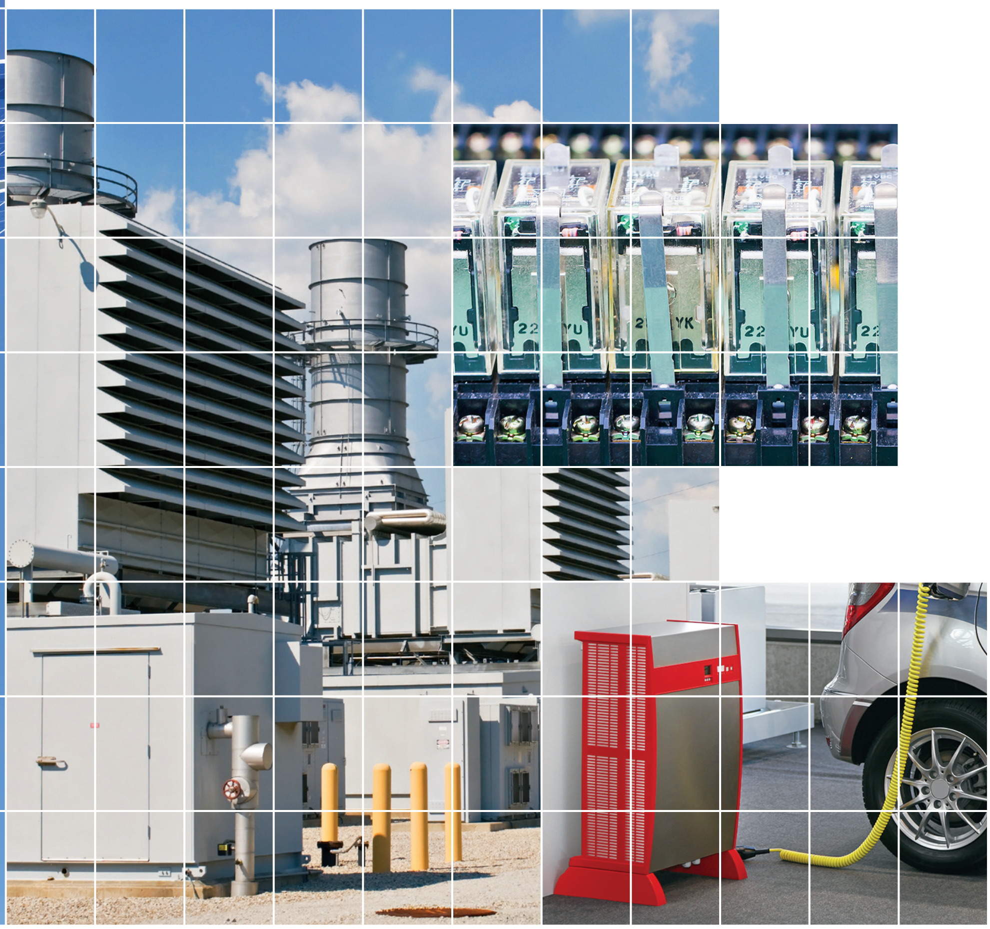
DISTRIBUTED ENERGY RESOURCES RATE DESIGN AND COMPENSATION



A Manual Prepared by the NARUC Staff Subcommittee on Rate Design

November 2016

NARUC Manual on Distributed Energy Resources Rate Design and Compensation

Prepared by the Staff Subcommittee on Rate Design

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NARUC, The National Association of Regulatory Utility Commissioners,
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Executive Summary

In November 2015, NARUC President Travis Kavulla announced that the newly created Staff Subcommittee on Rate Design would create a manual to assist commissions in considering appropriate rate design and compensation policies for distributed energy resources (DER). The reason for this manual is that the nature of electricity delivery, consumption, generation, and grid itself are changing, and changing rapidly. Instead of traditional, one-way delivery of electricity from large, central station power plants located far from load, via high voltage transmission lines, to lower voltage distribution lines, and, finally, to the home, technologies are now available directly to customers that allow them to generate their own electricity, respond to prices, reduce (or increase) demand when useful to the system, or store electricity for use at a later time. Many of these technologies are affordable to the majority of customers, with more technologies coming down in costs over the near term. Understanding how DER impacts the grid itself, including reliability, is an important factor, but also understanding where, when, and how DER can benefit the grid is of equal value. This manual attempts to provide regulators and stakeholders with information on how to address these opportunities, while maintaining affordable, reliable, safe, and secure electricity.

This Manual is organized to provide regulators with a comprehensive understanding of the question of how does DER affect regulation. It lays out a background on the principles of rate design and compensation, the availability and use of new technologies, an explanation of what is DER, and describes a set of certain types of DER. This is to provide a regulator ample background of not only how DER impacts existing regulatory and utility models, but also provides a foundation for considering how to evolve along with this transition. The Manual then describes a variety of rate design and compensation options that a jurisdiction may consider—the options described herein are not the only ones available to a jurisdiction, but are the most prevalent under discussion today. The Manual goes through them laying out the pros and cons of the option, and providing regulators with information to assist them in their consideration. Lastly, the Manual outlines a few practical ways for it to be used, including examples of determining costs and benefits of DER, questions for a regulator to support an investigation into appropriate rate design and compensation for DER, and how to use some of the details in this Manual to support a decision-making process.

This version of the Manual is not the final word. As noted throughout, customer preferences and adoption rates, and the implementation of new technology on the grid side will continue to grow, and with that growth comes new evidence, more solutions, and, perhaps more questions. The lack of more widespread experience with certain types of DER, and the shortage of available data at this point in time means that we have barely scratched the surface of what this future could look like. Commissions around the country are opening proceedings on the topics raised in this Manual almost every month; those proceedings will take time, the results of those proceedings will then take time to implement. This Manual provides a benchmark for those discussions and solutions and is limited only to the discussion rate design and compensation for DER; as noted throughout, there are a number of other topics that are closely related to this topic that are better suited for its own document. This Manual will be revised at some point in the future, when conditions or demand warrants it. Supplements may be added in the intervening years to assist with definitions or processes, but experience and data will drive its next iteration.

This Manual was created with the assistance of staff from around the country, many of whom are in the midst of the very same topics addressed here. The Manual is not designed to answer questions, but to provide regulators with support. Even at low levels of adoption, a jurisdiction should not be content to wait until adoption levels start to increase; planning for the future will enable a jurisdiction to have the tools in place when it is ready to act. Being proactive and maintaining awareness of customer adoption and behaviors will greatly alleviate the strain on a commission, utility, and stakeholders when it does come time to act. By acting now, even if the conclusion is to keep a particular policy in place, does much to inform a commission, and better understand what it may need to do in the future, and can put the commission on a path towards a smooth transition to this future.

Preface

On the same day as the creation of the new Staff Subcommittee on Rate Design, NARUC President Travis Kavulla noted in his elevation remarks that the subcommittee would be tasked with the simple project of preparing a manual on rate design and compensation for distributed energy resources. While sitting in the audience listening to the task assigned to the staff subcommittee, I realized that no one had told me about this project in advance. However, even having gone through everything related to the development of this Manual, I would do it again. The task placed under my care is a major component of understanding the current issue of how distributed energy resources play with existing electric utilities. The retail, regulated electric industry has operated largely the same way since the late 1800s. Evolution and progress are necessary, and unnecessarily relying on solutions of the past does little to meet the needs of the future. My hope is that this document provides useful insight and information to commissions across the country on the topic of rate design and compensation for distributed energy resources.

The development of the Manual underwent several variations over the course of the eight months it took to create. It seemed that no sooner had the drafting team settled on a course of action, a new state would issue a decision with a unique take on a question, or identify a new issue we had not considered. This Manual could sit around forever, constantly being modified as new policies, laws, and questions come up almost daily; however, we cannot wait forever. Commissions are struggling with these issues and we hope this Manual will provide some options for commissions and guide them through their proceedings. However, this is not the end of the project, as more work needs to be done.

The beginning of this Manual was in February 2016, when the drafting team first convened to talk about what the Manual should accomplish, what issues we needed to cover, how to start organizing the Manual, and assign responsibilities. A second face-to-face meeting was held in June 2016 to review progress, make alternations, and ensure we were still on track. We issued the draft version of the Manual in July 2016. The document that follows is a culmination of this work.

It would not have been possible to complete this project, or complete it in the time provided, without the drafting team, whose members volunteered their expertise and time, including nights, weekends, and, sometimes, very early mornings, to finalize this Manual. The drafting team included Anne-Marie Cuneo of the Nevada Public Utilities Commission, Stephen St. Marie of the California Public Utilities Commission, Jeff Orcutt of the Illinois Commerce Commission, Nick Revere of the Michigan Public Service Commission, Jamie Barber of the Georgia Public Service Commission, Dan Cleverdon of the District of Columbia Public Service Commission, and Erin Kempster and Emily Luksha of the Massachusetts Department of Public Utilities. Your devotion to public service, seeking out best practices, and, most importantly, keeping the best interests of consumers, through thick and thin, were a constant source of inspiration.

I want to thank other staff from around the country who provided information, answered questions, and helped with the content: Tricia DeBleeckere of the Minnesota Public Utilities Commission, Norm Kennard of the Pennsylvania Public Utility Commission, Jon Kucskar of the Maryland Public Service Commission, and Rachel Goldwasser of the New England Conference of Public Utility Commissioners. Additionally, the project received tremendous support from NARUC Executive Director Greg White, and NARUC staff, including Miles Keogh, Jennifer Murphy, and Kerry Worthington, who went more than out of their way to support the drafting team and keep the project on target. I also want to thank the Commissioners of the Minnesota Public Utilities Commission, including Chair Beverly Heydinger, Commissioner Nancy Lange, Commissioner Dan Lipschultz, Commissioner John Tuma, and Commissioner Matt Schuerger, for supporting my participation as chair of the Staff Subcommittee and the work of the subcommittee. Thank you to the commissioners from each jurisdiction that was represented by the drafting team for your support in this project. Also, to the individuals and groups that submitted comments in response to the survey and the draft, and at the town hall, the drafting team very much appreciates your thoughtfulness, thoroughness, and relentlessness, which has helped greatly with the final version of this manual. Lastly, a thank you to NARUC's Executive Committee and President Travis Kavulla; your advice, recommendations, and support were always timely and beneficial, which made the Manual better.

Chris Villarreal
Minnesota Public Utilities Commission
Chair, NARUC Staff Subcommittee on Rate Design

Table of Acronyms

AC	Alternating Current
ADMS	Advanced Distribution Management Systems
AMI	Advanced Metering Infrastructure
APS	Arizona Public Service Company
ATC	Available Transfer Capability
BGE	Baltimore Gas & Electric Company
CHP	Combined Heat and Power
C&I	Commercial and Industrial
ComEd	Commonwealth Edison
CPP	Critical Peak Pricing
CPR	Critical Peak Rebate
DBR	Declining Block Rate
DC	Direct Current
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management Systems
DG	Distributed Generation
DOE	Department of Energy
DR	Demand Response
EE	Energy Efficiency
EIM	Energy Imbalance Market
EPRI	Electric Power Research Institute
EV	Electric Vehicles
FERC	Federal Energy Regulatory Commission
FEUR Series	Future Electric Utility Regulation Series
FLISR	Fault location, isolation, and service restoration
GMP	Green Mountain Power
GWAC	GridWise Architecture Council
HAN	Home Area Network
IBR	Increasing Block Rate
IEEE	Institute of Electrical and Electronics Engineers

ISO........................... Independent System Operator
kW........................... Kilo-watt
kWh........................ Kilo-watt hour
LBNL .... Lawrence Berkeley National Laboratory
LIHEAP .... Low Income Home Energy Assistance Program
LMP......................... Locational Marginal Price
M-RETS .... Midwest Renewable Energy Tracking System
MW .... Mega-watt
NARUC .... National Association of Regulatory Utility Commissioners
NEM........................ Net Energy Metering
OASIS...................... Open Access Same Time Information System
PNNL .... Pacific Northwest National Labs
PTR.......................... Peak Time Rebate
PV .... Photovoltaic
RECs........................ Renewable Energy Credits
REV .... Reforming the Energy Vision
RMI .... Rocky Mountain Institute
RTO .... Regional Transmission Organization:

List of ISOs/RTOs:

- ISO-NE: ISO New England
- NYISO: New York ISO
- PJM Interconnection (Pennsylvania, New Jersey, Maryland)
- ERCOT: Electric Reliability Council of Texas
- SPP: Southwest Power Pool
- MISO: Midcontinent ISO
- CAISO: California ISO
- AESO – Alberta Electric System Operator
- IESO – Independent Electricity System Operator (Ontario, Canada)

RTP......................... Real Time Pricing

SCADA .... Supervisory Control and Data Acquisition
SMUD .... Sacramento Municipal Utility District
SPM .... Standard Practice Manual
TE .... Transactive Energy
TOU .... Time of Use
TTC.......................... Total Transfer Capability
TVR .... Time Variant Rate
UL .... Underwriter's Laboratory
Volt/VAR................ Voltage/Volt-ampere reactive
VOR .... Value of Resource
VOS .... Value of Service
WREGIS .... Western Renewable Energy Generative Information System

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.[1] The purpose of creating this Staff Subcommittee was to provide a forum for utility commission staff to discuss rate design challenges in their jurisdictions with staff from other 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 of rate design issues to policy development across the states, most notably as they apply 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."[2] 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 jurisdictions poses unique challenges to the status quo for regulators. The traditional way of electricity delivery from large

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

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

power plants over transmission and distribution wires to the customer is increasingly being challenged, in part due to the growth of DER and changing technologies. DER are resources located on the distribution grid, often on or close to the customer's premises, and are capable of providing many services to the customer and the grid. DER such as rooftop solar generation can offset the premise's consumption and deliver excess generation into the distribution grid. DER, like demand response, can allow the demand on the system to respond to system prices and conditions. DER are 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 may be needed to effectuate the two-way flow of electricity, new ways of allowing the utility to recover its costs may be needed, and new assumptions regarding the forecasting of customer demand will be necessary to meet this challenge. A jurisdiction will need to identify its current status regarding DER and what role it expects DER to have in the future, understand the nature of DER adoption rates, and identify necessary policy developments or rate design modifications 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 their jurisdiction. This Manual provides regulators with possible rate design and compensations options that a jurisdiction may want to consider and adopt. Its content should be applicable regardless of a jurisdiction's market structure (restructured versus vertically integrated), whether it is an organized wholesale market, or its adoption of technology, be it advanced utility infrastructure or availability of customer-sited technology.

The Manual is organized in five main sections. Section II describes the basic rate design process and how DER affects that process. Section III discusses what DER is, why it is important for states to consider, and an identification of an initial set of technologies. Section IV describes the systemic challenges and questions raised by the details of rate design and compensation. Section V outlines a variety of possible rate design and compensation methodologies that a jurisdiction may consider. Lastly, Section VI provides information to assist a regulator begin to collect information to support consideration of rate design and compensation options, identifies an initial set of questions to ask, an outline of how to identify costs and benefits of DER, 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 of 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 affect 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, jurisdictions gain greater experience and understanding of these issues, and adoption rates progress, new data will become available that will warrant revisions and updates to this manual.

In developing this Manual, the Staff Subcommittee on Rate Design provided three opportunities for public input on this process and document. In March 2016, NARUC released a survey seeking responses to five questions that would help the drafting team develop the scope of issues and an initial set of resources. The survey questions are attached in Appendix 1. Responses to the survey were received in April 2016. A draft version of this Manual was released in July 2016, in advance of the 2016 NARUC summer meeting, held in Nashville, Tennessee. At the 2016 summer meeting, NARUC held a town hall meeting to go through the draft Manual and receive initial, verbal comments from attendees and the public.[3] Written comments on the draft Manual were received on September 2, 2016. Those written comments on the draft Manual will be publically posted to the NARUC webpage around the time of the 2016 NARUC Annual Meeting on November 13-16, 2016.

The topics of DER, its impacts on rate design, and potential compensation options only scratch the surface of a wide swath of other issues implicated in this discussion. For example, this Manual does not address utility business model discussions, utility compensation and revenue recovery options, and larger market development solutions beyond simply addressing DER. Concepts such as performance-based ratemaking, distribution system operators, the role of the utility in providing technology to customers, or distribution utility system planning are not covered in depth in this Manual, but are important conversations to have considering the current state of the utility industry. NARUC may investigate these topics more fully in other forums.

The Staff Subcommittee on Rate Design thanks all who assisted in the development and review 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.[4]

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3 Agenda and notice of town hall are available at Appendix 2.

4 Members and Observers of the Staff Subcommittee on Rate Design are included in Appendix 3.

II. What Is the Rate Design Process?

A. Definition, Principles, Goals, and Purpose

Before going into the details of rate design modifications that may be needed due to the growth of 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 understanding costs and which costs a utility is allowed to recover by the regulator. This section provides an overview of these two components, which apply to most basic rate design processes across the country. This discussion recognizes that most existing rate designs are not explicitly designed to reflect the precise costs to serve each customer. Customers vary in ways often not recognized by rate design, such as multi-family residences compared with single family residences, or rural residences compared with urban residences, and the costs associated with these variances differ. 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 onto the utility new 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. Of course, over the long term, DER may reduce utility costs. Identifying the appropriate principles, goals, and objectives for rate design can assist a regulator in determining an appropriate 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 parties to the rate-setting process on the various goals and principles of rate design, parties will value and weight those goals and principles differently. Furthermore, the parties' opinions on the specific application of those goals and principles will vary based of their application. Rate design may be influenced by legislative initiatives and political and environmental policies. However, a single rate design may not meet all rate design principles and policy goals. Indeed, many of the goals and principles conflict with one another, and it is the job of the regulator to weigh these principles and goals and approve a rate design that best reflects the public interest as the regulator sees it.

