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Designing Tariffs for Distributed Generation Customers

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Disclaimer

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While MADRI work groups have produced in prior years several consensus documents, this paper was developed independently by RAP. RAP sought review of a draft of the paper from MADRI Staff Steering Committee members, for which we are grateful, and RAP is solely responsible for the contents of the final paper. Any views stated herein should not be attributed to MADRI commissioners, regulatory staff, US DOE, or any other stakeholders.

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Acronyms

CPP	Critical peak pricing	MGE	Madison Gas and Electric
DER	Distributed energy resource	PBR	Performance-based regulation
DG	Distributed generation	PGE	Portland General Electric
EDU	Electric distribution utility	PG&E	Pacific Gas and Electric
FIT	Feed-in tariff	PUC	Public utility commission
HVAC	Heating, ventilating and air conditioning	PURPA	Public Utilities Regulatory Policy Act of 1978
kVA	Kilovolt-amps	PV	Photovoltaic
kW	Kilowatt	QF	Qualifying facility
MW	Megawatt	SFV	Straight fixed/variable
kWh	Kilowatt-hour	TOU	Time-of-use
MWH	Megawatt-hour	US DOE	US Department of Energy
MADRI	Mid-Atlantic Demand Response Initiative	VIR	Volumetric incentive rate
		VOS	Value of solar

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Executive Summary

Ever since the introduction of retail competition in the late 1990s, the traditional regulatory paradigm that guided the last century has been evolving to adapt to the emergence of new energy technologies and the consumers' appetite to have more control over their energy usage. As happens with many new technologies, consumer adoption of rooftop photovoltaic (PV) arrays has brought down the unit cost, making it more affordable to more consumers than just five years ago. With the growth in PV, new regulatory issues have arisen that are being discussed in commission proceedings and energy conferences across the nation. There are differing viewpoints on the growth in rooftop PV, and reconciling these viewpoints is referred to in this paper as the Regulatory Challenge. Many in the utility industry are concerned that the growing number of PV units installed will reduce their sales and the revenues needed to operate the grid reliably. By contrast, customers with distributed generation (DG) worry that new rate designs that have been proposed by some utilities will erode the economic feasibility of their investment. Consumer advocates raise concerns that the DG have-nots (notably those who cannot afford PV) will be burdened with the responsibility of making up the revenue deficit through higher rates. Finally, businesses serving an increasing demand for DG hesitate to put significant resources in a region where the customers' financial calculations are uncertain. Reconciling these different viewpoints is a challenge, but prescient rate design can provide options that are equitable to all parties. Essentially, what occurs is that DG customers reflect the load and cost characteristics of partial (rather than traditional full) requirements customers. Rate design(s) that appropriately reflects the partial requirements characteristics of DG customers would tend to have the most equitable outcome for all customers. This is the backdrop and impetus for DG customers.

This paper explores rate design options for DG, and notes circumstances and examples that may help guide regulators, advocates, and other interested parties to determine which rate design is most appropriate for each jurisdiction. This paper was drafted with the particular perspective of the MADRI states in mind, but it will serve as a useful analysis to many other jurisdictions as well.

As a starting point, this paper proposes rate design principles that can be considered when designing rates for DG customers:

- A customer should be able to connect to the grid for no more than the cost of connecting to the grid;
- Customers should pay for grid services and power supply in proportion to how much (and when) they use these services and how much power they consume;
- Customers who supply power to the grid should be fairly compensated for the full value of the power they supply, no more and no less; and
- Tariffs should fairly balance the interests of all stakeholders: the utility, the non-DG customer, and the DG customer.

Next, this paper describes a variety of rate designs that are being applied in various jurisdictions along with case examples and analysis of how these rate designs comport with the regulatory principles enunciated above. Rate designs that are reviewed include: net metering; high customer charges; minimum bills; time-of-use rates (TOU); monthly demand charges; demand charges for large houses; subscription demand charges; bi-directional rates; fees imposed on DG customers; feed-in tariffs; and, value of solar tariffs.

The paper concludes with a finding that the most appropriate rate design for customers with DG may be one that combines time-varying power supply charges with bi-directional distribution charges. This kind of rate design can be structured so that the DG customer pays the cost of the connection and the full retail rate (customer charge plus volumetric component) for all power it purchases from the utility. The rate at which the customer is compensated for any power delivered from the PV to the grid is then based on a Commission-determined fair and reasonable rate that reflects the value of the power to the utility. One option that works well with bi-directional rates is to use a TOU rate, which may more accurately reflect the true cost to the utility at the time the electricity is generated. This is a fair proxy for determining the value of solar.

The importance in rate design with respect to DG and rates in general is to ensure that they adhere to the principles of cost-causation and equitable cost recovery for all customers as best as possible, while balancing the competing legitimate needs of the stakeholders who are affected by the rate design outcome.

1. Introduction and Statement of the Issue

Greater penetration of DG provides many opportunities for utilities and their customers. However, with this greater penetration, it will be important to anticipate and adequately manage the effects of growing DG with prescient regulatory policies. This paper explores these potential problems from a customer rate perspective and from a competitive energy market perspective, with attention focused on the economic true costs of the services provided and received. The electric industry has witnessed significant changes over the past two decades, chief among them the restructuring of utilities in many states providing customers a choice among suppliers for their energy. Many of the early battles were over market structures that made it difficult for third party providers to compete. Over the years, regulatory barriers have dissipated somewhat although many still remain.[1] The expansion of customer choice through DG may be no different in that there is often an initial resistance to change that is followed by finding compromises, solutions and workarounds.

The growth of DG also presents some manageable challenges in terms of system adequacy and engineering. EDUs will still have the obligation to satisfy energy requirements in the event that the customer's DG system is unavailable or does not meet all of the customer's electricity needs. However, as EDUs calculate how much capacity they need to meet these DG customer obligations in addition to their traditional retail obligations, they can consider a number of important factors, such as: the number and size of DG systems; the outage probabilities and characteristics of the DG systems; and the location of the DG in their service territory and surrounding territories, if a larger market area is relevant. Importantly, EDUs must consider how likely it is (or is not) for all DG systems on their system or on a given circuit to need backup energy at the same time. Moreover, even with a high number of small PV systems, the amount of standby capacity needed to be available for them could be minimal. Policies that allow customers with industrial cogeneration or Combined Heat and Power units to buy-through to the market rather than rely on the EDU for standby services can cut costs and utility requirements to have standby power available.

Because currently the EDU typically has little or no control over the output of most DG systems, and because many of those systems rely on variable energy resources like wind and sun, the need for frequency response, ramping, and other ancillary services may increase as DG deployment increases. This is not true in all cases, however, and advancements in technologies (e.g., smart inverters) are already allowing some DG resources to be used by EDUs as *providers* of ancillary services.[2] These advancements are creating new win-win opportunities for EDUs to control or reduce the costs of

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[1] Examples that were obstacles included how to unbundle the utilities and address stranded cost; how to establish fair market rules in order to create a vibrant market, creating structures to enable service providers to offer new services and interact with the customer directly; and increasing energy efficiency and demand response services to be considered resource options.

[2] A smart solar inverter, for example, improves the reliability of the electric grid by allowing distributed solar sources to stay connected to the grid in case of minor disturbances in voltage and frequency. Traditional solar inverters, by comparison, are not capable of handling voltage and frequency fluctuations, and are required by the Institute of Electrical and Electronics Engineers (IEEE) 1547 standard to trip and disconnect from the grid in such situations. See: Solar Electric Power Association. (2014, January 7). *How the inverter got "smart" and what that means for the growth of solar.* Retrieved from http://www.solarelectricpower.org/utility-solar-blog/2014/january/how-the-inverter-got-%E2%80%9Csmart%E2%80%9D-and-what-that-means-for-the-growth-of-solar.aspx

providing ancillary services for all customers, while potentially providing new energy market revenue opportunities for owners of DG systems.[3]

Looking at the economics and customer rates, traditional utility rate design in many cases will consider the embedded cost of service as one of the components in determining each customer class's allocation of utility revenue requirements. The revenue requirements are broadly based on three cost drivers: electricity usage, demand, and number of customers. Electricity usage costs are volumetric, and include elements such as fuel and operation and maintenance costs that are variable and increasingly differentiated by season and time of day. Demand costs represent the cost of building the system to its required size and capacity, and generally are based on a combination of system peak to provide the supply of energy and peaks for the facilities necessary for the delivery of power to customers. The number of customers drives metering, service, and billing costs. A few utilities do not apply customer charges, and most do not apply demand charges to residential customers. While the utility's cost to serve a DG customer will vary by the DG technologies in place, the operating characteristics of the DG systems, and the fuel choices customers make, the rates employed by utilities are typically not sophisticated enough to reflect these distinctions and many others.

Policymakers should consider the role DG can play as a resource to the utility system. Rather than viewing DG as an inevitable customer option that is tolerated, it can be viewed as a grid enhancement. From a supply standpoint, the aggregated DG within a utility system can reduce installed capacity needs, the reserve level required, the losses associated with the energy as well as peak demand required by customers, and all of the ancillary services which will not be required due to the avoidance of the energy generation.[4] A vertically integrated utility would reflect these benefits for all the ratepayers. In competitive markets, the availability of DG can help manage supply and demand, which could mitigate any rise in market prices. DG can especially be an enhancement when it is sited strategically in locations and in ways that bolster the grid.[5] Many forms of DG also have low or zero emissions, making them a useful component for meeting environmental goals. Some have local labor intensity, making them attractive for job growth. Regulators may want to consider these added values when designing partial requirements service tariffs for DG.

Rate design and the manner in which particular utility costs are caused and recovered from customers will be important in determining the extent to which DG affects a utility's revenues.[6] While rate design is the chief factor, other factors also include how regulation allows utilities to recover costs and the effect of policies promoting distributed energy resources (DER). The economic impact of partial requirements

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[3] In order to provide ancillary services, DG systems would need to have smart inverters controlled by the EDU or a third party provider of ancillary services. A smart inverter may increase the cost of installing the DG system, and use of the system for ancillary services may decrease its total kWh output. Customers would only welcome the use of their system for ancillary services if provision of those services generated at least as much economic value as was lost from the investment in a smart inverter and the decrease in kWh output.

[4] The impact of DG on utility system costs will vary with technology, location, and level of deployment. See, for example: Mills, A., & Wiser, R. (2012, June). *Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California*. Lawrence Berkeley National Laboratory. Available at:

[5] An example might be locating PV panels so that they face west and can provide value to the utility during peak times of the day, as well as identifying specific locations in the local delivery system that would avoid or defer investment or otherwise reduce costs.

[6] Performance-based regulation could provide incentives to utilities to remove barriers and considerations of lost revenues by compensating the utility for supporting the development of DG. These incentives, along with decoupling, could be tools to address the lost revenue issue associated with DG. While Performance Based Regulation has yet to be adopted in the US, Great Britain has adopted performance metrics known as "RIIO" (Revenues = Incentives + Innovations + Outputs).

customers on EDUs will be greatest in cases where the customer's rates are based mostly or entirely on volumetric energy charges, as is normally true for residential customers. In these cases, the rate is designed so that the EDU will recover most or all of its variable and embedded capital costs through volumetric energy charges. When the customer supplies some or most of its own energy, the EDU collects less revenue than it otherwise would but it also benefits from some reduction in costs. This revenue loss can put an economic burden on the utility and its shareholders in the short term. Longer term this loss could lead to a redesign or increase in retail rates, potentially to the disadvantage of customers without DG, as well as to a consideration of ways to reduce cost and redesign the utility business model for earning revenue and net income.

There is also a concern that such rate increases signal that non-DG customers are subsidizing DG customers. This may or may not be the case universally. If the DG has the net effect of avoiding more expensive utility investments, then all customers share these benefits. The question is, what is the value of the DG to the grid as compared to the compensation for the DG provided? Good rate design attempts to match charges and compensation based on cost and value respectively. Volumetric rates can increase when sales volume goes down even in cases where DG systems provide more value to the utility than the retail rate. The DG system might provide a net benefit to the utility system and might be under-compensated, but the nature of volumetric rates is such that the reduction in kWhs forces the utility to raise rates in order to collect the reduced revenue requirement. That hurts non-participants, but it doesn't mean they are subsidizing the DG owners. For example, the DG owners in this kind of hypothetical example might be providing $.11 worth of service and getting paid $.10. In this case, there is no subsidy. On the other hand, if the DG customer is providing $.10 of value and receiving $.11, there is a $.01 subsidy. One can only prove a cross-subsidy by showing that the cost of serving DG customers is greater than the revenue collected from them, and the mere fact that volumetric rates have increased is not sufficient to prove that.

From an energy markets perspective, the development of competition and customer choice is another important benefit of DG for regulators to consider. The jurisdictions participating in the Mid-Atlantic Distributed Resources Initiative (hereinafter called the "MADRI states," with an acknowledgment that one such jurisdiction—the District of Columbia—is not a state) offer customers the option of purchasing energy from competitive retail suppliers. Embedded in this choice is the option for customers to supply their own electricity. The increasing amount of DG capacity can be advantageous from a societal standpoint in that it allows customers more freedom of choice in their energy decisions, increases fuel diversification and, depending on the type of DG technology, could be better for the environment than large, centralized, fossil-fueled generation.[7] While this paper is prepared for the seven MADRI states, this paper can nevertheless provide useful insights to readers from other jurisdictions who will need to reflect upon their own state circumstances with regard to the issues addressed here.[8]

The benefits of DG to one customer need not come at the expense of other customers or unfairly disadvantage energy market participants. This basic principle should guide all rate design. The goal of the distribution service tariffs, therefore, must be to eliminate all barriers while simultaneously maintaining fairness for buyers and sellers of electricity.

[7] Large, centralized renewable generators can also provide fuel diversification and environmental benefits, often at a lower cost than DG.

[8] The MADRI jurisdictions are: Delaware, the District of Columbia, Illinois, Maryland, New Jersey, Ohio, and Pennsylvania.

This paper will set forth principles that should guide all rate designs generally. It will then examine the range of rate designs being discussed that could address DG issues in terms of how they work, provide an example of each, and conclude with an analysis. While this paper addresses DG generally, for most residential customers DG will be solar PV. It should be recognized, however, that technological advances are increasing the potential for PV systems to be operated in conjunction with natural gas fuel cells as well as storage capabilities.

