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NARUC MANUAL ON DISTRIBUTED ENERGY RESOURCES  
COMPENSATION

PREPARED BY THE  
STAFF SUBCOMMITTEE ON RATE DESIGN

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## I. Introduction

On November 11, 2015, at its Annual Convention, the National Association of Regulatory Utility Commissioners (NARUC) adopted a resolution to create a Staff Subcommittee on Rate Design.<sup>1</sup> The purpose of creating this Staff Subcommittee was to **provide a forum** for state commission staff to discuss rate design challenges in their states with staff from other state commissions. The Staff Subcommittee's purview includes electric, water, and natural gas rate design topics. The Staff Subcommittee also works with other NARUC Staff Subcommittees where areas of interest overlap. For example, the Staff Subcommittee on Rate Design works with the Staff Subcommittee on Water when appropriate, and also **works with** the Energy Resources and Environment Staff Committee on other select rate design issues.

In its Resolution creating the Staff Subcommittee on Rate Design, NARUC recognized the increasing importance that rate design issues has on policy development across the states, most notably as it applies to distributed energy resources (DER). Upon his **elevation** as President of NARUC, Montana Public Service Commission Commissioner Travis Kavulla announced that the Staff Subcommittee on Rate Design would prepare a DER compensation manual to assist jurisdictions in navigating the challenges, considerations, and policy development related to compensating DER. As stated by NARUC President Kavulla, "this subcommittee will work to create a practical set of tools—a manual, if you will—for regulators who are having to grapple with the complicated issues of rate design for distributed generation and for other purposes."<sup>2</sup> The development of this Manual is in response to NARUC's resolution and the request of the association's leadership.

The growth of DER across the jurisdictions poses unique challenges to regulators. The traditional ways of electricity delivery from large power plants over transmission and distribution wires to the customer are increasingly being challenged due to the growth of DER. **DER are resources** located on the distribution grid, often located on the customer's premise, and are capable of providing many services to the customer and the grid. A DER, like rooftop solar generation, can offset **the premise's consumption and deliver excess generation** onto the distribution grid. DER, like demand response, can allow demand to respond to system prices and conditions. DER is not simply supply or demand, as traditionally thought, but can be multiple types of resources, such as storage or advanced technology paired with a resource, capable of providing a variety of benefits and services to the customer and the grid.

Furthermore, traditional utility and regulatory models built on the assumption of the utility providing enough electricity to meet the entire needs of its service territory are under pressure by DER. New investments will be needed to better handle this two-way flow of electricity, new ways of **allowing** the utility to recover its costs may be needed, and new assumptions around customer demand will be necessary to meet this challenge. A jurisdiction will need to identify its current status regarding DER,

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<sup>1</sup> "Resolution to Create a NARUC Staff Subcommittee on Rate Design," NARUC (November 11, 2015) (<http://pubs.naruc.org/pub/D2DDD7AC-E73C-B386-630C-B88491DD0608>).

<sup>2</sup> Installation Remarks of NARUC President Travis Kavulla (November 10, 2015) (<https://www.naruc.org/about-naruc/press-releases/pr-111015/>).

what role it expects DER to have in the future, understand the nature of DER adoption rates, and identify necessary policy developments to accommodate that future.

This Manual is intended to assist jurisdictions in developing policies related to DER compensation. It is also intended to be similar to other NARUC manuals on topics such as cost allocation and natural gas rate design. Its purpose is to assist jurisdictions in identifying issues related to DER and assist regulators in answering questions in a way most appropriate for its jurisdiction. This Manual provides regulators with possible options that a jurisdiction may want to consider and adopt. This Manual should be applicable regardless of market structure (restructured versus vertically-integrated), organized wholesale market or not, or adoption of technology, be it advanced utility infrastructure or availability of customer-sited technology.

This Manual is organized in five main sections. Section 2 describes the basic rate design process and how DER impacts that process. Section 3 discusses what is DER and why it is important for states to consider. Section 4 is about the systemic challenges and questions raised by the details of rate design and compensation. Section 5 outlines a variety of possible DER compensation methodologies that a jurisdiction may consider. Lastly, Section 6 provides a description of advanced technologies that can potentially assist a regulator and utility in planning and monitoring DER development, and considerations for when it may be appropriate to reconsider existing DER compensation methods based on DER adoption levels in a jurisdiction or utility service territory.

This Manual provides a snapshot at options available today, and the role of advanced technology in the future to assist a regulator in monitoring the development of DER. This Manual cannot predict the future, such as future uses of DER, future DER technologies, future business model options, or any unanticipated advancements in market development or policy development that may impact this topic. Given that limitation, this Manual will hopefully provide regulators with the ability to meet current needs and plan for future demands. How it is ultimately used will be decided by regulators, utilities, customers, and other participants. As the pace of change develops over time, it should be expected that this Manual will be revised, as circumstances warrant.

The Staff Subcommittee on Rate Design thanks all who have assisted in the development of this Manual, and appreciates the time and effort of those on the Staff Subcommittee who assisted in the development and review of this Manual, and those who have provided input and/or comments on this Manual.

## II. What is the Rate Design Process

### A. Definition, Principles, Goals, and Purpose

Before going into the details of rate design impacts from DER, a foundation must be set relating to the basic purposes for rate design and associated foundational principles. Additionally, a key component of understanding how rates are determined includes the importance of understanding costs and what costs a utility is allowed to recover by the regulator. This section provides an overview of these two steps in most basic rate design processes across the country. As part of this discussion, it is recognized that most existing rate designs are not explicitly designed to reflect accurate costs to serve each customer. Electricity costs vary throughout the year, month, week, day, and hour; rate design balances this reality to allow for the utility to recover its total costs of service (*i.e.*, revenue requirement), over the course of time, be it monthly, yearly, or across rate case proceedings. This averaging of costs into a rate **supplies a convenient** rate over time, but does not reflect the **changing nature of electricity delivery** (particularly with increasing amounts of DER materializing). **DER may impose new costs onto the utility, costs which need to be recovered to ensure the utility's financial health and to allow the utility to recover necessary investments in the distribution grid to maintain reliability and quality of service. Identifying the appropriate principles, goals, and objectives for rate design can assist a regulator in determining an efficient rate (or compensation methodology) that collects the authorized utility costs or authorized revenue requirement.**

#### 1. Rates

Rate design, the process of translating the revenue requirements of a utility into the prices paid by customers, is often said to be more art than science. While there is often agreement amongst the parties to the rate setting process on the various goals and principles of rate design, the weights given by the different parties to each, and the opinions on the specifics of their application, vary greatly. Rate design may be influenced by legislative initiatives and political and environmental policies. **However, a single rate design cannot meet all rate design principles and all policy goals.** Indeed, many of the goals and principles conflict with one another, and it is the job of the regulator to **strike a balance** between these principles and goals that best reflects the public interest as they see it.

The basic purpose of rate design is to implement a set of rates for each rate class – residential, commercial, and industrial – that produces revenues to recover the cost of serving that rate class. In practice, rates are not based on an individual customer's cost to serve, rather similar customers are accumulated into rate classes, and the total cost to serve all of the customers in that rate class is allocated **equally** across all of the customers in that rate class.

Over the years, several authors have laid out goals and principles of rate design that continue to be referred to, both by more recent authors, as well as the various parties to the rate setting process. One of these enduring authors is James Bonbright, whose *Principles of Public Utility Rates* lists the following criteria of a desirable rate structure:

1. The related, practical attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies about proper interpretation.

3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of “undue discrimination” in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use
  - a. in the control of the total amounts of service supplied by the Company
  - b. in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).<sup>3</sup>

Bonbright distills these down to three primary objectives of rate design from which **his** others flow:

- (a) the revenue-requirement or financial-need objective, which takes the form of a fair-return standard with respect to private utility companies;
- (b) the fair-cost-apportionment objective, which invokes the principle that the burden of meeting total revenue requirements must be distributed *fairly* among the beneficiaries of the service; and
- (c) the optimum-use or consumer-rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received.<sup>4</sup>

## 2. Costs

While the most commonly used forms of rate design **may** not be an attempt to communicate costs with perfect accuracy to the customer, the cost of serving that customer is an indispensably important ingredient in any rate system. To create an appropriate rate, it is important to distinguish between fixed and variable costs. Such a distinction informs, though does not entirely decide, the basis on which those costs should be collected. Separately, a regulator may also choose to have the rate send a price signal to the customer which may reflect a more accurate price related to the cost to serve a customer at a certain point in time or over a specified time period. In the short-term, many of the costs of a utility are fixed. In the long-term, many of the costs of a utility are variable. The question, then, is how much of a utility’s costs should be considered fixed for the purposes of setting rates. Here, also, there is much disagreement. In the short- **to mid-term**, costs are not terribly sensitive to changes in use. **As a result, a customer who lowers their use creates an additional burden on others, as the costs must be covered by someone.** Others argue that the appropriate time horizon to price these costs over, because of economic theory or the long **planning horizon** of the utility, is the long-term.

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<sup>3</sup> James C. Bonbright, *Principles of Public Utility Rates* at 291 (1961).

<sup>4</sup> *Id.* at 292.

The majority of rate design considerations have corresponding considerations for cost allocation, and vice-versa. To the extent that regulators desire rates to be based on cost-causative elements, the allocation of those costs is (or should be) on the basis of those cost-causative elements. The regulator **may** decide that the allocation of costs should reflect decisions made about the way those costs are collected, or vice-versa.<sup>5</sup> This also mitigates potential intra- and inter-class subsidies.

## **B. Introduction to Rate Design**

### **1. Basic Service Rates**

There are several ways to structure the rates paid by customers. Each tends to accomplish certain principles, goals, and objectives of rate design, as determined by the regulator, while neglecting others. **Rates can also be combined** in varying degrees in an attempt to balance the objectives of the jurisdiction.

#### **a. Flat rates**

A flat rate design charges customers a per unit charge regardless of consumption. The total costs (or some subset) allocated to a class are divided by the usage of that class to produce a rate. This rate is then uniformly applied to any usage by a customer within that class. This rate structure (in combination with a monthly customer charge) is commonly used in designing rates for residential electric customers. Indeed, this is the most common form of residential rate design across the country today. Depending on the objectives identified by the state, a flat rate can meet some of them, such as affordability. On the other hand, recognizing that the cost of electricity varies throughout the day and by location, a flat rate **may** not reflect the costs to serve a customer at a given time period. For example, it tends to cost more to serve customers during peak periods due to the increasing marginal cost of generation (*i.e.*, peaking generation plants have higher operational costs, which is reflected in wholesale electricity costs), and **shortage** of available capacity on the transmission and/or distribution grid. A flat rate does not reflect these conditions. A flat per unit rate tends to benefit low-use customers and poses some disadvantages to some customer classes, such as C&I customers with high load factors and high volumetric consumption. For example, if the provision of service (*i.e.*, generation as reflected in \$/kWh) is more expensive at certain times of day, this rate fails to reflect that, and those customers using proportionally more of their electricity at the higher cost times are being subsidized by those who use proportionally more at lower cost times. Additionally, supply costs can vary daily and hourly, and therefore, a flat per unit rate sends a poor price signal for supply resources if they do not receive a time-differentiated wholesale price that reflects the **value** of their production.

#### **b. Block Rates**

An increasing or inclining block rate (“IBR”) structure is designed to charge customers a higher per unit rate as the customer’s usage increases over certain blocks of usage within a billing cycle. For example, a three tier IBR would identify three “blocks” of usage. Block one would be 0-150 kWh, Block 2 would be 150 kWh-250 kWh, and Block 3 would be all usage over 250 kWh. For each block, there would be a price for all electricity charged in that block, with the price increasing as a customer moves through the

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<sup>5</sup> For an introduction to cost allocation methodologies, see, “Electric Utility Cost Allocation Manual,” NARUC (January 1992).



blocks. One of the main purposes of an IBR is to send a conservation signal to customers and to incentivize energy efficiency and reduce consumption on the system. In other words, as the price increases with each block, customers may be encouraged to conserve to avoid the higher block price over a billing cycle. In designing an IBR, some considerations must be made, such as the price differentials between the various consumption blocks and the availability of timely consumption information to customers. If customers do not possess the ability to access their consumption data throughout the billing cycle, they will not know when additional consumption reaches the higher block rate. Another consideration is that IBRs impose higher per unit costs on high-use customers even though delivering additional volumes may not increase the costs of providing delivery service. Although the incentive to conserve over time is greater with an IBR design through avoiding higher prices over the month, this rate does not reflect the hourly or daily changes to the cost of electricity. A customer may pay more for electricity over a given month, even though a majority of its usage may be entirely off-peak; since an IBR does not reflect the day-to-day considerations of peak and off-peak, a customer may overpay for electricity as compared to its otherwise basic cost of service.

A decreasing or declining block rate (“DBR”) structure is designed to charge customers a lower per unit rate as the customer’s usage increases within a billing cycle. DBRs are still sometimes used to reflect decreasing fixed costs as output increases; a higher initial rate would recover initial fixed costs, and rates would decrease over the blocks as the rate reflects more variable costs. However, by lowering the savings potential, DBRs discourage conservation, energy efficiency, and customer adoption of technologies that may reduce consumption or otherwise reflect costs.

### **c. Time Variant Rates**

Time variant rates are designed to recognize differences in a utility’s cost of service and marginal costs at varying times during the day. Generally, a time variant rate design charges customers a higher price during peak hours than off-peak hours. Unlike flat rates, customers need to be aware of usage throughout the day and the month to respond to the price signals in a time variant rate design. A customer may increase savings under a time variant rate compared to a flat rate, if that customer uses energy appropriately during specific peak and off-peak hours. A variety of time variant price options can be considered by a regulator; each option provides the regulator with the ability to reflect a variety of goals. Additionally, with the advent of advanced metering infrastructure, the metering technology is capable of implementing these rate design options on a wider scale.

A time of use (TOU) rate charges customers different prices according to a pre-determined schedule of peak and off-peak hours and rates. For many utilities, TOU rates have been a voluntary option for residential customers for decades, but, generally, few customers participate. Lack of cost-effective metering technology hindered the wider development of TOU, but advanced metering technology is being rolled out across many jurisdictions, which can facilitate roll-out of TOU. Many commercial and industrial (C&I) electric customers already take service under TOU rate designs.<sup>6</sup>

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<sup>6</sup> One alternative to a TOU rate is a peak time rebate (PTR), which operates concurrent with traditional rate design. A pre-established customer baseline of energy consumption is established prior to implementation, and the PTR is awarded if a customer reduces their consumption below the baseline during those peak time hours. Customers will still pay the traditional rate during the peak time, but are also rewarded for any reduction in consumption during those peak hours. Since a PTR does not change the traditional rate design, it may be easier for residential customers to understand.

Under a real-time pricing plan for electricity rates, the customer is charged for generation at the price set in the wholesale market (for deregulated utilities) or the short-run marginal generation costs (for vertically integrated utilities) by the hour.<sup>7</sup> Large electric customers may already be indexed to the hourly generation price through a competitive supplier or utility rate design, but advanced metering infrastructure is needed to implement real-time pricing for residential and smaller C&I customers.<sup>8</sup> Real-time pricing is available to residential customers in the Illinois service territories for Commonwealth Edison and Ameren. The real-time rates for these programs are based on the day-head hourly wholesale price for the given utility zones.<sup>9</sup>

A dynamic pricing rate design contains pre-established blocks of hours reflecting the characteristics of costs that occur during those blocks. Compared to a TOU rate design that pre-determines a schedule of peak and off-peak hours and rates, the dynamic pricing schedule and rates may be revised based on market conditions.<sup>10</sup>

A utility may implement a critical peak pricing (CPP) rate during times of expected shortages or anticipated high usage days to mimic peak time price increases. The utility will announce the hours that the CPP rate will be in effect prior to the CPP event. The CPP rate reflects the higher generation price of electricity during those CPP hours or the existence of scarcity during the event hours. Generally, the CPP rate is set significantly higher than the non-CPP rate as a means of incenting customers to reduce consumption. A CPP can be included with a TOU rate; in both cases, the rate is determined by the regulator, but a CPP event is usually limited to certain peak hours over a year.

#### **d. Three part rate/Demand Charges**

Since the utility system is built to peak, the costs of providing electricity at peak hours is higher than during non-peak hours- greater infrastructure is necessary to serve peak load. To address this situation, another rate structure option is the three part rate, which adds a demand charge to the existing fixed charge and volumetric rate. This rate recognizes three of the major contributors to a utilities' costs. To the extent that each piece of the rate properly reflects the costs associated with each piece, the price signal should be improved over flat or block rates. Such rates have been commonplace for commercial and industrial customers, at least as an option, for a long time. This charge usually reflects the costs to provide electricity at a given time, usually the peak hour of the month. In an effort to identify costs associated with peak, a "demand charge" is one way for a utility to send a peak pricing signal over a certain time period, such as monthly. Peak coincident demand charges can be useful in sending a price signal to the customer regarding when the system peaks, and consumption during that period is charged accordingly; however, non-coincident peak demand charges merely charge a customer for its peak consumption, regardless of the time it occurred.

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<sup>7</sup> "Smart Rate Design for a Smart Future," Lazar, J. and Gonzalez, W., Regulatory Assistance Project (2015). Available at: <http://www.raponline.org/document/download/id/7680>.

<sup>8</sup> *Id.*

<sup>9</sup> Commonwealth Edison is in PJM, and Ameren is in MISO.

<sup>10</sup> "Designing Tariffs for Distributed Generation Customers," Migden-Ostrander, J. and Shenot, J., Regulatory Assistance Project (2016). Available at: <http://www.raponline.org/document/download/id/7983>

The metering necessary to apply these rates to residential customers, however, have only recently been installed by many utilities, as the costs to install new meters had previously outweighed the benefits. There is some disagreement over how appropriate it is to apply a demand charge to smaller customers. Some argue that the diversity of customers in a large class is such that any given customer's on-peak demand is not a good indicator of the costs associated with that customer. Given that these rates are calculated based on averages and generally applied to a number that is resistant to downward pressure, such a concern is somewhat mitigated. There is also disagreement on the amount of costs that are actually related to demand, or a particular measurement of demand.<sup>11</sup> Lastly, system peak is often only known after the month, so a customer has to best guess when the system peak occurs.

## C. Other Considerations

### 1. Vertically integrated versus restructured

A distribution utility in a restructured state is responsible for operating the distribution system and recovering associated costs through distribution rates. These utilities do not own generation assets. In such states, energy supply is procured in a competitive market and customers may be able to choose a company for their own supply services. Non-utility providers of supply operate under limited regulatory jurisdiction and may offer a variety of rates for supply service. A large portion of Texas, most of the Northeast, and some Midwestern states have restructured electric markets.<sup>12</sup> In restructured markets, retail utility rates are unbundled so that a customer will see a separate charge for generation, transmission, and distribution. Additionally, an independent system operator ("ISO") or a regional transmission organization ("RTO") facilitates the operation of the bulk power market and manages the transmission system across its footprint. With the exception of ERCOT, bulk power markets and transmission are subject to FERC jurisdiction. ISOs/RTOs include: ISO-NE, NYISO, PJM, ERCOT, SPP, MISO, and CAISO.

In jurisdictions with vertically-integrated utilities, the rates sometimes may not be unbundled into separate power supply and distribution rates. As many of the cost-causative elements differ between these utility functions, even for a single customer, an appropriate rate structure may be more difficult to agree on. To the extent that regulators wish to separate prices for different cost-causative elements, unbundling rates may be an important first step. The impact of lowered usage may also have more of an impact on integrated utilities' revenue collection ability, as it has more total revenue requirement associated with assets that needs to be recovered through rates.