The basic purpose of rate design is to implement a set of rates for each rate class—residential, commercial, and industrial—that produces the revenues necessary 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. In this way, the total cost incurred to provide service to the entire rate class can be determined through detailed studies using cost-causation principles. This total cost is then allocated across all 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, by both more recent authors and 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 for 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.).[5]

Bonbright distills the above criteria down to three primary objectives of rate design from which the others flow:

1. the revenue-requirement or financial-need objective, which takes the form of a fair-return standard with respect to private utility companies;

2. 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

3. 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.[6]

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 structure. To create an appropriate rate, it is important to distinguish between

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5 James C. Bonbright, *Principles of Public Utility Rates* (New York: Columbia University Press, 1961), 291.

6 Id., 292.

Case Study

Northern States Power Company–Wisconsin Rate Case Proceeding (Docket No. 4220-UR-121)

Key Topics: fixed costs; variable costs

The concept of fixed versus variable costs was illustrated in a Northern States Power Company–Wisconsin rate case before the Public Service Commission of Wisconsin. In its Order dated December 23, 2015, the Commission stated that the following cost components are reasonable to be included for consideration as fixed costs to serve the residential and small commercial classes: (1) administrative and general, (2) metering, (3) service drops-customer, (4) service drops-demand, (5) line transformers-customer (with the exception of the demand-related portion), (6) line transformers-demand, and (7) poles and conductors-customer.

Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates, Final Decision, Docket No. 4220-UR-121 at 46, PSC Wisconsin (December 23, 2015).

fixed and variable costs. Such a distinction informs, though does not entirely decide, the basis on which rates should be designed to collect those costs. Separately, a regulator may also choose to have the rate design send a price signal, which may more accurately reflect the cost to serve the customer at a certain point in time or over a specified time period.

Many utility costs are fixed in the short term. In the long term, many utility costs are variable. The question, then, for a regulator is how much of a utility's costs should be considered fixed for the purposes of setting rates. Here, also, there is much disagreement. Some argue that in the short term to mid-term, costs are not terribly sensitive to changes in use. As a result, a customer that lowers its usage creates an additional burden on others, as the reduction in cost recovery must be covered by someone else. Others argue that the appropriate time horizon to price these costs is over the long term, because of economic theory or the long planning horizon of the utility.

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, which may also mitigate potential intra- and inter-class subsidies.[7]

B. Different Types of Rate Design

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. Rate structures can also be combined in varying degrees in an attempt to balance the objectives of the jurisdiction.[8] The overwhelming majority of residential customers are on either a flat rate or an inclining block rate.[9] A jurisdiction may wish to consider alternative rate design on its own merits without considering it as a response to DER. What follows are descriptions of a variety of basic service offerings for residential customers.

1. Flat Rates

A flat rate design charges customers per unit of consumption, at the same rate for all units 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 used across the country today. A flat rate can meet certain objectives, such as affordability, identified by the

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7 For an introduction to cost allocation methodologies, *see* NARUC, *Electric Utility Cost Allocation Manual* (Washington, D.C.: NARUC, January 1992).

8 Not discussed in this Manual are pre-pay payment options. Pre-pay can utilize any type of rate design described in this section, but the customer pays in advance rather than at the end of a billing cycle. In other words, the customer pays in advance for its consumption, then as their balance falls below a certain level, the customer can add funds back into its account. Utility examples of pre-pay programs include Salt River Project's M-Power (http://www.srpnet.com/payment/mpower/) and Georgia Power's PrePay option (https://www.georgiapower.com/residential/payment-options/pre-pay-options.cshtml. *See also,* U.S. Department of Energy, "Bridging the Gaps on Prepaid Utility Service" (Washington, D.C.: U.S. Department of Energy, September 2015).

9 Peter Cappers, *et al.,* "Time-of-Use as a Default Rate for Residential Customers: Issues and Insights" (Berkeley, CA; Lawrence Berkeley National Lab, June 2016), 1.

jurisdiction. On the other hand, recognizing that the cost of electricity varies throughout the day and by location, a flat rate may not reflect the actual costs to serve a customer in 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 the shortage of available capacity on the transmission 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 commercial and industrial (C&I) customers with high load factors and high volumetric consumption. For example, if the provision of service (i.e., generation as reflected in dollars/kilowatts per hour [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 that use proportionally more at lower cost times. Additionally, supply costs can vary daily and hourly; 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. Flat rates do not require advanced metering infrastructure (AMI) technology to implement.

2. Block Rates

An increasing, inverted, or inclining block rate (IBR) structure is designed to charge customers a higher per unit rate as their usage increases over certain "blocks" within a billing cycle. For example, a three-tier IBR would identify three blocks of usage: block one could be 0 kWh–150 kWh, block two could be 150 kwh–250 kWh, and block three could be all usage over 250 kWh. For each block, there is a price for all electricity used within it, with the price increasing as a customer moves through the blocks over a billing period. 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 having to pay the higher block price. 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 their consumption reaches the higher block rate.[10] 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 electricity over time is considered greater with an IBR design through avoiding higher prices during the month, this rate does not reflect the hourly or daily changes to the cost of electricity.[11] 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 with its otherwise basic cost of service.

An example of an IBR follows. This example also contains a seasonal adjustment to reflect the increased costs of providing electricity during the summer peaking time for this utility.

Georgia Power

Schedule R-22, effective January 2016[12]

Block (kWh)	**October–May**	**June–September**
< 650	5.6582 cents per kWh	5.6582 cents per kWh
650–1,000	4.8533 cents per kWh	9.3983 cents per kWh
> 1,000	4.7641 cents per kWh	9.7273 cents per kWh
Basic Service Charge	$10	$10

10 It may be possible for utilities with AMI to provide a notification to customers when they cross over into the next block or are close to crossing into the next block.

11 An open question is whether a customer responds to the higher block price or the average price. *See*, Severin Borenstein, "The Economics of Fixed Cost Recovery" (U.C. Berkeley: Energy Institute at Haas, July 2016), 13.

12 Georgia Power, "Residential Service Schedule: R-22," 2016. https://www.georgiapower.com/docs/rates-schedules/residential-rates/2.10_R.pdf.

A decreasing or declining block rate (DBR) structure is designed to charge customers a lower per unit rate as their usage increases within a billing cycle. DBRs are still sometimes used to reflect decreasing fixed costs per unit as output increases; a higher initial rate would recover the initial fixed costs, and rates would decrease over the blocks as the rate reflects more variable costs. There is some disagreement that by lowering the savings potential, DBRs discourage conservation, energy efficiency, and customer adoption of technologies that may reduce consumption or otherwise reflect costs. These types of block rates do not require advanced metering technology to implement.

3. Time Variant Rates

Time-variant rates (TVRs) are designed to recognize differences in a utility's cost of service and marginal costs at different times (e.g., hour, day, or season). Generally, a TVR design charges customers a higher price during peak hours and a lower price during off-peak hours. Unlike with flat rates, customers need to be aware of usage throughout the day and the month to respond to the price signals in a TVR design. A customer may increase savings under a TVR compared with a flat rate, if that customer uses energy in response to the time-variant price signal, such as shifting usage to lower-cost periods or conservation. A regulator may consider a variety of time-variant price options; each option provides the regulator with the ability to reflect a variety of goals, such as cost causality and load shifting. TVR requires a meter capable of measuring the time of a customer's consumption. With the advent of AMI, 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 interval metering technology, as well as poor design, have hindered the wider development of TOU, but utility roll-out of advanced metering technology across many jurisdictions can help facilitate the implementation of a TOU rate design. Many C&I electric customers already receive service under TOU rate designs. The following are examples of TOU rate studies or pilot programs:

Case Study

California Residential Rate Design

Key topics: default TOU rates; residential rate reform

In July 2015, the California Public Utilities Commission (PUC) directed Pacific Gas & Electric, San Diego Gas & Electric, and Southern California Edison to introduce default TOU rates and an optional two-tier rate for residential customers by 2019. Starting in 2017, a "super user" electric surcharge will be introduced to penalize customers for excessive energy use (i.e., more than twice the average usage). In addition, the California PUC directed Pacific Gas & Electric, San Diego Gas & Electric, and Southern California Edison to develop TOU rate design pilots to begin in the summer of 2016.

California PUC, "Fact Sheet—Residential Rate Reform" (California PUC, San Francisco, CA, 2015), http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Meetings_and_Events/ResidentialRateReformFactSheet.pdf.

California PUC, "Residential Rate Reform/R.12-06-013" (California PUC, San Francisco, CA, 2016), http://www.cpuc.ca.gov/General.aspx?id=12154.

- Arizona—Arizona utilities have offered various time-varying rate options to their customers since the 1980s. As of 2015, Arizona Public Service Company (APS) has enrolled over 52 percent of its 1.2 million customers in an opt-in TOU rate (the most of any utility in the country), while Salt River Project has enrolled over 30 percent of its one million customers in an opt-in TOU rate.[13] APS offers segmented time-varying rate plans to suit diverse customer needs, including complex rates and shortened peak periods with high price differentials. In addition, the utility uses a "point of sale" strategy to enroll customers when they contract for a new service.
- Kauai Island Utility Cooperative TOU Solar Pilot, Hawaii—On September 21, 2015, the Hawaii Public Utilities Commission gave approval to Kauai Island Utility Cooperative to implement a one-year, 300-person TOU solar pilot that will offer a 25 percent discount on electric rates during off-peak

13 Ryan Randazzo, "Arizona leads California on time-of-use electricity plans," *The Arizona Republic* (May 26, 2015). http://www.usatoday.com/story/money/2015/05/26/arizona-california-time-of-use-electricity/27985581/.

daytime hours to shift load to when solar is overloading the grid. Participating customers need to have advanced meters and will also receive a digital monitor to see real-time usage, as well as $200 toward the installation of a water heater timer. The program began in the first quarter of 2016.[14]

- Oklahoma Gas and Electric Smart Hours—Oklahoma Gas & Electric has an opt-in TOU program with variable peak pricing called Smart Hours with 120,000 customers enrolled as of 2015. The program has a goal of enrolling over 20 percent of residential customers, with the final objective of delaying the building of a fossil-fuel generation plant. The program offers a non-peak rate and a high variable rate during peak times of 2 p.m. to 7 p.m.[15]

Under a real-time pricing (RTP) plan, the customer is charged for generation at the price set by the wholesale market (for deregulated utilities or vertically integrated utilities participating in an organized wholesale market) or at the short-run marginal generation costs (for vertically integrated utilities not participating in an organized wholesale market) by the hour.[16] Large electric customers may already be indexed to the hourly generation price through a competitive supplier or utility rate design, but with advanced metering infrastructure, it is possible to implement real-time pricing for residential and smaller C&I customers.[17] RTP is available to residential customers in the Illinois service territories for Commonwealth Edison (ComEd) and Ameren. The real-time rates for these programs are based on the day-ahead hourly wholesale price for the given utility zones.[18] If customers do not possess the ability to shift use during high-price hours, they may have a negative experience with this rate design.

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14 Robert Walton, "Hawaii PUC approves solar TOU rate pilot for co-op KIUC," *Utility Dive* (September 25, 2015). http://www.utilitydive.com/news/hawaii-puc-approves-solar-tou-rate-pilot-for-co-op-kiuc/406249/.

15 Oklahoma Gas & Electric, https://oge.com/wps/portal/oge/save-energy/smarthours/.

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

17 *Id.*

18 ComEd uses the day-ahead PJM price for its zone, and Ameren uses the day-ahead Midcontinent Independent System Operator (MISO) for its zone.

A dynamic pricing rate design contains pre-established blocks of hours reflecting the characteristics of costs that occur during those blocks. Compared with a TOU rate design that pre-determines a schedule of peak and off-peak hours and rates, the utility may revise the dynamic pricing schedule and rates based on market conditions.[19]

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, usually the day before, the hours that the CPP rate will be in effect. 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 incentivizing customers to reduce consumption. A CPP can be included with a TOU rate or paired with a demand response (DR) program; in both cases, the rate is determined by the regulator, but a CPP event is usually limited to certain peak hours over a year.[20] The following is an example

Case Study

Illinois Real-Time Pricing

Key topics: RTP bill savings

ComEd has offered real-time pricing tariffs to its customers since 2007. ComEd's Hourly Pricing Program, which currently has 11,000 participating customers, has resulted in average bill savings of 15 percent, or $15 million in total. The program allows customers to track their energy usage through an online portal and provides a bill comparison to ComEd's default residential rate. Additionally, participants receive real-time alerts when electricity prices are expected to be high (i.e., greater than 14 cents per kWh).

Ameren Illinois' Power Smart Pricing Program has over 10,000 participating customers.

Karl Lydersen, "In Illinois, real-time pricing saving utility customers millions," Midwest Energy News, (May 4, 2016), http://midwestenergynews.com/2016/05/04/in-illinois-real-time-pricing-saving-utility-customers-millions/.

For information on Ameren's program, see https://www.powersmartpricing.org/.

19 Janine Migden-Ostrander and John Shenot, "Designing Tariffs for Distributed Generation Customers" (Regulatory Assistance Project, Montpelier, VT, 2016), http://www.raponline.org/document/download/id/7983.

20 One alternative to a TOU rate is a peak time rebate (PTR), which operates concurrently with a traditional rate design. A utility sets a pre-established customer baseline of energy consumption before implementation, and the PTR is awarded if a customer reduces its consumption below the baseline during those peak time hours. Customers will still pay the traditional rate

of a CPP program:

- Baltimore Gas and Electric's Smart Energy Rewards, Maryland—Baltimore Gas and Electric began rolling out its peak time rebate program, Smart Energy Rewards, in 2012, as the default rate for all customers with an installed smart meter. As of 2016, more than one million customers were enrolled and the average bill credit earned during a peak event was $6.67. The program works by notifying customers by phone, email, or text the day before an Energy Savings Day. If the customer reduces its usage from 1:00 to 7:00 p.m. the following day, it receives a $1.25 per kWh bill credit. Customer participation remains high.[21]

These TVRs may be used singly or combined as part of a suite of options. The following are examples of combined pricing plans or projects:

- Massachusetts—The National Grid Smart Energy Solutions program in Worcester signed up 11,000 customers and saved a total of 2,300 megawatts per hour in 2015. The pilot includes two dynamic pricing tariffs: Smart Rewards Pricing and Conservation Day Rebate. The programs notified customers of 20 peak event days when the price of wholesale electricity was

Case Study

Green Mountain Power eEnergy Vermont Smart Grid Project, Rutland, Vermont

Key topics: TVR peak load reductions

During the fall of 2012 and summer of 2013, Green Mountain Power conducted a consumer behavior study to compare the results of two different electricity-pricing structures: CPP and critical peak rebate (CPR). The project, which included over 18,000 customers, resulted in the average CPP customer reducing its energy usage by 5.3–15 percent and the average CPR customer reducing its energy usage by 3.8–8.1 percent during peak events.

Seth Blumsack and Paul Hines, "Load Impact Analysis of Green Mountain Power Critical Peak Events, 2012 and 2013" (U.S. Department of Energy: Washington, D.C., March 5, 2015), https://www.smartgrid.gov/files/GMP-CBS-Final-20150305.pdf.

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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.

21 Smart Grid Consumer Collaborative, "Smart Grid Customer Engagement Success Stories" (Smart Grid Consumer Collaborative, Atlanta, GA, 2016), https://www.silverspringnet.com/wp-content/uploads/BGE-2016-SGCC-Customer-Engagement-Case-Study-3-10-16.pdf.

expected to spike. During these days, participating customers reduced their energy usage by over 30 percent. The average residential customer participating in the Smart Rewards Pricing program saved over $100 in the summer of 2015, while the average residential customer on the Conservation Day Rebate program received over $20 in rebates. Combined, both programs saved customers $1.25 million. Additionally, National Grid achieved a 98 percent retention rate, which demonstrates customer satisfaction in the program.

- California— During 2012 and 2013, Sacramento Municipal Utility District (SMUD) conducted a SmartPricing Options Pilot program for over 8,000 customers. The pilot included three time-based rate programs: a two-period TOU rate with a three-hour on-peak period (4:00–7:00 p.m.), a CPP on a flat underlying rate, and a TOU with a CPP overlay. Overall, load reductions from the pilot ranged from 6 to 26 percent during peak hours. The CPP rates (with a maximum of 12 events per year) saw the highest reductions. Additionally, over the entire pilot period, only 4–9 percent of customers elected to leave the pricing pilot.[22]

4. Three-Part Rate/Demand Charges

Because the utility system is built to serve peak loads, the costs of providing electricity at peak hours is higher than during non-peak hours. Part of this reflects the increased costs of having sufficient infrastructure and generation necessary to serve customers during peak demand times. 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 utility's costs. To the extent that each component of the rate properly reflects its associated costs, the price signal to customers should be improved over the use of flat or block rates. Such

22 Jennifer Potter, Stephen George, and Lupe Jimenez, "SmartPricing Options Final Evaluation" (U.S. Department of Energy, Washington, D.C., September 5, 2014), https://www.smartgrid.gov/files/SMUD_SmartPricingOptionPilotEvaluationFinalCombo11_5_2014.pdf. For additional information on consumer acceptance and behavior under the SMUD pilot, see Cappers, "Time-of-Use as a Default Rate."

rates have been commonplace for C&I customers, at least as an option, for a long time. The demand charge component usually reflects the costs to provide electricity at the peak hour of the month. In an effort to identify costs associated with peak hours, a "demand charge" is one way for a utility to send a peak pricing signal over a certain time period (such as a month). Coincident peak demand charges can be useful in sending a price signal to the customer regarding system costs at the system peak, and consumption during that period is charged accordingly; however, non-coincident peak demand charges a customer for its peak consumption, regardless of the time it occurred.