This paper addresses rate design issues and options with full consideration of both distribution services *and* power supply. All of the MADRI states allow retail competition in power supply, and recognize that state regulators have limited authority to regulate the service plans offered by competitive power suppliers. However, a comprehensive approach to rate design is merited for at least three reasons. First, regulators in the MADRI states have some authority (and, in most cases, broad authority) over the design of rates for default service customers (those who do not choose to purchase power from a competitive retail supplier, but instead receive both power supply and distribution service from the EDU). This includes rates for default service customers that have DG systems. Second, a default service option is currently available to residential customers throughout the MADRI states. Third, the vast majority of customers who have installed DG systems to date have done so while operating under a net metering tariff (discussed later). The MADRI states are divided as to whether the distribution utility is required to offer net metering tariffs: Delaware, Illinois and New Jersey require it, while the other states do not. (Ohio requires it, but the utility only pays the generation rate for any excess power that is produced and not credited against consumption). In states where competitive suppliers need not offer net metering tariffs, they generally do not—and customers with DG will usually end up taking full service (distribution and power supply) from their EDU. These facts justify a discussion of DG tariffs that encompasses both power supply and distribution service, with an understanding that the relevance of power supply rate design issues is greater in some jurisdictions than in others.

2. The Regulatory Challenge: Balancing the Interests of DG Customers, Non-DG Customers, and the Utility

Solving the regulatory challenge involves finding working solutions through the implementation of tariff designs to address the concerns of three major stakeholder groups: the DG customers (participants); the non-DG customers (non-participants yet system beneficiaries); and the electric distribution utilities (EDUs). This echoes similar issues which arose as a result of energy efficiency programs reducing utility revenues, but on a potentially larger scale with DG. Policy goals of tariff design to address DG issues include:[9]

- Assuring the financial integrity of the utility so it has access to sufficient revenue and capital to operate its grid, including the reasonable opportunity to provide a reasonable return to shareholders;
- Fairly compensating DG customers for the net value of their contribution to the grid (considering both the system costs and system benefits associated with that contribution), and erecting no undue barriers to DG customers; and
- Ensuring that rates and bills remain fair and affordable for non-DG customers and provide proper price signals to minimize long-term costs.

Beyond these policy goals, the tariff design must follow the principles of rate design in order to create a fair and balanced approach that recognizes and assigns costs (and benefits) based on those causing them. These topics are discussed in Section I, which follows this discussion of the needs of each of the three stakeholders.

A note on dilemmas is warranted. In rate design, some principles may come into conflict. In these situations it is the task of the regulator to signal priorities, sometimes guided by statutes and sometimes not. Readers should remain alert for dilemmas, recognizing that their resolution reveals the priorities of decision-makers, whether those priorities are explicitly stated or not.

Below is a discussion of the perspectives and concerns of each of the three stakeholder groups which, when viewed together, do not reveal apparent solutions. What is important, however, is that the solutions not address the needs of one or two groups to the exclusion of the other. Any solution that does not address the concerns of any one of the stakeholders is not likely to work in the long run.

a. DG Customers ("Participants")

DG customers are a diverse lot consisting of households or commercial establishments with PV, farms with a variety of possible self-generation options, or industrial customers with combined heat and power, among other alternatives. A first concern for the DG stakeholder group is that policies not erect economic disincentives for customers interested in installing a DG system. For DG customers there has to be an economic rationale for the investment with a reasonable payback for that customer.[10]

[9] It should be noted that this partial list is consistent with principles in formative rate design treatments like those enunciated by Bonbright in *Principles of Public Utility Rates*, 1961. This paper is an effort to apply those principles to new facts arising from the emergence of DG.

[10] An economic rationale does not exclude the prospect that customers can have an array of non-monetary reasons for deploying DG. A customer can be a technophile, or have environmental imperatives that permit a long payback period. Value may also reside outside strict electricity payback, such as communicating to customers and employees a commitment to DG.

Connecting to the system should be based on the cost to do so. The number of businesses available to help customers with DG products is expanding and will only continue to grow as policies enable the growth of DG.[11]

Regulatory certainty is another consideration. Customers engaged in DG (whether in the stage of considering the investment or having already made the investment) value being able to rely on the regulatory construct in place at the time they enter into the decision to build DG. Because the customer constructing the DG unit bears the risk for changes in regulation, any anticipation of changes in costs or regulation imposed on DG customers can present significant barriers to the development and success of DG. Unlike utilities that can pass costs associated with changed regulations back to consumers, these customers are left to bear the cost of changes to the deal. While all customers bear the risk of rate increases and shifts in rate design to accomplish policy objectives, stability is an important rate design principle and attention should be paid to the effect of potential changes on customers. The size of DG investments underscores the seriousness of this issue for DG customers. Their response to regulatory changes being made or contemplated may hinge on their confidence in recouping their investment, even if it takes a longer period of time to do so. Businesses supporting a growing DG demand are likely to perform best under a stable regulatory system that fairly values their products.

In areas where DG deployment is low and the revenue impacts of a sub-optimal rate design are minimal, regulators can consider protecting existing DG customers from changes to their deal for a period of time likely to exceed payback expectations while considering any prospective changes for more numerous future DG customers. The concern for DG customers is being able to rely on the regulatory construct to recover their investment costs.

Tariff rate designs for distribution service and supply service will be critical to DG project economics and deployment decisions. For customers with residential scale PV, high fixed charges and fees for using the grid are a prominent concern. As will be explored below, time varying rates are a better alternative because they can more accurately reflect the customer’s coincident peak demand, standby requirements, and value of the energy delivered through the distribution system.

Changes to net metering policies can also affect the financial viability of a project. And for customers who lease their DG system, or who buy power from a DG system owner but are still utility customers, unanticipated costs could negatively affect the life cycle economics of the DG project and severely hamper the market for prospective solar leasing customers.

DG has a number of societal benefits. These benefits, however, may not be explicitly recognized by regulation. For example, if one customer builds generation thereby reducing its load requirements for the system, there will be savings for all customers. This phenomenon may be more easily appreciated by imagining thousands or millions of customers making this individual choice. In other words, some of the cost to serve all customers will be shouldered by the DG customer making an investment in a resource. With the exception of the value of solar tariffs, externalities and societal benefits are typically not

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[11] In addition to rate designs that properly compensate and charge DG customers, other issues such as interconnection practices are also important. They include the fees for interconnection, the requirements to connect to the grid, and the time it takes to complete the interconnection analysis by the utility. Part of the regulator’s job will be to ensure that the interconnection standards are reasonable. This issue was first addressed by MADRI in 2005. See: *MADRI Model Small Generator Interconnection Procedures*. (2005, November 22). Available at: http://sites.energetics.com/MADRI/pdfs/inter_modelsmallgen.pdf.

included in rate designs.[12] An argument can be made that, in weighing costs and benefits, it is appropriate to include all the benefits and not just the costs. Often regulators and stakeholders are either constrained by legal frameworks or choose not to quantify longer-term infrastructure costs related to growth or societal benefits, tagging them as "difficult to quantify." However, in not quantifying or estimating these benefits, they are inaccurately assigned a value of zero.

b. Non-DG Customers

DG tariff policy must also address the needs of customers who do not have DG. As more customers engage in providing part or all of their electric service from DG installed at their home and their business, utility sales will decline concurrently with utility net-revenues, unless decoupling is in place or the utility has periodic rate cases to adjust rates. Utilities argue they need adequate revenue to continue their normal operations, to raise capital at a reasonable cost and to earn a return for shareholders, and that any revenue shortfall needs to be covered. The concern is that making up the difference in net lost revenues from DG will fall on the remaining customers who lack access, cannot afford, or choose not to install DG.

Utilities lose revenues from a variety of customer choices. For example, a customer deciding to install ceiling fans, invest in higher SEER HVAC systems, or other energy reducing choices will reduce the revenues collected by the utility. Additionally, some customer premises are secondary (vacation) homes which may impose high load requirements during peak periods, and the cost for the facilities to serve those high load requirements are not recovered during the non-peak periods when the customer returns to their primary residence. Businesses change their processes, move, or go out of business. Some customers may be struggling to pay their utility bills as it is, and many may be on a fixed income. Low income customers pay twice as high a proportion of their income on utility service as do other customers and utility bills are generally their second highest expense next to a mortgage or rent.[13] The potential effect on low-income customers could be factored into cost-allocation and rate design decisions (beyond calculable and typical allowances for non-payment and arrearages) to the extent that an economic regulatory agency wishes to incorporate social policy in its considerations.

As a first step, utilities should look at ways to reduce system costs through reliance on DG and also take advantage of the benefits to the utility system as a whole from customer-funded DG. Customer investment in DG replaces utility investment in assets over time. Cost savings realized will minimize the effects on remaining customers. Further, care must be taken to avoid creating incentives for utilities to overbuild. Given the juxtaposition of decreasing sales and the need for infrastructure upgrades, sharp attention needs to be focused on the efficiency and efficacy of utility distribution planning and to ensuring that least-cost solutions, including an awareness of risk, are developed. This includes analyzing how strategically located DG can offset costs the utility might otherwise incur to address growth, a weakening infrastructure, congestion, and line losses. Utility executives who are looking for ways to cut

[12] California, however does account for these benefits through various incentive programs to encourage DG development. California Public Utilities Commission. (2013, May). *Biennial Report on Impacts of Distributed Generation*. Prepared in Compliance with AB 578 – With Data through 2011 and Selected 2012 Data. Black & Vetch. Available at: http://www.cpuc.ca.gov/NR/rdonlyres/BE24C491-6B27-400C-A174-85F9B67F8C9B/0/CPUCDGImpactReportFinal2013_05_23.pdf

[13] See Chrisman, K. R. (2014). The Great Solar Divide. *Breaking Energy.* Available at: http://breakingenergy.com/2014/10/22/the-great-social-solar-divide/

costs over the long run will benefit their companies by incorporating reliance on DG and other distributed energy resources into their planning.

Part of the concern is that there is a mismatch between short-term costs and long-term benefits. In the short term, rates may go up to cover lost utility revenues, but in the long run the presence of DG and other DER solutions can eliminate or delay the need for other, more costly utility investments that would drive up rates even more. For customers with limited income and a high energy burden, however, this may be a small consolation.

Some of the equity concerns associated with DG can be partially addressed through policies and programs that create opportunities for greater numbers of customers to benefit. More creative solutions are needed to allow all customers the option to economically participate in DG. Energy efficiency is generally available to all customer groups at all income levels, while this is not typically the case for DG. This is a distinguishing characteristic among the distributed energy resource options. Several states are developing variations of a shared renewable model to enable non-DG customers interested in participating to receive bill credits for the output of a DG installation that is not located on their property.[14] Under this model, the customer gets credited for a specified share of the solar energy produced every month from the PV facility. The credit is applied in some manner to the customer's bill, depending on the utility's design of the rates. A successful model requires the cooperation of local utilities to ensure that their billing mechanisms can accommodate the extra detail of showing a solar credit and the new calculation of a customer's bill as a result of that credit. Maryland, Washington DC, and Illinois have active shared renewable energy programs and Delaware has enacted policies to enable shared or community solar.[15] Additionally, in some states (e.g., Delaware) Community Energy Facilities provide for a renewable energy facility to be a free-standing resource with identified subscribers who receive benefits as if the facility were located on their premise. A non-profit organization, for example, could assist in the funding for a Community Energy F?? which provides opportunities for customers at any income level to participate in the benefits of renewable energy.

c. Distribution Utilities

The third stakeholder perspective to consider is that of the EDU. Utilities collect a large portion of their revenues through volumetric sales of electricity and there is sound reason for this practice.[16] DG installations reduce sales and thus reduce revenues. Most of the EDU's costs for providing distribution services are not reduced or avoided when volumetric sales decrease. Thus, the core concern of EDUs is that revenues decline more than costs decline. (See text box for possible solutions to this "revenue model" problem.)

In regions with competitive wholesale and retail electricity markets (such as the MADRI states), the utility's concerns about net lost revenues are mainly directed at those revenues collected to provide for distribution services. However, in the MADRI states, the EDU is also responsible for providing "default

[14] Shared renewable programs come in many different forms. Some programs rely on small, distributed solar arrays owned by third parties, while others can be backed by very large projects owned by utilities, just to name a couple of the varieties. The terms "community solar" and "solar gardens" are commonly used to describe shared solar programs, despite the diversity in program characteristics.

[15] Vote Solar (2015). Shared Renewables HQ webpage. Available at: http://sharedrenewables.org/

[16] Lazar, J., & Gonzalez, W. (2015). *Smart Rate Design for a Smart Future.* The Regulatory Assistance Project: Montpelier, Vermont. Available at: http://www.raponline.org/document/download/id/7680.

service" to residential customers (i.e., obtaining supply as the provider of last resort to those customers that have not exercised their right to choose an alternative energy supplier). Obtaining such supply service is usually accomplished through a bidding process to acquire energy at least cost. The EDU would be responsible for a rate design that allows for recovery of its default service costs as well as its delivery costs. The EDU, therefore, will see reduced power supply costs (in the form of reduced default service purchase requirements for capacity and energy) that will roughly equal its lost power supply revenues.

The Utility Business Model

Several states are beginning to explore alternative utility business models to provide additional opportunities for utilities to secure the revenues they need to run a healthy company and a reliable grid. Some ideas are regulatory in nature, while others are more business/entrepreneurial.

Regulatory approaches include decoupling, which has long been viewed as a mechanism to address the throughput incentive by severing the link between sales and revenues. (A more detailed discussion of decoupling is contained later in this paper).

Another regulatory mechanism garnering increased interest is Performance-Based Regulation (PBR), which provides a return to the utility based on its performance on commission-established metrics. The benefit of PBR is that it provides regulators with significant flexibility to determine what kind of actions in which to encourage the utility to engage, and what level or range of compensation it should receive based on how well it does. For example, under one model, a commission could establish a low to moderate base for the return on equity, and reward the utility with upward basis point adjustments based on the utility's performance in such areas as reliability, energy efficiency, encouraging DG, customer satisfaction, efficiency of operations, etc. This turns the utility away from a focus on volumetric sales and returns for capital additions to a performance-centric focus that is tailored to achieve public policy goals.

Another approach is to allow utilities to charge fees to third party businesses that are providing energy-related services to end-use customers. The compensation provided to the utility for providing services and/or products (such as in New York's Reforming the Energy Vision platform) would reduce the burden of customers by removing from rates the cost of utility services that permit third party businesses to obtain data and services from the utility. Further, under some models the utility may be permitted to compete with private businesses in unregulated, utility-related services. In this instance, establishing some form of separation between the regulated and unregulated portions of the utility company along with comprehensive codes of conduct would be necessary.