### 2. Revenue Decoupling

Decoupling severs the link between sales volume and revenue for the utility. Under decoupling, a utility has the opportunity to recover the authorized revenue requirement, determined in a base rate case proceeding, without regard to the amount of sales. The authorized revenue requirement does not change between rate cases. Under full revenue decoupling, a utility is made whole for the difference in

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<sup>11</sup> For example, non-coincident peak or coincident peak. See Section V.C, *infra*.

<sup>12</sup> California is also a restructured market with unbundling and an independent system operator, but has a very limited retail choice market. California's regulated utilities are subject to regulated rate making, similar to a vertically-integrated state, but generally do not own generation.

its annual actual revenues and annual target revenues. A utility will charge or refund the difference to all customers on an annual basis through a true-up rate mechanism. Decoupling eliminates revenue fluctuation resulting from the installation of energy efficiency and demand resource technology, distributed energy resources, and external factors such as weather, economic conditions, and power outages. Partial revenue decoupling isolates changes in consumption caused by energy efficiency and demand resources from unrelated **external factors**, mentioned above. The decoupling true-up mechanism under partial revenue decoupling would exclude changes due to the external factors. This approach to decoupling is more complex than full revenue decoupling.

### **3. Rate design as **social policy****

Regulators differ in their willingness or ability to utilize the administrative rate-setting process to advance social policy. Often, regulators will consider the requests of parties to the rate-setting process to advance certain goals **that may create cross-subsidies**. The regulator must carefully consider the public interest and the direction it receives from the legislative body with ultimate authority over it in creating specific cross-subsidies to support social policy goals of the state. Sometimes this may result in approval of non-cost-effective programs or rates that subsidize other customers, but a regulator **may** decide that such decisions serve a mandate or statute, or are otherwise in the public interest. Research and development projects **may** also fit under this consideration.

### **4. Low-income needs/Affordability**

Many states implement policies to reduce the burden that low-income customers face in paying their utility bills. Recognizing that electricity service is in the public interest, many states have created programs to assist low income or at-risk customers in maintaining electricity service. There are many different programs for low-income customers across states. These programs may include: a flat rate payment/discount, percentage of income payment plan, a percentage of bill discount, waived fees, a block rate approach, and/or usage based discounts.<sup>13</sup> Additionally, the **Low Income Home Energy Assistance Program (LIHEAP)** assists eligible low-income households with their energy costs, bill payment assistance, energy crisis assistance, weatherization and energy-related home repairs. A customer must meet certain eligibility requirements to enroll in LIHEAP and utility programs.

### **5. Wholesale Markets**

The Energy Policy Act of 1992 established the framework for competitive wholesale electricity generation markets, and allowed for a new type of electricity producer, called the exempt wholesale generator, to enter the wholesale electricity market.<sup>14</sup> Additionally, the Energy Policy Act of 1992 directed the Federal Energy Regulatory Commission ("FERC") to allow wholesale suppliers access to the national electricity transmission system. With these provisions, independent power producers could compete to build new non-rate-based power plants.<sup>15</sup> FERC Order 888 (1996)<sup>16</sup> and FERC Order 2000<sup>17</sup>

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<sup>13</sup> "Low-Income Assistance Strategy Review," Brockway, N., Kallay, J., and Malone, E., Synapse Energy Economics, Inc. (2014). Available at: <http://www.synapse-energy.com/sites/default/files/Low-Income-Assistance-Strategy-Review-14-111.pdf>.

<sup>14</sup> Energy Policy Act of 1992, P.L. 102-486 (signed October 24, 1992).

<sup>15</sup> Energy Information Administration, Energy Policy Act of 1992 (n.d.). Available at: [http://www.eia.gov/oil\\_gas/natural\\_gas/analysis\\_publications/ngmajorleg/engypolicy.html](http://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/engypolicy.html)

(1999) reduced impediments to competition in the wholesale bulk power marketplace, with a goal to bring more efficient, lower cost power to electricity consumers. In FERC Order 2000, FERC established guidelines for the voluntary formation of RTOs to oversee the wholesale markets.<sup>18</sup> An RTO's four characteristics are: independence, scope/regional configuration, operational authority, and short-term reliability. An RTO's eight functions are: tariff administration and design, congestion management, parallel path flow, ancillary services, OASIS/TTC/ATC, market monitoring, planning and expansion, and interregional coordination.<sup>19</sup>

Two-thirds of the electricity consumed in the United States is delivered in regions that operate wholesale electric markets.<sup>20</sup> Wholesale electric markets are facilitated by ISOs/RTOs including: ISO-New England, California ISO, New York ISO, the Electricity Reliability Council of Texas, Southwest Power Pool,<sup>21</sup> PJM Interconnection,<sup>22</sup> and the Midcontinent ISO.<sup>23,24</sup>

Additionally, the Energy Imbalance Market ("EIM") allows balancing authorities ("BA") in the western United States to voluntarily participate in a real-time imbalance energy market operated by the California ISO. The EIM dispatches economic bids to balance supply, transfers between the California

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<sup>16</sup> *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,705 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and rev'd in part sub nom.*, *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom.*, *New York v. FERC*, 535 U.S. 1 (2002).

<sup>17</sup> *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom.*, *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

<sup>18</sup> *Regional Transmission Organizations*, Order No. 2000, 65 FR 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, 65 FR 12088 (Mar. 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Public Utility District No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

<sup>19</sup> Order 2000 at 5.

<sup>20</sup> *The Value of Independent Regional Grid Operators*, ISO/RTO Council (2005) (available at: [http://www.nyiso.com/public/webdocs/media\\_room/press\\_releases/2005/isortowhitepaper\\_final11112005.pdf](http://www.nyiso.com/public/webdocs/media_room/press_releases/2005/isortowhitepaper_final11112005.pdf)).

<sup>21</sup> In all or part of the following states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming.

<sup>22</sup> In all or part of the following states: Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia, and the District of Columbia.

<sup>23</sup> In portions of 15 states in the Midwest and the South, extending from Michigan and Indiana to Montana and from the Canadian border to the southern extremes of Louisiana and Mississippi.

<sup>24</sup> FERC, "Electric Power Markets: National Overview" (available at: <http://www.ferc.gov/market-oversight/mkt-electric/overview.asp>).

ISO and other EIM entities, and load within its footprint. The EIM provides cost saving benefits as well as improved renewable integration and increased reliability.<sup>25</sup>

Electricity in the bulk power market is valued at the locational marginal price (“LMP”) at numerous locations on the bulk power system. There may be two LMP values: day-ahead and real-time, and the LMP may include the wholesale price of energy, congestion charges, and line losses. Occasionally, wholesale prices will drop to zero or become negative. This occurs when generators are unable to reduce output and demand is low. Hydroelectric, nuclear, and wind generators are typically the generators that will produce negative prices because they either cannot or prefer not to reduce output. Sellers pay buyers to take the output.

In some restructured states, customers are allowed retail access to the wholesale market and can choose a competitive supplier. In New England, large industrial customers can choose a supply rate indexed to the wholesale market and be charged a real-time rate for electricity. Further, ComEd and Ameren in Illinois have operated real-time pricing programs for residential electricity supply since 2007, when they implemented the first pilot programs. Currently, both utilities provide hourly pricing programs to residential customers who prefer to pay the hourly, market price for electricity.<sup>26</sup>

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<sup>25</sup> California ISO, *Energy Imbalance Market Draft Final Proposal* (2013) (available at: <https://www.caiso.com/Documents/EnergyImbalanceMarket-DraftFinalProposal092313.pdf>); see also, *California ISO*, 147 FERC ¶ 61,231 (2014), *order on reh’g, clarification, and compliance*, 149 FERC ¶ 61,058 (2014), *Order Accepting Compliance Filing* (June 18, 2015).

<sup>26</sup> Commonwealth Edison Company, “Hourly Pricing Program Guide: 2015-2016” (available at: <https://hourlypricing.comed.com/wp-content/uploads/2016/04/2015-2016-HourlyPricing-Guide-v1.pdf>).

### III. What is DER?

There is **single** definition for a Distributed Energy Resource (DER). Some technologies and services easily fit into any definition, such as **residential roof-top wind or solar**, but others have yet to be definitively placed inside or outside of the category. DERs are being adopted at ever increasing rates due to favorable policies, improvements in technology and costs, as well as becoming more widely accepted with identifiable customer benefits, both at the individual level and possibly for the grid. However, once DER adoption passes certain levels, DERs can begin to cause significant issues for traditional rate making, utility models, and delivery of electricity. In defining DER, it is important for regulators to identify potential economic and grid issues from DER. Then, after **empirically establishing at what adoption level they will affect the grid**, regulators should explore and implement rates and compensation methodologies that will lead to greater benefits for the public, customers, and utilities alike.

Addressing these issues will require looking at utility regulation from a new perspective and indeed, a few states have initiated “utility of the future,” or similar reevaluations of their regulations partially in response to the changes DER represents. **These processes are at the vanguard of an anticipated shift from centralized control and evaluation at a system-wide level to a more technology-dependent, and data-driven focus on more localized effects and situations represents a steep learning curve for everyone involved.**

#### A. Defining DER

Absent direction from the legislature, a regulator may need to define DER, or at least provide guidance to utilities, customers, and other stakeholders regarding the jurisdiction’s viewpoint on what constitutes DER.

In the past, the electric utility system has been composed of large, centralized generation, not necessarily sited near customers, and connected to load through the bulk, higher voltage, transmission grid which later **flows down** to the lower voltage distribution grid. This was due to economies of scale; sometimes it was cheaper for large amounts of generated electricity to travel long distances before reaching the utilities distribution system, and, ultimately, the customer. Traditionally, regulators and utilities looking to add a “resource” through a regulatory planning process in order to serve anticipated load would site a large generation plant, or at the very least a transmission project, to relieve congestion on the bulk transmission system and facilitate delivery of electricity to load.

Compared to the traditional, central-generation model, it could be said that a distributed model is turning the traditional model upside down by trending away from large, centralized generation connected to the interstate bulk transmission system to building and integrating new resources at the distribution level.

The following are some examples of definitions of DER from across the industry to give one an idea of the variety of descriptions used and the similarities and differences.

The Department of Energy defines DER as follows:



- Distributed energy consists of a range of smaller-scale and modular devices designed to provide electricity, and sometimes also thermal energy, in locations close to consumers.<sup>27</sup>

Lawrence Berkeley National Laboratory has published a series of papers on the Future of Electric Utility Regulation which focuses on DER. This definition was taken from the “Key Definitions” section of their paper, “Distribution Systems in a High Distributed Energy Resources Future”:

- Distributed Energy Resources (DERs) include clean and renewable distributed generation systems (such as high-efficiency combined heat and power and solar photovoltaic systems), distributed storage, demand response and energy efficiency. Plug-in electric vehicles are considered as part of distributed storage. While not included in the formal definition of DER, this report also considers the implications of customer back-up generation on grid operations given that over 15 percent of U.S. households have either a stationary or portable back-up generator to enhance their reliability.<sup>28</sup>

California Public Utilities Code, the New York Public Service Commission, and Massachusetts Department of Public Utilities have each provided a definition of DER applicable to the proceedings currently ongoing in their respective states:

- California: “‘distributed resources’ means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.”<sup>29</sup>
- New York: “Distributed Energy Resources (DER) is used in this context to include Energy Efficiency (EE), Demand Response (DR), and Distributed Generation (DG).”<sup>30</sup>
- Massachusetts: “A DER is a device or measure that produces electricity or reduces electricity consumption, and is connected to the electrical system, either “behind the meter” in the customer’s premise, or on the utility’s primary distribution system. A DER can include, but is not limited to, energy efficiency, distributed generation, demand response, microgrids, energy storage, energy management systems, and electric vehicles.”<sup>31</sup>

The Electric Power Research Institute defines DER as:

- Distributed energy resources (DER) are smaller power sources that can be aggregated to provide power necessary to meet regular demand. As the electricity grid continues to modernize, DER

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<sup>27</sup> <http://energy.gov/oe/technology-development/smart-grid/distributed-energy>.

<sup>28</sup> “Distributed Systems in a High Distributed Energy Resources Future,” Paul DeMartini and Lorenzo Kristov, Lawrence Berkeley National Laboratory, Future Electric Utility Regulation, Report No. 2 (October 2015) (available at [https://emp.lbl.gov/sites/all/files/FEUR\\_2%20distribution%20systems%2020151023.pdf](https://emp.lbl.gov/sites/all/files/FEUR_2%20distribution%20systems%2020151023.pdf)).

<sup>29</sup> California Public Utilities Code § 769(a).

<sup>30</sup> *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, “Reforming the Energy Vision,” NYS Department of Public Service Staff Report and Proposal, Case 14-M-0101 at 12, fn. 7 (April 24, 2014).

<sup>31</sup> *Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid*, D.P.U. 12-76-C, Business Case Summary Template: Glossary (2014).



such as storage and advanced renewable technologies can help facilitate the transition to a smarter grid.<sup>32</sup>

The following components make up the basic characteristics in defining DER: 1) the resource is connected to the distribution grid and not the bulk transmission system; 2) a relatively small resource, **certainly under 10MW** but generally much smaller; and, 3) generally not individually scheduled by an RTO and/or ISO. Nor is it necessary to report a DER individually to an RTO/ISO, since, if a DER is procured or dispatched at all, it would be on an aggregated manner by a 3<sup>rd</sup>-party or the utility itself. There may be many other **qualities** associated with DERs, such as responsiveness, specific values or services, and dispatchability, but these are largely related to the technology itself.

For this Manual, the following definition of DER will be used:

A DER is **a resource** sited close to customers that can **provide** all or some of their immediate **power** needs and **can also be used by the system** to either reduce demand (such as energy efficiency) or increase supply to satisfy the energy or ancillary service needs of the distribution grid. The resources, if **providing** electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include photovoltaic solar, wind, and combined heat and power (CHP), energy storage, demand response, electric vehicles, microgrids, and energy efficiency.<sup>33</sup>

This definition reflects the variety of DER, **both technologically, but also in** capabilities and benefits (and costs) to the grid.

## **B. Types of DER Technologies and Services**

As discussed above, energy resources that are considered to be DER include solar PV, combined heat and power (CHP), **wind**, storage, microgrids, and electric vehicles. EE and DR **may** also be considered as DER resources.

### **1. Solar photovoltaic (PV) systems**

Solar photovoltaic (PV) systems use solar cells, formed into solar **panels**, to convert sunlight into electricity. Solar PV systems can be located on rooftops of homes or commercial and industrial buildings or can be ground-mounted. The PV systems can be used to meet the energy requirements for the home or building or the energy from the system can be exported to the grid through the distribution system to be used by a nearby load. Due to technological advances and falling panel prices, PV systems have become the fastest growing DER. This category also includes community solar gardens, which are larger, both by available generation capability and acreage, solar installations that allow customers unable to

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<sup>32</sup> <http://www.epri.com/Our-Work/Pages/Distributed-Electricity-Resources.aspx>.

<sup>33</sup> Diesel-fired backup generators may also fit in this definition. Whether a jurisdiction allows backup generation to count should be determined by the jurisdiction. For purposes of this Manual, **it generally does not include backup generation**.

have rooftop solar PV participate in a solar program. Regulators will need to create rules or tariffs regarding appropriate sizes of community solar gardens that are allowed to interconnect at an interconnection point.

## **2. Combined Heat and Power (CHP)**

Combined Heat and Power systems, often referred to as cogeneration or CHP, provide both electric power and heat from a single fuel source. While most power plants in the United States create steam as a byproduct that is released as waste heat, a CHP system captures the heat and uses it to generate electricity which is used for many purposes such as heating, cooling, domestic hot water, and for industrial processes. CHP systems can use a diverse set of fuels to operate including natural gas, biomass, coal and process wastes. CHP can achieve efficiencies of over 80 percent, compared to 50 percent for conventional technologies.<sup>34</sup>

## **3. Wind**

Distributed wind energy systems use wind energy to create power and are commonly installed on residential, agricultural, commercial, industrial, and sometimes community sites, and the systems vary in size. Sizes that are common for a home can be as large as a 10 kW turbine and can be several MW at a manufacturing facility. Distributed wind systems can be connected on the customer's side of the meter to meet their energy needs or directly to distribution to support grid operations or offset loads nearby. Distributed wind systems are often defined by technology application, based on location relative to end-use and power distribution infrastructure, and not size, however, distributed wind systems are typically smaller than 20 MW.<sup>35</sup>

## **4. Storage**

Energy storage can be used as a resource to add stability, control, and reliability to the electric grid. Historically, storage technologies have not been widely used because it has not been cost competitive with cheaper sources of power, such as fossil fuels. However, given the recent decline in cost as well as improved storage technologies, storage has become an option that is able to compete.<sup>36</sup> With the growing use of intermittent technologies such as wind and solar energy, energy storage technologies can provide the needed power during periods of low generation from intermittent resources that will assist in keeping the electric grid stable and possibly prevent curtailment of resources in spring and fall

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<sup>34</sup> <http://www.energy.gov/articles/top-10-things-you-didn-t-know-about-combined-heat-and-power>;  
<https://www.epa.gov/chp/what-chp>

<sup>35</sup> <http://energy.gov/eere/wind/how-distributed-wind-works>

<sup>36</sup> "Batteries Charge Up for the Electric Grid," Moody's Investors Service at 5 (September 24, 2015). Other recent reports show that energy storage can be cost competitive with existing generation resources when all values are added. See, "The Economics of Battery Energy Storage," Rocky Mountain Institute (October 2015); "Levelized Cost of Service of Storage Analysis – Version 1.0," Lazard (November 2015).

months when electricity consumption is not impacted by summer air conditioning or winter heating loads.<sup>37</sup>

## **5. Microgrids**

Microgrids are localized grids that can disconnect from the traditional grid to operate independently and help mitigate grid disturbances. Microgrids can strengthen grid resilience and help mitigate grid disturbances because of their ability to continue operating while the main electric grid is down thereby functioning as a grid resource for faster system response and recovery.