The metering technology necessary to offer these rates to residential customers has been gradually installed by many utilities across the country, as the costs to install the new metering technology had previously outweighed the benefits. There is some disagreement over the appropriateness of applying 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 serving 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.[23] Lastly, system peak is often known only after the month is over; therefore, a customer has to guess when the system peak might occur, which may lead customers to view demand charges as a fixed charge. The following is an example of a demand charge:

- Arizona—APS has offered residential demand rates since 1981 and has 120,000 customers that have chosen a rate plan combining TOU and peak usage pricing. APS states that 90 percent of customers saved money on their summer bills and almost half the highest savers are small to mid-size customers.[24]

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23 For example, non-coincident peak or coincident peak. See Section V.A.1.e-f, infra.

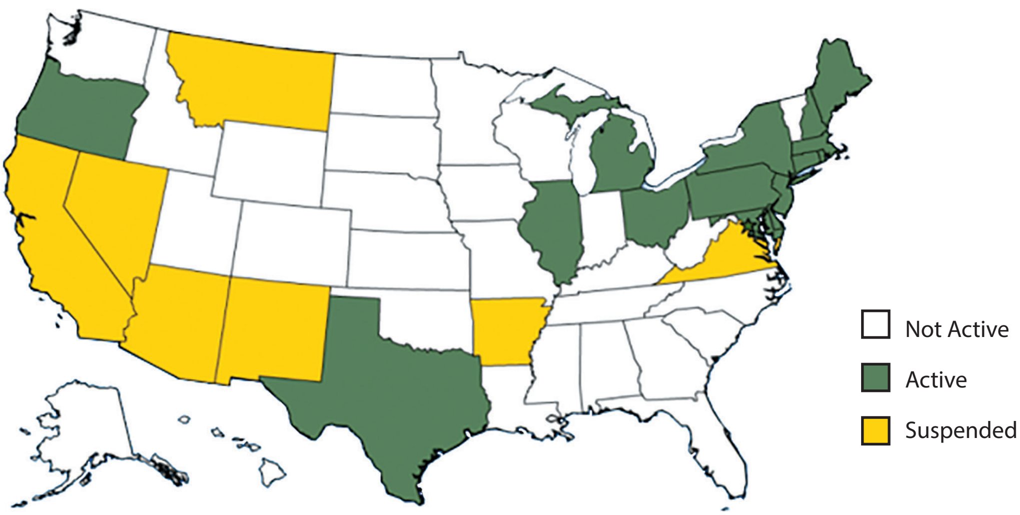
24 APS, https://www.aps.com/en/residential/accountservices/serviceplans/Pages/demand-rates.aspx. See also, Herman Trabish, "APS rate case sparks concern beyond mandatory demand charge proposal," *Utility Dive* (June 7, 2016), http://www.utilitydive.com/news/aps-rate-case-demand-charge-proposal/420332/.

C. Other Considerations

1. Vertically Integrated versus Restructured

A distribution utility in a restructured jurisdiction is responsible for operating the distribution system and recovering associated costs through distribution rates. These utilities do not own generation assets. In such jurisdictions, 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 service operate under limited regulatory jurisdiction and may offer a variety of rates for service. A large portion of Texas, most of the Northeast, and some Midwestern states have restructured electric markets.[25] In restructured markets, retail utility rates are unbundled so that a customer will

Electricity Restructuring by State



Source: Energy Information Administration

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

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 the Electric Reliability Council of Texas (ERCOT), bulk power markets and transmission are subject to Federal Energy Regulatory Commission (FERC) jurisdiction. ISOs/RTOs include the Independent System Operator-New England (ISO-NE), New York Independent System Operator (NYISO), PJM Interconnection (PJM), ERCOT, Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), and California Independent System Operator (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; indeed, unbundling of billing determinants themselves may be beneficial to customer education and understanding of the provision of service. The impact of lowered usage may also have more of an impact on integrated utilities' total revenue collection ability, as it has more total revenue requirements associated with assets that need to be recovered through rates. Conversely, as a percentage, fewer distribution costs may vary directly with usage, thereby making lowered usage affect distribution-only utilities' revenue collection ability.

2. Revenue Decoupling

Decoupling is intended to sever the link between sales volume and revenue for the utility between rate cases. Under decoupling, a utility has the opportunity to recover their 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. Decoupling means the utility's revenue does not increase and decrease proportionally with usage levels. Approximately 60 percent of jurisdictions do not have a decoupling mechanism, so use of decoupling as a solution may be an option for many jurisdictions to consider.[26] Under full revenue decoupling, a utility is made whole for the difference between its annual actual revenues and annual target revenues. Decoupling is often implemented in conjunction with a multi-year rate case, which allows the utility to balance year-to-year fluctuations in cost recovery and total costs. If a utility is experiencing significant over- or under-collections in a given year, a utility may be allowed to recover any under-collections through an increase in the rate, or provide a refund if it is over-collecting. Decoupling is intended to mitigate or eliminate revenue fluctuation for the utility resulting from the installation of energy efficiency and demand resource technology, DER, and external factors such as weather, economic conditions, and power outages. Partial revenue decoupling isolates changes in consumption caused by energy efficiency and demand response from unrelated external factors, outside of the potential for utility management control, 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. Regulators should also take into account changes in a utility's risk profile as a result of decoupling when determining authorized rates of return.

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 and executive bodies with ultimate authority over it in creating specific cross-subsidies to

26 https://www.nrdc.org/resources/gas-and-electric-decoupling.

support social policy goals of the jurisdiction. 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 jurisdictions 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 jurisdictions 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 jurisdictions, and eligibility for these programs usually requires confirmation of a qualified income by the utility. These programs may include a flat rate payment or discount, a percentage of income payment plan, a percentage of bill discount, waived fees, a block rate approach, or usage-based discounts.[27] For example, APS offers a medical care equipment program offering discounts to customers using certain qualifying life support devices.[28]

APS Medical Care Equipment Program (e-4)	
Amount Used (kWh)	**Discount**
0–800	65%
801–1,400	45%
1,401–2,000	26%
2,001+	$60

Additionally, the Low Income Home Energy Assistance Program (LIHEAP) assists eligible low-income households with their energy costs,

27 Nancy Brockway, Jenn Kallay, and Erin Malone, "Low-Income Assistance Strategy Review" (Synapse Energy Economics, Inc., Cambridge, MA, 2014), http://www.synapse-energy.com/sites/default/files/Low-Income-Assistance-Strategy-Review-14-111.pdf.

28 APS, "Limited Income Home," 2016, https://www.aps.com/en/residential/accountservices/assistanceprograms/pages/limited-income-home.aspx.

including 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.[29] Additionally, the Energy Policy Act of 1992 directed 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.[30] FERC Order 888 (1996)[31] and FERC Order 2000 (1999)[32] reduced impediments to competition in the wholesale bulk power marketplace, with a goal to bring more efficient, lower-cost power to electricity consumers. In Order 2000, FERC established guidelines for the voluntary formation of RTOs to oversee the wholesale markets.[33] 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,

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29 Energy Policy Act of 1992, Pub. L. No. 102-486 (1992), http://www.eia.gov/oil_gas/analysis_publications/ngmajorleg/enrgypolicy.html.

30 *Id.*

31 *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).

32 *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).

33 *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).

ancillary services, Open Access Same Time Information System/ Total Transfer Capability/ Available Transfer Capability, market monitoring, planning and expansion, and interregional coordination.[34]

Two-thirds of the electricity consumed in the United States is delivered in regions that operate wholesale electric markets.[35] Wholesale electric markets are facilitated by ISOs/RTOs, including ISO-NE, CAISO, NYISO, ERCOT, SPP,[36] PJM,[37] and MISO.[38, 39]

Additionally, the Energy Imbalance Market (EIM) allows balancing authorities in the western United States to voluntarily participate in a real-time imbalance energy market operated by CAISO. The EIM dispatches economic bids to balance supply, transfers between the CAISO and other EIM entities, and load within its footprint. The EIM provides cost-saving benefits as well as improved renewable integration and increased reliability.[40]

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 can drop to zero or become negative. This occurs when generators are

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34 Order 2000, 5.

35 ISO/RTO Council, *The Value of Independent Regional Grid Operators* (2005), http://www.nyiso.com/public/webdocs/media_room/press_releases/2005/isortowhitepaper_final11112005.pdf.

36 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.

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

38 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.

39 FERC, "Electric Power Markets: National Overview," http://www.ferc.gov/market-oversight/mkt-electric/overview.asp.

40 CAISO, *Energy Imbalance Market Draft Final Proposal* (Folsom, CA: CAISO, 2013), 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).

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, or that price remains above their marginal cost of operation. Sellers pay buyers to take the output.

In some restructured jurisdictions, customers are allowed retail access to the wholesale market and can also 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 RTP programs for residential electricity supply since 2007, at which time the first pilot programs were implemented. Currently, both utilities offer hourly pricing programs to residential customers that prefer to pay the hourly, market price for electricity.[41]

ISOs/RTOs have limited visibility into the operation of certain DERs. DERs may be aggregated by various parties to participate as generation or demand response resources in the energy, capacity, or ancillary services markets of certain ISOs/RTOs.[42] Participation in such markets typically requires some degree of metering to measure and verify participation. ISO/RTOs also may be aware of certain DERs through registries that track production of energy from certain power sources, including distributed retail sources, to create renewable energy credits (RECs). For example, PJM is aware of the deployment of solar, including behind-the-meter retail solar, in its footprint through the Generator Attributes Tracking System for RECs.[43]

A regulator may want to consider how the location and operation of both dispatchable and non-dispatchable DER may be made known to the regional

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41 ComEd, "Hourly Pricing Program Guide: 2015-2016," https://hourlypricing.comed.com/wp-content/uploads/2016/04/2015-2016-HourlyPricing-Guide-v1.pdf.

42 PJM, ISO-NE, ERCOT, NYISO, and CAISO allow DER to participate in certain parts of their regional wholesale markets. NYISO and ISO-NE allow individual customers that can meet the minimum participation thresholds to become market participants and represent themselves in ISO-administered demand response programs.

43 ISO/RTO Council, "IRC Comments on NARUC Distributed Energy Resource Compensation Manual," (September 2, 2016).

grid operators to increase the reliability and efficiency of the regional dispatch, and to consider whether and how the regional grid operator may be able to call on dispatchable DER, if such resources could alleviate reliability issues on the wholesale grid. A regulator in jurisdictions in ISO/RTO regions may want to consider how they may leverage the wholesale markets as they develop their DER policies.[44] This discussion includes the ability of retail customers' demand or DER to be aggregated and bid into wholesale markets by a third party. Some RTOs, such as CAISO, have products in place specifically for aggregations of retail DER to be bid into the wholesale market.[45]

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44 *Id.*, 3-4.

45 *California Independent System Operator Corporation*, 155 FERC ¶ 61,229 (2016).

III. What Is DER?

There is no single definition for a distributed energy resource (DER). Some technologies and services easily fit into any definition, such as residential rooftop wind or solar, but others have yet to be definitively placed inside or outside of this definition. DERs are being adopted at ever-increasing rates due to favorable policies from both the state and federal governments, improvements in technology, and reduction in 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 the delivery of electricity. In defining DER, it is important for regulators to identify potential economic and grid issues and benefits from DER. Then, after empirically establishing at what adoption level DER will affect the grid, regulators should explore and implement rates and compensation methodologies that will lead to greater benefits for the public, customers, developers, and utilities alike. Importantly, having a plan in advance of that determination will facilitate the ability of a jurisdiction to be proactive in planning for and responding to increased levels of DER in concert with the increase.

Addressing these issues will require looking at utility regulation from a new perspective. Indeed, a few states have initiated "utility of the future" proceedings, or similar reevaluations of their regulations partially in response to the changes a 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.

For the majority of its history, the electric utility system has been composed of large, centralized generation, not necessarily sited near customers, and connected to load through the bulk, high voltage transmission grid. That electricity then flows down to the lower voltage distribution grid, and eventually to the customer. This set-up was due to economies of scale; generally it was cheaper for large generation plants to produce electricity and for that 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 to serve anticipated load would construct a large generation plant to serve that increase in demand, or at the very least build a transmission project to relieve congestion on the bulk transmission system and facilitate delivery of electricity to load. Simply put, the term "resource" has traditionally referred to a resource for electricity generation.

When compared with 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 and connected to the distribution grid.

The following are some examples of definitions of DER from across the industry to provide an idea of the variety of descriptions used and their similarities and differences.[46]

Lawrence Berkeley National Laboratory (LBNL) has published a series of papers on the Future of Electric Utility Regulation (FEUR), which focuses on DER.[47] 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

46 Although not discussed in detail in the Manual, a jurisdiction will need to decide how "green" or renewable a DER will need to be to fit in that definition. It may be that renewable distributed generation resources would provide greater societal benefits than other generation resources, especially when sited next to residential load, but any inclusion of environmental or emission criteria should be up to the regulator to decide whether it is defined as a DER.

47 *See* fn. 75, *infra*.

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.[48]

California Public Utilities Code, the New York Public Service Commission, and the Massachusetts Department of Public Utilities (DPU) 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."[49]
- New York—"Distributed Energy Resources (DER) is used in this context to include Energy Efficiency (EE), Demand Response (DR), and Distributed Generation (DG)."[50]
- 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."[51]

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48 Paul DeMartini and Lorenzo Kristov, *Distribution Systems in a High Distributed Energy Resources Future,* Future Electric Utility Regulation, Report No. 2 (Berkeley, CA: Lawrence Berkeley National Laboratory, October 2015), https://emp.lbl.gov/sites/all/files/FEUR_2%20distribution%20systems%2020151023.pdf.

49 Cal. Pub. Util. Code § 769(a) (2015).

50 *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision,* "Reforming the Energy Vision," New York Department of Public Service Staff Report and Proposal, Case 14-M-0101 at 12, fn. 7 (April 24, 2014).

51 *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).

The Electric Power Research Institute (EPRI), in recognizing these seismic changes across the electricity landscape, established the Integrated Grid Initiative, which seeks to realize the optimal integration of distributed and centralized energy resources and to ensure utilities can serve all customers at established standards of quality and reliability as the power system transforms. The Initiative's Benefit-Cost Framework provides a methodology for determining the full value of DER. The Initiative's pilot projects are putting the framework into action by testing a variety of emerging technologies and resources under diverse, national scenarios. In support of this project, EPRI provides the following definition of DER:

- "Distributed Energy Resources (DER) are electricity supply sources that fulfill the first criterion, and one of the second, third or fourth criteria:

1. Interconnected to the electric grid, in an approved manner, at or below IEEE medium voltage (69 kV).
2. Generate electricity using any primary fuel source.
3. Store energy and can supply electricity to the grid from that reservoir.
4. Involve load changes undertaken by end-use (retail) customers specifically in response to price or other inducements or arrangements.[52]

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 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 third 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:

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52 Electric Power Research Institute, *The Integrated Grid: A Benefit-Cost Framework* (Palo Alto, CA: Electric Power Research Institute, Report No. 3002004847, February 2015), xvii. More information about the Integrated Grid Benefit-Cost Framework and pilot projects is available at integratedgrid.epri.com.

> A DER is a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, 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 solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE).[53]

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

B. Types of DER Technologies

These types of DER listed above can provide services and applications directly to the utility or ISO/RTO, or to support customer needs. Examples of the types of services envisioned by vendors and suppliers include microgrids, conservation voltage reduction, volt/VAR support, the potential to provide ancillary services, frequency ride-through, and locational ramping. These types of services, while clearly valuable and potentially worthy of compensation, are included in the definition in this Manual, but may not be sufficiently used or considered as a DER. This is due to the relative low use across the industry, lack of sufficient technology installed to assist in measuring, and the lack of experience in using these technologies, which limits certainty and confidence of response.[54]

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53 Diesel-fired backup generators may also fit in this definition. Whether a jurisdiction allows diesel-fired backup generation to count as a DER should be determined by the jurisdiction. For purposes of this Manual, the definition generally does not include diesel-fired backup generation.

54 At the time of this Manual, key standards to support integration of these resources, such as UL

1. Solar PV Systems

Solar 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, falling panel prices, and other policies, including favorable tax treatment, PV systems have become the fastest-growing type of DER. This category also includes community solar gardens, which are solar installations that are larger, both by available generation capability and acreage, and allow customers that are unable or choose not to have rooftop solar PV to participate in a solar program. Regulators will need to create rules or tariffs regarding the sizes of community solar gardens that are allowed to interconnect at an interconnection point.

2. Combined Heat and Power

CHP systems, also referred to as cogeneration, 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 for many other purposes such as heating, cooling, domestic hot water, and 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 with 50 percent for conventional technologies.[55] Certain types of CHP systems are capable of islanding or offering black start services, where allowed by rules or tariffs.

1741 and IEEE 1547, are either recently finalized or are undergoing revision, which has delayed the introduction of these resources into the grid. Without standards in place, testing and trials of new technologies is limited, which affects the ability of the utility and the developer to gain information and knowledge about the technology and its interaction with the utility system.

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

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. The systems vary in size. A turbine for a home can be as large as a 10 kilowatt (kW) turbine, whereas a turbine for a manufacturing facility can be several megawatts. Distributed wind systems can be connected on the customer's side of the meter to meet its energy needs or directly to distribution to support grid operations or offset nearby loads. Distributed wind systems are often defined by technology application, based on location relative to end use and power distribution infrastructure, and not by size.[56]

4. Energy 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 they have not been cost competitive with cheaper sources of power such as fossil fuels. However, given the recent decline in costs and technological improvements in storage, storage has become an option that is able to compete with many other resources.[57] With the growing use of intermittent technologies such as wind and solar energy, energy storage technologies can provide 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 months when electricity consumption is not affected by summer air-conditioning or winter heating loads.[58] There are a variety of storage types, from large storage resources (e.g.,

56 http://energy.gov/eere/wind/how-distributed-wind-works.