These approaches can work individually, or in concert. Other business model options, both regulatory and competitive, may yet emerge.

3. The Principles of Rate Design

It is easy to be mesmerized by the rapid and extraordinary changes in technology that are profoundly altering the economics of electricity production and delivery. It is, therefore, just as easy to think that our approaches to the pricing of electricity services must likewise profoundly change--and perhaps they should. But it would be wrong to conclude that the fundamental objectives of rate setting, and the principles for rate design that flow from them, have also changed. They have not, because the underlying laws of economics and notions of equity rightly still apply. The goal of rate design is to set prices that are economically efficient and fair to consumers and that enable utilities to recover their costs of providing service (including return of, and on, their investment). Decades ago, James C. Bonbright and Alfred Kahn, two of the leading experts on rate design, set forth principles defining revenue-related and cost-related objectives. These principles are still adhered to today. Bonbright summarized the objectives of rate design as follows.

Revenue-Related Objectives:

- Rates should yield the total revenue requirement;
- Rates should provide predictable and stable revenues; and,
- Rates should be stable and predictable.

Cost-Related Objectives:

- Rates should be set to promote economically-efficient consumption (static efficiency);
- Rates should reflect the present and future private and social costs and benefits of providing service (i.e., all internalities and externalities) and promote economically-efficient investment;
- Rates should be apportioned fairly among customers and customer classes;
- Undue discrimination should be avoided; and,
- Rates should promote innovation in supply and demand (dynamic efficiency).

Bonbright's principles were first published in 1961. Kahn's work was published in 1970. The evolution of the utility industry since then and the growth of customer solutions in meeting energy needs have not changed the broad applicability of these principles.

Bonbright also identified several practical considerations that designers of rates should have in mind:

- Rates should be simple, certain, conveniently payable, understandable, acceptable to the public, and easily administered.
- Rates should be, to the extent possible, free from controversies as to proper interpretation.

The rate design principles established by Bonbright and Kahn made perfect sense in an era when nearly all electricity flowed in only one direction: from utilities to their customers. In light of the industry changes since the time of those publications, some additional principles, derived from the originals and adjunct to them, might be adopted to specifically guide the fashioning of rates in an environment of ubiquitous distributed energy resources. They include:

- A customer should be able to connect to the grid for no more than the cost of connecting to the grid;

- Customers should pay for grid services and power supply in proportion to how much (and when) they use these services and how much power they consume;
- Customers who supply power to the grid should be fairly compensated for the full value of the power they supply, no more and no less; and
- Tariffs should fairly balance the interests of all stakeholders: the utility, the non-DG customer, and the DG customer.

These principles will guide the examination of various rate designs. It may be true that a single rate design, applicable to DG customers and non-participants alike, can satisfy these principles, or it may be necessary to provide separate tariffs for DG customers. In any event, as the proliferation of DG may result in system investments that are different from the avoided costs resulting from DG, those costs will need to be factored into rates in accordance with the principles outlined above.

4. Rate Designs for Residential DG Customers

While all the MADRI states are restructured, the details regarding how that works varies from state to state. For example, the Public Utilities Commission of Ohio oversees a competitive auction for energy supply to standard service offer customers and approves not only the winning bid price, but also how that rate is allocated across the customer classes, as well as the rate design within each customer class. In the District of Columbia, on the other hand, an auction is used to procure least-cost energy supply for default service customers, but the Commission only has jurisdiction to set distribution service rates. This distinction has resulted in varying views among commissions regarding the parameters of their jurisdiction and attention.

There are a number of different rate design mechanisms that have been employed or are under consideration across the country to determine how to fairly compensate and charge DG customers for their use of the grid and the energy they use and produce. Each of these rate designs will be explained, followed by a case study and an analysis. We will start with a review of the traditional approach to net metering, as this is the most common rate design for DG customers. Next, we will consider several variations on traditional residential rate designs that can be used to at least partially address DG compensation and utility cost recovery issues. Following that, a variety of rate designs that involve non-traditional demand charges for residential customers or special demand charges only for DG customers are considered. Finally, we look at rate designs that offer alternatives to the traditional net metering approach to compensating customers for the generation from their DG systems.

We begin with a table summarizing the tariffs discussed in this paper. Other designs are undoubtedly possible, but we believe these are the ones that have been implemented or debated in the most venues to date. As noted, some tariffs address primarily issues of compensation to DG customers, some primarily compensation to utilities, and some reducing peak demand. There is some overlap among these categories.

Table 1

Tariff Design	Basic Features	Issue Addressed: Compensation to DG Owner	Issue Addressed: Equitable Allocation of Grid Costs	Issue Addressed: Reduce Peak Demand
Residential Rate Designs				
Net Metering	Balance generation and use, retail rate credit for generation	X		
High Customer Charges	Decrease volumetric, increase fixed charges			
Minimum Bills	Customer pays at least a minimum amount that is credited towards whole bill		X	
Time of Use Rates	Cost and payment for energy used and produced reflects values at various times of day, week, season	X	X	X
Monthly Demand Charges	Demand charge based on highest use (kW) in month		X	X
Demand Charges for Infrastructure Upgrades	Demand charge to recover utility infrastructure upgrades		X	
Subscription Demand Charges	Customer pays a fee to be connected to the grid, and the fee increases with power rating of customer's connection		X	
Fees Imposed on DG Customers for Using the Grid	Flat fee charged to DG customer to compensate utility for lost revenue due to lower sales			
Bi-Directional Distribution Rates	Customer pays a volumetric rate for distribution services whether importing or exporting power	X	X	X (when combined with TOU)
Feed-In Tariffs (FIT)	Utility pays DG customer for energy produced at fixed rate under long-term contract	X		
Value of Solar Tariffs (VOS)	Customer pays full retail price on energy used and is compensated at commission approved rate for all energy produced; rate for payment designed to reflect all benefits of solar (e.g., includes societal benefits)	X	X	

Note that for some of these, the box may not be checked because it represents an over or under payment by the DG customer or over or underpayment to the DG customer.

a. Net Metering

Definition and How It Works

Net metering is the most common design utilized to determine the pricing and payment to DG customers. Its virtue is simplicity and rough accuracy. A net metering tariff bills the customer, or provides a credit to the customer, based on the net amount of electricity consumed during each billing period (i.e., the kilowatt-hour [kWh] difference between electricity consumed and electricity produced). Net metering does not require separate metering of consumption and generation; a bi-directional meter can be used to measure net consumption. Net metering rate design allows residential and small commercial customers who generate their own electricity from solar power and other qualifying DG resources to get credit for the excess electricity they do not use and feed into the grid. Typically, DG customers are allowed to bank this excess electricity production, usually in the form of kWh credits but sometimes in the form of dollar credits. Customers can use these credits to offset the cost of electricity they use when their systems are not generating enough electricity to meet their needs, and which they would otherwise have to pay for at the utility's retail rate. Banked energy may be 'cashed out' at the end of a defined time period, available indefinitely, or may expire after some time has elapsed. Net metering is a state jurisdictional option that involves only retail rates.

The methodology used to value electricity produced by the DG owner has been questioned. Some contend that compensating net metering customers at the full retail rate is too generous and that compensation should be limited to the avoided cost, or generation, rate.[17,18] Others say that the value to the grid and society of customer generation is actually higher than the retail rate.[19] Issues to consider concerning net metering include, among others, whether compensation should be based on the whole rate, including costs such as distribution costs, or just the retail energy rate; what the retail energy rate is;[20] what costs are being avoided due to the presence of DG; and whether societal benefits should be included in valuing DG production.

There are different views on net metering applicability. Regarding size, some say net metering can apply to any project than can fit on a customer's premises, including multi-MW projects. Others assert there should be smaller site-based net metering limits. What technologies should receive this treatment? Many focus on solar, but many other on-site generation systems could also be permitted to qualify.

If the DG customer's rate varies by TOU, then that DG customer owner could be compensated at a higher rate for production than what the customer pays for consumption. At current penetration levels PV often produces energy at times when energy is more valuable than when the electricity is used. Although this is not always the case, as indicated by the fact that the PJM system annual peak in a recent year occurred at 8 a.m. in February—an atypical time. Furthermore, as the penetration of PV increases, this will have the effect of altering when the utility system peak occurs. Customers may self-supply during the hottest, sunniest hours of the day, but as the sun wanes, the customer draw on the utility system will increase, thus altering when those system peak periods occur. TOU rates will need to be assessed periodically to ensure that retail pricing reflects the true peak and off-peak time periods. It is a dynamic situation that will require regulatory flexibility to take corrective actions as warranted.[21]

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[17] Such is the case in Ohio as a result of a Supreme Court decision appeal brought by FirstEnergy Corporation. In that case, the Court held that the bundled rate for compensation was unlawful in that it required FirstEnergy to compensate the customer for costs that were unrelated to the generation of the customer's electricity and resulted in an unconstitutional taking.

[15.] FirstEnergy Corp. v. Pub. Util. Comm., 95 Ohio St.3d 401, 2002-Ohio-2430. The Court stated at p. 6, "A net-generator customer of FirstEnergy only generates and supplies electricity; it does not provide transmission, distribution, or ancillary services. It has no allowable transition costs for which transition charges are assessed, and is not responsible for paying into the Universal Service Fund or the Energy Efficiency Fund."

[19] See, for example, Ong, S. (2012). *The Value of Grid-Connected Photovoltaics in Michigan.* National Renewable Energy Laboratory. Available at: http://www.michigan.gov/documents/mpsc/120123_PVvaluation_MI_394661_7.pdf

[20] For example, should the energy rate be the Standard Offer Service rate? If a customer has exercised choice and is buying from a third party supplier, should the price the customer is paying to the third party be used?

[21] Lazar, J. (2014, January). *Teaching the Duck to Fly.* The Regulatory Assistance Project: Montpelier, Vermont. Available at: http://www.raponline.org/document/download/id/6977

Case Study
Net metering rules apply to Delaware residential customers of Delmarva Power and Light with generation facilities with a capacity of no more than 25 kW. The facilities must use solar, wind, hydro, a fuel cell, or gas from the anaerobic digestion of organic material as their primary fuel source. The systems must be designed to produce no more than 110 percent of the customer's expected electrical consumption. This moderates the amount of DG a customer can install under a net metering tariff.

Customers are credited in kWhs valued at an amount per kWh equal to the sum of volumetric delivery service charges and supply service charges for any excess production during a billing period. Excess credits are applied to subsequent billings. At the end of the annualized billing period, a customer may request payment from Delmarva Power and Light for the excess kWh credits. These credits are valued at the supply rate only, based on a weighted average.

Delaware law also provides for net metering for aggregated meters (virtual net metering) and community-owned generating systems, nonresidential customers with systems that do not exceed specified capacity limits, and for customers of other Delaware utilities. Separate rules apply for these.

Analysis
Table 2 below summarizes how net excess generation is compensated under net metering policies in effect in the MADRI region. More information related to state-level policies in the rest of the country can be found on the Interstate Renewable Energy Council's website.[22]

Table 2

MADRI State Compensation Rules for Net Excess Generation as of April 2012

Delaware	Credited to customer's next bill at retail rate. After a 12-month cycle, customer may opt to receive payment for credit at the energy supply rate.
Illinois	Credited to customer's next bill at retail rate; granted to utility at end of 12-month billing cycle (credits expire). Only applicable to non-hourly tariff customers in non-competitive classes.[30]
Maryland	Generally credited to customer's next bill at retail rate; reconciled annually in April and paid to the customer at the commodity energy supply rate.
New Jersey	Generally credited to customer's next bill at retail rate; excess generation is reconciled annually at avoided cost.[31]
Ohio	Credited to customer's next bill at unbundled generation rate; customer may request payment for excess at end of 12-month billing period.
Pennsylvania	Credited to customer's next bill at retail rate; reconciled annually at "price-to-compare".[32]
Washington, D.C.	Credited to customer's next bill indefinitely at retail rate for systems 100 kW or less, and at avoided-cost rate for larger systems.

[22] Interstate Renewable Energy Council. (2012, April 27).*State and Utility Net Metering Rules for Distributed Generation.* Available at: http://irecusa.org/wp-content/themes/IREC/includes/dsire-xml-feed/fs-net-metering-table.php.

Net metering as deployed in MADRI states and elsewhere represents a rough balance of considerations and has accommodated a new practice in its early stages. As DG proliferates, the issue with net metering, as with all the rate design options, is defining and recognizing value with accuracy typical in utility rates. The value to the utility system of having DG in place is one issue category. The factors bearing on DG customers is a second category, such as how to appropriately compensate DG customers for production, and deciding how to charge DG owners for grid services they use. Investment in the distribution system may sometimes be necessary because of DG, and those utility costs should also be part of the net value equation if they are not recovered separately through the interconnection process. Net metering reduces the amount that DG owners pay toward distribution costs, since these costs are typically charged based on volumetric sales. And finally, net metering rate design does not explicitly recognize the additional values that solar DG may in some cases contribute, such as producing energy at times of peak system demand or reducing societal environmental costs.[23]

While current net metering designs represent a kind of "rough justice," it may not in all instances be consistent with the principles of good rate design described above. Although net metering has the benefit of simplicity, it muddies the question of whether DG customers are paying for grid services in proportion to their use of those services, and the question of whether DG customers are fairly compensated for the full value of the power they produce. For example, to the extent that the value of solar exceeds the retail rate that a DG customer receives for its output, the DG customer is providing a net benefit to the grid for which it is not being fully compensated. On the other hand, the DG customer is contributing less to cover the cost of operating the grid by virtue of its diminished purchases from the utility. Without question, net metering reduces the amount of revenue a utility collects through volumetric sales, a portion of which would normally pay for grid services. In the long run and based on the cumulative effect of many net metering customers, utility costs may be reduced also. But if in a particular case the value of the customer's DG generation exceeds the customer's retail rate (i.e., it allows the utility to avoid costs in excess of the retail rate), the net effect could be that the customer is under-compensated by a net metering tariff even though he or she superficially appears to not pay their "fair share" for grid services. The net effect of a net metering tariff on utility costs is a matter of evidence requiring detailed analysis based on local conditions.