Microgrids help with the integration of growing deployments of renewable sources of energy such as solar and wind and distributed energy resources such as combined heat and power, energy storage, and demand response. By using local sources of energy to serve local loads, there is a reduction of energy losses in transmission and distribution, which further increases the efficiency of the grid.<sup>38</sup>

## **6. Demand response**

Demand response can be used as a resource by utilities and grid operators in order to balance supply and demand. The use of demand response as a resource can lower the cost of electricity in wholesale markets, by avoiding the dispatch of more costly generation resources, which then could lead to lower retail rates. There are **several options** for customers to participate in demand response products which include participating in a time-based rate, such as time-of-use pricing, critical peak pricing, variable peak pricing, real time pricing, and critical peak rebates. Another method is the use of direct load control programs which allow for the cycling of customer air conditioners and water heaters on and off during periods of peak demand in exchange for a financial incentive. With the continuation and increased focus of grid modernization efforts, demand response is becoming an increasingly valuable DER resource.<sup>39</sup>

## **7. Electric Vehicles**

EV's can be responsive to price or demand response signals and change **when it charges**. This flexibility to participate as a demand response resource, located throughout a service territory provides a utility with targeting EV demand response programs **where most beneficial to the grid**. Additionally, EVs have the ability to put power back onto the grid which provides the grid with additional flexibility when connected to the grid. This capability allows electric vehicles to act like an energy source by supplying grid services as a grid-connected battery which is able to provide mobile backup power during an outage or emergency situation. In order to benefit from this capability, it will require the development of vehicle power electronic systems with bidirectional flow, integrated communications, and improved battery management systems. Since EVs are often stationary for many hours of the day, the battery from the electric vehicle can be used as a storage device that can provide additional grid services.<sup>40</sup>

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<sup>37</sup> <http://www.epri.com/Our-Work/Pages/Distributed-Electricity-Resources.aspx>

<sup>38</sup> <http://energy.gov/oe/services/technology-development/smart-grid/role-microgrids-helping-advance-nation-s-energy-system>

<sup>39</sup> <http://energy.gov/oe/technology-development/smart-grid/demand-response>

<sup>40</sup> [http://energy.gov/sites/prod/files/2015/09/f26/QTR2015-3D-Flexible-and-Distributed-Energy\\_0.pdf](http://energy.gov/sites/prod/files/2015/09/f26/QTR2015-3D-Flexible-and-Distributed-Energy_0.pdf)

### C. Expanding the Definition of “Resource”

The term “resource” has traditionally referred to a resource for electricity generation. How a regulator defines DER will likely include resources other than the generation needed to meet the needs of the utility and customers in serving their electrical load. Most parties generally agree that Distributed Generation, such as rooftop PV, as well as storage technologies, which often include Electric Vehicles, meet the definition of DER. **There is less agreement on whether other services on the demand-side, which reduce load, should be considered a DER as envisioned by regulators.** Of the above definitions, most incorporate Demand Response (DR) which is used by some RTOs and other jurisdictions as a dispatchable resource to relieve stress on the grid during peak periods. Thus, DR is not a traditional resource as it is not a generator supplying electricity into the grid; rather, it is a demand-side resource that changes the demand curve in response to a price or can be dispatched to meet system needs by using demand in response to system conditions. Again, the main **difference lays** between a resource that acts as supply resource as opposed to a resource that affects demand. Other services and applications as envisioned by vendors and suppliers, such as microgrids, **Volt/VAR**, frequency ride-through, and locational ramping, also do not clearly **fit inside** current definitions of resources. These types of services, while clearly valuable and potentially worthy of compensation, are not **as** universally accepted as DER primarily due to lack of use across the industry, lack of sufficient technology installed which can assist in measuring, and scheduling such resources with greater certainty and confidence.<sup>41</sup>

Energy efficiency programs are also sometimes included in the definition, as reflected in the definition adopted above. Since EE is not dispatchable, but reduces load **on a constant** basis, it is not always included in the definition of a “resource.” Measurement and forecasting **play a large part in** EE, and whether the assumptions that are required for predicting what the demand/supply would look like absent EE, adds significant complexity to the issue of determining what is the “resource” value of the EE. A regulator will need to determine whether or not it is appropriate to include EE in its consideration of DER.

**Another issue is whether a DER must be renewable or “green.”** A regulator will need to balance the importance of its related environmental policies regarding how it defines a DER. For purposes of the adopted definition above, green is not an explicit requirement to be a generation DER. It may be that renewable distributed generation resources would provide greater societal benefits than other generation resources, especially when sited next to residents and load, but the fact is that any benefits or costs of distributed generation apply equally to renewable or non-renewable generation if the value of the renewable energy credits are tracked separately. For purposes of the adopted definition, environmental or emission criteria is not included as it should be up to the regulator to decide whether or not the definition, and compensation for DER, should be limited only to renewable resources.

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<sup>41</sup> An additional constraint is the delay in development of standards to support the safe and reliable operation and integration of many of these technologies into the grid. At the time of this Manual, key standards to support integration of these resources, **such as UL 1741 and IEEE 1547**, have delayed the introduction of these resources into the grid. Without standards in place, testing and trialing of new technologies is limited, which impacts the ability of the utility and the developer from gaining information and knowledge about the technology and its interaction with the utility system.

#### **D. Increasing Importance of DER and the Issues it Presents**

Rapid proliferation of DER in a few jurisdictions has led to a national discussion and highlighted the issues that increased adoption of the technologies represents for regulators, utilities, and customers, alike. The proliferation of DER has been driven by favorable legislative and regulatory policies, historical rate design, changes in technology, such as price and functionality improvements in renewable generation and storage, and the proliferation of communication functionality throughout utility distribution systems. The technological development, as described above, is a reflection of how much the adoption of DER has grown in the recent past as well as the anticipated increases in the level of adoption in the near future. The rapid adoption of DER also signals a shift away from the centralized utility model briefly outlined at the beginning of this Section.

The increasing importance of DER led to the development of this Manual and a number of other articles and reports addressing DER and its impacts on the utility, regulators, and rate design.<sup>42</sup> For example, Lawrence Berkeley National Lab has initiated a series of papers entitled the “Future of Electric Utility Regulation” to assist in this dialogue.<sup>43</sup> These papers employ a point-counterpoint format to explore the future of electric utility regulation in a future dominated by DER. Other stakeholders have also identified options in response to the stress DER places on utilities and traditional regulatory models.<sup>44</sup>

While DER have yet to reach significant levels of adoption rates in many states, some jurisdictions have seen higher levels of adoption of DER and it seems that favorable policies and compensation have been driving these adoption rates. The fourth report from FEUR begins, “By almost any reasonable standard, however, high penetration of distributed generation is now evident in Hawaii and moving quickly in this direction in locations in California, Arizona, Texas and New Jersey. The Hawaii Public Utilities Commission (PUC) reports that solar photovoltaic (PV) capacity in Maui will soon equal more than half of the system peak demand.”<sup>45,46</sup> The issues presented by DER in the current regulatory landscape primarily involve the costs that DER impose on the grid, and recovering the cost of the grid from DER customers; properly incorporating and compensating the benefits DER provide; dealing with other physical challenges that the technologies imposes on the physical grid; and ownership issues.

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<sup>42</sup> See fn. 36, *supra.*, and fn. 44, *infra*

<sup>43</sup> More information on the project and access to all reports can be found at: <https://emp.lbl.gov/future-electric-utility-regulation-series>.

<sup>44</sup> A number of reports and white papers have been issued on this topic. The following are just a small sampling: “A Pathway to the Distributed Grid,” Solar City Grid Engineering (February 2016); “Disruptive Challenges,” Edison Electric Institute (January 2013); “Pathway to a 21<sup>st</sup> Century Electric Utility,” Ceres (November 2015); “Rate Design for the Distribution Edge,” Rocky Mountain Institute (August 2014).

<sup>45</sup> “Distribution System Pricing with Distributed Energy Resources,” Ryan Hledik and Jim Lazar, Lawrence Berkeley National Lab, Future Electric Utility Regulation, Report No. 4 at 3 (May 2016) (<https://emp.lbl.gov/sites/all/files/feur-4-20160518.pdf>).

<sup>46</sup> *Instituting a Proceeding to Investigate Distributed Energy Resource Policies*, Decision and Order No. 33258, Hawaii PUC, Docket No. 2014-192 (October 12, 2015).

As with any regulatory issue, of course, each state and each utility territory is unique with its own set of circumstances which may render the ideal regulatory treatment from one territory unworkable or not advisable in another.

Take for example, one key variable in considering DER ratemaking: the level of adoption of the resources.<sup>47</sup> The threshold level of adoption for significant impacts **may** not just only vary from state to state and utility to utility, but often varies from feeder to feeder or circuit to circuit inside one service territory. More discussion on this can be found in Section VI.

Thus, in any evaluation, the utility's specific characteristics and **their** most likely reaction to any rate design changes must be clearly and thoroughly **determined** before questions and challenges from DER are addressed through rate making changes. **The level** of transparency and detail on the operations and physical characteristics of a utility's distribution system **may** be significantly more than **may** have been employed in the past.

## **E. Costs**

The economic pressures DER puts on the utility and non-DER customers within a rate class is one of the most **divisive** issues facing regulators today. These economic issues include revenue erosion and cost recovery issues as well as inter-class cost shifting **apparent in** traditional utility rate design and Net Energy Metering (NEM) discussions. These **issues** have been driving most of investigations into NEM policies and searches for alternate ways to treat DER in rate making.

### **1. Revenue erosion**

A majority of utility costs are not variable in the short term. Traditionally, most utilities take in most of their revenue through a **flat, volumetric** charge coupled with a fixed or customer charge. This has been the simplest way to collect revenue, both for historical metering technology and customer understanding. Many **businesses** use a flat charge for their products or services to recover their costs, including fixed costs. For this type of rate design, revenue recovery is at risk to any reduction in usage (*i.e.*, variation in weather or DER) unless there is a mechanism that "decouples" revenue from customers' usage. Decoupling means the utility's revenue does not increase and decrease proportionally with usage levels. Approximately 60% of jurisdictions do not have a decoupling mechanism, so use of decoupling as a solution **may** be an option for many jurisdictions to consider.<sup>48</sup>

DER compensation that nets off a one-to-one credit for energy and distribution costs reduces the utility's collected revenue at the retail rate while already reducing the customer's bill by the same amount. This netting does not necessarily **reduce any** of the utility's costs, but negatively impacts its revenue collection, though the effect is different in vertically integrated jurisdictions versus restructured jurisdictions. This revenue erosion issue is what has brought many of the utilities to the table to discuss DER issues and **leads to the** cost recovery and cost shifting issues below.

### **2. Cost Recovery**

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<sup>47</sup> Sometimes called the level of "penetration."

<sup>48</sup> <https://www.nrdc.org/resources/gas-and-electric-decoupling>

Reducing the utility's opportunity to recover the amount of revenue needed to reach its authorized rate of return threatens its ability to recover its costs for operations of the system. This in turn may lead to arguments for regulated utilities that these utilities are "riskier" than others and thus are deserving of a higher return on equity, which would increase rates to all customers of the utility. Many view the primary responsibility of **utility rates as: recovering** the embedded cost of the utility's assets; earning a fair return, or profit, on the same; as well as recovering the operations and maintenance expenses necessary for providing their service. This cost recovery covers the dollars that the utility has already invested into the assets required to deliver, and, if applicable, to generate the electricity for a safe, adequate, and reliable level of service. The actual costs to build, operate, and maintain an adequate distribution system are often viewed as being primarily driven by the number of customers served by the system or by the aggregate demand—**which is the one-time highest peak demand the system must accommodate**.<sup>49</sup> Regardless of the drivers of cost, most utilities and many regulators view the utility's short-term costs, especially for their distribution system, as fixed; indeed, the rate base and authorized revenue requirement is "fixed" by the state regulator during rate cases. This "fixed" amount is then allocated to the different classes before being **calculated into the billing determinants** that decide an individual's bill.

Subsequently, DER can affect the cost recovery of distribution, transmission, and generation assets. To use distribution as an example, under traditional **rate making**, a reduction in usage, and thus revenue, in a single year driven by DER may lead to little, if any, reduction of the costs of the system - —the territory still has the same number of poles, wires, and other equipment, all with the **same useful life**.

This is a simplification, since utilities are not simply handed the money they spend on their systems, but should illustrate the issue with recovering utility costs and the increased risks faced by utilities.

### **3. Cost Shifting**

Cost shifting is another issue which affects customers in the same rate class **with** significant DER adoption. Cost shifting, or subsidies, are unavoidable in practical rate design but regulators endeavor to mitigate these effects in the larger context of the many, often conflicting, rate design principles. The response to a decrease in cost recovery certainty or to an actual reduction in revenue is for the utility to come back to the regulator to change its revenue requirement and rate design. In the case of DER, often the billing determinants are changed to mitigate the pressure on revenue caused by reduced usage volume. Thus, the decline in usage would be shifted to other customers when the billing determinants are reset to account for the decreased revenue from the DER customers. At a low level of penetration, this **may** be another imperfection in rate design, but at large levels of penetration it can be problematic and represent large amounts of revenue being shifted to other, non-DER customers in the same rate class. There **may** also be equity considerations to take into account. For example, if customers living in multi-family housing are in the same class as DER customers and there are no DER options available to multi-family customers (since they do not generally own their property), a regulator must consider

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<sup>49</sup> For more information, see the NARUC "Electric Cost Allocation Manual." This in itself is an over simplification since, for example, location plays a role in cost allocation as rural customers could be more costly to serve than certain urban customers of the same rate class.



whether shifting additional cost recovery to customers who **may** not have a chance to participate in DER is appropriate.

In sum, under the traditional ratemaking model and commonly used rate design, if the utility passes its relevant threshold of DER penetration, it **may** face significant intra-class cost shifting and erosion of revenue in the short-run. If left unaddressed, it could face pressures in the long term that would prohibit it from recovering its sunk costs necessary to provide adequate service.

#### **4. Technology and Physical Issues**

In addition to the economic issues related to revenue erosion and cost shifting, DER, primarily DG, can put pressure on the physical grid. Many of these problems are different depending on the technology, but they are all often compounded by a utility's lack of control over, and visibility of, DER's effects. Customer sited DER, especially renewable generation, is generally "non-dispatchable" and its effects are often localized at the feeder level.

Utilities procure or generate electricity themselves that is planned long beforehand and includes margins for increasing and decreasing electrical output as well as ancillary services to ensure power quality is maintained system-wide. DERs that are renewable generation, such as wind or PV, are intermittent in nature (absent storage), which means that the generation is only available when the sun is shining or the wind is blowing, and only up to the quality of the resource (e.g., strength of the wind or **angle of solar panels, whether they are fixed or tracking, and the daily intensity of the sun**).

Additionally, the presence of clouds or sudden changes in wind velocity can mean that output can vary greatly from moment to moment, including going from 100% output to **0%** almost instantaneously. In this regard, **DER can act** as if sizable loads are coming on and off of the system, and makes utility and RTO demand **forecasting problematic**.

These effects are amplified when DER is clustered in a specific area. For instance, if DERs are clustered on one feeder and reacting to the same sudden changes in electrical output (say, due to a cloud moving overhead) that feeder could **suffer** outsized effects while the rest of the system is relatively unaffected. If the utility does not have visibility into the situation on that feeder at sufficient granularity necessary to have visibility into **the feeder**, this could **make the voltage on that line outside of acceptable parameters without the wider system being able to timely absorb the impacts**. This may impact local reliability conditions if unaddressed, by either the utility or the customer. Many interconnection tariffs provide details on performance requirements for DER, including flicker and other voltage requirements and standards.<sup>50</sup>

The relevant thresholds, as mentioned, are different depending on the local characteristics, but **some** utilities have already seen output that exceeds an individual feeder's peak usage. Depending on the coincidence of the relevant peaks with the productivity of the DERs, this could represent a feeder that is exporting to the wider grid for significant periods, only to abruptly change course due to **a cloud**.

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<sup>50</sup> Flicker generally refers to the **variability of light output from lightbulbs**. In some cases, flicker can be caused by voltage drops caused by large industrial loads, or from voltage swings from solar installations. IEEE 141 and IEEE 1453 are the standards relied upon for addressing flicker concerns from resources connected to the grid. Interconnection tariffs or utility engineering handbooks may include guidelines and requirements related to flicker and other voltage fluctuation tolerances from loads or DER.



These physical issues often have a more disruptive effect on “non-modernized” systems which possess less granularity in the visibility of the system. If the utility has installed advanced metering on its customers’ load or has SCADA across its distribution grid, it may be able to gather better data in order to understand the impacts of DER on certain locations. Advanced metering technology also allows for greater options in rate designs, which will be discussed further in this paper. Other technologies may also benefit the utility in planning and responding to DER growth across the utility system. See Section VI for greater discussion.

## **F. Benefits**

The challenge of acknowledging, identifying, quantifying, planning for, and optimizing the benefits DER provide to utilities and customers, both those with and without DER, is an issue on par with identifying appropriate utility costs, as discussed above. If the primary goal is only mitigating the cost considerations introduced above, the regulator may choose from a suite of other options to accomplish this goal. On the other hand, if the regulator seeks to better integrate and identify how to address DER impacts, the regulator should first decide whether he or she is interested in using rate design options to promote DER and calculating these attendant benefits. Understanding the tradeoffs of this choice, as, for example, one response could be seen as leaving value “on the table,” jurisdictions interested in moving beyond the more traditional rate design discussion will need to be open to a variety of options to best understand what is in the best interest of the particular jurisdiction.

A growing number of parties involved in the DER debate acknowledge some benefits of DER, and some jurisdictions, utilities, researchers, and advocates have concluded or posited that responsible encouragement of DER adoption leads to positive cost benefit results. In this respect, when using the traditional model for rate design, which does not compensate (or charge) customers for producing benefits (or costs) for the grid (except through DR programs), it is possible that a portion of the cost benefit analysis for DERs would be missing. At the very least, this could represent a lost opportunity to meet customer needs on a more cost effective basis. As it applies to emission or renewable credits, it is important to note that many states track “Renewable Energy Credits” separately, and it is wise to consider if DER is already being tracked or valued in that manner already. Renewable Energy Credits are used to value the “green” component of the DER resource, but may not account for distribution-related benefits of the energy.

There is some debate over what are the benefits of DER. Part of the confusion here is in quantifying benefits from DER and integrating DER into the grid and utility systems. Regulators are increasingly interested in calculating benefits which have not traditionally been incorporated in rate design or are hard to quantify. Environmental benefits of distributed carbon-free generation is one example, but the ancillary markets of many RTOs are another example of recent increased quantification of benefits.

The services and benefits from DER at question are often provided by the utility on a system-wide basis, or at the feeder level. However, some services, such as local reliability or resilience, may be more cost effectively provided by resources distributed across the system, rather than developed and procured at wholesale levels. These considerations cover many different types of DER and represent value or compensation that can vary widely depending on the time and location they are provided.

These types of rate designs and proceedings will be explored in more depth in Section V, but listing some of the categories of benefits explored in the “Value of Solar (VOS)” proceedings will give some indication of what benefits are being debated.

Minnesota enacted the first VOS tariff and identified a list of benefits to be measured, or, in some cases, costs to be avoided: environmental costs, distribution capacity costs, transmission capacity costs, reserve capacity costs, generation capacity costs, variable utility plant operations and maintenance costs, fixed utility plant operations and maintenance costs, and fuel costs.<sup>51</sup> Some advocates have pushed for including even more benefit categories, such as economic development or jobs. Categories such as the promotion of jobs are normally not under regulators’ purview, but can be used by the utilities to advocate for changes beneficial to them when before commissions or legislatures.

Many experts and advocates have already begun exploring different long-term options for planning, evaluating, and compensating DERs. Some jurisdictions are already moving in the direction of significantly changing the way utilities recover its costs.<sup>52</sup> Others are looking at implementing a distribution system operator model and/or market models for requesting and compensating DERs based on need, time, and location.<sup>53</sup> Other states have moved to greatly expand the transparency for, and participation of, regulators into the planning of a utility’s distribution system.<sup>54</sup> In many cases, these efforts are based off of the electrical sector’s non-profit model of third-party ISOs and RTOs, which for many utilities are responsible for planning and operating the bulk transmission systems.

Regardless of what direction regulators of any particular jurisdiction would like to head in the future, the acknowledgement and study of these benefits will most likely be necessary. As such, they are just another “issue” brought to the forefront by DERs.

## **G. Ownership and Control**

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<sup>51</sup> “Minnesota Value of Solar: Methodology,” Minnesota Department of Commerce at 2 (January 30, 2014) (available at <http://mn.gov/commerce-stat/pdfs/vos-methodology.pdf>).

