility. Under simple net metering, excess generation is "sold" to the utility at the retail rate charged for electricity purchased from the utility. (Technically, the meter rolls back, and thus excess electricity is netted against purchases.) Under a buy/sell mechanism, DER customers pay the retail rate for all electricity they consume, but are separately metered and compensated at a distinct rate for their PV generation. The rate could be higher or lower than the retail rate.

As Ryan Hledik outlines, buy-all, sell-all may be beneficial because utilities avoid having to change retail rates for all customers, and instead can focus on the price paid to DER customers for their output. They also could provide the utility some control over the procurement of customer-sited distribution services and the reliability of these DER resources. "In developing the tariff that specifies payment for various distribution services, the utility can establish eligibility requirements and other performance guidelines that will ensure a certain threshold of dependability in the services from DER customers."[40]

One potential drawback to the buy/sell arrangement is there can be significant debate over what the precise payback rate should be, particularly with Value of Solar tariffs, explored in greater detail below. Utilities would want to base their compensation on the avoided cost of purchasing energy from other sources, while DER providers and other stakeholders seek to include external costs and benefits, such as avoided distribution investments and environmental benefits.[41]

Buy/sell arrangements can take multiple forms, including value of solar, feed-in tariffs (FITs), and avoided cost payments. While FITs have been common in Europe[42], they have not been employed much in the United States. Gainesville Regional Utilities in Florida was the first utility in the country to offer a FIT, and it has since discontinued offering a FIT to new DER customers.[43]

40 Hledik and Lazar, Distribution System Pricing, p. 42

41 Ibid.

42 See the appendix of APPA, Distributed Generation: An Overview of Recent Policy and Market Developments (November 2013) for an analysis of the German and Spanish experience with FITs.

Value of Solar

While Austin Energy is the only U.S. utility to implement a value of solar (VOS) tariff to date, this approach has received an enormous amount of consideration.[44] Many utilities and policy associations have done value of solar analyses to determine the value of solar generation to their utility, or even more broadly to a state or region. Investor-owned utilities in Minnesota may apply to the Public Utilities Commission (MPUC) to adopt VOS rates in lieu of net metering, and the MPUC has established a VOS formula.[45]

Value of solar tariffs could be designed as buy-all, sell-all arrangements, as is the Austin Energy VOS tariff, but an alternative approach is "net excess transaction." Under this approach, the customer offsets its electricity demand through self-generation, and all excess generation is sold to the utility at the VOS tariff. As explained in a report published by the National Renewable Energy Laboratory, the disadvantage of this approach is that it does not decouple the solar customer's purchase of electric generation from its production and sales of generation. Thus it does not adequately address cross-subsidization.[46]

43 See ibid., pp. 25-26 for more information about GRU's FIT.

44 Austin Energy, Texas. See ibid., p26; APPA, Rate Design for Distributed Generation, pp. 6-7; and Karl R. Rabago, et al. Designing Austin Energy's Solar Tariff Using a Distributive PV Calculation (Austin, TX: Austin Energy, 2013).

45 See Dan Haugen, "Minnesota becomes first state to set 'value of solar' tariff.,"Midwest Energy News, March 12, 2014, accessed at http://www.midwestenergynews.com/2014/03/12/minnesota-becomes-first-state-to-set-value-of-solar-tariff/. No IOU has applied for a VOS tariff. See http://programs.dsireusa.org/system/program/detail/5666.

46 Mike Taylor, et al. Value of Solar: Program Design and Implementation Considerations. (Golden, CO: National Renewable Energy Laboratory, 2015), p, 9. Available at http://www.osti.gov/scitech.

Whatever the tariff mechanism, the VOS approach is an effort to assign a quantifiable benefit to each kWh of solar energy exported to the electric grid. Though utilities and analysts have developed differing methodologies and sometimes arrived at completely opposite valuations, generally speaking, VOS valuation studies generally have the following core components:

- Energy
- Emission reductions or Renewable Energy Credits
- Transmission and distribution loss savings
- Generation capacity
- Transmission and distribution capacity
- Ancillary services
- Other costs and benefits, including environmental, fuel price hedging, operation and maintenance expenses, and others.[47]

The end result of weighing these factors is a kWh value for solar generation, generally calculated as a fixed value for some prospective period of time.