Any re-design of net metering tariffs should not be biased toward one stakeholder or another. Balance is key, and consideration should be made to design policies that are not so harsh that they lead to customers bypassing the grid entirely. The policies should, instead, address the goal of keeping DG customers on the system so that they continue to provide economic and engineering value to the distribution system. In areas where there is very little PV penetration, current net metering standards may be sufficient.

Another design concern is how to ensure that, if DG makes a sizeable impact on utility sales, utilities have mechanisms to maintain their financial health including lost revenues. Decoupling, discussed later in this report, is one such mechanism.

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[23] This is not to suggest that DG systems always provide these values. One can easily find examples where periods of peak demand in the MADRI states occurred at a time when DG output was relatively low or even zero.

b. High Customer Charges

Definition and How It Works

Typically a customer's bill will have both volumetric and fixed charge components. A Volumetric Charge is a charge for a commodity service; in this case, electricity that is based on the amount or volume consumed by the end-use customer. As customers use more electricity their bills increase. In some tariffs energy (kWh) is the sole volumetric element, while in others there is a separate demand (kW) element. In nearly every electric utility, volumetric charges also include the cost of building and maintaining the grid and its services; that is, these relatively fixed costs are billed out based on volume of consumption.

A fixed charge, also known as a customer charge, does not vary based on the amount of consumption; it is the same for all customers in a class. Ideally, fixed charges will only cover the cost that the utility incurs in order to serve that customer and nothing more. This typically would include just billing and metering costs and, where applicable, the customer drop facilities back to the pole mounted transformer.

Some in the industry advocate for shifting costs from volumetric charges to fixed (customer) charges as a means of recovering lost revenues and financially stabilizing the utility business. This shift, however simple it may be, would not adhere to rate design principles in that it is not based on cost if resulting volumetric rates would be below long-run marginal costs, including any of the imputed costs of policy choices to reflect externalities, and would not promote economically efficient consumption. If volumetric charges fall, consumption can be expected to increase. Reliance on fixed customer charges for recovery of non-volumetric costs, therefore, provides completely erroneous price signals not only for decisions on the customers' consumption of energy, but the avoidance of energy consumption as well.

The chart below illustrates this shift in cost from a volumetric to a fixed charge. In this example, the customer charge starts at $5 per month, which covers billing and metering, and increases to $20 per month to include a significant contribution to utility grid costs. In order to keep utility revenues even, given the increase in the customer charge, the volumetric charge has to go down; otherwise, the utility would over-recover its revenue requirements.

In this hypothetical example, with a national average residential price for electricity of about $.12/kWh, a $15 increase in the customer charge results in a $.03/kWh (25 percent) reduction in the energy (volumetric) charge. This price decrease would be expected to result in higher consumption, as customers adjust thermostats, delay buying more energy efficient appliances, and generally reduce their vigilance over energy consumption. With a conservative -0.2 elasticity factor, moving from a volumetric to fixed charge rate would result in an expected increase in consumption of approximately 5 percent.

Table 3

Impact of Increased Customer Charge		
Customer Charge	$5.00	⮉ $20.00
Energy Charge	$0.12	⮋ $0.09
Change in Price/kWh		-25%
Predicted Change in Usage		+5%

This cost shift from volumetric to fixed charges would be revenue neutral for a non-DG customer (as long as the customer does not change consumption); however, it reduces the compensation to a net-metered customer, probably to a figure below long-run marginal cost. It also violates the principle that grid services should be paid for by all customers in proportion to their usage of grid services, because this rate design charges all customers the same monthly fixed amount even though some customers require significantly less fixed infrastructure than others. For example, it is less expensive for the utility to serve 20 customers in one large apartment building than 20 customers in 20 detached houses.

Case Study

In December 2014, the Public Service Commission of Wisconsin approved Madison Gas and Electric's (MGE's) application to restructure its rates to increase its customer charge and slightly reduce its energy charge. Under the new rate structure, the monthly customer charge increased from $10.44 to $19.00. For 2015, the summer energy charge decreased from $0.15222 to $0.14133 per kWh and the winter energy charge decreased from $0.13992 to $0.13006 per kWh.[24] MGE also proposed a grid connection charge of $4.03 per month, but the Commission declined, arguing that a separate grid connection charge on the customer bill may be confusing for customers and is unnecessary to achieve the stated goals of the rate restructuring. MGE was therefore ordered to rename the customer charge a "Grid Connection and Customer Service" charge to clarify that fixed grid connection charges are included.

Analysis

Several utilities have proposed to shift cost recovery from volumetrically based rates to fixed charge rates independent of sales volume. While this solution to ensuring that the utility receives an assured stream of revenue from all customers is popular with the utilities, it is not so with consumer, or environmental or renewable energy advocates. Severin Borenstein, a respected economist wrote: "…the statement that I have heard a number of times recently that 'the utility should cover fixed costs with fixed charges' has no basis in economics when it comes to system fixed costs."[25] Most industries that have high fixed infrastructure costs in fact recover those costs (and earn profits) through volumetric sales, not fixed charges. For example, the cost of an oil refinery is recovered one gallon of gasoline at a time, and the cost of a passenger plane is recovered one seat at a time.[26]

High fixed charges, also referred to as straight fixed/variable rates (SFV), can result in greater customer usage, which leads to a need for more facilities, raising costs for everyone. This rate design also imposes disproportionately higher costs on lower-volume (often low-income)[27] customers in a significant departure from regulatory practice. Furthermore, a high fixed customer charge subjects all customers to a high bill irrespective of their efforts to conserve energy and, therefore, discourages conservation as illustrated in the hypothetical in Table 3. Raising fixed charges and lowering volumetric charges increases the payback period and decreases the value to customers of investments in energy efficiency and DG. If the volumetric charge is less than the long-run marginal cost (because the fixed charge is so

[24] Before the rate case settlement, these differentials were greater.

[25] Quoted from: Wellinghoff, J. & Tong, J. (2015, February 15). Why fixed charges are a false fix to the utility industry's solar challenges. *Utility Dive.* Available at: http://www.utilitydive.com/news/tong-and-wellinghoff-why-fixed-charges-are-a-false-fix-to-the-utility-indu/364428/. Wellinghoff and Tong continue by commenting, "Borenstein accurately notes that fixed-cost recovery can be addressed through smarter, more efficient kWh volumetric pricing that accounts for all cost variations due to timing and location, as well as externalities such as carbon emissions."

[26] Without question, some industries do recover costs through fixed charges, typically in the form of a subscription charge. Cable television service, for example, has almost always been billed through a fixed monthly subscription rate no matter how much television the customer watches. However, even in this industry we are seeing the rise of pay-per-view services.

[27] Colton, R. (2002, April). Energy Consumption and Expenditures by Low-Income Households. *The Electricity Journal*, 15(3), 70–75. Available at: http://www.sciencedirect.com/science/article/pii/S1040619002002798.

high) then customers will behave as if their incremental usage has less of a cost effect than it does. This can result in greater customer usage, which leads to a need for more facilities, raising long-term rates.

The high fixed charge design falls short on design principles of promoting economically efficient consumption, promoting innovation in demand and supply, being free from controversy, and paying for grid services in proportion to usage. It does, however, provide rate and revenue certainty and is simple. By contrast, volumetric charges meet the objectives of the principles of promoting economically efficient consumption, fairly apportioning costs among customers in accordance with the amount used, promoting dynamic efficiency, and properly assigning costs in a manner that has been understood and accepted for generations. Volumetric charges, however, do not reflect the fixed characteristic of costs to provide service. Later, this paper will look at how time varying rates can align cost-causing peak use with cost recovery. A small demand charge may be an option in a rate design that includes a small customer charge and a volumetric charge.

c. Minimum Bills

Definition and How It Works
The minimum bill design combines attributes of a fixed charge, which guarantees a certain level of utility revenues, with the value of a volumetric rate that prices electricity based on the amount used. Under a minimum bill design, the customer pays a minimum amount each month for his/her connection and for a block of usage. The minimum bill guarantees the utility a minimum level of revenue each month from each customer, including DG customers, regardless of the customer's actual net usage—which could be zero or negative. Because of the guaranteed revenues from a minimum bill, the volumetric energy charges can then be reduced by a very small amount. Table 4 illustrates how the minimum bill design would work, compared to low and high customer charge designs.

Table 4

Comparison of Minimum Bill Design to Low and High Customer Charge Designs

	kWh	Low Customer Charge	High Customer Charge	$20 Minimum Bill*
Customer Charge		$5.00	$20.00	$5.00
Minimum Bill				$20.00
Per-kWh Charge		$0.10	$0.085	$0.099
	10 kWh	$6.00	$20.85	$20.00
	100 kWh	$15.00	$28.50	$20.00
Customer Bills	200 kWh	$25.00	$37.00	$24.80
	500 kWh	$55.00	$62.50	$54.50
	1,000 kWh	$105.00	$105.00	$104.00
	1,500 kWh	$155.00	$147.50	$153.50
	2,000 kWh	$205.00	$190.00	$203.00

**The minimum bill will only apply when customer's usage is so low that their bill falls below $20.*

In this example (see the column at the far right of the chart), the low customer charge is maintained, but a $20 minimum bill fee is overlaid. A very low-use customer, specifically one using less than 152 kWh per month, would pay the $20 minimum. This would mean an increase in that customer's bill, relative to a traditional low-customer-charge rate design. Customers using more than 152 kWh per month would pay about the same under a minimum bill rate design or a traditional low-customer-charge rate design. Compared to a high-customer-charge rate design, the minimum bill design would cost less for customers using up to 1,000 kWh per month but more for those using greater than 1,000 kWh.

Case Study

Standard residential rate customers of the Los Angeles Department of Water and Power pay a minimum amount of $10/month.[28] At the June residential rate, $10 would pay for about 68 kWh. Thus, only customers using less than about 68 kWh in a month would be subject to the minimum charge. DG owners who generate as much as or more than the amount they use would pay the $10 minimum charge.

San Diego Gas & Electric charges all customers a minimum amount of $0.17 per day. This charge is offset by energy charges.

In both the Los Angeles Department of Water and Power and San Diego Gas & Electric cases, there is no separate customer charge. However, the minimum bill could also be combined with a customer charge, as illustrated in Table 4.

Analysis

The difference between a high customer charge and a minimum bill is that the minimum payment amount is compared to the customer charge plus the volumetric usage charge. Once the sum of the customer charge and the volumetric charge exceeds the minimum bill amount, the minimum bill requirement is met. The minimum bill only applies when the sum of the customer charge and the volumetric charge is less than the minimum bill amount. By contrast, a high customer charge applies in all circumstances.

The vast majority of customers without DG systems have enough usage that they would not be affected by a minimum bill. Only a very small fraction of customers would have average monthly bills below the minimum bill threshold and would have increased bills as a result of the minimum bill design. In fact, only a few percent of customers, accounting for less than one percent of total energy consumption, are likely to have usage below the threshold amount of 150 kWh per month in the hypothetical illustration above. This small minority of customers whose bills would be under $20 with a traditional rate design would instead pay the minimum amount of $20.

It is important to recognize that the size of the minimum bill amount is critical. The higher the minimum bill, the more customers will be affected and the more energy a customer would have to consume to reach a break-even point compared to traditional rate designs. On the other hand, if the minimum bill amount is too low, it may not offset the need for the utility to increase rates to offset lost sales and revenue shortfalls.

The value of a minimum bill concept lies in its ability to produce a guaranteed minimum amount of revenue from each customer, including customers with DG, without imposing undue costs on the vast

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[28] Los Angeles Department of Water and Power Standard Residential Rate schedule. Available at: https://www.ladwp.com/ladwp/faces/wcnav_externalId/a-fr-elecrate-schel?_adf.ctrl-state=hcoz4ka5c_17&_afrLoop=37206739964636.

majority of customers. The utility gets a revenue amount it can rely on and all customers avoid being saddled with high customer charges and their adverse consequences.

DG customers would contribute the minimum bill amount, or more, to the system. This could alleviate the lost revenue concerns associated with net metering under a traditional rate design. Whether the minimum bill design results in a higher payment would depend on the size of the customer's DG system, the average output of the DG unit, and the minimum bill payment amount.

With regard to the principles enunciated above, a minimum bill will provide both revenue and rate stability and will promote innovation in supply and demand. It is arguable as to whether it is entirely fair in terms of its effect on very small users.

d. Time-of-Use Rates

Definition and How It Works

TOU rates are rates that vary by time of day, day of the week, and season of the year in which the energy is consumed. They are a pricing strategy for reducing energy use at times of high system demand. By reducing peak demand, utilities may be able to avoid building new power plants that would be needed only a few times each year. Further, utilities may be able to avoid investments in new distribution and transmission infrastructure by reducing increases in peak demand. TOU rates can help avoid or defer costs that would affect all customers.

There are several types of TOU rates:

- Fixed TOU: Rates are pre-determined but vary for different times of the day, week, and season. Rates are higher during typical times of high demand or high cost, such as summer days, but they do not fluctuate based on real-time system conditions.

- Peak-time rebate (PTR): If customers reduce demand during specified peak times, they receive a credit on their bills. The utility establishes a baseline against which reductions would be measured, and notifies customers in advance of a peak period. Participation by customers during any given peak period is voluntary.

- Critical peak pricing (CPP): Like a fixed TOU rate, this rate also includes an on-peak and off-peak component but with an additional critical peak price which is significantly higher than the peak price. The critical peak price is reserved for a limited number of hours per day and days or hours per year when the utility system is reaching a high peak or high cost that may cause them to have to bring expensive peaking units online or purchase expensive power. Customers on a CPP rate will pay a lower TOU rate during non-critical peak periods. Typically enrollment in a CPP design is voluntary, although utilities may establish tariffs that place customers on a CPP rate with an opt-out provision.

- Dynamic pricing: This approach offers pricing in blocks of hours that reflect the different characteristics of costs that occur during those pre-identified blocks. The blocks of hours can be revised on a daily, weekly, or monthly basis.

- Real-time pricing:Under this model, customers pay for their electricity based on each hour's wholesale market price. This is usually, but not always, reserved for industrial customers.

Case Study
Baltimore Gas and Electric offers optional TOU rates to residential and small commercial customers. Large commercial customers are automatically enrolled in TOU rates. Under these rates, customers are charged based on the amount of electricity they use and when they use it. The rates include different prices for different periods as follows:[29]

- **On-Peak**
  Summer: weekdays 10 a.m.-8 p.m.
  Winter: weekdays 7 a.m.-11 a.m. and 5 p.m.-9 p.m.