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

58 http://www.epri.com/Our-Work/Pages/Distributed-Electricity-Resources.aspx.

pumped hydro) to thermal storage (e.g., ice energy or electric waters) to chemical storage (e.g., flow batteries or solid state) and mechanical devices (e.g., flywheels).[59] These different technologies provide different types of responses and services.

5. Microgrids

Microgrids are localized grids that can disconnect from the traditional grid to operate independently. 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.[60]

Microgrids help with the integration of growing deployments of renewable sources of energy such as solar and wind and other DER such as CHP, energy storage, and DR. 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.[61]

6. Demand Response

DR can be used as a resource by utilities and grid operators to balance supply and demand. The use of DR 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 (including participating in a time-based rate) in DR products, such as TOU, CPP, variable peak pricing, RTP, or CPR. Another

59 http://energystorage.org/energy-storage/energy-storage-technologies.

60 For additional information on policy and regulatory perspectives on microgrids, see, Minnesota Department of Commerce, "Minnesota Microgrids: Barriers, Opportunities, and Pathways Toward Energy Assurance" (Minnesota Department of Commerce; St. Paul, MN, September 30, 2013); and California Public Utilities Commission, "Microgrids: A Regulatory Perspective," Policy and Planning Division (California Public Utilities Commission, San Francisco, CA, April 14, 2014).

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

method is the use of direct load control programs, which allow for the cycling of customer air conditioners or electric 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, DR is becoming an increasingly valuable DER.[62] Although traditionally viewed as a peak reduction resource, DR can be used to increase consumption when there is excess generation, or more regularly to avoid dispatching of more costly generation resources and enhance the efficiency of the grid.

7. Electric Vehicles

EVs can time charging (or dispatch of the battery) to be responsive to price or DR signals. This flexibility to participate as a DR resource, located throughout a service territory, provides a utility with the ability to target EV DR programs where they are most beneficial to the grid. Additionally, EVs have the ability to put power back onto the grid when connected, which provides the grid with additional flexibility. This capability allows EVs to act as an energy resource by supplying grid services as a grid-connected battery, which is then able to provide mobile backup power during an outage or emergency situation. To benefit from this capability, the development of vehicle power electronic systems with bidirectional flow, integrated communications, and improved battery management systems is required. Because EVs are often stationary for many hours of the day, the battery from the EV can be used as a storage device that can provide additional grid services.[63]

8. Energy Efficiency

EE is capable of providing both energy and demand savings. EE can be used by a utility to displace generation from other sources, such as coal, nuclear power, natural gas, or any other supply-side resource. The decision to

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62 http://energy.gov/oe/technology-development/smart-grid/demand-response.

63 http://energy.gov/sites/prod/files/2015/09/f26/QTR2015-3D-Flexible-and-Distributed-Energy_0.pdf.

invest in EE is generally made when the utility is considering whether to invest in other new generation resources. EE can provide a transmission and distribution benefit by allowing the utility to reduce or eliminate the need for upgrades or new equipment on the transmission or distribution system.[64]

This Manual includes EE as a resource, even though some may not. However, EE programs do effectively shift or shave load, or both, which certainly can fit within the view of acting as a resource, especially if the load shift can be predicted or scheduled.[65] Measurement and forecasting play a large part in EE. Attempting to determine what a load curve would look like absent EE adds a level of complexity to the issue of determining the resource value of the EE. A regulator will need to determine whether it is appropriate to include EE in its consideration of DER.

C. Enabling Technology

1. Advanced Metering Infrastructure

According to the Energy Information Administration, nearly 52 million advanced meters have been installed across the residential customer class throughout the United States as of 2014.[66] These advanced meters are capable of measuring consumption in 15-minute to one-hour increments. The meters are connected to a communications network, which then transmits the consumption information to the utility's back office for billing. This stands in stark contrast to the historical mode of metering, which usually occurred once a month and included either a physical reading of the meter or collecting the information through a local radio network. Some modes of automated meter reading were capable of reading daily, in support of specific tariffs, but were

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64 http://aceee.org/topics/energy-efficiency-resource.

65 In the PJM and New England ISO markets, EE can be bid in and dispatched by the market operator.

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

not implemented widely. In other words, utilities have gone from having 12 data points about a customer per year to 8,760 data points if measured hourly. It is also now possible for customers to access that same amount of information; instead of waiting for the monthly bill, customers can log on to their utility's online portal and access the hourly usage information, typically on a 24-hour lag.[67] The uses for this information are still in their infancy and are likely to evolve over time.

With the installation of AMI, implementing rate designs like TOU, CPP, and RTP becomes possible at lower costs than in the past. An integral part of an AMI 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.

AMI 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 Wi-Fi–enabled thermostats.

With these 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 rollouts of new rate designs. Furthermore, with this information, customers can better understand the potential impacts of installing DER or signing up for community DER

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67 To enable this functionality, a meter data management system is necessary to provide the data analytics on the metering data, including turning the raw meter feed into information understandable to the customer and to support other utility business needs.

programs at their location. By being able to "do the math," customers can better understand whether it makes sense to invest in DER. With policies supporting the development of HAN and data access, it may be possible to identify additional services from the location itself that may be beneficial to the grid, either individually at the premise or aggregated across a specific geography.

Lastly, AMI can not only collect consumption information about a premise, but can also collect generation data related to an on-site DER, such as solar production and voltage. By being able to collect this information, AMI can be used as a data source for distribution planning and operation, facilitate compensation of DER for its generation, and assist customer adoption and participation in many other DER products and services. Such policy development presumes a large enough amount of DER is present across the distribution system to affect delivery of electricity. Use of data generated by AMI 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

To support the adoption levels of DER, utilities may seek additional infrastructure and technological support to assist in maintaining reliability and enhance resilience across the distribution grid. Two options to support that goal are Advanced Distribution Management Systems (ADMS) and Distributed Energy Resource Management Systems (DERMS).

ADMS add 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 provide utilities with several specific functions, such as automated fault location, isolation, and service restoration (FLISR); conservation voltage reduction; and volt/VAR optimization.[68] Installing ADMS is not merely about better integrating DER;

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68 Department of Energy, "Voices of Experience: Insights into Advanced Distribution Management Systems" (Department of Energy, Washington, D.C., February 2015),

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 can be gathered from ADMS investments will help the utility meet customer demands while maintaining reliability, resilience, and flexibility. Functionally, an ADMS system integrates several utility systems, such as outage management, geographical information, AMI, and customer information systems, into one, enterprise-wide system.

With higher levels of DER adoption, DERMS provide an additional set of tools in addition to 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 24–48 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.[69] 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 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.

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https://www.smartgrid.gov/files/ADMS-Guide_2-11.2015.pdf.

69 Jeff St. John, "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.

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 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.[70] 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; 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 the energy to the distribution grid is a value and service that can be provided by the customer, which can defer or avoid additional distribution upgrades.

The image below shows the voltage fluctuations caused on a feeder in San Diego Gas & Electric's distribution grid from solar PV that violates existing operational standards for the distribution grid.[71] This information shows how voltage fluctuations can be masked by not having sufficient granularity and visibility into the grid, and also the importance of maintaining voltage levels as electricity from solar PV is exported onto the distribution grid.

In many cases, the Smart Inverter is now included in new solar PV installations.[72] Indeed, the recommendation of the Smart Inverter Working

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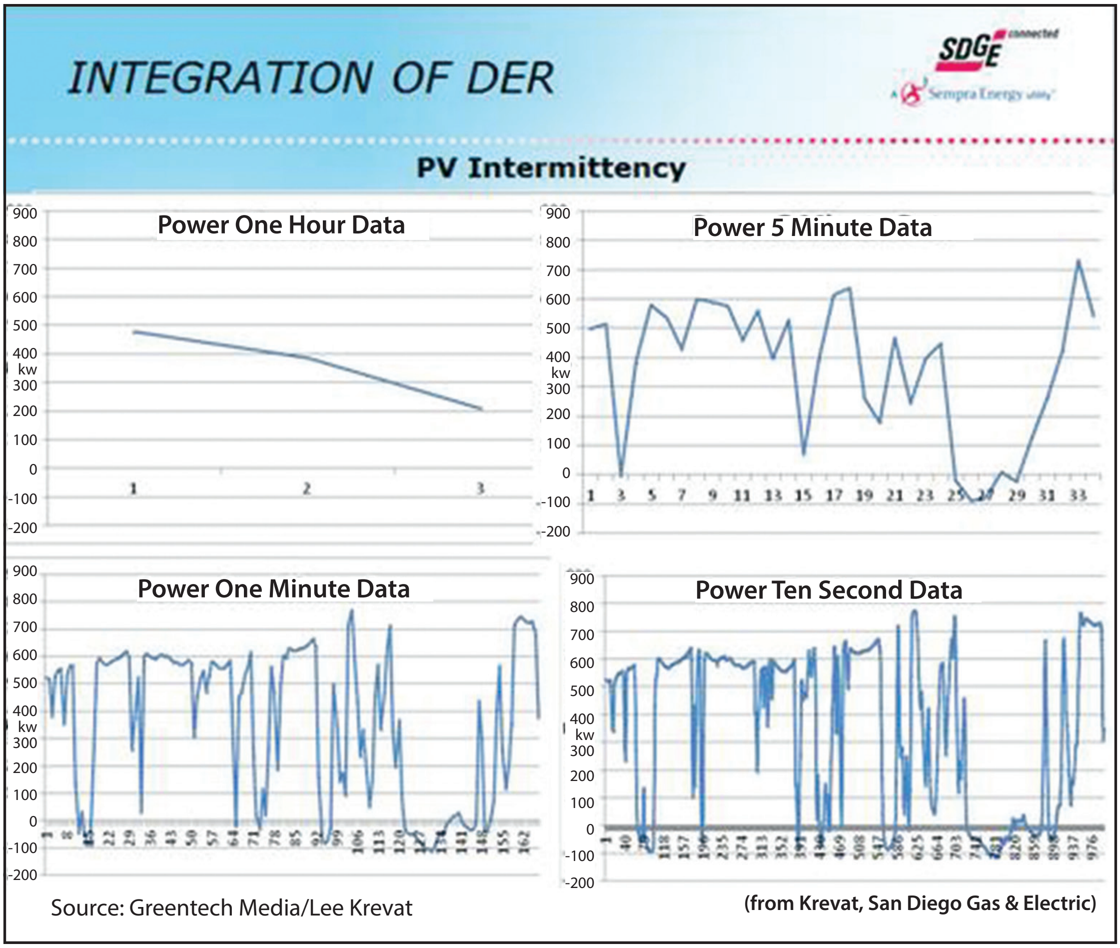
70 California Public Utilities Commission, "Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources: Smart Inverter Working Group Recommendations," Smart Inverter Working Group (California Public Utilities Commission, San Francisco, CA, January 14, 2014), 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.

71 Herman Trabish, "The Nuclear Failure in California Could Be a Big Test for Solar," Greentech Media (March 30, 2012), http://www.greentechmedia.com/articles/read/The-Nuclear-Failure-in-California-Could-Be-a-Big-Test-for-Solar.

72 San Diego Gas & Electric was an early proponent of the use of smart inverters to manage



Group, subsequently adopted by the California Public Utilities Commission, is to require Smart Inverters for all new solar PV installations seeking to interconnect with the distribution grid upon completion of the safety standard starting one year from the publication of Underwriters Laboratory (UL) 1741.[73]

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voltage fluctuations from solar PV. In August 2013, it issued a proposal that outlined necessary changes to existing utility standards to enable the functionality embedded in Smart Inverters to meet this technical need. See San Diego Gas & Electric, "Inverter Technical Standards Proposal" (San Diego Gas & Electric, San Diego, CA, August 2013), https://www.sdge.com/sites/default/files/documents/2060692059/Inverter%20Technical%20Standards%20White%20Paper%20August%207%202013.pdf?nid=7771.

73 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

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

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 (e.g., 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 has led to the development of this Manual and a number of other articles and reports addressing DER and its

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Inverter is operating safely, both independently and in conjunction with utility distribution systems. UL 1741SA, published in September 2016, provides the testing and certification specifications for certain advanced inverter functions: anti-islanding, low-/high-voltage ride-through, low-/high-frequency ride-through, must trip test, normal ramp rate, soft-start ramp rate, fixed power factor, and volt/VAR mode. 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. See, California Public Utilities Commission, "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, San Francisco, CA, February 28, 2015), http://www.energy.ca.gov/electricity_analysis/rule21/documents/SIWG_Phase_2_Communications_Recommendations_for_CPUC.pdf.

impacts on utilities, regulators, and rate design.[74] For example, LBNL's FEUR series of papers is designed to assist in this dialogue.[75] These papers employ a point–counterpoint format to explore the evolution of electric utility regulation in a future with potential high levels of DER and other changes in technologies, customer desires, loads, and federal and state policies. Other stakeholders have also identified options in response to the additional considerations that DER places on utilities and traditional regulatory models.[76]

Although many types of DER have yet to reach significant levels of adoption in many states, some jurisdictions have seen higher levels of adoption, and it seems that favorable policies, rate designs, and compensation have been driving these 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 reports that solar photovoltaic capacity in Maui will soon equal more than half of the system peak demand."[77,78] The issues presented by DER in the current regulatory landscape primarily involve the potential costs that DER impose on the grid, and the recovery of the cost of the grid from DER customers; properly incorporating and compensating the benefits DER provide; dealing with other physical challenges that the technologies present to the

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74 *See* fn. 48, *supra*.

75 More information on the project, and access to all reports, can be found at: https://emp.lbl.gov/future-electric-utility-regulation-series. This project is funded by DOE to help better inform stakeholders and policymakers on the future of electric regulation in response to the changes currently ongoing across the industry.

76 A number of reports and white papers have been issued on this topic. The following are just a small sampling: Solar City Grid Engineering, "A Pathway to the Distributed Grid" (Solar City Grid Engineering, San Mateo, CA, February 2016); Edison Electric Institute, "Disruptive Challenges" (Edison Electric Institute, Washington, D.C., January 2013); Ceres, "Pathway to a 21st Century Electric Utility" (Ceres, Boston, MA, November 2015); Rocky Mountain Institute, "Rate Design for the Distribution Edge" (Rocky Mountain Institute, Boulder, CO, August 2014).

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

78 Instituting a Proceeding to Investigate Distributed Energy Resource Policies, Decision and Order No. 33258, Hawaii PUC, Docket No. 2014-192 (October 12, 2015).

physical grid; and ownership issues.

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

Take, for example, one key variable in considering DER ratemaking: the level of adoption of the resources.[79] The threshold level of adoption for significant impacts may not vary only from state to state and utility to utility, but also 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 the most likely reaction to any rate design changes must be clearly and thoroughly determined before questions and challenges arising from DER are addressed through ratemaking changes. The required level of transparency and detail for the operations and physical characteristics of a utility's distribution system may be significantly more than may have been employed in the past.

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79 Sometimes called the level of "penetration."

IV. DER 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 instances a century—being challenged by these new technologies. Traditional means of regulation, rate design, and planning largely assume the utility will meet all demand with large, central-station generation facilities. With the increase in DER and the recent lack of load growth, the current regulatory and utility models are a constraint to effectively address the growth of DER and its impacts on utility and regulatory frameworks. Identifying and understanding these challenges will assist the regulator in determining an appropriate rate design to implement for its utilities.

A. Ongoing Monitoring and Adoptions Rates

The level and pace of adoption of DERs in a system is important in the determination of what, if any, policy reforms are needed. The actual adoption levels of DER vary greatly across the country and even within the same jurisdiction. Since all electric systems are affected by DER increases differently, before a jurisdiction embarks on the journey to implement substantive reforms due to the growth of DER adoption, it should look closely at data, analyses, and studies from its particular service area before any such actions are taken. The impacts that are occurring in one jurisdiction due to higher DER adoptions may not necessarily be the same for another that is experiencing similar DER adoption levels.

In a report for LBNL'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.[80] In this paper, they include an adoption curve that points out the importance of monitoring adoption rates of

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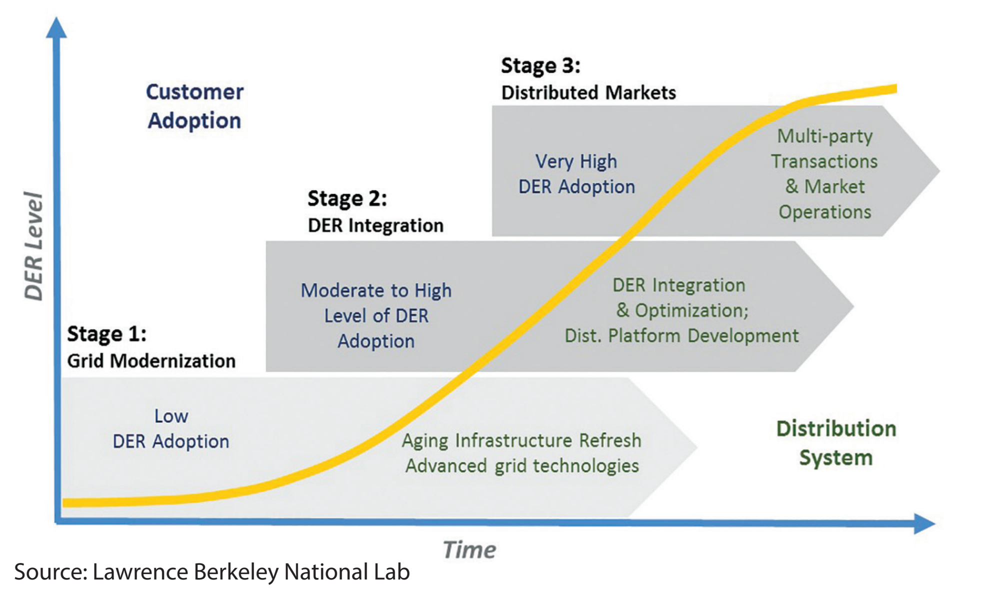
80 DeMartini and Kristov, *Distribution Systems*.