<sup>52</sup> See, e.g., *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, New York PSC, Case 14-M-0101.

<sup>53</sup> See, e.g., *Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769*, California PUC, R.14-08-013.

<sup>54</sup> See, e.g., *Instituting a Proceeding to Review the Power Supply Improvement Plans for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited*, Hawaii PUC, Docket No. 2014-183; *Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid*, Massachusetts DPU, D.P.U. 12-76. See also, *In the Matter of the Commission Investigation into Grid Modernization*, “Staff Report on Grid Modernization,” Minnesota PUC, Docket No. 15-556 (March 2016) (describing next steps for the Minnesota PUC to consider on grid modernization activities, including development of a distribution system plan).

One last overarching category of “issues” from DERs roughly falls under the category of ownership and control, though these are overlapping. The increased adoption of DER is often promoted by third parties and not the utility, and can be driven by third party business models which are responding to price signals that compensate **strictly on the basis of total energy production** and not grid benefits (or costs). Additionally, the lack of visibility into the current state of any DER and the lack of the ability to control the DER when it is exporting to the grid, while two very distinct issues, give rise to many of the **physical problems** with incorporating DERs into the grid.

To compensate, utilities in various jurisdictions have attempted to build into regulations the ability to interrupt the “dispatch” of energy from a customer’s DG, or to discourage 3<sup>rd</sup> party products, such as the practice of 3<sup>rd</sup> party leasing of rooftop solar. Also, regulators are beginning to see the need for distinction between types of DER with respect to the relative values/costs each may have on the system. For example, solar PV panels that are westward-oriented **may** be more valuable to a utility system that peaks in the late afternoon **than** panels with a south orientation.

An additional issue has been the concerns about predatory lending and the need for consumer protection regulations which **may** accompany pushes to get large amounts of DG installed at customer residences and through community solar projects, especially when involving programs aimed at increasing low income participation. Despite there being programs targeted for low-income customers, DERs are not always available to all communities. **Low-income** customers face affordability issues, and due to their credit history, **may** not be able to finance DER investments or participate in community renewable projects. Additionally, low-income customers may rent their homes or live in multi-family buildings where DER is not accessible or able to be installed. DER resources **may** only be available to this demographic through community programs and virtual net metering.

Though many of these issues are not directly related to rate design they are included here so regulators can ensure they are addressed when they become relevant for their jurisdiction.

#### **IV. **Rate design and compensation considerations, questions, and challenges****

Often, discussions on DER are made more difficult **due to the regulatory** framework and utility incentives that have been in place for decades, or in some respects a century, are being challenged by these new technologies. Traditional means of regulation, rate design, and planning largely assume the utility will meet all demand with generation; with the increase in DER, and the recent lack of load growth, the current regulatory and utility models are a constraint to effectively addressing the growth of DER and its impacts on utility and regulatory frameworks. This is made more difficult by parties in regulatory proceedings often only addressing one aspect of the interaction; either cost recovery for utilities or customer compensation on the part of the advocates. This **separates** the conversation and makes it harder to reach an agreement that is beneficial for the public interest. Though these specific challenges will lessen with time as knowledge and experience are accumulated, currently one of the biggest issues, if not currently the biggest, is the dearth of empirical data available on the impacts and specific pros and cons of the different ways regulators can address DER and rate design. Identifying and understanding these challenges will assist the regulator in determining an appropriate rate design for its utilities.

**A. What do you want to accomplish with the rate?**

In order to develop an appropriate rate or compensation method, a regulator should identify what the rate should accomplish, and how to determine the best way to implement the rate.

**1. What costs should be paid by DER and what should be recovered from base rates?**

**a. Different rates vs. changing all rates**

Ratemaking is often the result of a regulatory balancing of a variety of interests and goals of the parties, and in response to technological and political considerations. The prevailing rates for any given utility represent a history of compromises; on goals, on the balancing of different rate design philosophies, on the practicality of a given rate component based on available data, etc. Given this history of compromises, there have always been “winners” and “losers” in rate design; DER just potentially shifts who are those winners and losers. The question then becomes whether the entirety of the rate structure that would apply to all customers of a given class, including DER customers, should be modified to better match cost-causative factors, or whether a special rate should be created that only applies to DER customers. There is a strong argument to be made for changing the rate structure that applies to all customers, as sending all customers the most appropriate price signal should result in the most economically efficient outcomes related to electricity consumption, as well as decisions on the installation of DER.<sup>55</sup> For a number of reasons, regulators may decide this is not the best approach to recommend, or they may decide this is not the best approach to approve (*e.g.*, promotion or demotion of DER, availability of data, customer acceptance or fears related thereto).<sup>56</sup>

**b. Different customer classes to recognize difference in service**

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<sup>55</sup> “A Primer on Rate Design for Residential Distributed Generation,” Edison Electric Institute at 10 (February 16, 2016).

<sup>56</sup> See, *e.g.*, “Distribution System Pricing with Distributed Energy Resources,” Ryan Hledik and Jim Lazar, Lawrence Berkeley National Lab, Future Electric Utility Regulation, Report No. 4 at 46-47 (May 2016).

Another option, one which might be particularly attractive to a jurisdiction unwilling to commit to a wholesale restructuring of rates or uncertain about the cost differences between DER customers and others, is separating DER customers into their own cost of service class. Such an approach would identify the different ways in which DER and non-DER customers contribute to costs, at least according to the traditional embedded cost of service approach utilized in many jurisdictions, and thereby reduce the cross-subsidies between DER and non-DER customers. A separate DER class may also aid in identifying and quantifying benefits and costs associated with DER.<sup>57</sup>

Traditionally, customers are separated into classes based on some important distinction in the service provided to different groups of customers which affects the cost to serve those customers.<sup>58</sup> The question for DER customers, then, is whether or not the difference in the service provided to DER customers differs in a way that justifies their separation into a separate class.<sup>59,60</sup> If so, should these customers also be further subdivided into technology-specific classes or subclasses? It is instructive to consider what happens when a customer's usage changes for reasons other than DER. If a customer replaces an appliance, or light bulbs, or the number of people living in a home is reduced, other things being equal, there is less usage to spread costs over. Therefore, the rate increases, provided that the lower usage has not offset all the costs built into the rate the declining-usage customer has been paying. Costs are shifted to those customers who did not reduce their consumption. Generally, these customers would not be separated into another class, as the service supplied to each set of customers is essentially the same. Air-conditioning or electric heat, however, are sometimes considered to be a different type of service, as the impact on costs is significantly different from those customers that do not have these items. Separating DER customers out allays concerns about other customers covering costs to the extent that those costs are associated with determinants used in allocation. If this is the case, rate structures do not necessarily have to change, as the associated costs are allocated on the appropriate basis. The remaining concerns would then be potential intra-class subsidization between technologies with different characteristics<sup>61</sup> and a lack of connection between the causation of costs and their collection. In the end, regulators must examine the particular load profiles associated with various customers, including DER customers and subsets thereof, and how those profiles correspond to costs, and decide whether or not those differences constitute a substantial enough difference in the service provided to justify their separation.

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<sup>57</sup> "Designing Tariffs for Distributed Generation Customers," Janine Migden-Ostrander and John Shenot, Regulatory Assistance Project at 45 (February 2016).

<sup>58</sup> See, e.g., "Electric Utility Cost Allocation Manual," NARUC at 22 (January 1992).

<sup>59</sup> It can be argued that a separate class is not necessary until DER constitutes some threshold portion of an important cost determinant, and that doing so before this threshold is met constitutes rate discrimination. See, e.g., "Rethinking Standby and Fixed Cost Charges: Regulatory and Rate Design Pathways to Deeper Solar Cost Reductions," Jim Kennerly, NC Clean Energy Technology Center (August 2014).

<sup>60</sup> It can be argued that the difference does just that. See, EEI Primer at 11.

<sup>61</sup> See "Distribution System Pricing with Distributed Energy Resources" at 47.

## **2. Price Signals**

As previously mentioned, the more a rate structure reflects the costs associated with an activity, the more appropriately decisions can be made about how much of a service to use, when to use it, and whether other options for the provision of said service make economic sense. Ideally, rates are price signals for the consumption of electricity. Those same price signals are used to compare the utility's provision of said service against the alternatives. Regulators may wish to consider how appropriate the price signal provided by a particular rate structure is, in order to induce economically efficient consumption.

## **3. Long-term vs. short-term costs/benefits/outlooks**

Another consideration in the examination of the appropriate rates and rate structure is weighing long- and short-term costs and benefits. The relative importance placed on the long-term versus short-term, as well as that between benefits and costs, can have a large impact on the way regulators choose to set rates and rate structures. The discussion is often couched in language referring to the appropriate marginal cost to be considered: long run or short run. Theoretically, in a competitive market, these two are equal. Given that theory so often fails to hold and electricity is not a purely competitive market, this observation is mainly academic.

It can be argued that the majority of a utility's costs are fixed. It can also be argued that the majority or entirety of a utility's costs are affected by the way customers utilize the service provided, making the costs variable. The two opinions vary mainly in the time horizon considered. Those who feel the appropriate time horizon is the short-term tend to identify more costs as fixed. Those who feel the appropriate time horizon is the long-term tend to identify more costs as variable. There are additional considerations related to historical responsibility for long-term investments made to serve the customers and usage that were projected at the time they were made.

## **B. Impacts on other customers**

When deciding on a rate structure to be used for DER, it is important to consider the various impacts DER has on non-DER customers, both positive and negative. A thorough understanding of these impacts can help guide regulators in choosing a rate structure that properly reflects them.

### **1. Does DER avoid utility infrastructure costs?**

One potential benefit of DER is avoidance of investment and its attendant costs; conversely, increased investment costs is a potential detriment. Avoided investment can lead to lower rates for all customers,

depending on whether said cost avoidance materializes and how rates are set to spread the lower costs among customers. This is generally a longer-term consideration, as the planning horizon for a utility is quite long. As a result, the reduced costs associated with DER may be slow to be realized, as they will not occur until the utility makes a smaller new investment than it would have absent the presence of DER. It may also prove difficult to quantify these cost savings and identifying the portion associated with DER as opposed to other factors. DER can also cause increased costs, including distribution system upgrades and additional generation to back up intermittent resources, particularly at high penetration levels.

It is helpful to divide the potential for increases and decreases in infrastructure investment between the functions of the utility in order to examine each more closely.

On the generation side, DER can reduce investment in two ways. DER, insofar as it supplants (or even supplies) usage during peak times, avoids the variable cost of running more expensive units at the margin, lowering the overall average cost to all customers.<sup>62</sup> DER can also reduce or avoid investment in capacity. If the DER reduces a customer's peak load on the system, it may delay or avoid the need for peaking plants or market purchases for capacity. If the DER offsets usage more evenly, it can avoid investment in more expensive baseload plants.

Conversely, depending on the nature of the DER, DER could require increased investment in generation units to make up the difference for intermittent resources<sup>63</sup> or to meet the generation flexibility requirements of a large ramp up in demand.<sup>64</sup>

On the distribution side, the argument is basically the same, though the equipment at issue differs. Insofar as DER reduces usage during peak times at any given level of the distribution system, future investment in capacity may be reduced. There is even potential for targeting incentives for DER installation to portions of the system which may otherwise require expensive upgrades.<sup>65</sup> At higher penetrations of DER, however, additional costs may be incurred to upgrade the distribution system to act as step up facilities.

## **2. Cost shifting due to recovery of fixed costs through a volumetric rate**

One potential detriment to other customers of DER is cost shifting. As the planning horizon is long and benefits may be slow to materialize, in the short-term costs change very little, particularly with regard to non-energy related infrastructure. If these costs are collected through a per kWh (or volumetric) rate, there will be fewer kWh to spread those costs over, thereby increasing the costs collected from those whose usage has not been lowered by DER. These costs could be considered stranded costs, and

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<sup>62</sup> See "Smart Rate Design for a Smart Future," Jim Lazar and Wilson Gonzalez, Regulatory Assistance Project at 43 (July 2015).

<sup>63</sup> *Id.* at 63-5.

<sup>64</sup> "Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future," Rocky Mountain Institute, eLab at 16 (2016).

<sup>65</sup> See, e.g., ConEd's Distribution Load Relief Program ("Demand Response Programs Details," ConEdison, available at [http://www.coned.com/energyefficiency/demand\\_response\\_program\\_details.asp](http://www.coned.com/energyefficiency/demand_response_program_details.asp)).

collected from all customers in some fashion; the arguments for and against which are discussed in a later section. If the costs are demand or customer related, they could be collected through a charge for those determinants, potentially avoiding some cost-shifting. It can also be argued that these cost shifts are no different than cost shifts related to any other change in usage, or that the impact to other customers is minimal, and should therefore not be dealt with in any way other than the traditional way

To the extent that DER reduces a customer's usage, that customer is less reliant on the utility for their energy needs. This reduction in usage may have a corresponding reduction in costs; most assuredly a reduction in variable costs at the least. A change in usage may affect other customers. If usage lowers enough in aggregate as a result of DER, wholesale power prices may be affected, as other units are able to operate less. There is also a potential effect on capacity prices for much the same reason; reduced demand for capacity may drive the price down. If the DER customer exports to the grid, either in aggregate or at more expensive times, other customers will be using the energy supplied by the DER customer (though the utility will still provide the infrastructure allowing its delivery<sup>66</sup>).

### **3. Customer is still tied into the grid/utility is still responsible for delivery**

There are many costs associated with a customer being connected to the grid, as well as benefits to the customer. Particularly to the extent that rates are volumetric, a DER customer may not be paying for all such costs. These costs would then be paid for by other customers to the benefit of DER customers. This is essentially the justification for standby rates; as such, the considerations related to this issue will be more fully explored in the section on standby rates.

### **4. DER customer may still be grid reliant during peak times**

Depending on many factors (*e.g.*, DER technology, siting, production times), the DER customer may be more or less reliant on the grid during peak times, when costs are generally higher. Identifying how to ensure the customer is paying for its costs of taking service from the grid, is important to ensure a level of fairness between DER customers and non-DER customers. The use of certain rate designs, such as TOU or demand charges may be an option for regulators, or, as explained in Section 5, other options may also be available.

### **5. Cost allocation inside classes**

As discussed earlier, if DER customers are no longer paying for the entirety of their use of the grid, whether due to rates not being charged on the cost-causative determinant or because the investment of the utility has not yet been lowered to take into account the lower need for its services, other customers necessarily pay the difference. Such a situation presents several potential problems.

It can be argued that the resulting cost-shift is regressive. Those with the financial means to undertake investments in DER are likely above the average income for a service area. If this is the case, the customers who pick up any potential slack in the utility's bottom line are those less able than DER

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<sup>66</sup> However, it can be argued that it is still most appropriate for the customer using energy to pay for the delivery system, not the generator, as is done with all other generators.



customers to shoulder that burden. A regulator should ascertain whether or not this is happening, and may wish to consider “fairness” as part of its ratemaking decisions.<sup>67</sup>

Others worry that the cost of remaining tied to the grid at all will be outweighed by DER, leading to customers completely disconnecting from the distribution system and potentially installing batteries to completely self-supply. This leaves the entirety of costs, rather than just some portion, previously borne by that customer for others to pay and eliminates any benefits to the grid that DER may provide. In this situation, no amount of rate design changes can extract more from a customer (other than exit fees). Depending on technological changes, this potential outcome could result from pushing costs onto DER customers which could lead to uneconomic bypass.

It can be argued that the result of such cost-shifting will make DER more attractive. More people then invest in DER, requiring additional cost shifts ad infinitum. If such a pattern were to hold, it would also worsen the regressivity problem previously discussed, as the increasing rates would incentivize customers to invest in DER who may not have in the absence of the previous cost shifts.

#### **6. Lifespan of utility assets do not match lifespan of DER**

As the lifespan of most DER systems is generally 20 – 30 years (and maybe less for individual parts such as the inverter) and may be significantly shorter than the distribution and transmission investments made by the utility to serve a customer, an interesting problem arises. If the utility is the provider of last resort, how do they plan for a customer who may or may not come back once their system is no longer functional? If other customers are paying for assets that would be necessary to serve the customer should they return, the resulting transfer of cost responsibility may not be acceptable. Additionally, to the extent that a DER system becomes less reliable over time, the utility will be providing additional services to maintain the customer’s or the system’s reliability.

#### **7. Stranded costs and dealing with stranded costs**

As mentioned previously, when customers reduce their usage or other billing/rate recovery determinants, costs that were previously collected from those customers (or investments previously made to serve them) may be stranded, at least in the short- to mid-term until rates are re-set. As these costs were prudent when incurred, and are currently being recovered in rates, they are usually permitted to be recovered in rates until fully depreciated. When rates are re-set, these costs are often either collected from other customers as a result of normal rate setting or collected from the responsible customers by changing the rate structure to reflect determinants closer to those that cause the costs. An alternative treatment for these costs, however, is to set up a special charge to collect the costs from the customers who were previously responsible for them. This was the route taken by some states with the advent of deregulation of power supply. This treatment only encompasses those customers whose usage was reduced by DER, not those customers who leave the system entirely. Such charges also have the potential of increasing the likelihood that customers will find it economic to leave the system, though the decision also depends on the feasibility and costs of doing so.

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<sup>67</sup> In Docket Nos. 15-07041 & 15-07042, Exhibit 64A at the Nevada Public Utilities Commission, testimony was filed regarding the relative incomes of NEM customers.

### **C. Impacts on utility**

In addition to considering the impact DER have on other customers, it is also important to consider the impact to the utility. DER introduces potential system planning complications to the utility, particularly if the resource exports to the grid. The utility may need to upgrade distribution equipment if circuits become exporters to the rest of the grid and begin acting as step up facilities. The utility is still required to maintain and upgrade the system as necessary to ensure reliability, which can be complicated by DER. The utility, or other entity responsible for operations, needs to take the impact of DER into account, though there may not be significant information flow from the DER to the utility. To the extent that DER does reduce investment in any portion of the system, this lowers the utility's rate base, and therefore the amount of return. Additional complications have been discussed previously in the context of the impacts on other customers.

Utilities have seized on the potential impacts on other customers as a justification for increasing fixed charges (discussed in more detail in other sections of this Manual). Utilities, however, have been using various justifications to attempt to get increases in fixed charges for a century. Their claims related to fixed charge increases and DER should be taken in that context and also with an eye toward authorized return if larger portions of revenue recovery shift to more fixed components, making the utility potentially less risky, all else remaining equal.

### **D. Cross Subsidies, including cross-class**

The issue of cross-subsidies has long been contentious in DER ratemaking as noted energy expert Ahmad Faruqi stated in his response to the NARUC DER Ratemaking Survey: *"The biggest challenge posed by existing tariffs is the creation of cross-subsidies between customers who have DERs and those who don't. This needs to be overcome since DERs are penetrating rapidly."*

Cross subsidies, subsidies from one group of ratepayers to another, are endemic in all utility ratemaking as there are variations in consumption patterns within rate classes which cause one part of a rate class to subsidize another part and differences among classes due not only to differential use but also differential impacts of utility rates. The classic cross subsidy is to have industrial and commercial rate classes subsidize residential, *i.e.*, there are differential impacts of electricity costs. In the case of DER-owning customers, there are now a group of customers who differ significantly in both usage patterns and the effects of rate levels on decision making. Eliminating, or at least minimizing, the cross subsidies enjoyed by DER-owning customers has both efficiency implications and equity implications. If the cross subsidies are leading to uneconomic bypass, *i.e.*, bypass that while decreasing costs for DER owners increases the overall cost to the general body of ratepayers, elimination of cross subsidies will increase economic efficiency. Often DER owning customers are higher income customers who can make investments that lower income customers cannot make. Reducing intra-class subsidies would minimize lower income ratepayers from subsidizing higher income ratepayers.<sup>68</sup>

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<sup>68</sup> Increasing subsidies to lower income ratepayers so they can invest in DER may reduce the inequality but exacerbate any efficiency reducing subsidy effects.