- **Intermediate-Peak**
  Summer: weekdays 7 a.m.-10 a.m. and 8 p.m.-11 p.m.
  Winter: weekdays 11 a.m.-5 p.m.

- **Off-Peak**
  Summer: weekdays 11 p.m.-7 a.m.
  Winter: weekdays 9 p.m.-7 a.m., Saturday, Sunday, major holidays

Delaware's Delmarva Power and Light has a PTR program for residential customers. During peak periods, customers receive a $1.25 credit for every kWh of reduced usage below their baseline usage level. Customers get this credit automatically; they do not have to enroll in the program.[30]

Pacific Gas & Electric (PG&E) in California offers a CPP program called SmartRate. The program is offered on an opt-in basis, and customers may opt out at any time. Under the program, customers have rates that are $0.03 per kWh lower during non-peak times. PG&E applies a $0.60 per kWh surcharge during critical peak times. Peak periods last from 2 a.m. to 7 p.m. PG&E can call 9 to 15 critical peak day events during the period May to October. PG&E notifies customers one business day ahead of the critical peak period. Days when the critical peak surcharge applies are called SmartDays. The first year of participation is risk free. For that year, if a customer's total SmartRate summer bill is higher than it would have been under the customer's previous plan, PG&E will automatically credit the customer with the difference.[31] This is sometimes referred to as shadow billing.

In Illinois, two utilities, Ameren Illinois and ComEd, offer residential customers a real time pricing option. Customers who elect this structure pay for the electricity they consume each hour based on the corresponding wholesale hourly market price of electricity.[32]

Analysis
TOU rates communicate time-based value to utility customers. Well-designed TOU rates enable and motivate most customers to take action that is economical and sensible for them to avoid usage at high prices and to potentially add usage at low prices. In this manner, TOU pricing offers a way for utilities to

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[29] Baltimore Gas and Electric's Time of Use Pricing. Available at: http://www.bge.com/waystosave/manageyourusage/Pages/Time-of-Use-Pricing.aspx
[30] Delmarva Power and Light's Peak Energy Savings Credit. Available at: http://www.delmarva.com/my-business/save-money-and-conserve-energy/delaware-energy-efficiency-programs/peak-energy-savings-credit/
[31] PG&E's SmartRate Plan. Available at: http://www.pge.com/en/myhome/saveenergymoney/plans/smartrate/index.page
[32] Plug In Illinois. *Residential Real Time Pricing Options.* Available at: http://www.pluginillinois.org/realtime.aspx.

shave the peaks from their demand. Generally, demand spikes at certain times; significantly higher levels of generation are needed for just a short period each year to meet demand at these peak times. If these peaks can be reduced or eliminated, utilities may be able to avoid building new power plants or purchasing power when prices are high, thus benefitting all customers.

Customers must have meters that can measure usage hourly in order to participate in any of these TOU structures, although data logging systems that have this capability have existed for decades and millions of customers in the MADRI states now have advanced digital meters with even greater capability. However, where data logging systems are not in place, it may not be viable to deploy this technology at the moment as new, more advanced technology may soon become available. This is a dilemma that is confronting the industry—when to launch a new technological capability so that the investment is not subject to obsolescence in the near future as even newer technologies surpass the technology installed. However, a more in-depth discussion of this issue is beyond the scope of this paper.

DG customers could theoretically participate in any of the TOU pricing structures noted above. The introduction of time-varying rates complicates net metering tariffs slightly, but this complexity is certainly manageable. Instead of billing the customer based on monthly net energy consumption, it would be necessary to measure net energy consumption in each billing interval for which rates vary, multiply that value by the applicable rate, and then aggregate those values to obtain a monthly net bill. The application of credits for net excess generation would be slightly more complicated, but an easy solution would be to apply a dollar credit rather than a kWh credit to future bills.

Allowing DG customers to participate in a PTR program would require advanced metering infrastructure. These programs require establishment of a baseline usage against which critical peak reductions can be measured. For PV customers whose energy use is measured on a net basis (usage less production) with a single meter, a different methodology may be needed that accounts for when power is produced on the PV system.

TOU rates address the DG rate principle that customers should pay for grid services based on how much and when they use them. Given that PV systems will usually be reducing consumption at high-value times of day, TOU rates also at least partially address the principle of fairly compensating DG customers for the full value of the power they supply.

Any transition to TOU rates from flat rates is generally accompanied by advice to customers on how to use their newfound choices and create simple strategies for making the best of the new rates.

e. Monthly Demand Charges

Definition and How It Works

Demand charges are assessed based on a customer's *maximum* use of power (kW) over a defined period of time. This contrasts with energy charges, which are assessed based on the customer's total quantity or net quantity of electricity consumed (kWh) during each billing period (usually monthly). Demand charges have long been accepted as a reasonable way for utilities to recover fixed costs, because these charges can better reflect how each customer contributes to fixed costs than energy charges can.

Demand charges are frequently used in commercial and industrial tariffs but are rarely included in residential tariffs. This is based partly on the historical challenge and cost of metering demand and managing demand data in the days before automated metering infrastructure was available, partly on the sense that demand charges make bills too complicated for residential customers to understand, and partly based on the belief that residential customers are less able to respond to the price signals that are inherent in demand charges. For example, it may be difficult to tell the children not to do their homework on the computer or wash the dirty uniform they just brought home and need that night for a game because their mother has a casserole in the oven for dinner and their father is mowing the lawn with his electric mower before it gets dark. Plus, automated appliances, such as water heaters and space conditioners driven by thermostats, may kick on at these times. On the other hand, the presence of demand charges could provide incentives to households to consider the most efficient decisions regarding consumption during periods with higher costs. Demand charges Demand charges also might encourage households to invest in newer-technology appliances whose operations can be more easily controlled at higher-cost times.

Demand charges are usually based on the customer’s highest average power usage (kW) during a specified period of 15 to 60 minutes. Some utilities base demand charges on the customer’s highest usage during the utility’s peak demand periods (coincident peak), while some measure the customer’s highest usage in any period (non-coincident peak).

Monthly demand charges are normally assessed by multiplying the customer’s coincident peak demand (or non-coincident peak demand) by a demand rate. However, many utilities also apply what is called a “demand ratchet.” In those cases, the customer’s demand charge is based on whichever of two values is higher: either the *monthly* peak demand or a ratchet value which is based on some fraction (e.g., 75 percent) of the customer’s highest monthly peak demand during some longer period of time. Many ratchets last a full year. There are many possible variations on the idea of a ratchet, but they all have the same effects on customers: 1) no matter how much the customer reduces their peak demand in a given month, there is a limit on how low the demand charges can be; and 2) a short-term spike in the customer’s peak power demand, even during an off-peak period, may result in higher demand charges for many months to come. From the utility’s perspective, the ratchet also provides greater assurance that it will collect sufficient revenues to pay its fixed costs.

In order for a demand charge to be part of a tariff, customers could be required to have meters that measure usage in specific time intervals (for example, late afternoon or early evenings during weekdays), or surrogate data could be used instead. Where interval metering data is not available, any utility that performs a fully allocated cost-of-service study relies on estimates of peak and non-peak demand characteristics of rate classes from load research studies, e.g., Lodestar. Those same characteristics used to allocate demand costs in a cost-of-service study could be used as surrogates to develop estimates of peak and non-peak demand for customers within each rate class. It could even be argued that to the extent that interval data is not used as the basis for allocating demand costs in the cost-of-service study, rates should not be designed using data that conflicts with the data used to allocate the costs to be recovered in those rates. A demand ratchet can have a punitive effect on a customer who has a spike in usage at a single time interval within a month, which could have, for example, been caused by having visitors at the residence. If that spike causes a high demand charge for a customer that carries over the entire month or year, it can have an unfair adverse impact on the customer’s bill—especially if the customer’s peak usage is non-coincident with that of the utility. Thus, if demand charges are considered for residential customers, a more fair approach would be to add a daily demand charge rather than a monthly or annual demand charge. A daily demand ratchet will cause that customer to pay a higher rate for just that one day.

Demand charges incentivize customers to smooth out their hour-to-hour electricity use, thus lowering their own peak usage and demand on the grid, improving their load factor, and lowering the overall bill. When customers across a utility system respond to this price structure by doing actions such as not running a dishwasher and dryer at the same time, and adjusting their thermostats, the total capacity needed for the grid is lowered. Utilities may be able to avoid or defer building additional plants, distribution lines, and transmission lines as a result; in addition the avoidance of energy use during peak times puts downward pressure on the overall price of electricity.

Demand charges also compensate the utility for the overall draw on its system and the amount of capacity it must have available to meet that demand. Yet it is also important to recognize whether an individual customer's spike in demand is coincident with the utility's peak demand. A high demand by a residential customer during a non-peak hour will not have the same effect on the utility as it would during a peak period. While demand charges work better for larger customers, TOU rates may be a better option for residential customers since it matches customer use with utility peaks. Alternatively, TOU rates could be combined with other demand-based rate components. For example, generation supply rates could be TOU based while transmission and distribution rates could have a demand component.

Case Study

Georgia Power offers a residential demand rate, a fairly new offering. It includes TOU rates and is similar to the utility's nights and weekends rate except, under the residential demand rate, the energy prices are significantly less for both on-peak and off-peak time periods, and there is a demand charge of $6.53 per kW of peak demand. Peak demand is defined as the highest 30-minute interval load during the current month.

The table below compares the rates of these two plans. On-Peak hours are from 2 p.m. to 7 p.m. Monday–Friday, June through September.

Table 5

Example of Residential Demand Rate Tariff

Georgia Power Comparison Demand and Nights and Weekends

Type of Charge		TOU with Demand	Nights & Weekends
Customer charge		$10	$10
Energy:	*On-Peak*	$0.096052/kWh	$0.203217/kWh
	Off-Peak	$0.009754/kWh	$0.048490/kWh
Demand		$6.53/kW	NA

A DG customer could potentially benefit from each of these rates. Under the TOU with Demand schedule, the DG customer benefits from flattening demand and because its PV system would be offsetting usage during the more expensive peak period. Under the Nights and Weekends schedule, a PV customer benefits because its PV system would be offsetting usage during the very expensive peak period. Neither the DG nor non-DG customer would be penalized for using many appliances at once under the Nights and Weekend schedule.

Analysis
Critics argue that a demand charge based on non-coincident peak demand unfairly penalizes or burdens customers who use a lot of power during off-peak periods, because those customers' peaks do not necessarily add to the utility's fixed costs, which are generally determined by system peak demands. However, a demand charge that is coincident with the utility's peak demand has value in terms of curtailing usage when the cost to the system of providing for that usage is high. It also allocates costs to those who are contributing most to peaks in demand.

In the future there may be ways to manage, through smart appliances and other advanced technologies, the concern that a customer may incur a high demand charge for a temporary spike in power demand during a non-coincident peak time. DG customers may be able to further offset a high demand charge through reliance on their DG to provide a portion if not all of their peak power needs. The less the DG customer (or any other customer) needs to lean on the grid during utility peak periods, the greater the benefit for the system as a whole.

In terms of the principles for good rate design, monthly demand charges can lead to a significant amount of customer confusion in mass market groups because these customers lack awareness of the demand contribution from their devices, are not used to being concerned with simultaneous usage and (absent a comprehensive load control program) lack control of significant demand contributors such as space and water conditioning and refrigeration. Therefore this rate design lacks the simplicity and certainty customers prefer.[33] The issue of notifying customers when there is a system peak so that they can respond to their best advantage would require consumer education and/or technology. On the other hand, this rate design could promote dynamic efficiency, properly allocate costs to customers who cause spikes in demand, and produce the revenues to meet the utility's requirements. But the concern here is that customers could be charged for an incidence of high usage occurring at a time when the utility system can easily absorb that demand. Consequently, demand charges that are not based on coincident peaks may fail to send the right price signals to align customer usage with system costs.

The implementation of demand charges for all customers also avoids the potential for rate design targeted at DG customers that could be viewed as punitive, arbitrary, and potentially discriminatory. It may be appropriate, however, for a TOU rate with a critical peak price to be used in conjunction with a separate demand charge that reflects the costs of other facilities that have less diversity than the system peak.

f. Demand Charges for Infrastructure Upgrades

Definition and How It Works
Sometimes a utility will incur extra costs for infrastructure upgrades to accommodate DG, or to bring service to large homes in rural areas. This rate design features a demand charge for those customers only that recovers normal billing and collection costs plus the cost of necessary infrastructure upgrades. For example, a distribution transformer might sometimes be required to accommodate a DG unit. The transformer must be sized to cover the individual customer's (or a group of nearby customers') maximum use, and this rate form seeks to recover that cost in a fixed monthly charge.

[33] See, for example: Rubin, S. (2015, November). Moving Toward Demand-Based Residential Rates. *The Electricity Journal*, 28(9), 63–71, and: Springe, D. (2015, November). *Customer Concerns with Implementing Demand Rates*. Presentation at NARUC and NASUCA annual meetings.

Case Study
Manitoba Hydro implemented a rate for DG customers to allow it to recover the cost of a transformer installed to accommodate the DG load.[34]

Table 6

Example of Demand Charges for Infrastructure Upgrades	
Customer Charge	
200 Amps and below	$7.28
Over 200 Amps	$14.56
Energy Charge	$0.0738/kWh

A variation on this Manitoba rate is to graduate the customer charge based on the size of the service such that below a certain size there would be no customer charge. From there, up to a standard size, there would be a typical customer charge. After that, the customer charge would continue to rise based on the size of the transformer. This design would provide payment from the DG customer or the larger, remotely located homes that are adding costs to the system by having those who are imposing the cost pay for it.

Analysis
This rate design places the incremental cost directly on its "cost causer" as opposed to spreading it out among all customers. It is analogous to a line-extension program where developers or individual beneficiaries pay the cost of the utility connecting the remote location to the grid. Note that the transformer charge may need to be adjusted from time to time to reflect new customers who would share in the cost of the transformer and/or to retire this charge once the transformer is paid for. For the DG customer, this design can be a way to properly reflect the discrete costs that the utility system incurs on its behalf. It avoids the possibility of a charge that appears punitive, or appears to be a utility attempt to recover lost revenues not based on a service provided. Great care, however, needs to be taken to ensure that a subsidy is not created where other customers could receive a benefit from the upgraded facilities.