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 jurisdictions 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."[81] Stage 3 occurs when a high amount of DER adoption occurs and regulators construct a system to allow for multi-sided transactions to occur between DER and the distribution 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.[82] This process is depicted in the figure below.



Source: Lawrence Berkeley National Lab

81 *Id.*, 9.

82 *Id.*, 10.

This discussion is included here to provide regulators with a visual of a future for DER adoption and an awareness that decisions on DER rate design and compensation methodologies are not static determinations that can be made once and then left alone. Rate design and compensation decisions made in one year will likely need to be reviewed, modified, or changed over time as technology continues to develop, as customers adopt DER at greater (or slower) rates, and as needed to support economics. For example, a decision to adopt net energy metering (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 their 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 EVs, increase in adoption, a regulator may try to turn NEM into a technology-agnostic program, or may choose to implement an entirely new suite of compensation options. All the while, the regulator will need to also address how the compensation methodology is working with the existing rate design for those customers.

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 regulators in making these decisions. Hawaii, for example, has had significant adoption of solar PV, and the Hawaii Public Utilities Commission decided to close its NEM tariff altogether, deciding that other compensation methodologies and rate designs are more appropriate for its jurisdiction.[83] Understanding and monitoring how DER is affecting the grid and utility rates is essential to fairly compensating DER. A jurisdiction must also be flexible enough to recognize when those methodologies and rate designs are no longer meeting its policy goals. At that time, it is appropriate to consider other means of determining compensation or other rate design options.

For jurisdictions with currently low DER adoption levels 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 DER. For the jurisdictions with low DER adoption 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 or making inefficient investments in DER. That is not to say a jurisdiction should ignore the issue. Understanding how its existing rate design interacts with its compensation may be worthwhile to consider at any time. The important point is that a jurisdiction be situated to analyze, plan, and be prepared for its next steps before the market and customer adoption rates overtake its ability to respond.

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 grid feeders. Hosting capacity helps the distribution utility assess the impacts of DER on its feeders, and identify available capacity on those feeders.[84] This analysis can determine where there is available capacity and where there is little available capacity; making this information available

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

84 EPRI, "Hosting Capacity Method," http://dpv.epri.com/hosting_capacity_method.html; EPRI, "Distribution Feeder Hosting Capacity: What Matters When Planning for DER?" (EPRI, Palo Alto, CA, April 2015).

to developers can assist DER developers in better locating potential DER. Currently, to the extent a utility is conducting a feeder-by-feeder hosting capacity analysis, the information is largely kept inside the utility. Without such information, DER developers have no visibility into the 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 LMPs to drive economic siting of DER, much the same way that transmission planning and transmission LMPs identify areas in need of additional resources to relieve congestion, for example.

B. Costs

The economic pressures that DER may put on the utility and non-DER customers within a rate class is one of the most challenging 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 NEM discussions. These issues have been driving most of the 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 from any reduction in usage (e.g., due to variation in weather or DER) unless there is a mechanism that decouples

A Brief Word on Distribution System Planning

As noted in section 1, there are many related and worthwhile topics that are not covered in this Manual because they are considered as out of scope for this particular discussion. One such topic is distribution system planning. It is clear that distribution system planning is a topic of great interest in many jurisdictions, and it exists regardless of market structure across jurisdictions. Distribution system planning will increasingly be more important over time as DER continues to grow across the country; having a framework in place that builds in consideration and integration of DER can help a jurisdiction and utility meet this growth. Jurisdictions such as Minnesota, Rhode Island, Maryland, New Hampshire, Vermont, and the District of Columbia have opened proceedings investigating how best to plan for DER, including looking specifically at distribution system planning. The first step in any discussion of distribution system planning is knowing how well the distribution utility knows its own system; without such knowledge, planning can be frustrated.

A goal of distribution system planning is how to build a distribution system that can interact, engage, and utilize DER in a more effective manner that minimizes service quality and reliability impacts. In essence, if the DER is in place, how can a distribution utility use that resource and, potentially, compensate it? This Manual addresses the compensation part of the equation, but the planning, impacts on the utility business model, and future business opportunities remain outside this document. Even though this Manual does not go into greater detail on distribution system planning, it is undoubtedly an important part of this conversation. As noted to the Minnesota Public Utilities Commission in a recent paper, the "integrated grid will evolve in complexity and scale over time as the richness of systems functionality increase and the number of distributed resources extend to hundreds of thousands and possibly millions of intelligent utility, customer and merchant distributed resources. To address this evolution, robust planning processes and engineering methods are required to advance distribution planning." ICF International, "Integrated Distribution Planning" (paper prepared for the Minnesota Public Utilities Commission; ICF International, Fairfax, VA, August 2016), 19–20.

Lastly, pairing distribution system planning with integrated resource planning will be vital to ensuring that efficiencies gained from the use of DER are not lost. For a fuller discussion on the importance of resource planning, ***see*** Fredrich Kahrl, ***et al.***, "The Future of Electricity Resource Planning," *Future Electric Utility Regulation,* Report No. 6 (Berkeley, CA: Lawrence Berkeley National Laboratory, September 2016).

revenue from customers' usage.[85]

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 reducing the customer's bill by the same amount. This netting may not reduce any of the utility's costs, but can negatively affect 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 discussed below. In considering alternative ways for a utility make up lost revenue, other revenue models may be available with changes to the utility business model. For example, in the New York Reforming the Energy Vision (REV) proceeding, the New York Public Service Commission identified a set of examples of "market-based services that could generate revenues for utilities. These include: customer origination via the online portal; data analysis; co-branding; transaction and/or platform access fees; optimization or scheduling services that add value to DER; advertising; energy services financing; engineering services for microgrids; and enhanced power quality services."[86]

2. Cost Recovery

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 responsibility of utility rates as recovering the embedded cost of the utility's assets; earning a fair return, or profit, on the

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85 For more information on decoupling, *see*, II.C.2, *supra*.

86 *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, "Order Adopting a Ratemaking and Utility Revenue Model Policy Framework," New York Public Service Commission, Case 14-M-0101, 41 (May 19, 2016).

same; and recovering the operations and maintenance expenses necessary for providing 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 demand, whether it is the coincident peak demand—the one-time highest peak demand the system must accommodate—or the non-coincident peak demand, which is the customer's highest demand.[87] Regardless of the drivers of cost, most utilities and many regulators view the utility's short-term costs, especially for its distribution system, as fixed; indeed, the rate base and authorized revenue requirement are fixed by the state regulator during rate cases. This fixed amount is then allocated to the different classes before being divided amongst 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, driven by DER in a single year 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 illustrates the issue with recovering utility costs and the related risks faced by utilities.

On the other hand, DER can also, over the long term, avoid or defer the construction of new infrastructure, including generation facilities and transmission lines, and assist and support meeting local reliability needs.[88] Therefore, understanding whether the time frame being considered is short

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87 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. For more information, see NARUC, *Electric Utility Cost Allocation Manual*.

88 Solar Energy Industries Association, *et al.*, "Rate Design for a Distributed Grid: Recommendations for Electric Rate Design in the Era of Distributed Generation" (Solar Energy Industries Association, Washington, D.C., July 21, 2016), 2.1.

term or long term is important to determining whether DER is truly affecting the ability of a utility to recover its costs.

3. Cost Shifting

Cost shifting is another issue that may affect customers in the same rate class as customers that have adopted DER. Cost shifting, or subsidies, is 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 traditional 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 request a change in its revenue requirement or rate design, or both. In the case of DER, often the billing determinants are lowered to mitigate the pressure on revenue collection effected by lower sales. Thus, the decline in usage would effectively be shifted to other customers when the billing determinants are reset to account for the decreased revenue received from the DER customers. At a low level of adoption, this may be considered merely another imperfection in rate design, but at large levels of adoption 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 whether shifting additional cost recovery to customers that 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 adoption, the utility may face significant intra-class cost shifting and erosion of revenue in the short run. If left unaddressed, the utility could face pressures in the long term that might prevent it from recovering its sunk costs, which are 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 themselves procure or generate electricity 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. For DERs that are intermittent in nature (absent storage), such as wind or solar PV, the generation is available only 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 the panels 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. There is less variation for solar PV, but wind output can go from 100 percent output to 0 percent almost instantaneously. Having a better handle on weather forecasting and monitoring can assist in better planning for these types of immediate variations. In this regard, some types of DER can act as if sizable loads are coming on and off of the system, and this situation makes utility and RTO demand forecasting problematic.

These effects are amplified when some types of DER are clustered in a specific area. For instance, if solar PV is clustered on one feeder and reacting to the same sudden changes in electrical output (for instance, 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 that may occur on that feeder, the voltage on that line could become outside of acceptable parameters without the wider system being able to timely absorb the impacts. At certain thresholds of solar PV deployment, this may affect 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, which can help mitigate some of these concerns.[89] Because DER is not only one type of resource, a mix of several types of DER and other technologies can be used to more actively manage these circumstances.

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 direction due to a cloud.[90]

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 AMI on its customers' load or has supervisory control and data acquisition (SCADA) systems across its distribution grid, it may be able to gather better data to understand the impacts of DER on certain locations. AMI and smart inverters also allow for greater options in rate designs, which is discussed elsewhere in this paper. Other technologies may also benefit the utility in planning and responding to DER growth across the utility system. Planning for building DER into the system may mitigate these physical concerns as the DER can be relied on by the distribution utility. See section VI for greater discussion.

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89 Flicker generally refers to the variability of light output from lightbulbs. In some cases, flicker can be caused by voltage drops due to large industrial loads, or from voltage swings from solar installations. IEEE 141 and IEEE 1453 are the standards relied on 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.

90 How a utility and jurisdiction determine available capacity is important to define. Many utilities' interconnection practices limit additional resources to interconnect above a certain threshold, such as 120 percent of minimum daytime load. The National Renewable Energy Laboratory (NREL), working in conjunction with Hawaiian Electric Companies and Solar City, found that with a combination of advanced technologies, like smart inverters, individual feeders could operate at 250 percent of minimum daytime load. NREL, *et al.*, *Inverter Load Rejection Over-Voltage Testing: Solar City CRADA Task 1a Final Report* (NREL: Golden, CO, February 2015).

C. Benefits

The challenge of acknowledging, identifying, quantifying, planning for, and optimizing the benefits DER can provide to utilities and customers, both those with and without DER, is an issue on par with identifying appropriate utility costs, as discussed above. Currently, in many jurisdictions, a customer with DER that has DG or ancillary service attributes may realize savings beyond any avoided cost savings due to avoided energy usage. This is because a growing number of parties involved in the DER debate acknowledge DER can provide material benefits beyond just those enjoyed by the customer behind whose meter the DER is sited (in applicable). In the case of EE, many jurisdictions already socialize some of the costs to lead to cost savings beneficial to the entire jurisdiction. Some jurisdictions, utilities, researchers, and advocates have also concluded or posited that responsible encouragement of other types 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) particular customers for producing particular benefits (or costs) for the grid (except through DR or EE programs), a regulator would be missing that portion of the cost benefit analysis for DER. This is an issue only to the extent that a regulator wants to acknowledge, encourage, and optimize any benefits from DER. At the very least, neglecting DER benefits could represent a lost opportunity to meet customer needs on a more cost-effective basis. To put it another way, if a regulator conducted a detailed planning process beyond the distribution grid using today's technology, theoretically, some level of DER (beyond EE) could be used in a targeted basis throughout the grid to reduce costs. For example, several states are exploring how to use DER to avoid infrastructure investments.[91]

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91 *See*, California Public Utilities Commission, Docket No. R.14-08-013 (proceeding to consider utility distribution resources plan, including development of locational net benefit analysis to determine benefits of DER at a location, including as alternative to utility infrastructure investments); *Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program*, "Order Establishing Brooklyn/Queens Demand Management Program" (New York Public Service Commission, Albany, NY, December 12, 2014); Oklahoma Gas & Electric, Integrated Resource Plan (2014) (OG&E also restructured existing demand reduction programs, added a combination of new energy efficiency and demand

There is debate over the benefits of DER. Part of the disagreement is in quantifying benefits from DER and the effects of integrating DER into the grid and utility systems. Regulators are also increasingly interested in calculating benefits that have not traditionally been incorporated in rate design or are hard to quantify. Environmental benefits of distributed carbon-free generation[92] and the ancillary services markets of many RTOs are examples of recent attempts at increased quantification of benefits.

The services and benefits that may be provided by the many types of 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" proceedings will give some indication of what benefits are being examined.

Minnesota enacted the first Value of Solar 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.[93] In July 2016, the Minnesota Public Utilities Commission issued an order requiring the Value of Solar rate for all new community solar garden applica-

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response programs, including the technology enabled SmartHours program, and announced the termination of 300MW of wholesale contracts by 2015.).

92 As it applies to emission or renewable credits, it is important to note that many jurisdictions track RECs separately, and it is wise to consider if DER is already being tracked or valued in that manner.

93 Minnesota Department of Commerce, "Minnesota Value of Solar: Methodology" (Minnesota Department of Commerce, St. Paul, MN, January 30, 2014), http://mn.gov/commerce-stat/pdfs/vos-methodology.pdf) at 2.

tions filed after December 31, 2016.[94] 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 to advocate for changes beneficial to the particular interest during discussions with regulators 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 their costs.[95] Others are exploring implementing a distribution system operator model or market models for requesting and compensating DERs based on need, time, and location.[96] Others have moved to greatly expand the transparency for, and participation of, regulators into the planning of a utility's distribution system.[97] 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 take in the future, the acknowledgment and study of these benefits will be necessary. As such, this is another area that must be given thorough consideration by a regulator. A starting point used by many states is the

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94 *In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program,* "Order Approving Value-of-Solar Rate for Xcel's Solar-Garden Program, Clarifying Program Parameters, and Requiring Further Filings," Minnesota PUC, Docket No. E-002/M-13-867 (issued September 6, 2016).

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

96 *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.

97 *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).

Standard Practice Manual (SPM), developed by the California Public Utilities Commission. The SPM outlines five different tests that a jurisdiction can use to determine the cost-effectiveness of a demand-side resource.[98] The tests provide alternative ways of determining cost-effectiveness of a variety of demand-side resources from different stakeholder perspectives.[99]

D. Ownership and Control

The increased adoption of DER is often promoted by third parties rather than the utility, and can be driven by third-party business models that respond to price signals that compensate strictly on the basis of total energy production rather than the temporal energy value of grid benefits (or costs). Additionally, the lack of visibility into the current state of any DER, as well as 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 issues 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 third-party products, such as the practice of third 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 for 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 southward orientation.[100]

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98 California Public Utilities Commission, *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* (California Public Utilities Commission; San Francisco, CA, October 2001), http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx-?id=7741. This includes the Societal Test, which is treated as a variant of the Total Resource Cost test. The SPM is currently under revision by the California Public Utilities Commission.

99 California Public Utilities Commission, http://www.cpuc.ca.gov/General.aspx?id=5267.

100 Traditional NEM programs compensate for total production, which incentivizes solar PV to maximize total production; in other words, panels face south or southwest to maximize solar radiance. 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 reduced during late afternoon hours, as it may assist in alleviating

An additional issue has been concerns about predatory lending and the need for consumer protection regulations that 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 the existence of programs targeted for low-income customers, DERs, such as solar PV, 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. Some types of DER may be available to this demographic only through community programs and virtual net metering, if at all.

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.

E. What Can the Rate Accomplish?

Regulatory proceedings are made more difficult by parties often addressing only 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 to the public interest. Lastly, siloes continue to persist across utility and regulatory commissions that limit knowledge and information sharing across the utility or commission, or both. Though these specific challenges will lessen with time as knowledge and experience are accumulated, currently one of the biggest issues, if not 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.

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afternoon ramping conditions due to the setting sun. See Pecan Street Project, 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 of NEM with policies supporting total production without location or timing attributes.

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. Rate Impacts on DER and Customers

a. Different Rates versus Changing All Rates

Rate making is often the result of a regulator balancing a variety of interests and goals of the parties, as well as 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, and so forth. 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 applies only 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.[101] For a number of reasons, regulators may decide this is not the best approach to recommend or to approve (e.g., promotion, neutrality, or demotion of DER; availability of data; customer acceptance or fears related thereto).[102]

b. Different Customer Classes to Recognize Difference in Service

Another option, one that might be particularly attractive to a jurisdic-

101 Edison Electric Institute, "A Primer on Rate Design for Residential Distributed Generation" (Edison Electric Institute, Washington, D.C., February 16, 2016), 10 (EEI Primer).