Cross subsidies affect restructured jurisdictions differently than they affect vertically integrated jurisdictions. Conceptually it is easier to deal with cross subsidies in restructured jurisdictions so this discussion will tackle them first and then expand the discussion to include vertically integrated utilities.

### **1. Restructured Jurisdictions**

In restructured jurisdictions with retail choice, the costs of energy are set by the market either by third party sellers or by competitively bid default arrangements. This largely removes the cost of energy from creating cross subsidies for DER. The market underlying restructured jurisdictions also can provide market based prices for many elements of value of DER pricing.

The biggest cross subsidy in energy pricing in restructured jurisdiction is when a NEM customer has a net export from their system and is compensated at their retail rate. This is clearly a subsidy to the NEM customer paid for by the general body of ratepayers. While it can be argued that compensating the energy portion of net positive NEM production at retail rates is appropriate, most observers would say that the true value of such energy is “as available energy” and should be compensated as such, which in most restructured jurisdictions is the locational marginal price (LMP). Most NEM customers have invested in their DER to offset their own consumption and systems are often required to be sized to be no bigger than would supply annual requirements. A system so sized would have an expected value of zero net positive generation over a given year’s operation. Another way to limit cross subsidization of energy and other charges is to have a DER owner forfeit any net positive credits at the end an annual period. This would negate any benefits to oversizing a DER system.

For generation in a restructured market, regulators may want to consider a variety of options, including, but not limited to the following:

- Compensate net energy production at LMP (on a monthly/daily basis)
- Limit the effects of over production by:
  - Limiting the size of a DER to a system the size necessary to supply the DER owner’s use over an annual cycle;
  - Have a DER owner forfeit any net positive credits at the end of an annual cycle.

Reducing cross subsidies of non-energy portions of a bill based on throughput is more difficult. One way to start is to have all kWh charges denominated in currency terms, *i.e.*, dollars and cents, not in kWh terms. If an energy charge is based on time varying prices, *i.e.*, kWhs of energy vary in price by when they were generated, currency values rather than kWh have to be used as kWh are no longer fungible between time periods. When NEM credits are denominated in currency it is easier to identify when subsidies exist than when they show up as kWh credits. For distribution costs, the important thing for both economic efficiency and subsidy reduction is to have distribution rates based on cost causation. Energy throughput is not a good proxy for cost causation on a distribution network. For example, a demand charge based on KW is a much better proxy and a distribution rate based on kW rather than kWh may be a more economically efficient manner to eliminate cross subsidies in distribution rates. However, as discussed elsewhere, demand charges come with their own set of complications, such the need to educate customers on demand, and availability of advanced metering technology.

### **2. Vertically Integrated**

From a cross subsidy viewpoint, the main difference between a restructured jurisdiction and a vertically integrated jurisdiction is that a vertically integrated utility has made investments in generation capacity to serve its customers and those customers have an obligation to provide the utility with the opportunity to recover those investments including a return on the investment. DER directly challenges that opportunity. A utility has an obligation to serve and that includes the full needs of DER customers. However, DER customers supply most, if not all, of their own needs annually, but not necessarily daily, and so chronically are under compensating the utility under traditional NEM rate design for the generation, transmission, and distribution investments made on behalf of the DER customer. Under such a situation it is difficult to design a single rate that is appropriate for all customers in an existing rate class as non-DER customers end up subsidizing DER customers. It is often suggested that instituting time varying prices can help eliminate cross subsidies, but the basic problem is that utilities do not recover sufficient funds from DER customers to compensate them for the investments they have made on their behalf. The solution is to design rates that recover from DER customers an appropriate amount to compensate the utility for the investments it has made. The key here is how to determine the “appropriate” amount. Utilities often claim that they need to be able to supply their entire DER customer’s needs at a moment’s notice and should be compensated on that basis. However, that does not take into account DER diversity of outages or loads. Any charges over and above the class based kWh energy charge should be compensatory not punitive. Such a charge can be developed either by creating a DER rate class or by creating a DER surcharge within a rate class. Such a charge can be fixed, equivalent to a demand charge, or variable but should be designed to just compensate the utility and keep it whole.

Distribution charges can follow the ideas for a restructured utility, including unbundling the bill into separate energy and delivery portions.

### **3. Other Cross Subsidy Issues**

One other potential cross subsidy issue has to do with situations where a uniform charge involving DER is applied to the general body of ratepayers, but the majority of benefits from the charge or policy flow to a limited number of customers. A hypothetical can best illustrate such a situation. If a utility has 80 percent of its load in commercial and/or industrial load and only 20 percent in residential load, but all of the NEM customers are residential and the costs of NEM subsidies, *i.e.*, the cost of net positive NEM, are spread across all ratepayers, the residential class is receiving all of the benefits, but paying only 20 percent of the cost. In this case the C&I customers are subsidizing the NEM customers much more than are residential customers. The way around this is to match more closely the recovery of the cost of subsidies with the class that has caused the subsidies. Another example may be rates that include social policies, such as adders for low income assistance or social programs. If usage declines significantly, one may find that the revenues received for those social programs which are collected through utility rates correspondingly decline. This may also put additional pressure on remaining ratepayers to fund those social or governmental programs.

#### **E. “Grandfathering” or “Transitioning”**

A regulator may need to determine whether it is in the best interest to all ratepayers to transition DER customers from one rate schedule to another. This is sometimes known as “Grandfathering” customers into or out of a rate scheme.

The choice of how or whether to transition customers from one rate schedule to a separate rate schedule depends on a few factors:

- Do DER customers have a unique service, usage, or cost characteristics that would be tracked by a separate rate class;
- Are there now or are there expected to be a sufficient number of customers to justify a new rate class; and,
- Does the utility provider have sufficient capability/technology (such as metering/billing) to separate the customers and bill differently.

Assuming the regulator has the authority to determine this, there are arguments for both treating DER customers similarly and differently. In either case, the regulator must assess which rate best promotes innovation and responsiveness to changes in demand in its jurisdiction.

The primary arguments supporting shielding current DER customers from a change in rates/policy (possibly due to meeting a regulatory or statutory threshold) is that customers desire and expect some level of certainty when making decisions about their individual investments in DER. While individual investment decisions are personal, a regulator should consider whether the policies of the jurisdiction require/desire to use ratemaking as a policy and technology support tool. Also, if a jurisdiction allows 3<sup>rd</sup> party leasing of DER systems, the viability of those contracts/leases may be premised on the applicability of a certain rate scheme for the life of the system, usually anywhere between 15 and 30 years. DER customers may have the expectation from the 3<sup>rd</sup> party that there is a prohibition against changing their rate schemes and may argue that any change in rate regime is an impairment to their contracts with a 3<sup>rd</sup> party. The regulator must decide if those expectations are reasonable and were caused in whole or in part, by either the utility or the regulator. For example, one should examine the contracts signed by customer-generators at the time of interconnection to determine if any expectation of rate regime was included in those contracts.

A regulator should examine whether the current or transitional rate scheme is effective in yielding revenue requirements or if there is a likely shortfall – an indicator that inter- or intra-class subsidies are occurring. A regulator should also determine whether the cost, load profiles and/or usage for DER customers is unique enough to warrant a separate rate regime. When comparing the options of shielding DER ratepayers or transitioning to a new rate regime, a regulator should examine the other rate design goals and attributes. Grandfathering gives the DER customer rate stability, but potentially at the expense of utility revenue stability. If the regulator believes that DER customers are similar to non-DER customers (in cost causation, load profile, and usage), then the fairness attributes can be met. Finally, keeping DER customers on a rate regime comports with the rate design attributes of being simple and convenient the best.

The counter arguments to grandfathering customers onto a rate regime are: 1) If the rate recovery from those customers is not effective at yielding revenue requirements, a separate rate regime may better yield that result; 2) While grandfathering customers may result in greater rate stability for those customers, it may come at the expense of revenue stability for the utility and also may cause greater volatility to non-DER customers; 3) Rates are conventionally subject to change, unlike contracts; and, 4)

Depending on the usage/load/cost characteristics, keeping DER customers on a previous rate schedule may be less fair both horizontally and vertically and may create subsidy issues. For example, if DER customers have a different load/usage/cost profile and they are treated similarly to non-DER customers, then the vertical dimension of fairness may be violated. If different generations of DER customers are put on different rate regimes then the principle of horizontal fairness could be violated. Discrimination of the provision of services amongst customers in the same class – is a violation of horizontal equity principle of Bonbright (similarly situated customers should be treated similarly). In practical terms, this means that a Commission designs rates commensurate with cost and usage differentiation, but once those rate classes are set, it must offer service to all within that class non-discriminatorily.

Regulators must consider the effects of transitioning in the future as well. If DER customers are shielded from structural rate changes for a lengthy period of time, will the potential rate shock that occurs at the end of the time period be understood and publicly accepted at that time? Regulators and consumer advocates should consider some form of public information/outreach programs to clearly explain to all ratepayers these effects, now and prior to the time any rate design change is implemented.<sup>69</sup>

If a regulator determines that a grandfathering period is reasonable, it must also determine how it should be implemented. The considerations regarding an appropriate period for transitioning to a different rate may include:

- 1. Payback periods**

Prior to the time when an investment in DER is made, customers have certain expectations regarding the rate treatment for energy exported to the grid from DERs. These expectations affect the payback time of the investment in the DER. State policy and customer expectations of consistent application of DER policies ultimately drive the decision of the customer regarding whether to make the investment in a DER. The use of effective, appropriate, and consistent rate design structures by states is the foundation for efficient DER deployment and can facilitate investment in DERs, consistent with the goals of the jurisdiction. What expectation did customers have regarding the length of time the rate regime would be used? What expectation did the utility or 3<sup>rd</sup> party provider have? The choice for a customer to invest in DER is made once, new rates can only affect customer investment and behavior going forward, but not the choice to invest/not invest in DER. However, the value of DER may factor into the decision whether or not to maintain the DER system. This is the difference between the investment in DER and the continuing operation of it. Additionally, the payback period is an individual decision and varies depending on if the DER system was a Purchase/Install, PPA, or Lease and may not account for the long term “value” to the customer, for example if a customer has installed because of environmental rather than economic reasons.

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<sup>69</sup> Additionally, when making decisions related to DER, customers may lack sufficient education about the difference between a “rate” and a long-term contract with a DER provider. Regulators and other consumer protection advocates may want to monitor marketing materials from DER providers to ensure that customers are being adequately and correctly informed of their options and the potential results of their actions.

Other factors that are important for consideration prior to investing in a DER resource are: available tax credits, RECs, rebates and incentives, initial cost of installation or monthly costs (loan or lease payments) for the lease term, maintenance costs for the system, replacement costs of system, the customer's average and annual electricity use and cost per kilowatt-hour, both current and projected, the expected output from the system, how the DER may affect the home's appraised market value and length of time the customer plans to reside in the home, and the expected life of the solar power system or the length of the lease contract.<sup>70</sup>

**2. Type and degree of rate change**

Are the changes between rate regimes mild or severe? Are there ways to mitigate the severity such as staggering the implementation dates?

**3. Differential DER customers**

If certain DER customers are to be moved to another rate regime while others remain on a different regime, is it appropriate to use the billing data/usage of 'grandfathered' customers to set the rates going prospectively for other, non-grandfathered customers? Is the use of a proxy group in that circumstance appropriate? Does the utility have the appropriate billing structure in order to distinguish between different types or generations of DER customers? And if not, does this add additional costs to the class?

**4. Billing considerations**

Should the rate structure being 'grandfathered' stay with the customer, the premise, the utility account, or some combination thereof for the duration? Does this allow for transactions between customers, such as the sale of the house or panels?

**5. Dynamic changes to a system**

Can a 'grandfathered' customer add panels and have the new panels also be under the grandfathered rate? Is there a limit that the regulator should set on additions/replacements and how is that to be enforced?

**6. Other questions**

How should the regulator value the tradeoffs between stability of customer investment and the dilution of appropriate forward price signals or potential cross-subsidization? Is there a regulatory precedent that could be used to guide this decision?

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<sup>70</sup> "Solar Power for Your Home: A Consumer's Guide," Claudette Hanks Reichel, LSU AgCenter (2015) (available at <http://www.lsuagcenter.com/~media/system/e/4/8/8/e48836bdb7da5028f3116b6531b344d7/pub3366solarpowerforyourhome2.pdf>).





## **V. Compensation Methodologies**

The growth of DER across the country and its impacts on the utility is increasing every day. Regulators are often tasked with two, potentially competing goals: ensuring the financial health and viability of the regulated electric utility and developing policies, rates, and compensation methodologies for DER. This section outlines several options that a regulator may consider in determining how to compensate DER. It is possible that a regulator may choose to implement one or more of them at a time. Additionally, it is important to note that a regulator maintain flexibility in determining the compensation policy, as changes in the market, policy, law, and technology continue to evolve over time; understanding this is an evolution will assist the regulator in recognizing that the appropriate compensation methodology may change over time.

### **A. Net Energy Metering**

Net Energy Metering (NEM) is the simplest and least costly method to implement a compensation methodology for DER. NEM adapts the traditional monthly billing practices to the introduction of generation facilities located on the customer side. In traditional, non-time-differentiated billing, the meter is read once a month. The difference between two consecutive readings defines the quantity of electric service provided by the electric utility and received by the customer. If, for example, a meter displayed 10,000 kWh (cumulative) on March 30, and subsequently displayed 10,200 kWh on April 30, the difference between the two readings, 200 kWh, signifies the movement of 200 kWh across the meter from the electric service provider to the customer. That 200 kWh is then calculated against the rate to determine the cost, plus additional billing determinants, such as a fixed customer charge, taxes, or other charges as approved by the regulator to form the total bill. The key point is that the measure of service is determined by the differences between the periodic readings of the meter. This is the method of calculating electric energy consumption used by most U.S. utility systems for residential service.

NEM works in the same way: the kWh charge is based on the difference between two periodic readings of the meter. The new ingredient in NEM is that there is not only energy consumption behind the meter, but also energy generation. Neither the amount of generation nor the amount of energy consumption can be determined from the meter reading alone. Using the same example, the 200 kWh difference between the two subsequent meter readings signifies the net movement of the meter and the net quantity of service provided by the utility for the benefit of the customer. It is possible that the customer produced some amount of kWh greater than zero while consuming some amount of kWh greater than 200 between the two readings. Neither the amount of production nor the amount of consumption can be determined from the two readings of the meter, only the net movement of the meter can be measured by this method. Once again, the key point is that the measure of service is determined for billing purposes by the difference between the two periodic readings.

NEM developed as a straightforward method for interconnection of very small distributed energy systems at a time when residential electric meters were analog systems designed to be read manually. While the high capital cost and operating expenses associated with multiple specialized interval-

recording meters could be justified – and were required – for large industrial and commercial electric service customers, such costs would have been prohibitive for residential properties and would have overwhelmed any savings from self-generation. As long as only a very small fraction of households were connecting PV or other self-generation systems, and as long as the quantities of energy moving from customers to the grid were very small, it seemed reasonable to allow customers to hook up their behind-the-meter solar panel systems without mandating additional costs for more precise metering systems. So, in the age of analog meters and manual reading of those meters, NEM was the only practical way to introduce PV and other home-based generation systems. At the time when residential PV systems were new and costly, adoption of NEM provided a strong incentive to install home systems. Much has changed since then; solar PV costs continue to decline and the cost of advanced meters are much less expensive, are more precise than the interval meters of the last century, and can be read electronically at very short intervals (five minutes or even shorter).

NEM has great advantages for a homeowner or small system operator by allowing the customer to generate electric energy when the power is available and then consuming it at a time of convenience. For solar PV systems, solar panels are situated at an angle best identified to capture the greatest solar radiance, which typically covers noon to 4:00 PM in the afternoon.<sup>71</sup> The customer can then “use” the electric energy at a time more convenient, such as in the late afternoon and evening. Essentially, the customer is able to use the utility as a bank for energy.

Proponents of NEM argue that the revenue reduction of utilities from NEM is justified and appropriate. First, utilities are not required to purchase or generate the electric energy that the customers are generating and using themselves. Customer generation, it is argued, reduces utility generation even if the generation occurs at times other than when the customers consume electric energy. Besides saving the system the cost of generating the electric energy that the customer generation offsets, customer generation also unloads the distribution system (and to some degree the transmission system), thereby reducing system losses and forestalling required expansion and/or upgrades. Proponents argue such savings to the system (and therefore to all system users), though difficult to calculate, justify granting customers the full benefit of reduced bills, including not only reduced energy costs but also any margin built into the kWh charge.

There are complications that arise from NEM. First, it is possible – even likely – that during some hours between the two monthly readings, the amount of generation exceeded the amount of consumption. That is to say, at times the meter may run “backwards” in the sense that the flow of kWh was from the customer to the electric service provider. Then, during other hours, the meter will run “forward”

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<sup>71</sup> Typically, solar panels face southwest, which allows for the greatest amount of sunlight to power the panels. However, as identified by the Pecan Street Project, this may exacerbate afternoon ramping periods as the solar output declines rapidly as the angle of the sun goes down. Research from Pecan Street Project highlights the need for some panels to face west, even though solar radiance is less during late afternoon hours, as it may assist in alleviating afternoon ramping conditions due to the setting sun. (See <http://www.pecanstreet.org/2013/11/report-residential-solar-systems-reduce-summer-peak-demand-by-over-50-in-texas-research-trial/>). This highlights one of the technical and economic challenges with NEM with policies supporting total production without location or timing attributes.

recording consumption in excess of the amount of customer generation at that time. That one net measure is the billing determinant under NEM.

Returning once again to the example discussed previously, if the April 30 reading is 9,990 kWh, the net difference is -10 kWh, that is, consumption of a *negative* amount of electric service for the month. The result of NEM in this example is that the customer produced more kWh than was consumed, and it appears that the customer produced net electric service for the electric service provider. Under NEM in this example, the billing determinant of energy consumption is a negative number. Applying that negative number to the rate in the tariff may result in a negative invoice, which, depending on the rules in place in the jurisdiction, may be carried over into the next month as a credit.

It is not the purpose of NEM for customers to achieve negative net energy consumption overall, but it may occur during times of the year when both heating and cooling demands are low. At other times of the year, such as during the summer, when electric energy is used for air conditioning, and during the winter, when electric energy is used in heating systems, the net energy consumption would be positive. That is, for most months, the amount of energy consumption over the month is likely to be greater than the amount of energy produced by the customer's generating equipment during that month, outweighing or at least matching the negative measurement for this April example. Over a longer period, such as a year, it is possible for a customer would achieve a negative net balance for the whole period, thereby avoiding all charges associated with electricity service.