This rate adheres to cost causation principles by requiring the cost causer to pay for the grid connection. It achieves the objectives of revenue and rate stability, and apportions costs among customers fairly.

g. Subscription Demand Charges

Definition and How It Works
A subscription demand charge is a graduated monthly customer charge based on the customer's power

[34] See, for example: Rubin, S. (2015, November). Moving Toward Demand-Based Residential Rates. *The Electricity Journal*, 28(9), 63–71, and: Springe, D. (2015, November). *Customer Concerns with Implementing Demand Rates*. Presentation at NARUC and NASUCA annual meetings.

rating. France, for example, has long had subscription demand charges and TOU pricing. As new customers sign up for service, they complete a comprehensive form to estimate their power use. This estimate is used to determine the size of their connections and hence their subscription fees, which increase with their usage. Generally, an apartment owner and owner of a small house would pay $5 to $10 and $10 to $20 per month, respectively. The volumetric rate is the same for all customers.

Case Study

The residential “subscription” price used by Electricité de France, the state-owned utility in France, is illustrated in Table 7.

Table 7

Example of Subscription Demand Charges

Power Rating	Monthly Customer Charge	Price Per kWh
(kVA)	(Euros)	(Euros)
3	€5.43	€0.17
6	€8.81	€0.17
9	€11.66	€0.17
12	€17.98	€0.17
15	€20.63	€0.17
18	€23.73	€0.17

Analysis

The design feature in this method that is of particular note is that larger homes with a larger service pay a larger customer charge. This structure more properly correlates the fixed fee with usage as opposed to imprecise, large customer charges that are assessed uniformly. Demand charges for customers with rooftop solar could be adjusted to recognize the contribution the solar panels make toward meeting system peak demand. This rate design adheres to the principles of matching cost with causation and assuring revenue stability. These are important attributes that should be in the regulatory forefront.

h. Fees Imposed on DG Customers for Using the Grid

Definition and How It Works

Some utilities have recently received authorization to charge customers a fee for using the grid in order to compensate the utilities for the net lost revenues associated with lost sales from PV customers. This grid use fee, also called a connection charge, can be levied on DG customers. These customers are characterized by low net use volume with potentially high instantaneous use. They use the grid to buy and sell their energy and for its other capabilities. Under this fee design, the grid functions like a toll road; as long as the DG customer wants to remain connected to the grid and purchase electricity from the utility, it must pay this fee.

Case Study

Arizona Public Service proposed a $50 to $100 monthly fee for solar customers. The utility justification for this charge was that the grid would require specific upgrades like voltage regulators to accommodate more DG. This case was controversial and ultimately the Arizona Public Service Commission approved a fee of $.70 per kW, which is equivalent to $4.90 to $7.00 per month for the typical range of residential solar PV systems.[35]

Hawaiian Electric has proposed a new rate design, with a sharp increase in the monthly customer charge for all residential consumers from $9 per month to $55 per month, and an additional $16 per month for solar customers. The additional imposition on solar customers is based on Hawaiian Electric's estimate of additional investments in the grid needed to accommodate high levels of solar.

Analysis
One of the concerns with regard to a grid fee is that there is no rational basis for it without a demonstration that DG customers impose special costs on the grid. Rather, the rationale of the utilities has been to create a two-way toll road out of the grid to seek compensation for what may be covered in current rates, which reflect a one-way direction. It is therefore inconsistent with the principle that customers pay for the costs they cause. Grid fees are really a way to recover from DG customers the lost utility revenues associated with them consuming less electricity. Another concern among renewable advocates is that a high monthly fee would stifle the development of customer-installed PV as it is an added cost that cuts into the prospective DG customer payback analysis.

While Hawaii is unique in that, as an island, it imports most of its fuel resulting in electricity costs of over $.30/kWh, high fixed charges will still have the same adverse impacts as discussed previously in Section 4b ("High Customer Charges"). Roughly 20 percent of single-family residential households in Hawaii have solar systems and approximately half of the distribution circuits are "running backwards" during the middle of the afternoon. Hawaii, therefore, is in the forefront of PV adoption.

Unless grid fees are based on actual cost net of the benefits provided by the customers' investment in DG—and it does not appear that they are—they will violate the principle that a customer should be able to connect to the grid for no more than the cost of connecting to the grid. Moreover, while the fees provide revenue to the utilities, they do not promote economic efficiency in terms of reducing both short-run and long-run avoided costs.

i. Bi-Directional Distribution Rates

Definition and How It Works
Bi-directional rate design is a new idea gaining currency. Under this approach, a DG customer pays or receives compensation for a volumetric rate for distribution system costs for each kWh of net consumption or net excess generation within a specified time interval.[36] Bi-directional distribution charges would of course have to be combined with some approach for separately assessing power supply charges, most likely a modified version of net metering. The combined effect would be that the customer pays a full retail rate (distribution charges plus power supply charges) for each kWh of net consumption when importing power. But when exporting power, the customer *pays the bi-directional distribution rate* and receives *credit at the power supply rate* for each kWh of net generation.[37] All of

[35] Arizona Corporation Commission. (2013, December 3). Docket No. E-01345A: In the Matter of the Application of Arizona Public Service Company for Approval of Net Metering Cost Shift Solution.
[36] This rate would most logically be applied to net consumption or generation on an hourly basis or an even shorter interval, which allows for a reasonably accurate approximation of how much energy is flowing through the meter in either direction.
[37] In similar fashion, if a jurisdiction wanted to offer a subsidy or incentive for DG deployment it could potentially provide credit for exported power at a premium rate greater than the standard power supply rate.

these values can then be summed, and combined with any other applicable charges like a customer charge, to arrive at a total monthly bill (or credit).

This rate design requires metering that is able to measure power flows in either direction. Most smart meter systems can do this, but the meter data management systems must be programmed to collect the data and billing systems must be re-programmed (at some cost) to manage the data.

Case Study

The authors are unaware of any examples of actual bi-directional distribution rates as described herein. Below is a hypothetical example of a rate design that includes a bi-directional distribution charge of $.05/kWh that applies to all imported or exported energy. It is combined in this example with power supply rates that vary based on TOU. When importing, the customer pays the power supply rate and when exporting, the customer receives credit at the same power supply rate.

Table 8

Illustrative Example of a Bi-Directional Distribution Rate

Directional Pricing Example		
Customer Charge	Billing and Collection	$5.00/month
Distribution Charge	All Delivery Costs	$0.05/kWh
Power Supply ***(Either Direction)***		
On-Peak	Peak and Baseload	$0.15/kWh
Off-Peak	Baseload Only	$0.08/kWh

Analysis

The rationale for bi-directional distribution rates is that the DG customer needs distribution service regardless of whether he or she is importing or exporting power, and should pay for that service on a volumetric basis just as customers without DG do. These charges are assessed based on *net* consumption or generation because the customer does not rely on the grid for those kWh that are both generated and consumed behind the meter. A bi-directional distribution rate can be advantageous in terms of adhering to the principles outlined in this paper, especially as they relate to DG. This is especially true if the rate design includes TOU pricing for power supply. A bi-directional rate will result in the customer paying for grid service at the same retail rate as all other customers. At the same time, it will compensate the customer for net excess generation at a rate that reflects power supply costs (or a premium rate, if the utility or regulators choose that option) but not delivery costs.

One of the shortcomings of a rate design based on bi-directional distribution charges is that it assigns charges and credits to DG based on established retail rates that reflect embedded costs and current market rates, but might not reflect the potential for DG to avoid longer-term utility system costs. In order for rate design to reflect this fuller value of DG, it might be necessary to credit net generation at rates higher than standard power supply costs or to provide compensation outside of utility tariffs (e.g., through cash or tax incentives).

j. Feed-In Tariffs

Definition and How It Works

Feed-in tariffs (FITs) were first created to support the development of a nascent renewable energy industry. A customer with a FIT typically has a long-term contract with the utility, similar to a power purchase agreement, through which the customer sells every kWh of output from their DG system at a pre-determined rate for a fixed contract duration. The customer purchases electricity at a standard retail rate. In most of the FITs adopted around the world, the FIT rate has been designed to allow the average customer to recover the cost of a typical DG investment over the term of the contract and earn a return on its investment that is comparable to the returns that utilities earn on infrastructure investments. In other words, the rate is based on the *customer's* costs, not the utility's avoided costs or the "value" of the energy. This normally means that a FIT rate pays the customer substantially more than their retail energy rate and thus offers the customer a better deal than net metering.

FITs have been used to a much greater extent in other countries than in the United States, largely because US law (Public Utilities Regulatory Policy Act of 1978 [PURPA]) prevents state utility commissions from ordering utilities to pay more than their avoided costs for purchased energy. (See text box on FERC jurisdiction.) Most of the FITs adopted in the US more recently have been structured in a way that sidesteps the PURPA restriction by not having the state utility commission set the price that utilities pay for energy. Instead, the price can be set through market forces, by a state legislature, or by the utility or its governing board on a voluntary basis.[38]

Case Study

Portland General Electric (PGE) offers a FIT called the Solar Payment Option. For residential PV customers, there was a window for enrolling in the Solar Payment Option, which opened May 1, 2015, and was extended through March 31, 2016. This program is distinguished from net metering in that instead of receiving kWh bill credits at the customer's retail rate, Solar Payment Option participants receive a premium payment from PGE for the energy generated by their qualifying system for the duration of a 15 year period. The volumetric incentive rate (VIR) is $.227 per kWh for Hood River County customers and $.316 per kWh for all other customers for DG units that are 10 kW or less. The gross VIR consists of two components: (1) a retail bill offset based on applicable volumetric (kWh) charges, and (2) a net VIR payment. If kWhs exceed the total monthly use, they will be carried forward to the next month. Total monthly use is defined as net kWh from the retail meter (may be positive or negative) plus kWh from the qualifying system's meter. Participants are chosen in different ways depending on the size of their PV system. Small scale (10 kW or less) participation is made available first through a lottery-based application process and then through a first come, first-served process. Medium scale participants (10-100kW) are either determined through the small scale system or through a bid-option Request for Proposal process, where bid price is the sole factor in awarding bids. Large scale participants (greater than 100 kW) are eligible only through the bid-option process. Customers in the Solar Payment Option must have two meters; PGE will install these.[39]

Analysis

By creating revenue certainty, FITs can support investor confidence through a long-term power

[38] For a thorough examination of this subject, see: Hempling, S., Elefant, C., Cory, K., & Porter, K. (2010, January). *Renewable Energy Prices in State-Level Feed-in Tariffs: Federal Law Constraints and Possible Solutions.* National Renewable Energy Laboratory. Available at: http://www.nrel.gov/docs/fy10osti/47408.pdf.

[39] Portland General Electric: https://www.portlandgeneral.com/renewables_efficiency/generate_power/solar_payment/default.aspx.

purchase contract at a rate that is bankable for the developer. This certainty lowers financing costs and a project's required rate of return.[40] However, other ramifications of the FIT may raise project costs and make it harder for DG investors to earn a return. For example, there are open questions about whether the credits provided for all generation under a FIT represent taxable income and whether this rate design makes generators ineligible for the 30 percent federal investment tax credit.[41]

Regulators could consider establishing a competitive model for FITs that would use an auction rather than relying exclusively on an administratively established price. An auction approach would match buyers and sellers at the most efficient price and would provide a Qualifying Facility (QF)[42] with more options to sell its power. It may also free the utility from the obligation to purchase power from the QF (depending on the size of the facility). The most efficient prices may be determined by setting a quantity subject to competitive bidding, and setting this quantity is a way to meter the flow of DG into the system.

From the standpoint of the principles, the level of the FIT rate will be important. If it is set too high, it will negatively affect the utility revenues and may raise the question of whether the customer is being paid more than the full value of what it is supplying. In the PGE case in Section j., however, enrollment is limited so as to mitigate revenue impacts to the utility. Given that the price is set prospectively over a period of years, the appropriate price may be difficult to determine because important factors related to the value DG will have on the system will be hard to forecast.

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[40] KEMA, Inc. (2008). *Exploring Feed-In Tariffs for California: Feed-In Tariff Design and Implementation Issues and Options.* Final Consultation Report prepared for the California Energy Commission, CEC-300-2008-003-F. Available at: http://www.energy.ca.gov/2008publications/CEC-300-2008-003/CEC-300-2008-003-F.PDF.

[41] In an opinion submitted in 2013 to the Arizona Corporation Commission, attorneys for The Alliance for Solar Choice argued that sell-all tariffs are front-of-the-meter sales and that all proceeds from sales of electricity to the utility likely constitute gross income, which would be taxable to DG owners. They also argued that if all electricity is sold to the utility, none is used by the homeowner and the system would be ineligible for the federal investment tax credit. See Alliance for Solar Choice. (2013, August 15). Public Comment Letter in Docket NO. E-01345A-13-0248. Available at: http://www.rabagoenergy.com/blog/files/tasc-arizona-tax-memo-on-fits.pdf. Proponents of FITs have argued in turn that FITs can be structured as behind-the-meter billing arrangements that are not subject to income taxes, and if the personal investment tax credit were lost the property would be eligible for the 30 percent business investment tax credit and for benefits of accelerated depreciation. See Wesoff, E. (2014, September 24). Solar Policy Battle: IRS Now Part of Fierce Debate Over How to Value Solar Power. *Greentech Media.* Available at: http://www.greentechmedia.com/articles/read/Solar-Policy-Battle-IRS-Now-Part-of-Fierce-Debate-on-How-to-Value-Solar-Po. Also, an Austin homeowner filed an Information Letter Request with the IRS in September 2014 asking whether credits received by a hypothetical residential PV owner's system in exchange for sale of all energy generated by the owner's system would be taxable. The IRS has not made a definitive statement on these questions.

[42] Under federal law, a QF is a small power production facility that meets FERC rules for size, fuel use, and certification. A "small power production facility" for these purposes is a generating facility of 80MW or less whose primary energy source is renewable. A cogeneration facility may also be a QF. Linvill, C., Shenot, J., & Lazar, J. (2013, November). *Designing Distributed Generation Tariffs Well*. The Regulatory Assistance Project: Montpelier, VT. Available at: http://www.raponline.org/document/download/id/6898.

FERC Jurisdiction

There are some who worry that a “buy all, sell all” rate design (in which a DG customer purchases all power from the utility, and then separately sells all power from a DG system) could trigger FERC jurisdictional issues. The issue of whether FERC jurisdiction applies is relevant because it could affect the rate at which the DG customer could be compensated for his/her production.