It is possible to create localized VOS rates based on discrete parts of a service territory. For example, the value of solar generation in a more densely populated and congested part of the service territory could be higher than for solar generation in a suburban or less densely congested area. Establishing localized VOS levels makes sense "if these differences are based on issues that materially change the value of the solar energy to either the utility or to society."[48]

Pros

The benefit of a VOS rate design is the credit for solar production would be reflective of the actual value of solar to the system. If careful analysis demonstrates 1 kWh of solar power is worth the prevailing rate of electricity, then fair compensation would be a credit set at the retail rate or above it. Similarly, if a utility's analysis shows that under given circumstances the value of solar is not quite at the retail rate level, then the VOS rate can be set accordingly, thereby mitigating or even eliminating cross-class subsidies for solar.

A VOS rate could also provide some transparency. If a utility explains the rationale for setting its rate at a certain level, it could provide supporting research demonstrating the analysis underlying the rate. Though not all customers would necessarily entirely understand all of the given complexities, it would provide some measure of assurance that the utility has done its due diligence in setting a rate that is fair and equitable.

Another technical advantage is though a VOS tariff requires adding a second meter, only solar customers would require these meters. A VOS rate thus does not necessitate a system-wide meter upgrade.

Cons

A potential drawback to VOS rates is the need for careful and complicated analysis. While retail rates and even avoided energy costs — especially if avoided cost is defined as the wholesale rate for electricity — are relatively simple values to arrive at, establishing a VOS requires extra analysis.

This difficulty is compounded by disagreements between stakeholders over methodologies and parameter values. Even if all stakeholders are in agreement over the general costs and benefits to measure, they may disagree over the values assigned. This is especially true with regards to the environmental benefits assigned to solar generation. In the absence of a concrete cost of carbon and other greenhouse gas emitting generation, the environmental benefit may become a much more abstract value, and one which utility rate analysts and environmental groups could disagree about. Therefore, a VOS rate may be deemed insufficiently favorable to solar generation.

One straightforward option to value many of the VOS components is to benchmark DERs against the costs and dispatchability of equivalent resources procured from the wholesale market through either long term contracts or spot purchases. For example, utility-scale resources may have better capacity factors and provide voltage and frequency support that some DERs do not provide. However, DERs may reduce transmission and distribution losses. DER VOS

47 Ibid., p. 10.

48 Ibid., p. 46.

rates can also be benchmarked against local utility-owned and community solar projects.

Note that the costs of both utility-scale and customer-owned solar have been decreasing rapidly in recent years. Thus VOS valuations may fall significantly in the future. Utilities that propose to adopt a VOS credit for customer DER should be clear whether such VOS credits are locked in ("grandfathered") for some period of time or only through the utility's next rate change. Utilities should also carefully consider whether to adopt a kW cap on the size of customer DER installations, as well as a total cap on the total MWs it will procure from customer-owned DERs at the current VOS rate.

Even if a utility decides not to implement a VOS rate, VOS studies are still valuable. Even though disagreements are likely to occur, a utility should have a sense of what the true value of solar generation generally is for the utility. This will inform the cost of service analysis, and will assist utilities as they consider other rate design options.

Time-of-Use Rates

Time of use (TOU) rates or time-varying pricing (TVP) have become more viable rate options thanks in part to the increasing prevalence of smart meters, or more specifically, advanced metering infrastructure (AMI). Though TOU rates don't require AMI technology[49], they do provide a level of granularity as well as two-way communications that make such rates more attractive.

Utilities in 48 states have implemented time-based rates, though only about five million customers are enrolled in some type of time-variant electric rate as of 2014.[50] For the overwhelming majority of utilities, TOU rates are an optional rate which customers may voluntary enroll into. Mandatory TOU rates are rarer, though some utilities are preparing to make them the default option. SMUD, for example, plans to make TOU the default rate in 2018.

Whether to make TOU the default rate, to make it a voluntary program, or to make it available to a certain category of customers, is one set of considerations for utilities exploring this option. The specific design of the program, including how many peak periods to have, and when to have those peak periods, is another.