A second complication of NEM is that it does not account for any difference in value between the cost of service associated with the tariff rate for kWh and the value of the kWh itself. That energy may pass in either direction across the meter implies equivalence between the delivery of energy and the provision of electric service. Traditional electric rates carry a margin in excess of the direct costs of the measured kWh so that the total costs of the electric utility, including fixed costs and other variable operating costs, can be recovered through that charge. By measuring only net energy, and crediting excess against the total bill, NEM reduces not only the energy revenue of the utility but also the margin available for the coverage of other costs.

A third complication is that NEM does not account for time or locational differences in costs or value of energy. Of course, the timing and location question is not attributable specifically to NEM, but is a feature of traditional monthly billing systems with or without customer generation. Still, the matter becomes more complex when both consumption and production are involved. The simplicity associated with a single monthly meter reading provides no information about a customer's pattern of generation or consumption, or the location of the customer. The advent of advanced meters has facilitated the ability to adopt of time-of-use (TOU) rates for traditional electric service and for NEM. Different rates for different TOU periods may reduce, but does not eliminate the conceptual issue that neither the amount of generation nor the amount of consumption is measured under NEM, only the net.

Additionally, many NEM discussions fall back on recovery of system costs. First, the operational issue: NEM customers do not compensate the system for the operational costs they impose on it. They force the system operator to absorb their excess during peak generating periods, and they force the system operator to ramp generators and adjust the system to "repay" the customer generation at other

hours/days/seasons. This means the costs of the system are higher even though the NEM customers are not charged for those additional costs. Second, by overcompensating the NEM participants through their avoidance of kWh charges, NEM necessarily is imposing those avoided costs on the nonparticipants. In this view the nonparticipants are subsidizing the NEM participants.

Though NEM is the simplest form of interconnection for generating systems behind the meter, it fails to account for the complexity of grid operations. For grid stability to be maintained, there may be a need for the ability of the grid operator, such as the distribution utility, to curtail the operation of the generating system, essentially overriding the desire of the customer to generate as much as possible. The effects of any one customer's actions are negligible and make little difference to grid operations. However, NEM detractors argue that as greater amounts of customer generation are connected to the system, any savings to the system may be overwhelmed by greater costs. Customer-side PV generation peaks in the afternoon, and the grid operator accommodates the customer surplus flowing onto the grid by lowering the load service of dispatchable power plants down to minimum load, the lowest level of operation consistent with an ability to stay on line and be available to provide service. This action has a cost and, in the future, may strain the abilities of conventional plants. Then, later in the day, as customer generation falls off, customer loads begin to rise, and net customer loads, accounting for the reduction in customer-side generation, rise very rapidly. The dispatchable plants must rise quickly from their minimum loads up to their maximum to meet the increase in system load and keep the grid stable. This sudden ramp also has a cost. NEM detractors argue that NEM customers, far from saving costs to the system, may actually increase system costs. And because the system maximum loads do not occur at a time when the customer generation is high, there may be no savings from postponing system expansion or system upgrades. From the point of view of NEM detractors, NEM overcompensates customers with customer-side generation and adds system costs that must be paid by all customers.

Finally, while NEM may reduce the total amount of utility generation, it does little to encourage customers to use less electric service overall. In fact, under a situation of inclining-block rates, the charges that the NEM customers avoid are the in the highest blocks. NEM customers may move from a high block to a lower block, thereby decreasing the marginal cost of using more electric energy. If NEM customers use more than they otherwise would have, then any system savings – especially saving from reduced system generation – is reduced.

## **B. Valuation Methodology**

There are two main methods of determining the valuation model for this methodology: Value of Resource and Value of Service. Another term that may also be used to reflect this concept is “Buy All/Sell All.” In other words, a customer is charged for its consumption and is then separately paid for its generation. Conceptually, a valuation methodology allows for the disconnection of consumption from generation. Put another way, a customer would be charged for its consumption, including distribution, generation, transmission, taxes, and other fees or riders, which are often calculated based on total consumption. For its production, a customer would then be compensated (or charged, if the resource imposes a cost) at a separate rate based on a number of factors, as determined by the regulator. Deciding which path to take may depend on the level of penetration of DER. If the jurisdiction has

limited penetration of DER, Value of Resource may make more sense. On the other hand, if DER is showing significant penetration, then the Value of Service may make more sense.

### **1. Value of Resource (VOR)**

This method separates the costs of utility services and benefits that may occur from DER systems and attempts to value them separately. It is important to value both positive and negative factors for each of the categories of costs/benefits to ensure neutrality. This method attempts to recognize potential benefits to the grid, other customers, and/or society. A few states are currently investigating or determining the VOR variables and values and many use very similar variables. However, it is important to note that the value of DER changes over time based on a variety of factors: relative location and concentration, natural gas prices, and the price of utility-scale renewables amongst other things. Consequently, setting a fixed value for a long period of time may be unwise. However, a regulator can establish a process to set the values periodically to ensure that technological and practical considerations can be changed as the distribution and transmission and growth of DER occurs. Most methodologies consider both the positive and negative effects of:

1. Avoided Energy/Fuel
2. Energy Losses/Line Losses
3. Avoided Capacity
4. Ancillary Services
5. Transmission and Distribution Capacity
6. Avoided Criteria Pollutants
7. Avoided CO<sub>2</sub> Emission Cost
8. Fuel Hedging
9. Utility Integration & Interconnection Costs
10. Utility Administration Costs
11. Environmental Costs

The positives of the VOR method are that, once a value/rate is determined, it is known and can be relied on as a value of renewable or distributed generation sent to the grid. Customer-generators can gain certainty regarding the value of their investments (at least for a time). As this provides greater certainty, this method can encourage the use of DER. As stated previously, the values underlying this method can be updated as circumstances warrant or on a known timetable to reflect current market conditions, or to be included or determined as part of integrated resource planning. Since a VOR method values elements that are often overlooked and can quantify benefits in a transparent manner, it may be more accepted by parties. The more comprehensive the VOR method, the more comprehensive it will be in evaluating the full range of costs and benefits of DER systems. Finally, this method treats VOR similarly to other resources that a utility may obtain and provides a comparison with which to make resource planning decisions, and may be used to set the value for all types of renewables including PURPA resources.

For the short term, a VOR methodology allows a regulator to identify select resources that it determines as worthy of valuing. For example, a regulator may decide that electric vehicles or solar PV are of sufficient interest to the state to warrant specific valuation. A regulator could then develop a VOR tariff for a specific DER, and potentially pair it with an appropriate rate, such as TOU. This would allow the resources under that tariff to remain together for consideration and review by the regulator. A VOR tariff would also assist in keep costs contained under one tariff, so that total costs and benefits can be better identified. Again, the regulator will need to determine the values of each component, such as those listed above, but it can provide better signals to the resource, including location, timing, benefits, and costs.

One must use caution, however, that to ensure that any value component determined by the VOR is not already being tracked or traded separately. For example, in Nevada, renewable distributed generation is eligible for renewable energy credits and customer-generators are granted credits based on system output. However, a greater number of renewable energy credits are given if the system is a distributed energy system, so the value of the avoided distribution would be counted twice if valued both as a REC and as a component of a VOR payment. Also, if environmental credits/benefits (such as environmental costs, avoided CO2 and avoided pollutants) are separately tracked through issuance of renewable energy credits (RECs) through a recognized tracking mechanism,<sup>72</sup> one should remove them from the VOR list, else those same benefits or avoided costs would be double-counted. Determinations of value should attempt to reflect the actual, market value of a trait as identified and “valued” by that jurisdiction. In this instance, a value for carbon avoidance should be based on market value, and should avoid alternative, non-market based values.

As always, there are downsides to the VOR methodology as well. One detriment to this method is that it often requires subjective judgments and may allow for values that are not quantified in a rigorous manner. Another is that a process to determine both the list of items to be valued as well as the values themselves may be highly contested and prolonged. As stated previously, some of the benefits and costs, particularly distribution related, are site and location-specific and may switch between a benefit and a cost, depending on the location in the system. Since the VOR method is particularly site/location-specific it may need to be reviewed and revised regularly to ensure that pricing and value signals remain correct, which may result in contested proceedings more frequently. Finally, if a VOR is used, the value paid by the utility for the renewable output should be tracked through a fuel charge or other component that does not directly flow into a utility’s rate base such that there is not further erosion of the revenue requirement and potential cross-subsidization.

## **2. Value of Service**

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<sup>72</sup> Two examples are the Western Renewable Energy Generation Information System (WREGIS) and the Midwest Renewable Energy Tracking System (M-RETS). Both systems track and facilitate REC transactions in their respective geographical regions.

An alternative valuation methodology relates to identifying services that a DER can provide directly to a distribution utility. In this methodology, the distribution grid is treated as a network, where each piece connected to it provides value in being connected and by providing additional services to support the development of the network. To accomplish this, a functional unbundling of distribution services would be required by the regulator, similar to transmission unbundling in the 1990s-2000s. By introducing services, the distribution utility would be able to identify specific services necessary to maintain grid reliability, then the distribution utility would be able to procure DER that satisfied the technical and economic requirements. DER would then become built into distribution networks, able to be counted by resource and system planners, and dispatched by distribution grid operators. Identification of additional services from DER provides additional value streams from DER investments, other than simply paying for the generation (*e.g.*, solar PV) or adjustment to demand (*e.g.*, demand response). DER, much like traditional power plants, are capable of providing additional benefits directly to the distribution grid, such as voltage support, ramping, or even local blackstart, such as from a microgrid. Additionally, these resources can assist the distribution utility in maintaining reliability by encouraging a diverse resource mix; it may be possible for a regulator to consider compensating DER for reliability. By building in DER into a distribution utility's portfolio, the regulator may be able to provide additional opportunities for driving extra benefits for DER that supports both the customer and the utility.

Similar to VOR, a regulator would need to determine the services that would be sought from DER. Additionally, the values would need to be inclusive of many of the same factors as outlined in the VOR section. Understanding the services needed for the distribution grid, similarly like the transmission grid, the costs to serve will continue to fluctuate across the distribution grid as DER continue to proliferate. This may result in some areas of the distribution grid costing more to serve than others, which may upset a long-standing rate design goal of ensuring equity inside a class. As described elsewhere, divisions of customer classes may be an option to address this issue.

Finally, VOS will require substantial technological investment by the utility. Several of these technologies are discussed in Section VII. Nevertheless, in many instances, customers are investing their own money for DER, some of which may already come with technology to enable a VOS tariff; the lagging factor may remain the utility and regulatory approval of investments in new technology. Additionally, moving to a VOS model will likely require a re-framing of the utility (and regulatory) model for recovering costs. A regulator may consider a movement away from a utility recovering all costs directly from usage, and allowing the utility to recover costs through VOS, extra earnings on performance, or allowing a greater rate of return on operational and maintenance.

### **3. Transactive Energy**

A more future oriented version of a valuation methodology is Transactive Energy. Transactive Energy (TE) is a concept developed by the GridWise Architecture Council and Pacific Northwest National Labs (PNNL). TE is both a technical architecture and an economic dispatch system highly reliant upon price signals, robust development of technology on both the grid side and the customer side, and rules allowing for markets to develop that enable a wide variety of participants to provide services directly to each other. This "peer-to-peer" component differentiates TE from many of the other options discussed herein.

As explained by GridWise, TE is a means by which customer-sited resources, including demand response, storage, and other on-site generation sources, can be interconnected with the grid and be interactive with the grid. TE facilitates the coordination of these resources through markets and other means by which resources can be dispatched in response to price or other signals. As defined by GridWise, TE is “A system of economic and control mechanisms that allows the dynamic balance of supply and demand across the entire electrical infrastructure using value as a key operational parameter.”<sup>73</sup> Underlying this is the development and identification of services and value streams available to distribution resources. These services and values could be sought by the utility, a third party, or another customer.

GridWise notes that technology is becoming more widely deployed by utilities, businesses, and customers, devices across the spectrum are becoming more intelligent, and larger amounts of clean resources are being installed. These investments are increasingly being done closer and closer to the edge of the distribution and onto customer premises. With the changing nature of the distribution grid and the customer, planning and operating the distribution grid becomes increasingly complex. TE is a means by which an operator can rationalize these complex actions that may be occurring outside its control.

TE can enable a much larger set of value streams for customer-sited resources. As customers continue to invest in technology, trying to extract additional value out of those resources will be key to continued deployment of those technologies. Allowing these resources to offer the services, in a way that does not impact the reliability of the grid, may assist customers to pick and choose from a variety of preferences. Additionally, the flexibility provided by these resources to the utility could assist in avoiding costly infrastructure upgrades.

However, development and implementation of a TE system requires a significant amount of technology and communications equipment. AMI is a requirement under TE. Furthermore, anticipating customer acceptance of this concept remains unproven at best. Long-standing public policy on resource planning and procurement relies on long-term recover of investments, but TE focuses on a series of short-term transactions; ensuring adequate compensation and certainty for investments will need to be proven. Lastly, many states have policies limiting the ability of customers to sell excess electricity to other customers, or prohibit aggregators who may be in a better position to optimize a group of resources and integrate them with the utility.<sup>74</sup>

### **C. Demand Charges**

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<sup>73</sup> “GridWise Transactive Energy Framework, Version 1.0,” GridWise Architecture Council at 11 (January 2015).

<sup>74</sup> For more considerations, see “Transactive Energy: A Surreal Vision or a Necessary and Feasible Solutions to Grid Problems?” Nilgun Atamturk, California PUC (October 2014).



Demand charges have long been used in commercial and industrial customer class rates, but have not historically been applied to other customer classes. Some advocates are looking to use demand charges on a more widespread basis since all customer classes conceptually incur demand charges.

Demand charges are another line item cost included on a utility bill - in addition to fixed and energy costs, which make up a utility's revenue requirement. Demand is often calculated and charged in KW and used, at least in part, to "split up the pie" of the revenue requirement within each class. Demand charges endeavor to measure the "size of the pipe," or capacity needs of a customer. There are two historical ways to calculate a demand charge, either by taking the customer's highest instantaneous demand a customer draws from the system, measured in KW, over a certain time period; or, alternatively, by using the customer's highest KW (peak) divided by the relevant timespan, during the period in question.

When proposed or used in a residential context, demand charges are often included as a percentage of the delivery portion of a bill and are measured on a more frequent basis, often monthly presumably to increase bill stability and allow customers to react to price signals. If the rates are understood by customers and loads can be shifted, then these demand charges can incentivize customers to "shave" their peaks or shift usage to another time, and with coincident rates, reduce the overall system peak. How, when, and how often this demand is calculated can vary in practice.

Lately, interest has been paid to use of demand charges on residential and small commercial customer classes in areas with the technology to do so, such as advanced metering technology.

Parties advocating for the use of demand charges on a more widespread basis state that the short-run costs of the distribution system are all fixed in nature and should be proportioned among customers in the same rate class based on their maximum demand regardless if it contributes to a system peak. Other parties insist that to use demand charges they must be coincident and thus measure a customer's contribution to certain system peaks.

Advocates argue that demand charges can ensure greater revenue certainty and cost recovery for the utility – and costs are better covered by the cost causers (unlike NEM, or other rates which offset distribution costs). Since the costs are recovered based on individual peaks rather than overall volume of usage, which can vary greatly from year to year, there is also more certainty that the utility will be able to fully recover its authorized return. In this way it reduces risk for the utility. Additionally, advocates argue that demand charges are a charge the industry is familiar with, and therefore should come with a smaller learning curve.

However, as opponents argue, there are many unknowns and uncertainty surrounding the use of demand charges on classes other than C&I – mainly regarding customer impacts. Empirical data on the impacts and customer acceptance and responses to residential and small commercial demand charges

are insufficient. In a review of residential demand charge rate designs, RMI identified only 25 demand charge rates offered to residential customers.<sup>75</sup>

While demand charge structures may encourage reduction in peak (depending on how peak is defined), it may not send an adequate conservation signal to reduce usage, if implemented with an associated reduction in kwh/volumetric costs, and subsequently the costs of generation (as compared to volume-based rates). Additionally, demand charges do not assist in customer understanding of the rate design as there is a small margin for customer error; higher bills can be earned through a shorter timeframe of a lapse of attention (*i.e.*, too many appliances on at once) and can result in the possibility of higher bill volatility from month to month. Lower income customers (or those with low load factors) are especially hard hit as they can have less control over peak demand usage. Lastly, demand charges, if a large portion of a customer's distribution bill, would over collect customer costs as demand costs.

Importantly, many parties on all sides of the issue seem to recognize the potential for using demand charges sparingly (*i.e.*, to represent a dollar or two on an average bill) and when measuring demand coincident with system peaks,<sup>76</sup> but the number of opponents quickly grow as the utilities begin to depend more and more on these rates for recovering their distribution system costs.

Some utilities have proposed using demand charges in conjunction with NEM rates. Since the NEM rates usually provide a credit against consumption on a volumetric basis, charging a residential customer their distribution costs through KW-based rates eliminates the possibility that NEM compensation is shifting costs. This practice, however, would not compensate or charge DER customers for any benefits, or additional costs, they represent to the grid.

As discussed below, the demand charge success will be largely driven by the fine details of the structure imposed – ultimately who pays what portion of the charge and the parity of that allocation.

### **1. Considerations in Demand Charges**

As with many of the compensation methodologies available to regulators, the implications of the use of demand charges depend greatly on the details of the design and implementation of the charge. If done appropriately, reducing the system peak should lead to savings for all customers on the system in the long-run as generation becomes less expensive and if the regulator can properly incorporate any distribution savings in new rate proceedings.

If a regulator is interested in considering the use of demand charges for residential or small commercial classes, issues arise that are not as prevalent of problems for C&I classes. Each of these choices can represent very different impacts, customer experience, and policy implications:

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<sup>75</sup> "A Review of Alternative Rate Designs," Rocky Mountain Institute at 57 (2016).

<sup>76</sup> "Smart Rate Design for a Smart Future."

- Classifying users into classes on a type-basis, locational-basis, or on an individual basis

These considerations shape how costs will be allocated between these classes. They would also dictate who a customer would be compared to when determining the relevant portion of demand costs for which they are responsible.

- Defining 'system' and system peak

Due to the smaller locational nature of the distribution system, utilities and regulations need to determine what areas should be considered as a system in which to assess a customer's contribution to peak usage or demand/capacity needs. Should the utility use a system-wide peak or a more local area (*i.e.*, substation/feeder level)? Additionally, certain distributions costs are driven, not by demand, but by the number of customers, geographic circumstances, customer density, or other factors.

- Use of coincidental or non-coincidental peak

Is the demand measured coincident or non-coincident with the system peak? Are different customers' demand measured concurrently at a set point in time (system peak) or are different peak time spans used (*i.e.*, instantaneous, 15-minute, or 30-minute time spans to measure the individual customer's usage)?

## **2. Coincident Peak Considerations**

Using a coincident peak method better aligns the demand charge with economic principles (to align costs to cost causers, among others), however, coincident peak demand charges can be harder to understand and can lead to reduced rate stability on the part of the customer. Notably, customers and the utility may not know when the system peak occurred until the end of the month. While it may be possible for the utility to declare in advance that one hour on the next day will be calculated as system peak, the utility runs the risk of choosing the wrong day and/or time, which would then mitigate the economic signal the demand charge intends to reflect.

It can be difficult to implement true coincident peak pricing based on annual cycles, such as with C&I, since the various levels of the distribution system can peak at wildly different times and it can lead to varying and potentially very high customer bills as utilities collect substantial revenues in a single billing cycle. Understandably, regulators have acted cautiously when considering whether or not to collect all distribution costs during a short interval representing the highest system usage, while charging nothing or a minimal amount the rest of the year.