FERC has jurisdiction over all wholesale electricity sales, and states have jurisdiction over retail sales. Federal law (PURPA, the Public Utilities Regulatory Policies Act of 1978 as amended) requires utilities to purchase power from qualifying small generators at the utility’s avoided cost rate. Generally this rate has been interpreted to mean the cost of generation only; it does not include other avoided costs, such as the cost of distribution, that are bundled into a full retail rate.

Under net metering rates, customers generally can offset their electricity use with what they produce during a period such as a billing period, or a year. Because they are offsetting energy they would otherwise have to pay for at the full retail rate, they are, in effect, paid at the full retail rate for what they produce. Other rate designs where the price paid differs from the price of the power consumed also fall in this category, inasmuch as there is a netting of usage on the customer’s bill.

FERC’s policy is that net metering sales are not subject to FERC jurisdiction as long as net metering customers are net consumers of electricity. However, if customers are net producers, the amount by which their production exceeds use is deemed a wholesale sale and is under FERC jurisdiction. Thus compensation for this excess production is limited to the utility’s avoided cost rate.

If the sell-all portion of a rate is determined to be a wholesale sale, the compensation rate used to determine payments to the DG owner could be limited to the avoided cost rate, rather than an otherwise different rate. This issue of jurisdiction is an important one, and not yet settled.

k. Value of Solar Tariffs

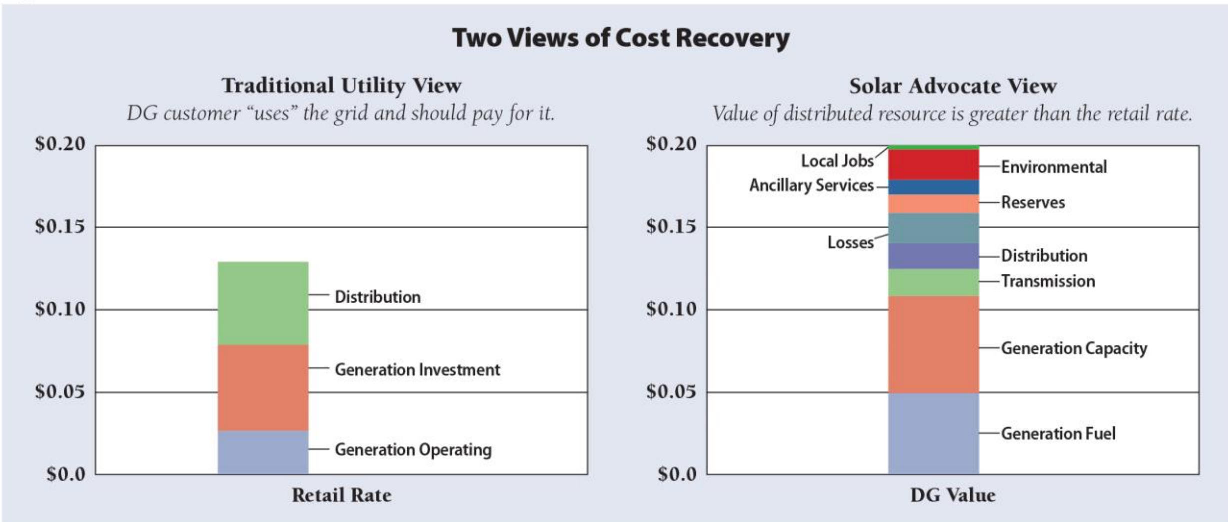
Definition and How It Works

The last rate design option we consider here is a fairly recent idea proposed or implemented thus far in just a few jurisdictions. A value of solar (VOS) tariff combines some of the elements of a FIT with elements of a net metering tariff.

As was the case for a FIT, the VOS tariff offers customers a pre-determined price for each kWh of solar generation their systems can produce for the duration of a long-term contract. However, the price used under a VOS tariff is not based on the customer’s costs or the utility’s avoided costs; rather, it is based on a comprehensive assessment by the utility and/or its regulators of the value of solar generation to the utility and society, as depicted in Figure 1. In theory, this value could be less than or greater than the customer’s retail rate.

The VOS tariff resembles net metering in that it is applied not through payments to the customer but rather through a bill credit mechanism. These are dollar credits rather than kWh credits. VOS is thus a net *billing* tariff and not a net metering tariff. The dollar value of all consumed electricity is calculated at the normal applicable retail rate. The dollar value of generated energy is calculated using the VOS as determined through an administrative process. The customer is billed or credited based on the net of these two values. Credits are rolled over onto the next bill. The net-billing aspect is important in that it (arguably) keeps the utility-customer transaction squarely within the domain of retail rate regulation and avoids the income tax and FERC jurisdiction issues raised in the FIT section above.[43]

Figure 1:



Case Study

In 2013, Minnesota passed legislation permitting all investor-owned utilities to apply to the PUC for a VOS tariff as an alternative to net metering, and as a rate available to community solar gardens.[44] The legislation specifically required that the valuation take into account energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value.[45]

The Minnesota Department of Commerce was assigned the task of developing and submitting the methodology to the PUC for use by the investor-owned utilities.[46] The document prepared by the department and submitted to the PUC includes detailed example calculations of the methodology for each component part as set forth below:

- A standard PV rating convention;
- Methods for creating an hourly PV production time-series, representing the aggregate output of all PV systems in the service territory per unit capacity corresponding to the output of a PV resource on the margin;

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[43] There remain some who suggest that the sales may be taxable. This might depend on how purchase of energy from the grid and compensation for energy sold are structured in the utility tariff. For more information on this issue, see the taxation discussion in Section 4h, "Bi-Directional Distribution Rates."

[44] MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

[45] The City of Austin looked at similar variables including system loss savings, energy savings, generation capacity savings, fuel price hedge value, T&D savings, and environmental benefits.

[46] See: Clean Power Research for the Minnesota Department of Commerce. (2014, April 1). *Minnesota Value of Solar: Methodology*.

- Requirements for calculating the electricity losses of the transmission and distribution systems;
- Methods for performing technical calculations for avoided energy, effective generation capacity, and effective distribution capacity;
- Economic methods for calculating each value component (e.g., avoided fuel cost, capacity cost, etc.); and
- Requirements for summarizing input data and final calculations in order to facilitate PUC and stakeholder review.[47]

Tables 9 and 10 show which potential components are and are not included in the Minnesota VOS methodology, along with an explanation of the basis on which the component value can be determined.

Table 9

Components Included in Minnesota VOS Methodology

Value Component	Basis	Legislative Guidance	Notes
Avoided Fuel Cost	Energy market costs (portion attributable to fuel)	Required (energy)	Includes costs of long-term price risk
Avoided Plant O&M Cost	Energy market costs (portion attributed to O&M)	Required (energy)	
Avoided Generation Capacity Cost	Capital cost of generation to meet peak load	Required (capacity)	
Avoided Reserve Capacity Cost	Capital cost of generation to meet planning margins and ensure reliability	Required (capacity)	
Avoided Transmission Capacity Cost	Capital cost of transmission	Required (transmission capacity)	
Avoided Distribution Capacity Cost	Capital cost of distribution	Required (delivery)	
Avoided Environmental Cost	Externality costs	Required (environmental)	
Voltage Control	Cost to regulate distribution (future inverter designs)		Future (TBO)
Integration Cost	Added cost to regulate system frequency with variable solar		Future (TBO)

[47] Id. at 3.

Table 10

Components Not Included in Minnesota VOS Methodology			
Value Component	**Basis**	**Legislative Guidance**	**Notes**
Credit for Local Manufacturing/Assembly	Local tax revenue tied to net solar jobs	Optional (identified in legislation)	
Market Price Reduction	Cost of wholesale power reduced in response to reduction in demand		
Disaster Recovery	Cost to restore local economy (requires energy storage and islanding inverters)		

The last step of the methodology calls for the conversion of the 25-year levelized value of these components to an equivalent inflation-adjusted credit. The utility then uses the first-year value as the credit for solar customers and each year thereafter adjusts using the latest Consumer Price Index data.[48] Finally, in order to ensure transparency, the methodology proposed by the Department of Commerce included two specific tables: the first was data of utility-specific input assumptions, and the second was the utility-specific total value of solar.

The PUC approved the department-proposed methodology in March 2014[49]; however, as of early 2015, no Minnesota utility had adopted the voluntary VOS tariff in lieu of net metering.[50] This is because the VOS yields less revenue to the DG customer than the combination of a net-metered rate plus the market value of the renewable energy credits. This circumstance may change over time if there are changes in the retail rate, the VOS, or the price of renewable energy credits.

Analysis

Generally speaking, the VOS serves an important role by carefully determining the economic value to the utility system and society of energy produced by a solar DG system. There is a lot of controversy regarding net metering where some are claiming that customers who receive net-metered rates are overcompensated. A VOS has the benefit of demonstrating whether that net-metered customer is being over or under-compensated by determining the value of the energy sold back to the utility. In cases where the retail rate is less than the VOS, the customer who is compensated at the retail rate will receive less than the value. Conversely, if the retail rate is greater than the VOS and the customer is compensated at the retail rate, they will receive a payment that exceeds the value of the solar they are providing. A VOS will encourage innovation in supply and demand since the calculated VOS gives consideration to environmental and other benefits. One of the drawbacks of VOS is that the value is very complex to calculate, as can be seen from the Minnesota example. However, once the value is calculated, its translation into a VOS tariff is simple.

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[48] Id. at 4.

[49] The Minnesota Department of Commerce committee submitted the draft methodology on the VOS tariff to the MN Public Utilities Commission (PUC) in January 2014. The PUC approved the methodology at a hearing on March 12, 2014, and posted the written order approving it on April 1, 2014. See Cory, K. (2014). *Minnesota Values Solar Generation with New "Value of Solar" Tariff*. NREL. Available at: https://www.nrel.gov/tech_deployment/state_local_governments/blog/vos-series_minnesota

[50] Id. To facilitate a possible future transition to a VOS rate, the Minnesota PUC directed the parties:

to engage in further discussions and to file comments by October 1, 2014, regarding the appropriate adder, if any, to apply in conjunction with a proposed value-of-solar rate to ensure compliance with the community solar garden statute, including, but not limited to, a requirement that the community solar garden plan approved by the Commission reasonably allow for the creation, financing, and accessibility of community solar gardens.

5. Other Tools

In addition to tariff design, other tools are available to help increase the value of DG for the customer who is making that sizeable investment or to offset utility revenue losses and effects on non-DG customers. Developing new revenue streams for DG customers that do not increase costs for non-DG customers, or that offset utility expenditures that would have incurred in the absence of DG, are important factors to explore. As regulators look for solutions to utility claims of revenue erosion and consumer advocate concerns that rates will increase, attention should be given to optimizing the value of DG and compensating for it in a way that creates win-win solutions.

Moreover, rate design is a separate issue from revenue sufficiency, and with the growth of DG these issues have gotten conflated. Separate tools that could address utility revenue concerns should also be explored. We discuss just a few options here.

a. Decoupling

Lost revenues associated with increased DG penetration are a key concern voiced by the utility industry. Regulators, utilities, and stakeholders have attempted to address this issue in different ways, predominantly through decoupling or SFV rates. Both of these mechanisms address the throughput incentive for distribution utilities, but only decoupling does so in a way that is equitable to all customers and simultaneously preserves the customer's incentive to be energy efficient and conserve. As noted, SFV rate design frequently results in volumetric charges that are below the long-run marginal cost. When that occurs, there is no signal to the customer of the true price to be paid for high consumption in the form of the need to add more generation.

Definition and How It Works
Decoupling (also known as revenue regulation) is among the tools that can be used to align the utility's interests with the customers' interests. Decoupling creates a mechanism that separates revenue recovery from sales and thus removes the utility incentive to increase sales. It adjusts utility rates (prices) between rate cases to account for changes in sales volumes and relies on the revenue requirement from a recent rate case as a fulcrum. Decoupling does not change the way in which a utility's allowed revenues (i.e., the "revenue requirement") are calculated.[51]

What is innovative about decoupling when compared with traditional regulation is that it combines with a defined revenue requirement to eliminate sales-related variability in revenues. It thus eliminates not only weather and general economic risks facing the utility and its customers, but also potentially adverse financial consequences flowing from successful investment in end-use energy efficiency and DG deployment.

Table 11 offers an illustration of how decoupling works:

[51] A revenue requirement is based on a company's underlying costs of service, and the means for calculating it rely on long-standing methods that need not be recapitulated in detail here.

Table 11

Simple Example of a Decoupling Adjustment	
Periodic Decoupling Calculation	
From the Rate Case	
Target Revenues	$10,000,000
Test Year Unit Sales	$100,000,000
Price	$0.10000
Post Rate Case Calculation	
Actual Unit Sales	$99,500,000
Required Total Price	$0.1005025
Decoupling Price "Adjustment"	$0.0005025

Decoupling is generally symmetric—if sales go up resulting in revenue in excess of planned amounts, the price adjustment is negative. Generally, adjustments to rates have been in the one to three percent range, with the bulk around one percent.[52,53]

Case Study

In 2006, a MADRI workgroup produced a *Model Rate Rider for a Revenue Stability Adjustment Factor*.[54] The MADRI model provides detailed revenue-per-customer decoupling formulas. Given the nature of the electricity markets in the MADRI jurisdictions, the model rate rider suggests separate revenue stability adjustment factors for demand charges and energy charges. Electricity rates in the District of Columbia, Maryland, and Ohio now include decoupling mechanisms that were informed by the MADRI model rate rider. Additional decoupling case studies from jurisdictions outside of the MADRI states can be found in a more recent publication by the Regulatory Assistance Project.[55]

Analysis

Rate design is best used to signal value and fairness to customers. It need not be used for the purpose of recovering revenue eroding from distributed resource deployment, as it is unlikely to yield a fair correlation between cost and cost causer. Lost revenues can therefore be addressed separately. Decoupling can be an effective way to eliminate utilities' throughput incentive and thus address a key point of utility opposition to DG and energy efficiency. It provides a way for a utility to maintain its

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[52] Sixty-four percent of all adjustments are within plus or minus two percent of the retail rate, which amounts to approximately $2.30 per month for the average electric customer. Across all electric and gas utilities and all adjustment frequencies, 62 percent of the adjustments were surcharges while 38 percent were refunds. Morgan, P. (2012). *A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations.* pp. 2-3. Graceful Systems LLC. Available at: http://switchboard.nrdc.org/blogs/rcavanagh/decouplingreportMorganfinal.pdf.