102 See, e.g., Hledik and Lazar, *Distribution System Pricing*, 46–47.

tion that is unwilling to commit to a wholesale restructuring of rates or is 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 any cost shifting, if it exists, between DER and non-DER customers. A separate DER class may also aid in identifying and quantifying benefits and costs associated with DER.[103]

Traditionally, customers are separated into classes based on some important distinction in the service provided to or usages of different groups of customers that affects the cost to serve them.[104] The question for DER customers, then, is whether the difference in the service provided to DER customers differs in a way that justifies their separation into a separate class[105,106]; for example, if a DER customer's load shape varies from a non-DER customer's shape in the manner depicted below:

In this example, comparing a subset of DER customers (net-metered residential customers) with their counterparts (non-net-metered residential customers) shows that the net-metered customers had higher hourly loads and usage than the non-net-metered customers.[107] It also shows that as a group, the delivered load for the net-metered customers is vastly different from the non-net-metered customers. Finally, one should look at how the loads and load

103 Migden-Ostrander and Shenot, "Designing Tariffs," 45.

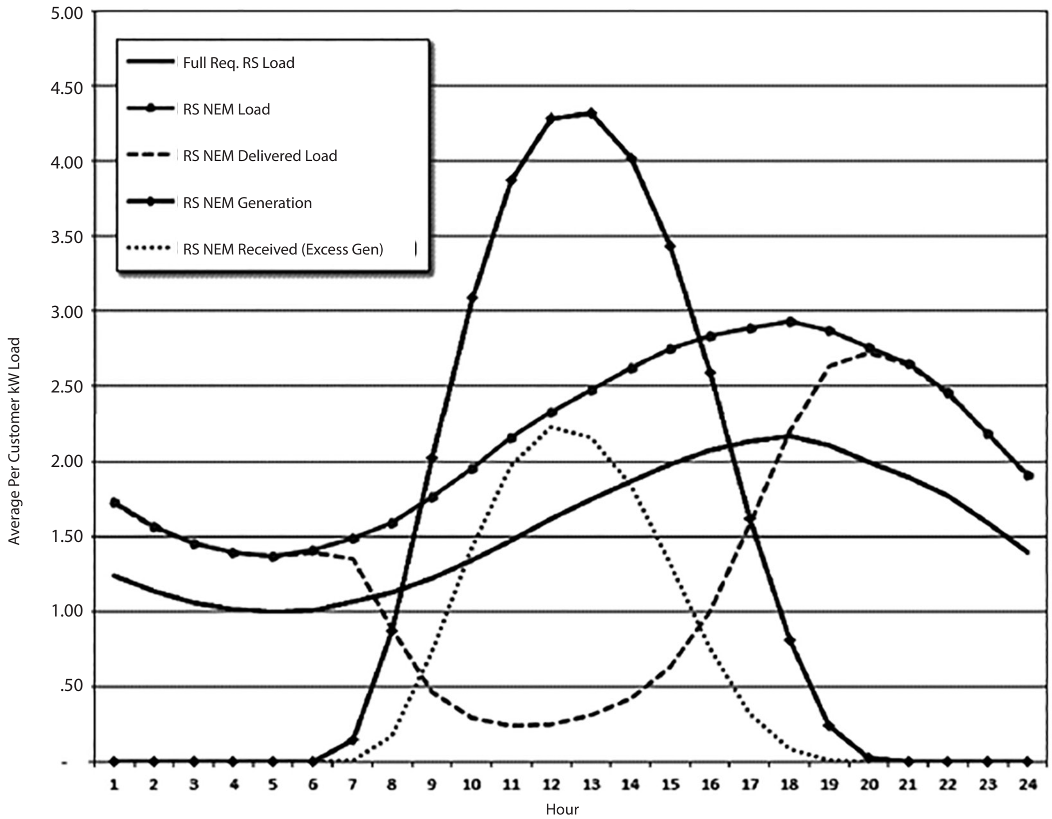
104 See, e.g., NARUC, *Electric Utility Cost Allocation Manual,* 22.

105 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.,* Jim Kennerly, "Rethinking Standby and Fixed Cost Charges: Regulatory and Rate Design Pathways to Deeper Solar Cost Reductions" (NC Clean Energy Technology Center, Raleigh, NC, August 2014).

106 It can also be argued that the difference does just that. See, EEI Primer, 11.

107 *Application of Nevada Power Co. d/b/v NV Energy for approval of a cost of service study and net metering tariffs,* Docket No. 15-07041, Nevada Public Utilities Commission, Original filing, Volume 2, p. 35 of 187 (July 31, 2015).

Nevada Power NEM & Full Requirements RS Customers Annual Average Loads



Source: Nevada Public Utilities Commission

profiles differ at the time of the system peak. If the differences between the DER and non-DER customers are significant, it may be reasonable to separate the customers into different classes for rate-setting purposes. Conversely, if the differences are minimal, then it may not be valuable to implement a separate rate class.

One must also consider whether these customers should 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 lightbulbs, or the number of people living in a home is reduced, other things being equal, there is less usage to spread costs over. It must also be noted that individual customers are not generally responsible for utility upgrades to meet specific customer actions. For example, if a customer installs an extra television or refrigerator or purchases an EV that requires an upgrade to the local transformer, the costs associated with that new infrastructure investment are recovered from the entirety of the customer class, and not from the specific customer responsible for the upgrade. To recover authorized costs, the rate increases due to reduction in usage (in a non-decoupled jurisdiction) are shifted to those customers that 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, electric heat, or undergrounding of distribution wires, however, are sometimes considered to be a different type of service, as the impact on costs is significantly different for 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[108] 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 those differences constitute a substantial enough difference in the service provided to justify their separation.

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

108 See Hledik and Lazar, *Distribution System Pricing*, 47.

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, to induce economically efficient consumption. Regulators should also consider if the price signal is being received by a customer. For example, a budget billing program that fixes the monthly electric bill for the year with an annual true-up effectively mutes any price signal received by a customer, at least over an annual period.

3. Long-Term versus Short-Term Costs, Benefits, and 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. These two positions 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. There may also be portions of the system that do not vary in cost with any amount of usage.

F. Impacts on Other Customers

When deciding on a rate structure to be used for DER, it is important to consider the various impacts, both positive and negative, that DER has on non-DER customers. 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 are 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 utility 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 to identify 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 adoption levels, whether system-wide or at the feeder level.

It is helpful to divide the potential for increases and decreases in infrastructure investment across the different functions of the utility 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.[109] 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 capac-

109 See Lazar and Gonzalez, "Smart Rate Design," 43.

ity. If the DER offsets usage more evenly, it can avoid investment in more expensive baseload plants.

Conversely, depending on its nature, DER could require increased investment in generation units to make up the difference for intermittent resources[110] or to meet the generation flexibility requirements of a large ramp-up in demand.[111]

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 that may otherwise require expensive upgrades.[112] At higher adoption levels of DER, however, additional costs may be incurred to upgrade the distribution system to act as step-up facilities. Adequate system and resource planning may assist in mitigating the potential higher system costs by allowing the utility to better target necessary upgrades, avoiding unnecessary investments and utilizing DER to make more efficient use of existing assets.

2. Revenue Recovery Shifting Due to Recovery of Fixed Costs through a Volumetric Rate

One potential detriment to other customers of DER is revenue recovery 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

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110 *Id.*, 63–5.

111 Rocky Mountain Institute, eLab, "Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future" (Rocky Mountain Institute, eLab, Boulder, CO, 2016), 16.

112 *See, e.g.*, ConEdison's Distribution Load Relief Program. ConEdison, "Demand Response Programs Details," http://www.coned.com/energyefficiency/demand_response_program_details.asp.

reduced by DER. These costs could be considered stranded costs and 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 from cost shifts related to any other change in usage by a customer, or that the impact to other customers is minimal, and should therefore not be dealt with in a non-traditional way.

To the extent that DER reduces a customer's usage, that customer is less reliant on the utility for its energy needs. This reduction in usage may have a corresponding reduction in costs, most certainly a reduction in variable costs. 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[113]).

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 costs are recovered through volumetric rates, 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.

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113 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.

4. The 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 V, 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. A regulator should also investigate whether adoption of certain DER, such as solar PV, is concentrated in wealthier- or above-average-income zip codes. If this is the case, the customers that then may be subject to any potential rate increase that may occur so the utility can earn its authorized revenue requirement are those less able than DER customers to shoulder that burden. A regulator should ascertain whether this is happening, and may wish to consider fairness or equitable treatment across income levels as part of its rate-making decisions.[114]

Others worry that the cost of remaining tied to the grid 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, rather than just a portion, of costs previ-

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114 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.

ously 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 would 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 that may not have in the absence of the previous cost shifts.

6. Lifespan of Utility Assets Does Not Match Lifespan of DER

The lifespan of certain DER systems is generally 20–30 years (and may be less for individual parts such as the inverter, and output may decrease over time), which may be significantly shorter than the distribution and transmission investments made by the utility to serve a customer. How to plan for the asset lifespan poses an interesting problem for arises regarding utility system planning.[115] A regulator must question how best to make the value of those assets match. Some types of DER, like DR and EE, generally affect demand and have different expected lifespans than other types of DER, like solar PV, which affects supply.

7. Stranded Costs and Dealing with Them

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

115 A regulator can compare the average service lives for FERC Accounts 361 to 369 for its distribution company providers to ascertain the difference for each utility or provider. An example from Nevada Power Company and Sierra Pacific Power Company shows accounts range from 38 to 70 years. See Attachment AED-4, Docket Nos. 15-07041 & 15-07042.

stranded, at least in the short term to mid-term until rates are re-set.[116] 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 that were previously responsible for them. This was the route taken by some jurisdictions with the advent of deregulation of power supply. This treatment only encompasses those customers whose usage was reduced by DER, not those customers that 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.

Keeping People Connected

It is believed that keeping people connected to the grid creates additional value to the customer, the utility, and society in general. This belief mimics a variety of so-called "laws," such as Metcalfe's law and Reed's law, which all posit that the value of a network increases the more things (or people) that are connected to it. On the electric utility side, it seems apparent that having more devices connected to the grid inherently enhances the value of the grid and the devices connected to it. If nothing else, having less people connected to the grid would seem to decrease the value of the grid. This is important because if customers decide to disconnect from the grid due to policies discouraging DER or erecting barriers to entry for DER, the costs of maintaining that system falls onto fewer and fewer customers; thus, the value of the grid is minimized. Therefore, it is important to recognize that there is a value from the grid not only for the provision of electric service, but also for enabling and integrating a greater number of devices that can be utilized by a greater number of other devices and customers connected to the grid.

116 While the term "stranded costs" may be used to refer to customer-specific investments that are not paid for by a customer that leaves the utility's service, it is used here to describe more general costs incurred (at least partially) to serve a given customer.

G. 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, and when, the resource exports electricity 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.[117] 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. On the other hand, DER can also provide the utility with an opportunity to operate its system more efficiently at a lower total cost, if DER can be integrated with a utility's operations and planning.

H. Cross Subsidies, Including Cross-Class

Cross subsidies, subsidies from one group of ratepayers to another, are endemic in all utility rate making as there are variations in consumption patterns within rate classes that cause one part of a rate class to subsidize another part, as well as differences among classes due not only to differential use but also differential impacts of utility rates. The classic cross-class subsidy is for C&I rate classes to subsidize the residential class (i.e., there are differential impacts of electricity costs). In the case of DER-owning customers, there is now a group of customers that differs significantly in both usage patterns and the effects of rate levels on decision making from others in the same class. Eliminating, or at least minimizing, the potential intra-class cross subsidies

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117 An additional consideration is whether the DER is acting in a coordinated or uncoordinated manner with the distribution utility.

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. Reducing intra-class subsidies would minimize lower-income ratepayers from subsidizing higher-income ratepayers.[118]

Cross subsidies affect restructured jurisdictions differently than they affect vertically integrated jurisdictions. Conceptually, it is easier to deal with cross subsidies in restructured jurisdictions; therefore, 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.

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 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 what is required to supply the customer's annual demand. A system sized this way 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.

118 Increasing subsidies to lower-income ratepayers so they can invest in DER may reduce the inequality but exacerbate any efficiency reducing subsidy effects.

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 or 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, or
  - ◊ having 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 method would be 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. It is easier to identify when subsidies exist when NEM credits are denominated in currency than when they show up as kWh credits. For distribution costs, the important thing for economic efficiency is to have distribution rates based on cost causation. Energy throughput is not necessarily 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 as the need to educate customers on what is a kilowatt, how demand rates operate, and the 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 the utility has an opportunity to recover those investments, including a return on prudent investments through authorized rates it charges to its customers. The increased adoption of DER may complicate that relationship. A utility has an obligation to serve, and that includes the full needs of DER customers. However, DER customers who supply most, if not all, of their own needs annually, but not necessarily daily, may be undercompensating the utility under certain NEM rate designs for the generation, transmission, and distribution investments that were 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. The solution would be to design rates that recover from DER customers an appropriate amount to compensate the utility for the investments it has made. The key question here is how to determine the appropriate amount. Utilities often claim that they need to be able to supply their DER customers' entire need 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, should a commission determine to do so after examining the data and evidence. Such a charge can be fixed (e.g., interconnection charges), equivalent to a demand charge, or variable, but should be designed to appropriately compensate the utility for the provision of distribution services.

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 is related to situations when 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 C&I load and only 20 percent in residential load, but all the NEM customers are residential and the costs of NEM subsidies (i.e., the cost of net positive NEM are spread across all ratepayers), customers within the residential class are receiving all the benefits, but the customer class is 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. A potential solution to this would be 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 the remaining ratepayers to fund those social or governmental programs.

I. Grandfathering or Transitioning

A regulator may need to determine whether it is in the public interest to transition DER customers from their current rate schedule to a new rate schedule or to allow the DER customer to be "grandfathered" in the existing rate schedule.

The choice of how or whether to transition customers from one rate schedule to a separate rate schedule depends on numerous factors, including, but not limited to, the following:

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

Assuming the regulator has the authority to determine these factors, there are arguments for treating DER customers both similarly and differently. In either case, the regulator must assess which rate best meets it goals and results in a fair and equitable cost and benefit allocation.

The primary argument 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 or desire using rate making as a policy and technology support tool. Also, if a jurisdiction allows third-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 that lease or contract, usually with a contract/lease term of 15 to 30 years.[119] DER customers may have the expectation from the third 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. The regulator must decide if those expectations are reasonable and were endorsed, 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 or any statutory construct.

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, 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 DER customers into an existing rate provides 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

119 http://www.solarcity.com/residential/how-much-do-solar-panels-cost.

be met. Finally, keeping DER customers on a single rate regime as other customers comports with the rate design attributes of being simple and convenient.

What follows are counter arguments to grandfathering customers onto a rate regime: (1) If the rate recovery from those customers is not effective at yielding revenue requirements, a separate rate regime may better yield that result.[120] (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 over time. (3) Rates are conventionally subject to change, unlike contracts. (4) Depending on the usage, load, or cost characteristics, keeping DER customers on a prior 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, or 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 the horizontal equity principle of Bonbright (similarly situated customers should be treated similarly). In practical terms, this means that a commission should design 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? Regulators and consumer advocates should consider providing some form of public information or outreach programs to clearly explain to all ratepayers these potential effects, immediately and before the time any rate design change is implemented.[121]

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120 Conversely, if DER customers generate benefits for other customers, those customers should realize those benefits and could be reflected in separate rates.

121 Additionally, when making decisions related to DER, customers may lack sufficient education

States that implemented some sort of grandfathering regime, either via legislature or via the regulator, include the following:

- California implemented grandfathering for a 20-year period for both NEM 1.0 customers and new customers taking service under the NEM 2.0 tariff.[122]
- Kansas grandfathered customers that began operating a renewable energy resource before July 1, 2014, for 15 years until December 31, 2029.[123]
- Nevada agreed to a 20-year grandfathering period for customers that had installed or had active applications before December 31, 2015.[124]

If a regulator determines that a grandfathering period is reasonable, it must also determine how it should be implemented. The following sections describe possible considerations.

1. Payback Periods

What expectation did customers have regarding the length of time the rate regime would be used? What expectation did the utility or third-party provider have? Before 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 customer's decision regarding whether to make the investment in a DER. The use of effective, appropriate, and

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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.

122 *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 Energy Metering,* "Decision Adopting Successor to Net Energy Metering Tariff," D.16-01-044, California PUC (January 28, 2016).

123 Kan. Stat. Ann. §§ 66-1265 and 66-1266 (2015).

124 *Application of Nevada Power Company d/b/a NV Energy filed under Advice Letter No. 466 to revise Tariff No. 1-B to modify Net Metering Rider-A Schedule NMR-A to establish separate rates for grandfathered private generation customers,* "Order," Nevada PUC, Docket Nos. 16-07028 and 16-07029 (September 21, 2016).

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. The choice for a customer to invest in DER is made only once; subsequent rate changes can affect customer investment and behavior only going forward, but not the choice to invest or not invest in DER. Additionally, the payback period is an individual decision and varies depending on if the DER system was a purchase/install, Power Purchase Agreement, or lease agreement, 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.

Other factors that are important for consideration by a customer before investing in DER 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 the system, the customer's average and annual electricity use and current and projected cost per kilowatt hour, 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 DER system or the length of the lease contract.[125]

2. Type and Degree of Rate Change

Are the changes between rate regimes mild or severe? Are there ways to mitigate the severity of these changes, such as staggering the implementation dates? How are different customers within the rate class affected by the rate regimes (e.g., are high users and low users affected differently)?

3. Differential DER Customers

What data should be used if rate regimes experience a significant

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125 Claudette Hanks Reichel, "Solar Power for Your Home: A Consumer's Guide" (Louisiana State University AgCenter, Baton Rouge, LA, 2015), http://www.lsuagcenter.com/~/media/system/e/4/8/8/e48836bdb7da5028f3116b6531b344d7/pub3366solarpowerforyourhome2.pdf.

change? Is the use of a proxy group in that circumstance appropriate? Does the utility have the appropriate billing structure to distinguish between different types or generations of DER customers? 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 to make its system larger and have the additions also be compensated under the grandfathered rate? Is there a limit that the regulator should set on additions or replacements, and how should that be enforced?

6. Other Considerations

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 help guide this decision?

V. Rate Design and Compensation: Mechanisms and Methodologies

As discussed previously, the growth of DER across the country and its impacts on the current utility business model are increasing every day. Regulators are often tasked with two, potentially competing, goals: (1) ensuring the financial health and viability of the regulated electric utility; and (2) developing policies, rates, and compensation methodologies for DER. This section outlines several options that a regulator may consider as an appropriate rate design for customers to address the impact of DER. Additionally, this section discusses a variety of compensation methodologies for DER. It is possible that a regulator may choose to implement one or more of these at a time. Additionally, it is important to note that a regulator maintain flexibility in determining the rate design and compensation policy, as changes in the market, policy, law, and technology evolve over time. Understanding this evolution will assist the regulator in recognizing that the appropriate compensation methodology may require changing over time.