## **3. Non-Coincidental Peak Considerations**

Use of the non-coincidental peak method in determining an individual customer's appropriate share of demand charges is functionally problematic. Non-coincidental peak usage does not correlate with how the system is designed, and costs are incurred, as the system needs to be designed for peak usage. In other words, if a customer's peak demand occurs in non-peak hours, there is likely plenty of available capacity, which has little economic impact on the utility's costs to serve that demand. Of the 25 demand charge rates identified by RMI, 66% of them base the charges on a residential<sup>77</sup> customers' non-coincident peak. As RMI notes, "Non-coincident-peak demand charges are more straightforward for customers to understand and for utilities to administer but, if applied to anything beyond customer-specific costs, they may not reflect cost causation."<sup>78</sup>

However, if non-coincident is used, there are methods that can better align costs. Factors to consider when determining a customer's non-coincidental peak: 1) within what time period is the peak measured (*i.e.*, a calendar day or business hours), 2) What days are measured (week days, weekends)? The longer the period measured in a non-coincident rate the harder it is for a customer to shift their peak outside of that time period and the more the rate behaves like a fixed charge. For example, a customer who welds in the middle of the night during a 24-hour measurement period may pay the same as if they were welding during a system peak.

#### **4. Re-calculation of Peak Usage Period**

How long is the period (or cycle) in which the peak is established? In other words, how often is the demand measured and a customer's rate re-calculated (*i.e.*, monthly or once a year)? Is it appropriate to use the C&I model in which a system's total peak is measured once a year and an individual customers usage at that time determines the individual's monthly rate for the next year?

When applied to the distribution system, the need for a much shorter peak usage period becomes necessary. In the case of demand being measured over 24 hours, a customer can only reduce their bill by reducing their peak in relation to other customers (*i.e.*, that peak shift no longer results in the opportunity for savings). If the KW peak is averaged over a period of time, then the longer the relevant timespan, the more short lived spikes (*e.g.*, a hair drier or welder) can be smoothed out and generally the lower the KW amount (*i.e.*, a spike during a 15-minute timespan would represent a larger demand than if the relevant timespan was 30- or 60-minutes).

Some examples of demand charges include: in one state legislature, a utility proposed a mandatory, non-coincident residential demand rate which would be measured monthly as the highest 30-minute usage over weekdays between 6am to 9pm and recover 100% of distribution costs when coupled with a reduced fixed customer charge.<sup>79</sup> Another example uses a customer's coincident demand to calculate a

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<sup>77</sup> "A Review of Alternative Rate Designs," Rocky Mountain Institute at 57 (2016).

<sup>78</sup> *Id.*

<sup>79</sup> <https://www.comed.com/News/Pages/EnergyPlan.aspx>;  
<http://ilga.gov/legislation/billstatus.asp?DocNum=1585&GAID=13&GA=99&DocTypeID=SB&LegID=88279&SessionID=88>

volumetric charge. In one jurisdiction, the capacity charges for a residential real-time pricing program are calculated by averaging the customer's highest electrical demand coincident with the five highest hours of overall system demand in PJM with the five highest hours on the local utility's system. The average is then adjusted and used to calculate the volumetric charge for the next year.<sup>80</sup>

## **5. Effect on DER customers**

Recent interest in demand charges is argued to stem from utilities trying to reduce the impact of the current incentives for DERs (such as NEM) and in doing so improve their rate recovery and reduce cross subsidy issues. These results do affect customers with different resources in different ways. Generally, and especially for PV and other DER customers, this rate design reduces their ability to lower distribution costs or what they are paying for the grid. From a policy perspective, without other compensation, demand charges rates would generally decrease the ROI for DERs and reduce the attractiveness of these technologies.

Some DERs, however, may allow customers to react favorably to demand charges and potentially save money. It could be said that demand charges encourage storage technologies, or any other technology or service which flexibly implements "peak shifting" or the practice of "filling the troughs" and "shaving the peaks" of a customer's instantaneous usage. Any resource that encompasses technology or a service which would enable a customer to reduce their relevant, measured peak as compared to others in their rate class should be able to reduce their distribution rates under most demand charges. Whether their rates would be lower, or whether they would have more control over their rates, under a demand charge versus another rate type would depend on the individual customer's sophistication and understanding of the rate, their load factor and profile, as well as the details of the demand charge. EE and DR programs both may help reduce a customer's peak load, but the results would be limited to specific circumstances and potentially for only brief periods of the year, depending on the program or technology involved.

## **6. Path forward for Regulators**

At the time of writing this Manual empirical data for demand-based rate designs that are being implemented on a mandatory basis for large investor-owned utilities is limited.<sup>81</sup> Thus, regulators should be wary of counting on unsupported, promised benefits and cautious when plausible harm may represent itself. It may be that pilots which hold their customer's harmless could be the best way forward. Regardless, more data should be available in the future as several utilities have submitted proposals to regulators and legislators. Whatever the implications of these newer rates may be a regulator must be comfortable with how they will interact with their jurisdiction's unique circumstances before implementing them.

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<sup>80</sup> <https://hourlypricing.comed.com/faqs/>

<sup>81</sup> "A Review of Alternative Rate Designs," Rocky Mountain Institute at 76 (2016).

#### **D. Fixed Charges and Minimum Bills**

Fixed charges (also called customer charges, facilities charges, etc.) are rates that do not vary by any measure of use of the system. Fixed charges have a long history of use across the United States, and are a fixture of many bills. Fixed charges have been used by utilities to recover a base amount of revenue from customers for connection to the grid. Some argue that, as the majority of a utility's costs are fixed (at least in the short run), fixed charges should reflect this reality and collect more (if not all) of such fixed costs. Others argue that higher fixed charges dilute the conservation incentive, fail to reflect the appropriate costs as fixed (long-term rather than short term), or should only be set to recover the direct costs of attaching to the utility's system.

Higher fixed charges accomplish the goal of revenue stability for the utility, and, depending on the degree to which one agrees that utility costs are fixed, match costs to causation. However, the interplay between collecting more costs through a fixed charge and the volumetric rate may result in uneconomic or inefficient price signals. Indeed, an increase in fixed charges should come with an associated reduction in the volumetric rate. Lowering the volumetric charge changes the price signal sent to a customer, and may result in more usage than is efficient. This increased usage can lead to additional investments by the utility, compounding the issue.

This potentiality also highlights the disconnect between costs and their causation that a higher fixed charge may have. If higher usage leads to increased investment, then it may be appropriate for the volumetric rate to reflect the costs that will be necessary to serve it, which would point towards the appropriateness of a lower fixed charge. In other words, it may be more reasonable to lower the fixed costs and increase the volumetric rate, which would send a more efficient price signal.

A related movement is the adoption of a minimum bill component. California, which does not have a fixed charge component for residential customer bills, adopted a minimum bill component to offset concerns raised by its regulated utilities regarding under-collection of revenue due to customers avoiding the costs of their entire electric bill.<sup>82</sup> In other words, some NEM customers in California were able to zero out the entirety of their bill, and avoid paying the distribution utility any costs. In a decision revamping its rate design, the California PUC adopted a minimum bill component, which ensures that all customers pay some amount to the utility for service. The California PUC set a minimum bill amount at \$10, which is collected from customers who have bills under \$10. Massachusetts passed the Solar Energy Act ("MA Solar Act"), Chapter 75 of the Acts of 2016 in April 2016. The MA Solar Act allows distribution companies to submit to the DPU proposals for a monthly minimum reliability contribution to be included on electric bills for distribution utility accounts that receive net metering credits. Proposals shall be filed in a base rate case or a revenue neutral rate design filing and supported by cost

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<sup>82</sup> *Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations*, "Decision on Residential Rate Reform for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company and Transition to Time-of-Use Rates," D.15-07-001 (July 13, 2015)

of service data. On the other hand, minimum bills eliminate a conservation signal by encouraging consumption up to the minimum bill amount.<sup>83</sup>

In either event, distribution utilities often dispute which components are fixed and should be recovered from customers. As discussed previously, there is a great deal of disagreement as to what constitutes a fixed cost. Are overhead costs fixed? What portion of the distribution system is fixed?<sup>84</sup>

Understanding and identifying what are “fixed costs” is a key component to determining compensation to DER, revenue recovery for the utility, and how to best balance utility financial health and the growth of DER.

#### **E. Standby and Backup Charges**

Standby service is service available to a full- or partial-self-generating utility customers to protect the customer from loss of service in the event of an unanticipated outage of its own self-generating equipment. Standby service is provided through a permanent connection in lieu of, or as a supplement to, the usual internal source of supply. It is power generally not taken, but available on an almost instantaneous basis to ensure that load is not affected. Of course, any and all generation sources are subject to failure from time to time. Therefore control areas and utility systems maintain reserves, including reserves that are operating and ready to pick up load. When utilities operated almost all of the power plants on the system, standby power was supplied by all generators to all generators, and it was an implicit part of the system of operating reserves supported through charges for retail service. Only large non-utility generators, such as combined heat and power systems, faced fees for standby service. Now, with the advent of ever larger portions of non-utility generation, the subject of the cost of providing standby service comes up anew.

Standby charges are charges assessed by utilities to customers with DER systems that do not generate enough electricity to meet its needs or may experience a planned or unplanned outage and therefore must receive power from the grid. These customers are commonly referred to as “partial requirements” customers. The standby charge is assessed by the utility to assist in the payment of grid services and standby generation and is usually comprised of a demand charge\$/kW and an energy charge based on a \$/kWh basis. These charges recover both the cost of the energy used to serve the customer as well as the costs of the utility for providing the capacity that has the ability to meet the peak demand of the customer receiving the standby service.

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<sup>83</sup> “Smart Rate Design for a Smart Future.” See also, “Recovery of Utility Fixed Costs: Utility, Consumer, Environmental and Economist Perspectives,” Lisa Wood, Ross Hemphill, John Howat, Ralph Cavanagh, and Severin Borenstein, Lawrence Berkeley National Laboratory, Future Electric Utility Regulation, Report No. 5 at 58-59 (June 2016).

<sup>84</sup> See, e.g., the discussion of the minimum system and zero-intercept methods of cost allocation in the NARUC Electric Utility Cost Allocation Manual at 136-142.

These charges are generally approved by state regulators primarily due to system reliability concerns of utilities. With the increase of DER systems on the grid, some parties fear that utilities are assessing these charges to discourage customers from investing in DER systems because projects become uneconomic with standby fees even though the DER project is providing benefits to the grid.

Electric system operators must be able to maintain satisfactory system conditions in the presence of changes in conditions, both on the production side and on the consumption side. They must be prepared for the largest contingencies that can befall their systems. Sometimes this kind of preparation is referred to as “n-1” or “n-minus-one” preparation. This relates to the planning for large system events, such as the loss of a transmission line or a commercial generating unit. In the traditional case of nearly all generation being supplied by utility-operated plants, standby is provided by all for all. However, with the advent of significant amounts of generation being supplied by non-utility generators, including DER, not explicitly accounting for the cost of standby power may provide a cost advantage to the non-utility generators and may be a cost burden upon traditional non-generating customers. It would never be the case that any single DER would rise to merit attention in a list of important contingencies for an electric system.

Backup service is similar to standby service except that it is a planned service and is usually not available on an instantaneous basis. When commercial generators plan maintenance, they provide long notice to the system operators and generally make contract arrangements for reliable backup service to maintain local area load, as well as system load. There may be regulated tariffs for backup service for commercial generators, but they are not common for DER, such as behind-the-meter systems of small commercial and residential customers. Still the term “Backup service” may, in some cases be used in the same way as “standby service.”<sup>85</sup>

Both backup charges and standby charges have been associated with large commercial and industrial systems, both load and generation.<sup>86</sup> Historically, they are most associated with non-utility generating systems, such as large self-generation systems at industrial plants and with combined heat and power cogeneration systems. They exist so that utilities and system operators are not saddled with costs of maintaining large reserves beyond mere prudence. They have not generally been associated with intermittent generating sources except for large commercial-sized projects whose output (or lack of output) could alter system operations and requirements.

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<sup>85</sup> The term “backup service” is being applied more generally to service options that appear to fit the general definition of standby service. An example is the Alabama Power “Rate Rider RGB Supplementary, Back-up or Maintenance Power” schedule, which states, “Back-Up Power is not available when the customer requires Maintenance Power, but is available only during unscheduled outages, which can occur when a customer’s own generation equipment is not producing energy or capacity, or is experiencing periods of intermittent generation.”

<sup>86</sup> There is another way in which the term “backup service” is used, but it is not directly related to DER. Buildings with elevators generally are required to have a backup source of power able to power the elevators and emergency lighting. Often the backup service is a diesel generator located on site. This type of service is more akin to standby service than to commercial backup service in that it is nearly instantaneous, and it is directly connected to the load. However, diesel generators on standby at commercial buildings are not considered DER.



The relevance of standby service to DER is that if a distributed source of power fails, the utility or other load-serving entity must be prepared to meet the load. Generally there is no direct purchase of standby service for DER, particularly at the residential or small commercial level. Power plants, including large commercial renewable energy resources, may make standby arrangements and may pay specific standby charges.

Even though most DER are small and operate independently, a large number of small DER in aggregate, if they all do the same things at the same time, whether planned or not, could rise to the level of an important contingency. For example, a large number of household PV systems, just a few kilowatts each, spread throughout a service territory, and all responsive to the same sun and the same clouds, could, and should, be considered an important planning contingency. Since PV generation is concentrated in the early afternoon, and their production drops off in a very predictable manner as the afternoon wears on, it may be difficult for the system operator to manage the system. The resulting net load, the load that the electric system must dispatch, can be counted on to vary up and down each day in response to the pattern of the PV systems. Sudden system changes, such as a change in cloud conditions, could make for a combined reduction in output that would be worthy of system operators' attention. However, there does not seem to be a call for specific standby charges for small distributed energy resources, particularly for behind-the-meter resources, at this time.<sup>87</sup>

If there is a reason for standby and backup service for DER systems, there will be a cost of providing it, of course. And if it were not charged to the DER system owners, that cost would still exist. Only it would have to be absorbed by the system overall and by the non-participating customers in the form of higher costs or in the form of lower reliability. If it is determined that system reliability will suffer without greater reserves than could be justified for a system without DER resources, then by all means, the DER customers should pay for the service. Instituting an explicit standby charge for DER would allow for the cost causer to pay for the costs associated with the standby service for which the utility provides. A study of the requirements of the utility by determining what customer demand may have to be met when the DER system goes down, either planned or unexpectedly, may produce evidence of considerable costs.

In considering whether to implement a standby charge or backup service charge, regulators should consider the policy impacts of requiring all DER to pay a small tariff to support standby power availability. When the concentration of PV and other DER generating systems becomes greater than it is now, that question should be considered again. Without a study of the actual costs of additional reserves required for system reliability, it is possible that a naïve calculation of the standby charge may

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<sup>87</sup> Though a Wikipedia article on net energy metering referred to a standby charge that was abandoned before 2005, and another on Solar Power in Virginia indicated a requirement for solar arrays of capacity above 10kW, there does not seem to be either standby charges or backup charges as a general matter in the distributed energy resources area. However, it may be possible that some utilities are currently considering whether to pursue this option.

overstate the actual costs to the system and the needs of the customers. Any charge would need to be justified directly and not be allowed to discourage the investment by customers.<sup>88</sup>

#### **F. Interconnection Fees/Metering Charges**

The interconnection process allows for DERs to connect to the electric grid. In many states, the DER owner will obtain approval from the local utility and receive authorization to connect, pursuant to that utility's interconnection tariff. Interconnection fees recover one-time costs that a utility incurs to set up the DER on the utility's system. These costs include reviewing the application to interconnect, account and billing set-up, various studies and system impact reviews.<sup>89</sup> The studies conducted during the application process determine whether the utility will need to invest in system modifications for safety or power quality. In most cases, the DER owner causing the need for the system modification is responsible for the cost of the system upgrade. Additionally, many states have straightforward procedures for simple interconnections (*i.e.*, for a DER less than a predetermined size, usually around 10kW - 20 kW). The California Public Utilities Commission allowed utilities to charge a one-time interconnection fee that recovers costs associated with interconnecting the DER to the electric system from the customer benefitting from the interconnection. The interconnection fee will range from \$75 to \$150.<sup>90</sup> Interconnection costs in Massachusetts may include an application fee (\$300-\$7,500, depending on the size of the DER proposed to be interconnected), various studies, system modifications, a witness test, and the cost of installing interconnection facilities).<sup>91</sup> For simple interconnections in Massachusetts, the DER owner will not generally pay an application fee, but may be responsible for other costs to interconnect. Interconnection fees in other states vary but are generally set at a flat fee plus a charge per kW.<sup>92</sup>

A metering charge recovers costs for meters that measure the energy from the DER sent to the electric grid. Some electric utilities include metering costs in the customer charge. Other utilities bill customers for a separate metering charge, which recovers the cost of the meter, the maintenance of the meter, meter reading, and services associated with the data output from the meter. For example,

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<sup>88</sup> For instance, a recent Wisconsin Dane County Court ruling (case #: 2015CV000153) overturned the WI PSC's previous decision that would have allowed utility We Energies to impose a standby charge on solar customers, citing a lack of evidence for the charge.

<sup>89</sup> EEI Primer at 9; "Interconnection of Distributed Generation to Utility Systems: Recommendations for Technical Requirements, Procedures and Agreements, and Emerging Issues," Sheaffer, P., Regulatory Assistance Project (2011). Available at: <http://www.raponline.org/document/download/id/4572>

<sup>90</sup> *Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Metering*, "Decision Adopting Successor to Net Energy Metering Tariff," Decision 16-01-044, California PUC (February 5, 2016).

<sup>91</sup> DG Interconnection Seminar. (2016). Available at: [https://www9.nationalgridus.com/non\\_html/MA\\_DG\\_Seminar.pdf](https://www9.nationalgridus.com/non_html/MA_DG_Seminar.pdf)

<sup>92</sup> "Interconnection of Distributed Generation to Utility Systems: Recommendations for Technical Requirements, Procedures and Agreements, and Emerging Issues," Sheaffer, P., Regulatory Assistance Project (2011).

Commonwealth Edison and Orange & Rockland (non-residential) impose a separate metering charge to their customers.<sup>93</sup>

The advantages an interconnection fee and/or a metering charge is that these compensation options are based on principles of cost causation. The cost of the DER connecting to the distribution system and the cost of metering services for that DER is charged to the customer imposing those costs. If there is a difference in cost to serve the DER owner for interconnection and metering, then it is the DER owner paying for those costs. The utility's other customers will not subsidize the DER owner.

There are also disadvantages of imposing an interconnection fee. For example, if the interconnection fee is a fixed charge, but there is no incremental cost to interconnect the DER, then the DER owner will be providing a subsidy to other customers. Additionally, if the utility determines in the studies conducted through the interconnection process that the DER will require distribution system upgrades, the DER owner is responsible for these costs regardless of the prior DER facilities installed on the distribution system. Thus, the final DER to interconnect is responsible for the total cost of the distribution system upgrade. Moreover, an interconnection fee may prevent DER adoption because the additional fee increases the payback period of the DER investment to the owner. Additionally, if the metering charge is greater than the compensation that the DER owner receives for the energy it provides to the grid, the overall DER investment value to the owner is reduced. Finally, the DER may cause the utility to incur other distribution-related costs, but the utility does not recover these costs from the DER owner through the one-time interconnection fee or the metering charge.