The Environmental Defense Fund lays out a menu of options[51]:

- Real-time pricing (RTP) — Prices under RTP vary over short intervals, such as an hour. The price is intended to reflect the real-time wholesale cost of electricity, although sometimes they are set by the day-ahead price of electricity.
- Time-of-use pricing (TOU) — Under TOU there are two or three broad intervals, fixed seasonally. The peak price usually occurs in the late afternoon and early evening, although it depends on the utility's unique cost structure. Off-peak hours are generally in the early morning and the evenings. There may be an intermediate or shoulder period occurring between the off-peak and peak hours.
- Variable peak pricing (VPP) — VPP is similar to TOU in that off-peak and intermediate period prices are the same as TOU, but the peak price varies according to system conditions.
- Critical peak pricing (CPP) — Under CPP, the utility may impose is a very high peak price on certain "critical" days. Usually customers are notified ahead of time of critical days and hours, and often the number of CPP events per year or season is limited. CPP may also be used as an "opt-in" rate program.

There are options within these different TVP offerings. For example, a utility employing CPP must determine the peak to off-peak price (POPP) ratio. Ratios typically have ranged from just above 1:1 to 7:1, though they can go as high as 20:1.[52] Research shows that higher POPP ratios gen-

49 Mina Badtke-Berkow, et al. A Primer on Time-Variant Electricity Pricing. (Environmental Defense Fund, 2015), p.11

50 Sherwood et al, A Review of Alternative Rate Designs, p. 18.

51 Badtke-Berkow et al, A Primer on Time-Variant Electricity Pricing, pp. 2-4.

52 Sherwood et al, A Review of Alternative Rate Designs, p. 25.

erate greater demand reduction. A POPP of 2:1 averages to a 5 percent reduction, whereas a 5:1 ratio averages 10 percent demand reduction.[53] On the other hand, very high POPP ratios also create greater customer dissatisfaction.[54]

Similarly, peak periods of long duration under TOU also lead to declining customer acceptance of such rates.[55] On the other hand, peak periods lasting approximately three-to-four hours may better enable customers to shift usage to off-peak or intermediate load periods.[56]

Utility experiences with TVP options demonstrate that customers are able to reduce demand. SMUD, along with Lakeland Utilities, have had pilot programs. SMUD developed its pilot to compare a set of customers who defaulted into the rate, but who could opt-out, and then a set of customers who could voluntarily opt-in to the program. Per household energy savings were below six percent for the default customers, versus 16 percent for opt-in customers.[57] However, SMUD concluded that overall peak shaving for the system would be much higher under the default option if extended to customers throughout its service territory. A default rate would yield aggregate savings of 5.7 percent, as opposed to aggregate demand reduction of 3.3 percent under an opt-in approach.[58] Opt-out would likely result in many more customers participating under the default option (close to 100 percent) versus the lesser number of participants in a voluntary program.

Lakeland's experience was similar to SMUD's. Customers who voluntarily placed themselves on the TOU rate reduced energy usage much more than those customers who were placed on a mandatory TOU rate. Voluntary customers had statistically significant savings during coincident peak hours, peak periods, and peak days.[59] Lakeland also found that the overall yearly load impacts were not statistically significant. Customers did not shift load, but instead reduced overall consumption at all times.[60]

Pros

Time-of-use or time-varying rates are an attractive option because they may align utility costs and revenues more equitably, regardless of whether a customer has invested in distributed resources. In other words, TOU rates could apply to a general rate design approach, thus mitigating some of the need to apply special rates to DER customers. A customer using the grid's supply of electricity at a more constrained time of day, thus at a period of higher cost, would be paying a higher rate that better aligns with that cost. Furthermore, because it is widely applicable beyond DER, it could reduce the need to continually refine rates and rate structures.[61]

TOU rates also would mean that credits applied under a net metering tariff would better reflect the actual value of energy supplied to the grid. If a customer can provide generation during a time of peak usage, the credit will be set at the peak TOU rate. If the customer provides generation during off-peak periods, the credit will be lower. This more accurate alignment of credits and excess solar generation could reduce the amount of cross-class customer subsidization.

In general, TOU rates offer more accurate price signals and induces more efficient energy usage. Customers can shift their usage to lower-priced time periods, thus flattening the utility's demand curve and helping reduce overall system costs.