This chapter lays out the pros and cons of a variety of options related to rate design and compensation. There are options not discussed in this section that may be appropriate for a particular jurisdiction; the options described in this chapter are certainly not the only ways of addressing this discussion. A jurisdiction may decide to keep its current rate design and implement something in section B; likewise, it is possible for a jurisdiction to simply use the rate design (and other options, such as decoupling) to meet its needs in regards to DER.

A. Rate Design Options

More traditional rate designs, as discussed in section II, may provide a reasonable first step, such as first considering TOU. Due to the in-depth discussion in section II, there is no need to restate that here. Instead, this section will detail several rate design options beyond the traditional flat rates and time-variant rates. However, a user of this document may wish to mix and match the traditional types of rate designs, such as a TOU, with options in either the rate design or the compensation sections. Examples of this can be found in California and Hawaii, which are moving toward default TOU for customers in response to the increased amounts of solar PV in their states. The right mix of options is best determined by the particular jurisdiction.

1. Demand Charges

This rate design method charges customers based on their rate of usage, measured in KW, rather than total volume of usage (i.e., kWh). Regulators have used demand charges historically to recover generation capacity, transmission capacity, or distribution system costs from customers, primarily C&I customers, and some also have experience with using demand on a class-wide basis for cost allocation.

Demand charges have increased in popularity in a relatively short period of time. The majority of the applications being discussed and proposed across the nation feature demand charges as mandatory or opt-out rates for residential and small commercial customers. This interest has largely been driven by DER's potential effect on utility cost recovery, since kW-based charges cannot be offset by NEM rates or similar programs, as well as by greater adoption of AMI and enabling technology.

As of the writing of this Manual, very little empirical data exist on impacts of demand charges on residential and small commercial customers, and no investor-owned utility currently uses a mandatory, or opt-out, demand charge, although several have proposed them.[126] Demand charges themselves can represent significant cost shifting, so regulators should be extra cautious in their development and implementation, ensuring they understand the implications of the charges for their jurisdictions and the rate's advantages (and

126 Rocky Mountain Institute, "A Review of Alternative Rate Designs" (Rocky Mountain Institute, Boulder, CO 2016).

disadvantages) over alternatives.[127,128]

Demand charges can be structured many different ways and they vary widely in their purpose, in their effect, and in the price signal they send.[129] Therefore, when considering implementing a demand charge, regulators must be comfortable with and clear on the costs they would like to recover, the price signals they would like to send, which principles of rate design they emphasize and why, and their plan for implementation.

In general, customers' understanding of, and their ability to react to, demand charges represents a challenge.[130] Opponents and proponents of demand charges both agree that significant customer education is key if implementing these rates and that regulators should employ pilot programs or shadow billing over a multi-year rollout.[131]

a. Historical Use of Demand Charges

Demand charges have long been used in commercial and industrial customer class rates, as these customers are generally more sophisticated, with better load factors and control of their usage.[132] Though there has been some experience with opt-in residential programs, historically, demand charges have not been applied to other customer classes.

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127 Jim Lazar, "Use Great Caution in Design of Residential Demand Charges" (Regulatory Assistance Project, Montpelier, VT, 2016), 13.

128 An alternative regulators should examine is satisfying the temporal changes in cost causation through TOU charges (with decoupling if revenue erosion or cost recovery is a serious issue). TOU charges may better reflect the cost structure of electricity for a majority of demand costs on a system, especially compared with non-coincident demand charges.

129 Since the increased interest in these rates is new, and due to lack of data and experience concerning residential and small commercial demand charges, this section of the Manual is relatively longer to provide additional information for regulators.

130 Paul Chernick, *et al.*, "Charge without a Cause? Assessing Electric Utility Demand Charges on Small Customers" (Electricity Policy, Portland, OR, August 2016).

131 EEI Primer, 11; Solar Energy Industries Association, et al., "Rate Design"; Ryan Hledik, "The Top 10 Questions about Demand Charges" (presentation at the EUCI Residential Demand Charges Symposium, Denver, CO, May 2015).

132 Ahmad Faruqui, *et al.*, "Curating the Future of Rate Design for Residential Customer" (Electricity Policy, Portland, OR, July 2016).

When used as a billing determinant for customers, 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. These charges endeavor to measure the "size of the pipe," or capacity needs of a customer, and in their purest form endeavor to measure a customer's contribution to the system's various peaks, and thus—to the extent that these costs are not fixed—the driver of the system's size and the resulting costs.

Utilities calculate demand charges as the rate at which a customer draws from the system, measured in kW, during a certain time period (e.g., during a coincident peak of the system, over all afternoon hours, over a seasonal period, during all hours) using the single highest peak of instantaneous demand, or combination of multiple peaks; or, more often, by using the customer's usage averaged over one or more measurement intervals (i.e., usually 15, 30, or 60 minutes) during the period in question.[133] A measurement interval is often used so that short-term demand spikes have less of an effect than sustained higher levels of usage.[134]

Even though annual demand on a class-wide basis is most often used to allocate costs,[135] when proposed or used in a residential context, demand charges are often included as a percentage of the delivery portion of a customer's bill and are measured and applied on a relatively more frequent basis, usually monthly, to increase bill stability and allow customers to react more frequently to price signals.[136] Utilities sometimes add a mechanism called a "ratchet," described further below. In some foreign countries, some utilities use pre-set demand levels, called "ex ante,"[137] by Rocky Mountain Institute (RMI) or

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133 Rocky Mountain Institute, "Review of Alternative Rate Designs."

134 Hledik, "Top 10 Questions," 13 ("precision" vs. customer bill stability).

135 Migden-Ostrander and Shenot, "Designing Tariffs," 29 ("It could even be argued that to the extent that interval data is not used as the basis for allocating demand costs in the cost-of-service study, rates should not be designed using data that conflicts with the data used to allocate the costs to be recovered in those rates.").

136 Rocky Mountain Institute, "Review of Alternative Rate Designs."

137 As opposed to the demand charges described above, which RMI calls "ex post."

a demand subscription, in which a circuit breaker is tripped, demand limited, or extra fees assigned if customers go over a pre-set kW level.

If the rates are properly understood by customers and loads can be shifted to outside the measured time period, 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. But how, when, and how often this demand is calculated can vary in practice and jurisdictions.

Some Examples of Demand Charges

- Arizona Public Service recovers for generation capacity, transmission, and distribution charges on an opt-in basis combined with a seasonal TOU rate. A customer's demand is calculated monthly as usage divided over a one-hour interval coincident with the highest seven hours of system peak. It has two seasons, with the summer peak running from May through October.
- Burbank Water & Power's Basic Service Rate recovers a preset level for a service size charge, which is the customer's service drop and last transformer based on the maximum possible demand.
- ComEd uses a customer's coincident demand to calculate a volumetric capacity charge: the following year's generation and transmission capacity charges for a residential real-time pricing program are calculated by taking whichever is higher, the customer's highest electrical demand coincident with the five highest hours of overall system demand in PJM or 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.

b. Rationale For and Against Demand Charges

Proponents of demand charges outline several reasons for the rates. The Edison Electric Institute advocates for demand charges, saying the "primary function of the demand charge is to accurately convey the cost structure of electricity to customers so that they can make informed decisions about how much power to consume and at what time."[138]

Other advocates state that the demand charges better reflect cost causation, or the driver of a utilities cost, than a volumetric rate does. Many argue this is because a utility's generation capac-

138 EEI Primer, 6-7 ("Whether customers reduce demand on response to a demand charge is a secondary benefit.").

ity and distribution costs do not increase and decrease with changes in the total volume of usage.[139] To many proponents, the short-run costs of the distribution system are fixed in nature, and as such these "sunk" costs should be split among customers in the same rate class based on their demand, regardless if their demand contributes to a system or local peak.[140] Utilities and other advocates of demand charges generally prioritize revenue recovery and stability in rate design by orienting the cost allocation and rate design process to look backward in time to recover the embedded cost that the utility prudently spent to provide service. Other proponents argue that low load factors, regardless of whether they contribute to a system or local peak, result in higher costs to the utility.[141]

Additionally, advocates argue that demand charges are a rate the industry is familiar with, and therefore are a well-tested model with a small learning curve.[142]

Theoretically, one of the main advantages of demand charges seems to be the greater revenue certainty, especially for certain forms of non-coincident rates, which improves the chances for full recovery of a utility's authorized return. This is mainly due to the costs being recovered based on individual peaks, which are relatively inelastic as compared with the overall volume of usage, which can vary greatly from year-to-year, largely due to weather, energy efficiencies and building standards, and customer behavioral changes.[143] In this way, these rates can reduce risk for the utility. Further, in line with utility desire for improved revenue stability, some advocates call demand charges a good "middle ground" or a compromise between higher fixed charges and pure

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139 Faruqui, *et al.*, "Curating the Future."

140 *Id.*; Leland Snook and Meghan Grabel, "There and Back Again" (*Public Utilities Fortnightly*, Reston, VA, November 2015), 48–49 ("almost 70% of the costs to serve APS's residential customers are fixed infrastructure costs").

141 Southern Company, "Comments on Draft NARUC *Manual on DER Compensation*" at 5 (September 2, 2016).

142 Hledik, "Top 10 Questions," 13.

143 Faruqui, et al., "Curating the Future."

kWh-volumetric pricing.[144]

Demand charges also have the potential to be an avenue to reduce the cost shifting illustrated in historical rates concerning DG customers (i.e., NEM). Some utilities have specifically proposed using demand charges to replace volumetric charges in distribution system cost recovery, leaving NEM rates to affect only the energy portion. Since the NEM rates usually provide a credit against consumption on a volumetric basis, charging a residential customer its distribution costs through KW-based rates eliminates the possibility that NEM compensation is shifting those costs. This practice, however, would not compensate nor charge DER customers for any benefits, or additional costs, they represent to the grid.

However, as opponents argue and proponents agree, there are many unknowns and much uncertainty surrounding the use of demand charges on classes other than C&I—mainly regarding customer impacts. Empirical data on the impacts as well as customer acceptance and responses to residential and small commercial demand charges are insufficient.[145] In a review of residential demand charge rate designs, RMI identified only 25 demand charge rates offered to residential customers, and none of them were large investor-owned utilities implementing mandatory demand charges for residential or small commercial customers.[146]

Opponents urge great caution in using these rates, as they state severe cost shifting can occur.[147] They also generally state that the primary function of demand charges, namely temporal differences in cost causation, can be better conveyed through other mechanisms. These parties assert traditional demand charges overcharge low-use customers, which tend to have lower load factors

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144 Jeff Zethmayr, "Bill Effects of Demand-Based Rates on Commonwealth Edison Residential Customers" (Electricity Policy, Portland, OR, July 2016).

145 Rocky Mountain Institute, "Review of Alternative Rate Designs"; Hledik, "Top 10 Questions"; Solar Energy Industries Association, "Rate Design."

146 Rocky Mountain Institute, "Review of Alternative Rate Designs," 57.

147 Lazar, "Use Great Caution."

but ones that often peak at times that do not contribute to system peaks. This stems from the fact that residential customers are much more diverse in their usage and thus tend to share capacity, especially multi-family customers, whose demand is met in the aggregate and not on an individualized basis.[148]

Opponents tend to generally approach rate design and cost recovery not from a backward-looking orientation that seeks to recover the sunk embedded costs already spent, but from a forward-looking marginal cost perspective that sees all costs as variable, but on a short-run and a long-run basis. Proponents agree these principles are theoretically sound.[149] These topics are addressed other places in this Manual and in the NARUC *Electric Utility Cost Allocation Manual*.

Opponents also argue that demand rates do not have an actionable price signal and are confusing to customers. Indeed, economists, such as UC Berkeley Professor Severin Borenstein, state, "It is unclear why demand charges still exist."[150] They assert the charges are poorly understood by customers as compared with volumetric rates, and therefore struggle to adequately convey an understandable price signal. Even if they did better reflect utility costs and represent a clear price signal, demand charge signals are most likely not sufficiently actionable for customers without demand limiters, expensive technology, or drastic behavioral changes.[151] Thus, lower-income customers may be disproportionally affected as they may have less control over peak demand usage. This signal could be further obfuscated as there is a smaller margin for customer error; higher bills can be earned through a shorter time frame of a lapse of attention (e.g., too many appliances on at once) or a one-off

148 *Id.;* Lazar and Gonzalez, "Smart Rate Design"; Chernick, et al., "Charge without a Cause?"; Coley Girouard, "Do Demand Charges Make Sense for Residential Customers?" (Advanced Energy Economy: Washington, D.C., June 21, 2016), http://blog.aee.net/do-demand-charges-make-sense-for-residential-customers.

149 Edison Electric Institute, "Comments of the Edison Electric Institute on the National Association of Regulatory Utility Commissioners' Draft Manual on Distributed Energy Resources Compensation" (Edison Electric Institute, Washington, D.C., September 2, 2016), 9.

150 Borenstein, "Economics of Fixed Cost Recovery," 16.

151 Chernick, et al., "Charge without a Cause?"

event such as a house guest, which can also result in the possibility of higher bill volatility from month to month.[152] Further, to the extent that demand charge structures may encourage reduction in peak (depending on how peak is defined), it potentially lacks an adequate conservation signal to reduce usage.

Importantly, many parties on all sides of the issue seem to recognize the potential for using demand charges sparingly (e.g., to represent a dollar or two on an average bill for customer-specific, local costs, such as the last transformer) and when measuring demand coincident with system peaks,[153] 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.

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.

c. Considerations in Demand Charges

As with many of the various 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. Once a jurisdiction has the technology to meter on a demand or interval basis, then regulators can examine demand charges and explore the purpose, price signals, and relative emphasis of rate design principles they could then enshrine in these rates.[154] The effects of a customer's demand seem to be clearer for generation capacity and transmission, which can be tied to larger peaks like the entire system, but when talking about the distribution system, the effects of a customer's demand on the system could be less clear. Furthermore, as Borenstein states, "the single

152 Rocky Mountain Institute, "Review of Alternative Rate Designs."

153 Lazar and Gonzalez, "Smart Rate Design."

154 Lazar's three-part rates found in Regulatory Assistance Project's materials might be a good starting point. Once a path is decided, it should be compared with alternatives. For instance, Lazar points out that compared with large demand charges, time-varying rates result in more equitable cost allocation, reduce bill volatility, and improve customer understanding. See Lazar, "Use Great Caution," 13.

highest consumption hour of the billing period is not the only, and may not even be the primary, determinant of the customer's overall contribution to the need for generation, transmission and distribution capacity."[155]

Unfortunately, analyzing the implications of the various forms and magnitude (or the level of revenue, or cost recovery components, being sought through the charge) of demand charges is currently difficult. Thus, regulators should be wary of relying on unsupported benefits as evidence and be cautious when plausible harm may represent itself. More data should be available in the future as several utilities have submitted proposals for mandatory and opt-out demand charges to regulators and legislators. In the meantime, regulators should also be cautious of proponents using the outcomes from opt-in tariffs as evidence or proxy for mandatory or opt-out tariffs, as the historical rates can suffer from self-selection bias and their customers have been reported to be significantly larger than average.[156]

Both increasing adoption of DER and moving beyond traditional, two-part (volumetric and fixed charge, or straight fixed variable) rates should require regulators to increase their visibility into, and their planning for, the relevant distribution system and the effects of individual customer usage patterns on its different levels. As discussed, this requirement is embodied in the changing landscape for electricity in the country. As such, regulators may find that their legacy processes, such as allocating cost by demand, do not easily translate into support for charges on an individual basis and that changes might be required.

It is relatively clear how demand charges benefit utilities with revenue stability. On the customer side, if done appropriately and properly understood, a rate's price signal could help contribute proportionally to reducing the peaks, which 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 incorpo-

155 Borenstein, "Economics of Fixed Cost Recovery," 16.

156 Hledik, "Top 10 Questions," 6.

rate any distribution savings in new rate proceedings. Ideally, any demand charges regulators implement should have clear, transparent support detailing the relevant peaks they are targeting to reduce; the costs caused by the individual's usage contributing to that peak; and how they will pass on the system savings, if any, resulting from demand reductions to customers, if not already automatic. These elements should come naturally from a more detailed look into the distribution systems and the pressure DER can place on them and the benefits DER can provide.

Demand charges' relation to cost causation for distribution systems can present a challenge. Whether a specific demand charge better aligns bill impacts with cost causation depends greatly on the structure of the charge and the jurisdiction's unique legacy processes and physical grid. The question becomes, in that unique situation, what effects an individual's usage, both rate and timing, has on the costs of the various components of the grid, and subsequently what is the best way of presenting those costs to the customer. In general, regulators should be wary of arguments, for or against, that conflate more efficient economic signals and alignment with cost causation with an individual's non-coincident peak maximum demand, unless backed up with detailed evidence and testimony.[157] Regulators may find, as some opponents have argued, that lower load factors result in higher costs for the utility, regardless of when the peaks occur.[158] However, it is questionable whether demand not aligned with a specific peak could drive distribution costs beyond their immediate surroundings, and if they do, whether it would be prudent to charge customers for it.

Regulators should remember that, to a certain extent, intra-class subsidies are unavoidable as, for example, it often costs more to deliver power on a

157 Discussed more below.

158 It certainly is understandable why, from a utility's perspective, a low-load-factor customer could represent "money left on the table" if it is paying volumetric rates. Conceivably it could be paying more for distribution if charged by peak than volume. But for this discussion it is relevant only to the extent that a load factor (without factoring in any temporal considerations) drives costs. This seems to be unlikely, and to the extent it would be true, would be coincidental.

per customer and per demand basis in rural areas compared with suburban or urban areas. Regulators should endeavor to ensure that any move to demand charges does not represent an undue burden on the customers that are, on an individual basis, actually the lowest cost to serve (e.g., multifamily customers in dense urban areas), nor burden the customers that are most expensive with costs that have historically been socialized for policy reasons (e.g., large, single-family rural customers).