## **VI. Technology, Services, and the Evolving Marketplace**

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<sup>93</sup> For ComEd, see <https://support.comed.com/articles/ce10000-Understanding-your-bill#1>; for Orange & Rockland, see <http://www.oru.com/customerservice/askusaquestion/aboutbilling/understandingyourbill.html>

Advanced technologies can not only support operations of a grid, they can support regulators in making decisions about rate design. Communication abilities are being coupled with advanced technologies, providing data to the utility, and potentially to the regulator as well, which can be used to make informed decisions about compensation. The resulting data can help the utility measure the impacts of DER, more accurately measure consumption and generation, and analyze the need for DER at a specified level (meter, bus, feeder, circuit). With this information the regulator can also make more accurate cost and benefit analysis of DER, can evaluate the current rate design methodology, and continuously reevaluate the proper methodology as levels of penetration change, new technologies and services are developed, and other objectives or public policy goals need to be met. Additionally, using this information, a regulator can better identify adoption levels across a jurisdiction. Being aware of the continual pace of change and adoption rates of technologies by customers, a regulator can identify appropriate strategies for addressing these changes in a more proactive manner.

#### **A. Ongoing Monitoring and Adoption Rates**

The level and pace of penetration of DER resources in a system is important in the determination of what, if any, policy reforms are needed. The actual penetration levels of DER resources vary greatly across the country and even vary significantly within the same jurisdiction. Before states embark on the journey to implement substantive rate reforms due to the growth of DER penetration in its jurisdiction, each state should look closely at data, analysis and studies from its particular service area before any such actions are taken since all electric systems are impacted by DER penetrations differently. The impacts that are occurring in one jurisdiction due to higher DER penetrations may not necessarily be the same for another that is experiencing similar DER penetrations.

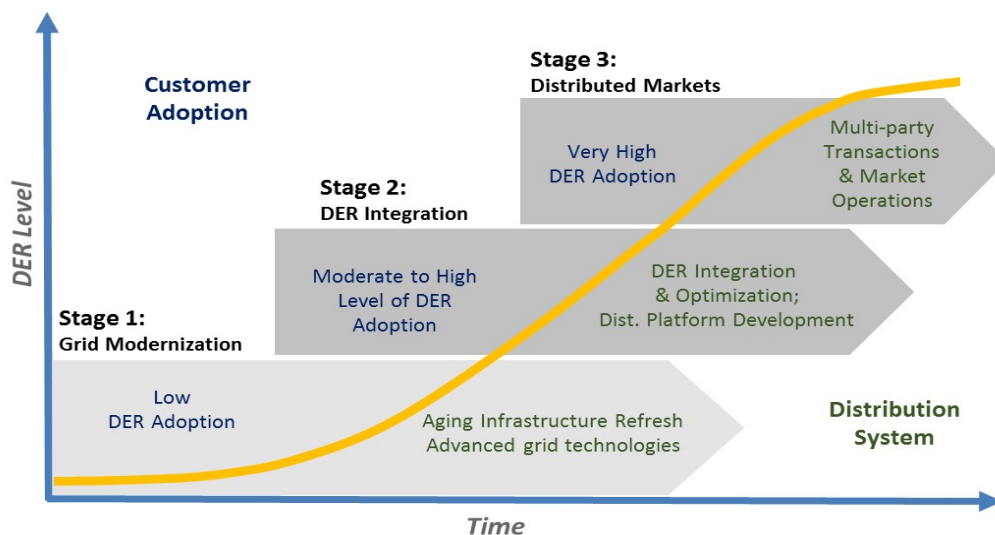
In a paper for Lawrence Berkeley Lab's "Future Electric Utility Regulation" series, Paul DeMartini and Lorenzo Kristov outline a path for regulators and utilities to plan for future utility and regulatory roles.<sup>94</sup> In this paper, they include an adoption curve that points out the importance of monitoring adoption rates of DER across a jurisdiction. Conceptually, the curve identifies three stages of activity: Grid Modernization, DER Integration, and Distributed Markets. Each stage is identified with two characteristics: adoption of DER and installation of technology to support DER development. The majority of states are still located in Stage 1, where there is a low amount of DER adoption and utility investments in grid modernization are still underway. According to DeMartini and Kristov, the move into Stage 2 occurs when DER adoption "reaches beyond about 5 percent of distribution grid peak loading system-wide."<sup>95</sup> Stage 3 occurs when a high amount of DER penetration occurs and regulators construct a system to allow for multi-sided transactions to occur between DER and the distribution

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<sup>94</sup> "Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight," Paul DeMartini, Lorenzo Kristov, Lawrence Berkeley Lab, Future Electric Utility Regulation, Report No. 2 (October 2015) ([https://emp.lbl.gov/sites/all/files/FEUR\\_2%20distribution%20systems%2020151023\\_1.pdf](https://emp.lbl.gov/sites/all/files/FEUR_2%20distribution%20systems%2020151023_1.pdf)).

<sup>95</sup> DeMartini/Kristov at 9.

utility, but also to and from customers. This means the development of policies to enable distribution level markets, and determining the role of the distribution utility into a market facilitator role.<sup>96</sup>



This discussion is included to provide regulators with a visual of a future for DER adoption and an awareness that decisions on DER compensation methodologies are not static determinations that can be made once and then left alone. Compensation decisions made in one year will likely need to be reviewed, modified, or changed overtime as technology continues to develop, customers adopt DER at greater (or slower) rates, and as needed to support economics. For example, a decision to adopt NEM as the compensation methodology may be appropriate if a regulator decides to incentivize adoption rates of solar PV; however, as adoption rates increase, it may not be necessary to continue to provide such an incentive. As such, regulators should remain flexible in its decision making. To continue the example, NEM may result in clustering of solar PV, which may cause the utility to incur additional costs to shore up reliability; a regulator may want to consider an alternative compensation methodology to reflect the costs of solar PV at that location. Alternatively, should other technologies, such as storage or electric vehicles, increase their adoption rates, a regulator may try to turn NEM into a technology agnostic program, or may choose to implement an entirely new suite of compensation options.

It is imperative that a regulator understand the tradeoffs in determining an appropriate compensation methodology, both in terms of technology adoption (does the methodology emphasize one technology over another; what does that mean to the market and the utility?) and over time (does the methodology encourage adoption of specific technologies in the short term as opposed to allowing a variety of technologies to develop over time to meet grid needs). The availability of new technology can assist

<sup>96</sup> *Id.* at 10.

regulators in making these decisions. Hawaii is an example of this. Hawaii has a significant adoption of solar PV, and the Hawaii Public Utilities Commission decided to eliminate its NEM tariff altogether, deciding that other compensation methodologies are more appropriate for its state.<sup>97</sup> Understanding and monitoring how DER is impacting the grid and utility rates is essential to fairly compensating DER, and then being flexible enough to recognize when those methodologies are no longer meeting the policy goals of the jurisdiction and is time to move on to other means of determining appropriate compensation.

For jurisdictions with currently low DER penetration and with current policies not designed to spur DER growth, reforms may not be as time sensitive in contrast to the needs of jurisdictions with higher DER penetrations. For the jurisdictions with low DER penetration and growth, there is time to plan and take the appropriate steps and avoid unnecessary policy reforms simply to follow suit with actions other jurisdictions have taken. Reforms that are rushed and not well thought out could set policies and implement rate design mechanisms that have unintended consequences such as potentially discouraging customers from investing in DER resources, or making inefficient investments in DER.

## **B. Role of technology**

As discussed, certain advanced technology investments are required in order to implement several methodologies described above. For example, without an advanced meter, implementing an option like Transactive Energy will not be feasible. These technologies allow for more granular information about usage and production to be collected; this information can then be used as a foundation for consideration of appropriate methodologies. However, decisions on investments in technology should not be limited only to implementing particular methodologies, rather, decisions on utility investments should continue to rely upon total benefits. In other words, specific investments should provide greater benefits than simply enablement of a specific methodology. Many technologies may provide multiple benefit streams, and enable greater opportunities. Understanding how these technologies fit in the larger context is important before approving any investment.

Nevertheless, it will be important for regulators to maintain an awareness of the pace of technological change over time as new technologies will provide new opportunities for identification of benefits and costs. This data can then be used to identify potential changes to existing rate design choices. Additionally, this data can be collected in real time. For example, traditional analog meters are read once a month, but digital meters connected to a communications network collected information on an hourly or 15 minute basis. Furthermore, meters connected to a customer's Home Area Network can be read in real-time in increments as low as 8 seconds. Having rate design options that can make use of this type of data may enable a wide variety of benefits available to the customer. This is but one example; technology is increasingly embedded in consumer products and can be leveraged for a potential wide variety of rate designs and compensation programs.

Technology implanted on the distribution grid can also provide important data for the development and implementation of DER compensation methodologies. Smart transformers, line monitoring, SCADA, hosting capacity, and other suites of services like ADMS and DERMS, allow for better integration of DER. By collecting information about the capability of the distribution grid, in real-time, utilities can have a

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<sup>97</sup> *Instituting a Proceeding to Investigate Distributed Energy Resource Policies*, Decision and Order No. 33258, Hawaii PUC, Docket No. 2014-192 (October 12, 2015).

clearer view of the state of the distribution grid. Knowing power flows, voltage fluctuations, and available capacity for feeders across the distribution system can greatly assist in helping locate DER in locations most beneficial to the grid. Having this information can also assist in developing appropriate DER compensation methodologies, as without this level of knowledge about the grid, DERs will be located with little input from the utilities. Similarly, recognizing how to use this information to understand adoption levels of technology will assist the regulator in determining when a change is needed.

### **C. Technology Options**

#### **1. Advanced Metering Infrastructure**

According to Energy Information Administration, nearly 52 million advanced meters have been installed across the residential customer class throughout the United States as of 2014.<sup>98</sup> These advanced meters are capable of measuring consumption in 15 minute to 1 hour increments. The meters are connected to a communications network and are then able to transmit the consumption information back to the utility's backoffice for billing. This stands in stark contrast to the historical mode of metering, which usually occurred once a month. Some modes of automated meter reading were capable of reading daily, in support of specific tariffs, but were not implemented widely. In other words, utilities have gone from having 12 data points a year about a customer to 8,760 data points, if measured hourly. It is also possible that customers can now access that same amount of information; instead of waiting for the monthly bill, customers can log-on to their utility's webpage and access the hourly usage information, typically on a 24 hour lag. The uses for this information is still in its infancy and is likely to evolve over time.

With the installation of advanced meters, implementing rate designs like TOU, CPP, and real-time pricing becomes possible at lower costs than in the past. An integral part of an advanced metering system is a communications network. That network allows the meter to communicate with the utility and can send information, like consumption, but also receive messages, like prices or demand response signals. This two-way flow of information means that the utility can provide customers with usage, price, and cost information over the course of the month rather than only once, at the end of the month.

Advanced meters also often includes a second radio to support a Home Area Network (HAN). The HAN is capable of transmitting information, including usage, voltage, and generation data to a router or other in-home display in as often as eight second increments. This communication is supported by Zigbee (IEEE 2030.5), which is a low-power communication standard. In-home displays or routers can connect to the customer's Wi-Fi networks and any other devices inside the customers home that support Wi-Fi, including thermostats.

With this new data and new communication networks, regulators can have a better understanding of potential customer responses to rate designs by having access to more granular data sets and expanded phased roll-outs of new rate designs. Furthermore, with this information, customers can better understand the potential impacts of installing DER at their location or signing up for community DER programs. By being able to "do the math," customers can identify the financial impacts to themselves

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<sup>98</sup> <http://www.eia.gov/tools/faqs/faq.cfm?id=108&t=3>. This number is likely higher as of the writing of this Manual.

and understand whether it makes sense to invest in DER or not. With policies supporting the development of HAN and data access, it may be possible to identify additional services from the home itself that may be beneficial to the grid, either individually at the premise or aggregated across a specific geography.

Lastly, advanced meters are not only capable of collecting consumption information about a premise, but can also collect generation data related to an on-site DER, such as solar, and voltage, to name two. By being able to collect this information, advanced meters can be used to facilitate compensating DER for its generation, as well as a number of other services that a regulator chooses to allow. Such policy development presumes a large enough amount of DER is present across the distribution system as to impact delivery of electricity. Use of data generated by advanced meters can assist regulators to identify potential DER compensation methodologies, and have the data available to support the viability of the methodology as well as use it for settlement and compensation.

## **2. ADMS/DERMS**

In order to support the adoption levels of DER, utilities may seek additional infrastructure and technological support to assist in maintaining reliability and enhance resilience. Two options include an Advanced Distribution Management System (ADMS) or a Distribution Energy Management System (DERMS).

ADMS adds levels of communication, intelligence, and visibility into the distribution grid for the distribution utility to better understand real-time conditions across its distribution service territory. ADMS provides the utilities with several specific functions, such as automated fault location, isolation, and service restoration (FLISR), conservation voltage reduction, and volt/VAR optimization.<sup>99</sup> Installing ADMS is not merely about better integrating DER; rather, ADMS will change how a utility operates and where a utility envisions itself and customers in the future. As customers continue to adopt technology and DER continues to grow, having the information about the grid that is possible from ADMS investments will help the utility meet customer demands while maintaining reliability, resilience, and flexibility.

With higher levels of DER adoption, DERMS builds upon an ADMS network. DERMS can allow the utility to dispatch resources, both on the utility side and the customer side, forecast supply and demand conditions up to 24 to 48 hours in advance, better integrate AMI data with other utility systems, such as ADMS, outage management, and weather systems, and communicate with third party/aggregator systems.<sup>100</sup> DERMS can also be used to support islanding and microgrid features, which may provide additional value to both the customers and the utility in certain times of need.

Both DERMS and ADMS are suites of technology solutions that can enable the distribution utility to better understand, plan, operate, and optimize the increasing amount of DER showing up across a service territory. Understanding the costs and benefits of these technologies, and how they can be used

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<sup>99</sup> "Voices of Experience: Insights into Advanced Distribution Management Systems," Department of Energy (February 2015) ([https://www.smartgrid.gov/files/ADMS-Guide\\_2-11.2015.pdf](https://www.smartgrid.gov/files/ADMS-Guide_2-11.2015.pdf)).

<sup>100</sup> "Inside SDG&E's Plan to Optimize the Distributed Grid of the Future," Greentech Media (May 16, 2014) (<http://www.greentechmedia.com/articles/read/sdge-and-spirae-break-new-ground-on-the-grid-edge>).



to better plan, price, and value the DER across a service territory can be very helpful in designing and implementing more advanced compensation methodologies. Indeed, by being able to make DER a dispatchable resource, technology can help mitigate and minimize risks to the reliability of the distribution grid. Utilizing technology to turn DER into a resource that can be counted on and dispatched may open up new value streams to the utility and the consumer.

### **3. Smart inverters**

As with the availability of technology on the utility side, there are technology options also available to customers. One specific technology is a Smart Inverter. For solar PV installations, an inverter is necessary to switch electricity from Direct Current (DC) to Alternating Current (AC). The grid, including the local distribution grid, uses AC power, so before electricity generated by a solar PV installation can be exported onto the grid, it must be changed into AC. More recently, this inverter can now be outfitted with additional software that can accomplish additional services. For example, a Smart Inverter is capable of actively regulating the voltage of the solar PV's output.<sup>101</sup> As clouds pass over a solar PV unit, the voltage can drop on the electricity that is exported onto the grid causing drops in voltage at that location; in order to raise the voltage levels up, the transformer capacitor will step in and provide voltage support. Having a Smart Inverter address voltage drops before exporting to the distribution grid is a value and service that can be provided by the customer, and deferring or avoiding additional distribution upgrades.

In many cases, the Smart Inverter is now included in new solar PV installations. Indeed, the recommendation of the California PUC Smart Inverter Working Group, subsequently adopted by the California PUC, is to require Smart Inverters for all new solar PV installations seeking to interconnect with the distribution grid upon completion of the safety standard currently pending before Underwriters Laboratory.<sup>102</sup> Utilizing the capabilities of the Smart Inverter to allow for the generation or storage resource to autonomously manage and balance the flow of electricity, and other ancillary services, like voltage ride-through, can be enabled and valued through appropriate compensation methodologies, especially in areas of high solar PV adoption. Regulators should continue to monitor progress on

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<sup>101</sup> "Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources: Smart Inverter Working Group Recommendations," Smart Inverter Working Group, California Public Utilities Commission (January 14, 2014) ([http://www.energy.ca.gov/electricity\\_analysis/rule21/documents/recommendations\\_and\\_test\\_plan\\_documents/Recommendations\\_for\\_updating\\_Technical\\_Requirements\\_for\\_Inverters\\_in\\_DER\\_2014-02-07-CPUC.pdf](http://www.energy.ca.gov/electricity_analysis/rule21/documents/recommendations_and_test_plan_documents/Recommendations_for_updating_Technical_Requirements_for_Inverters_in_DER_2014-02-07-CPUC.pdf)).

<sup>102</sup> There are two specific standards necessary to support the full implementation of Smart Inverters: IEEE 1547 and UL 1741. IEEE 1547 identifies the available functions for a Smart Inverter. The current version of IEEE 1547 does not allow for many of the identified functions of a Smart Inverter, and is currently undergoing revisions. An interim version of the standard (IEEE 1547(a)) that meets California requirements is available. UL 1741 ensures that the Smart Inverter is operating safely, both independently and in conjunction with utility distribution systems. This standard is also undergoing revision, with a final version expected sometime in 2016. Lastly, the California Smart Inverter Working Group also identified IEEE 2030.5 (also known as Zigbee) as the communication standard between utility systems and the Smart Inverter. "Recommendations for Utility Communications with Distributed Energy Resources Systems with Smart Inverters: Smart Inverter Working Group Phase 2 Recommendations," Smart Inverter Working Group, California Public Utilities Commission (February 28, 2015) ([http://www.energy.ca.gov/electricity\\_analysis/rule21/documents/SIWG\\_Phase\\_2\\_Communications\\_Recommendations\\_for\\_CPUC.pdf](http://www.energy.ca.gov/electricity_analysis/rule21/documents/SIWG_Phase_2_Communications_Recommendations_for_CPUC.pdf)).

adoption rates of Smart Inverters and the standards development process for this technology and capability.

#### **4. Hosting Capacity**

In order to better identify locations for development of DER, a utility needs to understand the characteristics of its grid. Technologies like ADMS and DERMS can facilitate that. The end result of this modeling is a hosting capacity analysis of the distribution grids feeders. Hosting capacity helps the distribution utility assess the impacts of DER on its feeders, and identify available capacity on those feeders.<sup>103</sup> This analysis can determine where there is available capacity and areas where there is little available capacity; making this information available to developers can assist DER developers in better locating potential DER. Currently, to the extent a utility is doing a feeder-by-feeder hosting capacity analysis, the information is largely kept inside the utility. Without such information, DER developers have no visibility into locations that can benefit utility planners, which can then delay ultimate construction of a resource by going through lengthy utility interconnection processes. With widespread adoption of DER and integration with utility distribution system planning efforts, the availability of hosting capacity analyses can also be paired with development of distribution locational marginal prices to drive economic siting of DER, much the same way that transmission planning and locational marginal prices identifies areas in need of additional resources to relieve congestion, for example.

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<sup>103</sup> EPRI, “Hosting Capacity Method” ([http://dpv.epri.com/hosting\\_capacity\\_method.html](http://dpv.epri.com/hosting_capacity_method.html)).