Cons

Though not absolutely required, time-varying rates typically require special metering, particularly AMI. Utilities must weigh the costs and benefits of a system-wide AMI imple-

53 Ibid., p. 27.

54 Ibid., p. 29.

55 Ibid., pp. 30-31.

56 Badtke-Berkow et al, A Primer on Time-Variant Electricity Pricing, p. 14.

57 P. Cappers, et al. Time of-Use as a Default Rate for Residential Customers: Issues and Insights. (Lawrence Berkeley National Laboratory, LBNL-1005704, 2016), p. 13.

58 Ibid., p. 14

59 Lakeland Electric Consumer Behavior Study Final Evaluation Report, Award Number: DE-OE0000242, submitted April 2015, p. 39.

60 Ibid.

61 Hledik and Lazar, Distribution System Pricing, p. 37.

mentation. Depending on the characteristics of the service territory (addressed in greater detail below), TOU rates may not be a viable option and/or not worth the cost of the meter upgrade.

Also, similar to demand charges, there is concern that customers may not be able to adapt to time-varying rates. Sophisticated customers will have the ability to shift usage as well as install controls that help them to avoid using electricity during peak periods. Many customers may not be sensitive enough to the peak rates to avoid them, while others may not be able to because of medical or other necessities. These customers may wind up paying much higher electric bills than under a flatter pricing regime.

Janee Breisemeister warns against making TOU rates the default option, despite their theoretical appeal. "But imposing a rate design as mandatory or default ignores the significant number of customers who cannot alter their usage patterns and may incur unaffordable bills for essential service."[62]

Another technical issue for utilities is that TOU rates could compound cost recovery issues if fewer peak price events occur than anticipated or if customers reduce consumption well more than anticipated in response to the peak rates.

TOU and TVP rates won't solve all problems. Unless the rate design is combined with a demand charge or customer charge that includes recovery for fixed costs, TOU and other time variant rates may under-recover a utility's costs to serve DER customers. This occurs for two reasons. First, DER output is generally non-firm, as available energy that depends on solar and wind conditions. Thus the utility still needs to build, maintain and dispatch adequate generation to meet the customer's load when DER output is not available. Second, the utility's distribution network needs to be sized and operated to both deliver generation to meet the customer's energy load when solar output is not available and to export the output of the DER solar array when its output exceeds the customer's load.

62 Breisemeister, Residential Consumers, p. 16.

Public Power Utility Profiles

Having discussed some of the rate design options being considered to address the impact of greater DER penetration, it is time to examine the characteristics unique to each utility. Not all utilities are the same, and thus not all rate options make as much sense for each utility. Various characteristics will make one option more viable than another. These characteristics may also impact how much DER penetration a utility can anticipate, and thus whether or not it is worth pursuing a complete overhaul of rate designs.

The Public Power Portfolio

In its submittal to the second phase of Smart Electric Power Alliance (SEPA) 51st State project,[63] APPA broadly outlined the "typical" public power utility:

- **Utility Type**
  Public power — state and community owned, not-for-profit distribution utilities
- **Service Territory**
  Varying; small cities and towns, large urban centers
- **DER Penetration**
  Fairly low but growing rapidly — like much of the nation
- **Utility Structure**
  Vertically integrated, with different degrees and varieties of generation ownership and power purchase arrangements
- **Wholesale Market**
  Roughly equally divided between RTO/ISO regions and bilateral market regions, with heavy concentrations in regions served by federal utilities
- **Retail Market**
  Cost-based, bundled service as opposed to retail competition; most public power utilities are self-regulated
- **Renewable Policy**
  State RPS requirements generally apply to public power

63 http://sepa51.org/

- **NEM Policy**
  Each utility generally establishes its own NEM policies[64]

As detailed in APPA's submittal, a typical monthly bill for a residential customer of a public power utility is $90 to $100, and thus generally below the threshold at which it is economically viable for a customer to install solar rooftop generation.[65] A cap on the amount of load or the number of customers eligible to install rooftop solar would limit the utility's financial exposure, but does not ultimately align "customer prices and incentives with the economic costs incurred by the utility." Therefore, a multipart rate design is ultimately the best and most fair solution to improve economic efficiency and send good price signals to all customers.[66]

Listed below are some of the more specific characteristics of public power utilities. These characteristics will affect how much DER penetration they will have, as well as what rate options might be available to them.