[53] For more information on the mechanics of decoupling, see Lazar, J., Weston, R., & Shirley, W. (2011). *Revenue Regulation and Decoupling: A Guide to Theory and Application.* Montpelier, VT: Regulatory Assistance Project Available at: http://www.raponline.org/document/download/id/902

[54] For more on the MADRI model, see: http://sites.energetics.com/MADRI/pdfs/Model_Revenue_Stability_RateRider_2006-05-16.pdf.

[55] Migden-Ostrander, J., Watson, B., Lamont, D., & Sedano, R. (2014, July). *Decoupling Case Studies: Revenue Regulation Implementation in Six States.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7209.

revenue to cover its service responsibilities even when sales decrease; as a result, decoupling can eliminate the cost of frequent rate cases, a cost borne by customers

b. New Cost-of-Service Studies

Definition and How It Works

One of the inputs in designing rates and allocating costs is the cost-of-service study. Economists and utility rate experts may debate the use of particular modeling approaches and methods, but the concept that utility service should be based on cost is at the core of determining the reasonableness of rates. Cost-of-service studies are in-depth analyses of cost-causation. A cost-of-service study will examine the costs on the system by function (generation, transmission, and distribution) and what/who is causing that cost. It will look at embedded and/or marginal costs for service and it will examine the costs on the system by customer class. Some costs are driven by the number of customers while others are driven by usage, and still others are driven by the coincident peak or other allocators. A cost-of-service study can help identify any new costs associated with the addition of DG and it could also examine potential benefits of DG, such as locating DG in a constrained area as a solution to a need that would otherwise require upgrading a feeder, installing a new transformer, etc. Cost-of-service studies that break out a subset of customer classes to arrive at the cost of service for partial and full requirements customers separately may offer a new view useful for developing rates that are fair and equitable in recovering utility costs. Establishing an appropriate cost to provide service to full versus partial requirements customers potentially establishes the most equitable and non-discriminatory basis for rate design.

Case Study

Energy and Environmental Economics conducted a detailed analysis of the cost-of-service implications with net energy metering customers in the state. [56] At the direction of the California PUC, the firm analyzed the net metering programs for each of the three large investor-owned utilities, with over 150,000 net metering customers and total installed capacity of 1,300 MW through the end of 2012.

A full cost-of-service assessment compares the utility's cost of serving net metering customers with the customer's actual bill payments. Utility costs of service are emulated from the methodology that each utility used in its most recent general rate case. The cost-of-service assessment compares the actual bills that net metering customers pay to the utility costs (including fixed costs) needed to serve those customers.

Due in large part to the utility's tiered rate structures, and the fact that residential customers who install DG are on average larger users, these customers' bills on average were 54 percent higher than their cost of service before the installation of DG.[57] However, Energy and Environmental Economics found that the gap between bills and the full cost of service shrank dramatically after considering the installation of the DG resource. Whereas total annual bills were $175 million in excess of the full cost of service before DG, the difference is only $23 million after DG installation for residential customers. The relative changes to bills and full cost of service, however, are not uniform across all utilities and customer sectors.

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[56] CA PUC. (2013, September 26). *California Net Energy Metering (NEM) Draft Cost--Effectiveness Evaluation.* Available at: https://ethree.com/documents/CSI/CPUC_NEM_Draft_Report_9-26-13.pdf

[57] Id. at 9.

With renewable DG, net metering residential customers pay 88 percent of their full cost of service compared to 154 percent before DG, and non-residential net metering customers pay 113 percent, compared to 122 percent before DG.

This cost-of-service study, thus, was able to analyze how the net metering tariff affected recovery of full cost of service.

Analysis

The growth of DG raises questions of equity and revenue recovery. This paper has examined various tariff designs under discussion that would address DG cost and recovery issues. Some tariffs, net metering for example, price electricity at the same rate for what is produced and sold. A FIT tariff, by contrast, assigns a contractual value to energy produced by DG. Minimum bills, increases in fixed charges, and subscription demand charges all seek to recover costs from DG customers to make up revenue that utilities lose because of lower sales volume. Yet these charges and prices are all approximations, and do not in themselves assure a fair assignment of costs between DG and non-DG customers.

Because cost-of-service studies break out classes of customers and examine costs that each cause and the benefits that each provides (e.g., PV contribution to peak load), they can be a useful tool for designing and evaluating the various possible DG tariff designs. Cost-of-service studies are at the root of most if not all rate designs in place today. Their vintage may be recent, suggesting good alignment between rate design and cost causation, or ancient, indicating that this relationship is inaccurate. The process of executing a cost-of-service study for a typical utility is arduous and expensive, which accounts for their usually being done on cycles from three to ten years, where this is a priority. A reasonably accurate relationship between rate design and cost causation makes for a strong foundation for fairness and for the other solutions discussed in this paper.

c. DG Distribution Credit

Definition and How It Works

DG can provide a myriad of system benefits, and therefore it is important that these values be quantified and compensated in order to ensure its continued contributions. Like any other investment, DG needs to be economically sustainable on its own merits for customers to continue to engage. One of the ways that DG can contribute to the system is through being strategically located in constrained areas or areas that require distribution system upgrades. While average distribution rates might be on the order of $.025 per kWh, marginal distribution costs vary substantially from one place to another and from one time to another, and can range from zero to substantially more than $.200 per kWh.[58] In some cases DG can be a smart economic alternative to distribution system upgrades, though it has to date been underutilized as a solution. However, this option is beginning to be explored in a few state proceedings and discussions on this topic are being included in conferences across the nation.[59]

Two of the mechanisms for recognizing the value of DG are de-averaged distribution credits and distributed resource development zones. De-averaged distribution credits would work through a utility program in which the EDU geographically de-averages distribution costs and provides financial credits to

[58] Moskovitz, D. (2001, September). *Distributed Resource Distribution Credit Pilot Programs: Revealing the Value to Consumers and Vendors*.

[59] For more information, see NY PSC. Reforming the Energy Vision. Case 14-M-0101. Available at: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument

DG installed in a particular area. The credit amount would be based on the distribution cost savings resulting from installing DG. The credits would be limited in duration and size so that they could match the timing and need for distribution system reinforcements. For example, credits might be available up to a certain number of MWs in a given area so as to meet the amount of DG support needed. The amount of the credit could be up to, but not in excess of, the value of the savings that accrue from deferring or avoiding the distribution upgrade in a given area. Therefore, the size of the credit could vary based on the specific facts and costs in any of the areas.[60]

Distributed resource investment zones would work hand-in-glove with the de-averaged distribution credit by having a standard credit for specific geographic areas. A competitive bidding process could be employed in which qualified DG customers bid to locate in a designated geographic zone to obtain the credit. Note that to obtain the credit, the DG customer would need to meet a number of criteria set forth by the utility relating to operating and performance standards; meeting milestones for installation; minimum and maximum capacity made available; duration of the DG unit; and being subjected to monitoring and evaluation to ensure performance, among other criteria.

d. Performance-Based Regulation

All regulation is incentive regulation.[61] The formula used to allow utilities to meet their revenue requirements plus a reasonable return for shareholders is dependent on how they are compensated. The traditional ratemaking formula rewards utilities through providing a return on investments in assets and also through increasing sales. Performance-based regulation realigns the signals sent to utilities regarding how they can increase earnings. It rewards utilities for performance that furthers public policy objectives. There are a number of ways to design performance metrics, but this is beyond the scope of this paper. In broad-brush terms, however, part of a utility's return for shareholders would be based on its performance under metrics established by the regulatory authority in a proceeding. Examples of metrics can include reliability measures, energy efficiency performance, policies and procedures for DG, customer service, etc.[62]

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[60] Moskovitz, id.

[61] Bradford, P. (1992). Foreword. In S. Nadel, M. Reid, & D. Wolcott (Eds.), *Regulatory Incentives for Demand-Side Management* (ix – xi). Washington, DC: American Council for an Energy-Efficient Economy. Available at: http://www.aceee.org/sites/default/files/publications/ebook/regulatory-incentives-for-demand-side-management.pdf.

[62] Whited, M., Woolf, T., & Napolean, A. (2015). *Utility Performance Incentive Mechanisms: A Handbook for Regulators.* Synapse Energy Economics. Available at: http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf

6. Conclusion

As energy technologies continue to advance and offer more options to customers, getting the rate design for DG customers right will be increasingly important. In some states, such as Hawaii, there is already a lot of PV activity; in others, solar PV is in its nascent stages. Thus the need to address these issues and the steps taken with some utility rate designs vary from jurisdiction to jurisdiction. Nevertheless, the cornerstones for developing rate designs for DG customers should include the following:

- A customer should be able to connect to the grid for no more than the cost of connecting to the grid;
- Customers should pay for grid services and power supply in proportion to how much (and when) they use these services and how much power they consume;
- Customers who supply power to the grid should be fairly compensated for the full value of the power they supply, no more and no less; and
- Tariffs should fairly balance the interests of all stakeholders: the utility, the non-DG customer, and the DG customer.

Evaluated through this prism, there are several rate designs that fall short. For example, a rate design based on high fixed customer charges may satisfy the utility desire for guaranteed revenues, but it does not do so in a manner that is fair to all customers. It does not adhere to policy objectives of conservation and, importantly, it is not based on cost-causation. While this rate design has gained some traction as an easy, simple-to-administer solution, it lacks accuracy and accountability. Imposing arbitrary fees on DG customers for using the grid is equally devoid of a rational cost basis and this rate design suffers from some of the same infirmities that plague high customer charges. Grid fees are also likely to be viewed by many customers as simply a barrier imposed by utilities to prevent, or mitigate, the development of DG resources that pose a threat to revenue recovery.

For a rate design to withstand some test of time and gain acceptance, it has to not only adhere to basic rate design principles, but it must also provide long-term equitable solutions for the DG customer, the non-DG customer, and the utility. Providing an advantage to one stakeholder group at the expense of another is unlikely to succeed as a long-term strategy.

Other rate designs discussed in this paper come closer to offering a balanced solution for all stakeholders. Many of these rate designs are premised on the DG customer paying the full retail rate for energy consumed. That is the easier part of the equation. The more challenging part is determining the appropriate level of compensation paid to the DG customer for power provided to the grid. There are a number of ways this can be calculated. The most prevalent mechanism that has been used historically is net metering. This has come under scrutiny recently with its detractors claiming that net-metered customers are being subsidized. Others disagree. However, the important point is that what is most fair is to independently determine the value of the power provided from DG. The relationship between the value of the DG unit to the grid as compared to the retail rate will determine whether a DG customer is being over- or under-compensated for the power he or she is providing. If the value provided by DG is higher than the net-metered rate, then the DG customer may be under-compensated; and conversely, if the value provided by DG is lower than the net-metered rate, then the DG customer may be over-compensated.

There are different mechanisms for determining the appropriate compensation to give a DG customer. And while net metering is being questioned in some jurisdictions, it nevertheless represents a rough justice premised on the assumption that the rate paid by the customer is equal to the value of the power being produced from the DG system. More precise quantification can occur through a VOS analysis. This analysis looks at all the value provided by a PV system, which may include a variety of externalities that may not typically be considered in an avoided cost calculation.[63] A VOS analysis that includes externalities will more likely than not result in a rate that is higher than a net-metered rate. Moving away from net metering and its simplicity requires an assessment of whether improved accuracy in compensation is worth a reduction in simplicity.

Another factor to be considered on a jurisdiction-by-jurisdiction basis is how advanced the solar market is in that jurisdiction. States with very little activity may want to consider more robust rate designs like FITs to help spur the market. On the other hand, utilities and regulators in well-developed solar markets might find such tariff designs unnecessary and prefer a different approach to determine the right pricing for the DG customer's power.

A rate design worth serious consideration is the deployment of bi-directional distribution rates applied to all net consumption or net generation, combined with TOU power supply charges and credits. Under this approach, the DG is paying a more accurately determined cost for the power it is consuming and at the same time being similarly compensated for the value to the utility of the DG power it delivers. It results in the customer being compensated appropriately if it helps the grid during peak hours by providing power, but it also charges that customer an on-peak rate for drawing power during peak times. Complementing this rate design with a small demand charge that recognizes that the cost to the system varies based on the size of the customer would also be appropriate to assist the utility in recovering costs from DG customers and large users.

Rate designs will need to be monitored and adjusted as customer loads continue to change and shift both in terms of volume and time of use. Revenue requirements and grid reliability will also need to be closely monitored. Revenue needs can be addressed outside of rate design. Mechanisms that could be explored as part of a power sector transformation initiative include decoupling, new cost-of-service studies, distribution credits, performance-based regulation, optimization of utility efficiency, and creating mechanisms for DG to support the utility grid infrastructure. [64]

DG has an important role to play where it can be a lower cost option than what the utility would otherwise invest in for infrastructure and generation upgrades. It is an alternative that should be considered in resource planning where it can produce savings for all customers. Viewed in that light, it is incumbent upon the utilities to optimize the efficiency of their operations so that as they receive less revenue, they also require less revenue. If DG is an alternative to utility investment, then rate design must communicate to customers the value that makes this substitution efficient. Rates should not promote uneconomic bypass in which marginal rates are too low and economic utility investments are squeezed out. Nor should it promote uneconomic stasis in which marginal rates are too high and uneconomic utility investments are chronically occurring.

[63] An exception would be in cost-effectiveness screening of energy efficiency programs where the societal test is used to calculate such benefits as environment, health, quality of life, impacts on the economy, etc.
[64] For more details, refer to: Lazar, J. & Gonzalez, W. (2015, July). *Smart Rate Design for a Smart Future*. The Regulatory Assistance Project: Montpelier, VT. Available at: http://www.raponline.org/document/download/id/7680.

For regulators, the challenge lies in balancing short-term customer costs with long-term system benefits and getting the price signals correct. In establishing rate designs, regulators should consider the following points:

1. Does the rate design fairly allocate costs in accordance with who is causing the cost?
2. Does the rate provide the proper price signals so that appropriate attention is paid to system costs and needs so as to avoid uneconomic investments?
3. Does the rate provide proper price signals so that customers pay in accordance with the costs they are causing on the system?
4. Is there fair and reasonable compensation for those providing a service/benefit to the grid?
5. Does the rate fairly consider the energy burden for low-income customers?
6. Are there policies in place to address utility revenue shortfalls and to reward the utility for implementing practices that increase its operating efficiency and advance public policy goals?

Rate designs that can affirmatively answer the above questions will have a higher likelihood of success as DER alternatives continue to gain traction.