Current rate structure

In a nutshell, are your utility's rates high, low, or somewhere in-between? These are relative terms, because "high" rates in North Dakota — where the average public power residential rate is 6.7 cents per kWh — may very well be lower than "low" rates in New Jersey (15.5 cents per kWh for public power residential customers). Generally speaking, the higher your rates, the more attractive rooftop solar becomes for your customers. Payback periods are much shorter for DER customers of high-rate utilities, especially if those rates are predicted to remain high.

64 APPA's Roadmap to the SEPA 51st State — Phase II, April 2016, p. 4, accessed at: http://sepa51.org/submissions/Roadmap_Reports/APPA_SEPA%20Roadmap.pdf.

65 Ibid., p. 14.

66 Ibid.

Utility size

The median size of a public power utility is just under 2,000 total customers. By comparison, the median customer size of a rural electric cooperative is approximately 20,000 customers. But several public power utilities well exceed one million customers, and many more have well into the thousands. Utility size per se will not necessarily impact the number of customers who may desire to install rooftop PV systems, but it may impact your utility's ability to develop complicated rate structures and then implement such rates through the utility's billing system. Again, generally speaking, the smaller the utility, the fewer the number of employees, thus less manpower available to dedicate to overseeing or employing complex rate mechanisms.

Local PV prices

Rooftop solar pricing has come down considerably over the past few years, but there is still some disparity between locations. NREL's Open PV Project provides a state-by-state ranking of installation costs per watt.[67] There can be as much as a three-fold difference between states at the high and low ends of the spectrum.

Region/market

The physical location of the utility is an important consideration in several respects. Simply put, some locations are much more ideal for solar than others. A map developed by the Department of Energy shows which locations have the most solar energy potential.[68] As one moves further to the south and west, solar potential increases, while there is much less potential in the northeast.

Regional location may also impact the energy market. In particular, utilities in states with regional transmission organizations (RTOs) may be subject to wholesale market rules that may inhibit or promote solar and other DER development, and may or may not curtail a utility's ability to develop special rates.

67 https://openpv.nrel.gov/rankings

68 http://energy.gov/maps/solar-energy-potential

Regulatory and legislative mandates

Some states have specific mandates and regulations concerning net metering. Utilities in California, for example, cannot discriminate between customers within the same class, thus they may not be able to establish unique rates just for DER customers. Thus any rate design overhaul would have to apply to all residential customers. If a state does have a regulatory or legislative mandate, it may or may not apply to public power utilities. Even if the mandate applies to public power, it may be slightly different than the mandate for an IOU. For instance, the overall program cap may be lower, or the system size thresholds may be lower for public power and cooperative utilities than for IOUs.

Local per capita income

Like local installed costs of solar, this is highly dependent on local economic considerations. Solar rooftop owners tend to be higher income than other customers, thus areas with more high-income individuals and families might tend to be more likely to have higher DER penetration rates.

Utility governance

Public power utilities have two primary governing types. Most public power utilities are governed by a city council, but larger public power utilities are generally overseen by an independent utility board. The utility board itself may be comprised different ways — mayoral appointees, local elections, a combination of city council and mayoral appointments. A utility's governing structure may impact its ability to revise rates, as there may be political pressure to avoid dramatic change, while conversely a utility may be permitted a relatively free hand. A utility board might also consist of people more intimately familiar with the nuances of the electric industry.

Typical customer usage profiles

This is in some way related to location, as utilities located in temperate climates might have much lower average household consumption. A utility located in a temperate climate might thus have less incentive to develop TOU rates than one located in an area where temperatures move from one extreme to another, and thus induce peakier patterns of energy usage.

AMI/No AMI

If a utility has not implemented AMI, it has fewer rate options than one which has already installed advanced meters. If a utility has not installed AMI, as discussed in the previous section, it must weigh the costs and benefits of implementing AMI, which of course can bring a variety of other operational benefits (e.g., automated meter reading; better outage management and fewer truck rolls for fault detection; automated remote customer disconnect and reconnection). Once again, utilities located in temperate climates might have less need or incentive for AMI than utilities where there is high demand for electricity at discreet times of the day or year.

Conclusion

Different utility circumstances make certain options more viable than others. AMI-enabled utilities may better be able to offer time-differentiated rates. For utilities in temperate climates, a modified customer charge may suffice. Utilities will also have to consider the political and customer feedback ramifications of certain rate design options.

Utility Actions

What steps should your utility should take to ensure rate equity in a world of DERs?

Estimate likely DER penetration

As discussed above, there are a few indicators that suggest the likelihood of greater DER penetration in your service territory, including: rates, local PV installation costs, local per capita income, plus other considerations such as tax incentives and state and community policy goals. Many of these factors will help determine if a significant number of your customers will decide to buy or lease solar panels in the short-term.

Your analysis of future DER penetration should not be confined to the short-term. Though it is difficult if not impossible to perfectly predict trends out over decades, it is still prudent to assess local, state, regional, and even national trends. Even if you are a low-cost utility in an area of the country with limited solar potential, state regulatory reforms could promote alternative forms of generation and even entirely new business models, such as the New York Reforming the Energy Vision.[69] At the time of this writing, the fate of the Clean Power Plan (CPP) is still unknown, but many states are still moving ahead with plans to promote clean technology, and solar PV is an important part of many of those plans.

Long-term planning will help your utility avoid having to change its rate design frequently. Even utilities who have a good deal of autonomy in setting their rates understand that rate cases are not exactly pleasant experiences. Furthermore, it is better to be ahead of the curve than to wait until the rate of DER penetration causes significant revenue erosion.

Estimate average rate impacts under varying penetration scenarios

You can use existing or self-designed models to examine the revenue impacts of different levels of DER penetration in your service territory, using current rate tariffs as a starting point. One such model has been developed by APPA[70], and can help you gauge these impacts. This analysis will help you determine potential revenue shortfalls, and will also help you quantify the amount of subsidization from non-DER customers. The APPA model will also help you measure the impacts of different rate designs and how they may help you mitigate cross-subsidization.

Most utilities already do cost of service studies to set rates for the future. The rate design concepts and options outlined above are no different, though they do require some effort to design and run more scenarios than "business as usual" would require. Implicit in these scenarios is that you have already done some work to measure the value of solar for your utility. Even if you do not intend to establish a VOS tariff, it is important to have some general idea of the value of customer-sited generation. That way, you help ensure any rate design you develop does not over-compensate or under-compensate DER customers.

Conduct benefit/cost analysis on possible rate design changes

Economic modeling can help you determine the relative merits of certain rate designs in terms of equitable rate recovery. Some rate designs will cause the utility to incur extra costs, and these costs must also be weighed. As has already been mentioned, TOU rates may require installing advanced metering technologies, especially AMI. If your utility does not have AMI installed in its service territory, the costs of a territory-wide installation, or even a dedicated installation for DER customers only, needs to be incorporated into your analysis of this specific rate design. Special metering may also be required for demand charges, and the same benefit/cost analysis applies here.

Similarly, new billing software may be required, regardless of whether new metering technology has been installed. New rate designs may also lead to increased staffing and training requirements, for billing analysis and customer

69 https://www.ny.gov/programs/reforming-energy-vision-rev

70 Available at APPA website at http://publicpower.org/Topics/Landing.cfm?ItemNumber=45624#Rate, see Rate Design subtopic.

service purposes. These considerations also need to be taken into account as you're considering new rate designs.

Gauge customer acceptance

Ultimately, your customers need to understand why you have decided to implement new rates and rate designs. You will need to remain engaged with your customers and the community through all stages of the process, from the early period when you're considering implementing new rates, to the post-implementation period. Even if you do not achieve complete buy-in, you should be able to fully explain why you have chosen to redesign your tariffs, as well as the ways customers can adapt to the rates to save money.

Customer education is particularly important if you implement demand charges or TOU rates. In the former case, most customers will not be familiar with the concept, thus you will have to explain what they are as well as how customers can shift usage to avoid incurring high demand costs. The same is true of TOU rates, perhaps even more so. With TOU rates, customers need to be educated not just about what they are, but how they can shift usage, and what technologies may exist to help them use electricity more efficiently.

It is inevitable that under any new rate design some customers will have higher bills than previously, whether they are DER customers or not. Customer service representatives will need to be informed about these new rates and be prepared to handle customer inquiries.

Each of these considerations show the need for public power utilities to develop both the technical basis and the public communications plan to support a new rate design. Governing board approval and customer support for a new rate design that achieves community policy goals, meets the utility's needs for good price signals and revenue stability, and balances the needs of its diverse customer base is never going to be easy. Rate analysts need to work with their engineering and public affairs colleagues to bring utility management and governing boards a forward-looking rate design reform plan that mitigates transition issues and puts the utility on a forward-looking path to integrating new technologies and meeting changing customer expectations.

Appendix:
Modeling Different Rate Design Options

Solar kWh =	***0***
Fixed Charge $$$ =	***$600***
Variable Charge $/kWh =	***$0.040***

	kWh	Fixed Cost $$$	Variable Cost $$$	***Total Cost $$$***	Fixed Charge $$$	Variable Charge $/kWh	***Average Charge $/kWh***	***Customer Bills/ Utility Revenues Bill $$$***
Customer A	5,000	$300	$200	***$500***	$300	0.040	***0.100***	***$500***
Customer B	5,000	$300	$200	***$500***	$300	0.040	***0.100***	***$500***
Total Utility	10,000	$600	$400	***$1,000***	$600	0.040	***0.100***	***$1,000***

Solar kWh =	***2,000***
Fixed Charge $$$ =	***$600***
Variable Charge $/kWh =	***$0.04***

	kWh	Fixed Cost $$$	Variable Cost $$$	***Total Cost $$$***	Fixed Charge $$$	Variable Charge $/kWh	***Average Charge $/kWh***	***Customer Bills/ Utility Revenues Bill $$$***
Customer A (Solar)	3,000	$300	$120	***$420***	$300	0.040	***0.140***	***$420***
Customer B (Non-solar)	5,000	$300	$200	***$500***	$300	0.040	***0.100***	***$500***
Total Utility	8,000	$600	$320	***$920***	$600	$0.040	***0.115***	***$920***

Solar kWh =	***2,000***
Fixed Charge $$$ =	***$0.00***
Variable Charge $/kWh =	***$0.100***

	kWh	Fixed Cost $$$	Variable Cost $$$	***Total Cost $$$***	Fixed Charge $$$	Variable Charge $/kWh	***Average Charge $/kWh***	***Customer Bills/ Utility Revenues Bill $$$***
Customer A (Solar)	3,000	$300	$120	***$420***	$0.00	0.100	***0.100***	***$300***
Customer B (Non-solar)	5,000	$300	$200	***$500***	$0.00	0.100	***0.100***	***$500***
Total Utility	8,000	$600	$320	***$920***	$0.00	$0.100	***0.100***	***$800***

Appendix:
Modeling Different Rate Design Options

Solar kWh =	***2,000***
Fixed Charge $$$ =	***$0.00***
Variable Charge $/kWh =	***$0.115***

	kWh	Fixed Cost $$$	Variable Cost $$$	***Total Cost $$$***	Fixed Charge $$$	Variable Charge $/kWh	***Average Charge $/kWh***	***Customer Bills/ Utility Revenues Bill $$$***
Customer A (Solar)	3,000	300.00	120.00	***$420***	$0.00	$0.115	***0.115***	***$345***
Customer B (Non-solar)	5,000	300.00	200.00	***$500***	$0.00	$0.115	***0.115***	***$575***
Total Utility	8,000	$600.00	$320.00	***$920***	$0.00	$0.115	***0.115***	***$920***

Solar kWh =	***2,000***
Fixed Charge $$$ =	***$400***
Variable Charge $/kWh =	***$0.065***

	kWh	Fixed Cost $$$	Variable Cost $$$	***Total Cost $$$***	Fixed Charge $$$	Variable Charge $/kWh	***Average Charge $/kWh***	***Customer Bills/ Utility Revenues Bill $$$***
Customer A (Solar)	3,000	300.00	120.00	***$420***	$200.00	0.065	***0.132***	***$395***
Customer B (Non-solar)	5,000	300.00	200.00	***$500***	$200.00	0.065	***0.105***	***$525***
Total Utility	8,000	$600.00	$320.00	***$920***	$400.00	$0.065	***0.115***	***$920***

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