Ultimately, the effects of increased DER adoption or future adoption do not obligate or require regulators to utilize demand charges, and it seems that, at a minimum, demand charges, if a large portion of a customer's distribution bill, would over-collect customer costs as demand costs.[159] In some respects, these conversations may mirror regulators' straight fixed variable discussions. Regulators may find large or non-coincident peak demand charges operate more like a fixed charge (as the "middle ground" or "compromise" argument from proponents highlights), which should, therefore, be avoided for similar reasons as to why the alleged high percentages of fixed electricity costs stemming from infrastructure are not currently fully recovered in a fixed charge.[160]

Finally, as mentioned before, regulators should be cautious if implementing demand charges to protect a utility's revenue recovery for the distribution grid is the goal, especially if the DER benefits to the grid are not accounted for in any way. In the example of combining demand charges with an NEM rate, the regulator may simply be layering one proxy, or imperfect solution, over another without addressing the underlying threats and opportunities for their distribution system. Implementing large or non-coincident peak demand charges for an entire residential or small commercial rate class to counter perceived cost shifting from a limited set of actors would most likely be a disproportional response if adoption rates are low or under, say, 10 percent.

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159 NARUC, *Electric Utility Cost Allocation Manual.*

160 EEI Primer, 13. *See also* sections on fixed charges and rates theory for more discussion.

d. Demand Charge Structures

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 as problems for C&I classes. Each of these choices can represent very different impacts, customer experience, and policy implications:

i. Classifying users into classes on a type basis, locational basis, or individual basis

These considerations shape how costs will be allocated between these classes. They would also dictate who a customer would be compared with when determining the relevant portion of demand costs for which it is responsible (*i.e.*, the amount of the billing determinants).

ii. Assigning the magnitude or scope of the charges

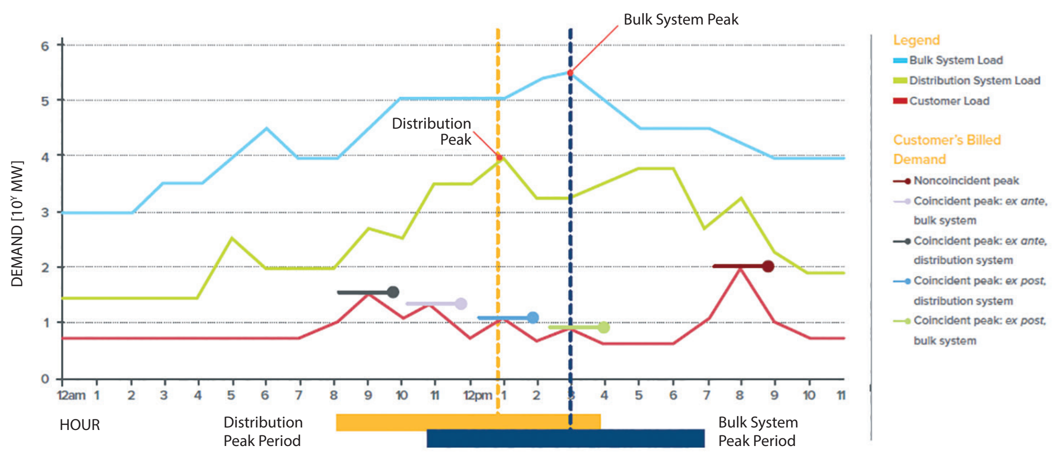
These considerations shape how much of a class's revenue requirement will be recovered through a demand charge. Is it a broad, or large, charge that recovers all demand-related costs from generation capacity down to all distribution costs, or on the opposite side of the spectrum, is it a small charge that recovers customer-specific, local transformer costs only? Again, differences within this range greatly affect the rationale and impact of these rates.

iii. Defining the relevant peak

Due to the smaller locational nature of the distribution system, utilities and regulations need to determine what geographic area 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 geographic area (e.g., substation or feeder level)? Additionally, certain distribution costs are driven not by demand, but by the number of customers, geographic circumstances, customer density, or other factors. A class peak could also be used since it is often the basis on which costs are allocated. The image below, from RMI, illustrates this.[161]

Illustrative Effect of Peak Coincidence on Measured Customer Peak Load

For a given time period, a customer's billed demand can vary significantly, depending on which peak-coincidence option is used.



Source: RMI

iv. Use of coincidental or non-coincidental peak

Is the demand measured coincident or non-coincident with the system peak? Are different customers' demands measured concurrently at a set point in time, often when usage is highest on a part of, or for the entire system (system peak), or is an individual customer's maximum usage measured regardless of the situation on the rest of the system?

e. Coincident Peak Considerations

Using a coincident peak method better aligns the demand charge with

161 Rocky Mountain Institute, "Review of Alternative Rate Designs," 59 (used with permission of RMI).

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 bill 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 a system peak, the utility runs the risk of choosing the wrong day or time, or both, which would then mitigate the economic signal the demand charge intends to reflect.

It must be mentioned that true marginal cost pricing using a coincident peak methodology based on annual cycles is basically impossible to implement since the various levels of the distribution system can peak at wildly different times, which can lead to varying and potentially very high customer bills as utilities collect substantial revenues in a single billing cycle. Understandably, regulators have, to date, declined to allow utilities 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.

f. Non-Coincidental Peak Considerations

Use of non-coincidental peak methods 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.[162] 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 percent of them base the charges on a residential

162 Alfred E. Kahn, *The Economics of Regulation* (The MIT Press, Cambridge, 1988), 96 (calling non-coincidental peak rates "illogical" and reiterating that it is consumption at the system's peak that determines how much capacity the utility must have available). *See also* Faruqui, *et al.*, "Curating the Future," 9 (Professor Bonbright quoting D.J. Bolton: "The effective power demand on the system made by any particular consumer is . . . very different from the individual maximum demand metered at the consumer's terminals.").

customer's non-coincident peak.[163] 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."[164,165]

Practically, as a demand charge becomes less coincident with peak and more non-coincident (i.e., if the peak measured the customer's maximum and the period measured approaches all hours), while the charge may become easier to implement and understand, it becomes closer in purpose and effect to a fixed charge, albeit one that is kW-based and not volumetric based. The charge would also concurrently move away from cost-causation principles.

However, if non-coincident peak is used, there are methods that can better align costs. The following are 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, business hours, or afternoon hours)? (2) What days are measured (weekdays, weekends)? The longer the period measured in a non-coincident rate the harder it is for a customer to shift its peak outside of that time period and the more the rate acts like a fixed charge. For example, a customer that welds or uses a pottery kiln in the middle of the night during a 24-hour measurement period may pay the same as if the activity was during a system peak.

g. Other Considerations in the Calculation of Demand Charges

There are multiple considerations under this criteria, including how often the calculation is performed; how long the measurement interval is; if one peak interval or multiple peaks averaged are used; and if a ratchet from a

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163 Rocky Mountain Institute, "Review of Alternative Rate Designs," 57.

164 *Id.*

165 For example, if a utility proposes a non-coincident peak charge that measures a customer's highest 30 minutes of usage during weekdays between 6 a.m. and 9 p.m., or 16 hours per weekday, that equals thirty-two 30-minute measurement intervals per day. During a monthly billing cycle that has 22 work days, there are 704 intervals in which a customer's individual maximum demand could fall, greatly reducing the chances that it would align with any peak beyond the immediate surroundings (*i.e.*, service drop, and possibly last transformer).

previous billing period, or periods, is included in whole or in some ratio.

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 one of the C&I models in which a system's total peak is measured once a year and an individual customer's 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. If the kW peak is calculated by averaging usage over a measurement interval, then the longer the relevant interval, the more short lived spikes (e.g., from a hair dryer or welder) can be smoothed out and generally the lower the kW amount (e.g., a spike during a 15-minute time span would represent a larger demand than if the relevant time span was 30 or 60 minutes). Some parties, including opponents of demand charges, have questioned whether intervals shorter than 60 minutes give typical customers enough time to adjust their demand and caution that short intervals may effectively function as a fixed charge that varies from month to month.[166] The illustration below, shows how longer measurement intervals affect a customer's peak demand.[167]

If instantaneous demand or a measurement interval is used, then is it the customer's single highest peak that is used to set the charge for the next billing period or are multiple peaks used? Again, the addition of multiple peaks should represent the opportunity for the customer to shield its bill from one-off events leading to high usage, such as a dinner party or afternoon playdate for kids or teens.

Should a ratchet, or a peak or peaks from a previous billing period, be used in calculating a customer's demand charge? Many existing examples use the preceding 11 to 12 months, but fewer months could be used or seasonal

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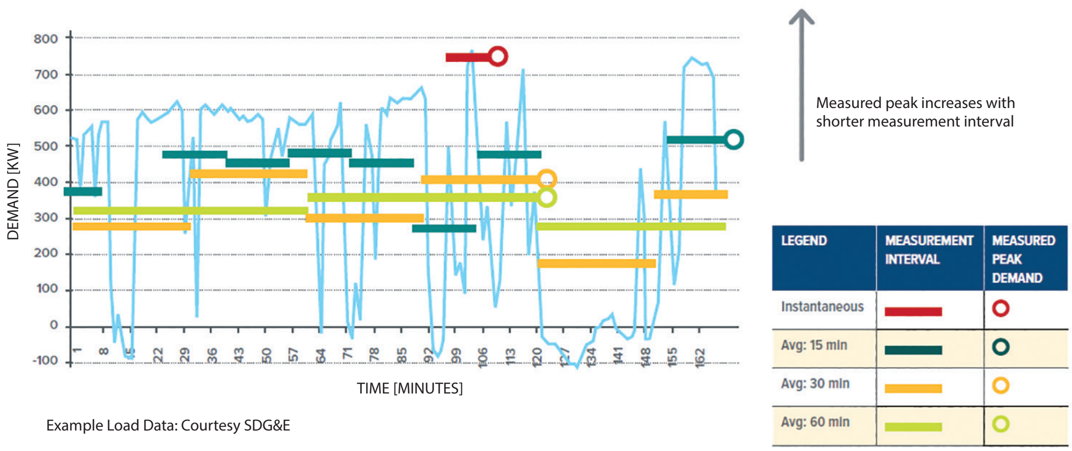
166 Rocky Mountain Institute, "Review of Alternative Rate Designs," 61.

167 *Id.*, 62 (used with permission of RMI).

Illustrative Effect of Different Measurement Intervals on Customer Peak Load

A longer measurement interval can be used to smooth the apparent load and reduce measured peak demand.



Source: RMI

blocks can be used (e.g., the previous June, July, and August maximums). Those previous months' demand used in the calculation can also be de-rated (e.g., 100 percent of last month's demand and 80 percent of the previous 11 months).[168] Using a ratchet should theoretically reduce the volatility for both utilities and customers alike, but also reduce a customer's ability to have a clear price signal and to be able to react to that and potentially save on its bill. A ratchet could make a rate closer to an unmoving, fixed charge.

As mentioned throughout this section, data supporting the theory behind these considerations when used on a mandatory basis for residential and small commercial customers are currently insufficient. Regulators must thoroughly work through the implications of any of these considerations

168 *Id.*, 69.

before phasing them in for their jurisdiction.

h. 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, if any. These results do affect customers with different resources in different ways. Generally, and especially for PV and other DG and EE 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 charge rates would generally decrease the return on the investment for DERs and reduce the attractiveness of customers investing in these technologies and in doing so may reduce adoption rates of technology that might be net beneficial for the utility and customers.

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 that flexibly and consistently 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 that would enable a customer to reduce its relevant, measured peak as compared with others in its rate class should be able to reduce its distribution rates under most demand charges. Whether its rates would be lower, or whether the customer would have more control over its rates, under a demand charge versus another rate mechanism would depend on the individual customer's sophistication and understanding of the rate, its load factor and profile, and the details of the demand charge. The impacts on a customer's rates would also probably greatly depend on enabling technology. 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.

i. Customer Understanding and Transition

If demand charges are adopted, regulators need to ensure utilities prioritize education for customers. The level of understanding of these types of rates seems to be low, and opponents often point to this as a major objection to the adoption of demand charges.

One problem is that consumers do not often, if at all, come in contact with a product or service, which is priced after it has been consumed based on some type of peak rate of consumption (or capacity) that occurs at a time that is not known in advance. Some proponents use as evidence customer understanding of some basic electric concepts,[169] but just because a customer may be aware of what a watt is or how the circuit breaker can trip does not mean that a customer can easily understand or change its demand patterns or understand the dynamics of sizing various components of the grid and electric capacity. Most examples given by proponents are examples of TOU rates (time-varying charges based on the volume consumed)—that is, Uber Demand or Surge Pricing—or fixed charges, which are known and set beforehand (e.g., monthly fees for Internet providers for a certain peak capacity, which can safely and easily be throttled at that level when being consumed.

Further, it seems that a demand charge could be a rate that is more difficult to respond to compared with a volumetric charge that requires only using less electricity over an entire month, or for TOU emphasizing reductions in overall usage when electricity is most expensive. As with most rates, technology significantly helps a customer react to any price signals; but to the extent that reacting to the rates are difficult, technology could be even more important in demand charges. Regulators should be wary of any advantage for higher-income customers that might be better able to afford these technologies, such as energy management systems. This technology can be hard to come by for low-income customers, and may be less economical for low-use customers.

As mentioned above, in addition to significant education for customers,

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169 Faruqui, *et al.*, "Curating the Future."

most parties agree any roll out of demand charges should be based on a full and detailed understanding of the implications for that jurisdiction's customers, accompanied by mechanisms such as pilots or shadow billing over a multi-year period.

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 are limited.[170] Thus, regulators should be wary of counting on unsupported, promised benefits and cautious when plausible harm may represent itself. It may be that pilots that 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 the new rates will affect the jurisdiction before implementing them.

2. Fixed Charges and Minimum Bills

Fixed charges (also called customer charges, facilities charges, and grid access charges) 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 be set to recover only the direct costs of attaching to the utility's system.[171] This disagreement has been a part of utility rate cases for a century. Those who argue that the majority of costs are fixed are using the potential

170 Rocky Mountain Institute, "Review of Alternative Rate Designs," 76.

171 See the bibliography for more references on fixed charge rationale.

increasing cost shift of what they view as fixed costs from DER customers to other customers as an extension of previous justifications for fixed-charge increases.[172]

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.[173]

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 toward 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 the under-collection of revenue due to customers avoiding the costs of their entire electric bill and not having a balance owed to the utility at the end of the month.[174] In other words, some NEM customers in

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172 For details on fixed charge proposals and decisions across the country, *see* NC Clean Energy Technology Center's *The 50 States of Solar Report* (https://nccleantech.ncsu.edu/?s=50+states+of+solar&x=0&y=0), which is updated quarterly.

173 Synapse Energy Economics Inc., "Caught in a Fix: The Problem with Fixed Charges for Electricity" (Synapse Energy Economics Inc., Cambridge, MA, February 9, 2016), 18.

174 *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

California were able to zero out the entirety of their bill, and avoid paying the distribution utility any grid costs.[175] In a decision revamping its rate design, the California Public Utilities Commission (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 that have bills under $10. In April 2016, Massachusetts passed the Solar Energy Act (MA Solar Act).[176] 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 of service data. On the other hand, minimum bills eliminate the conservation signal by encouraging consumption up to the minimum bill amount.[177]

In either event, distribution utilities often dispute which components are fixed and should be recovered from customers in a fixed charge or minimum bill. 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?[178] Understanding and identifying 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.

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, California Public Utilities Commission (July 13, 2015).

175 Due to the structure of NEM at the time, those customers also avoided paying "non-bypassable charges," which included components like nuclear decommissioning costs and public purpose charges, which are used to fund energy efficiency programs in California. Subsequent changes to the NEM program have changed this situation.

176 Act Relative to Solar Energy. (2016, April 11). 2016 Mass. Acts, Chapter 75.

177 Lazar and Gonzalez, "Smart Rate Design." *See also* Lisa Wood et al., *Recovery of Utility Fixed Costs: Utility, Consumer, Environmental and Economist Perspectives*, Future Electric Utility Regulation, Report No. 5 (Berkeley, CA: Lawrence Berkeley National Laboratory, June 2016), 58–59; Borenstein, "Economics of Fixed Cost Recovery," 14–15.

178 *See, e.g.*, the discussion of the minimum system and zero-intercept methods of cost allocation in NARUC, *Electric Utility Cost Allocation Manual*, 136–42.

3. Standby and Backup Charges

Standby service is service available to a full or partial self-generating utility customer to protect the customer from loss of service in the event of an unanticipated or planned 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 consumed, 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. Formerly, when utilities operated almost all 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 CHP 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 is being used by the utility more often.

Standby charges are charges assessed by utilities to customers with DER systems that do not generate enough electricity to meet their 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 usually comprises 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.

These charges are generally approved by 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 may be 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 on 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 for 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."[179] A number of Southeastern utilities have implemented or proposed standby charges that may affect customer investment in DER. An example is the Alabama Power Company Rate Rider RGB Supplementary, Back-up or Maintenance Power schedule, which applies a

179 The term "backup service" is being applied more generally to service options that appear to fit the general definition of standby service.

charge based on the size of the solar PV system.[180] A similar rate schedule is in place for Santee Cooper.[181]

Both backup charges and standby charges have been associated with large C&I systems, for both load and generation.[182] Historically, they are most associated with non-utility generating systems, such as large self-generation systems at industrial plants, and with CHP 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.

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 act the same at the same time, whether planned or not, could rise to the level of an important contingency. For example, a large number of residential solar PV systems, just a few kW 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

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180 The Alabama Power Rate Rider RGB Supplementary, Back-up or Maintenance Power schedule 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." Alabama Power, Rate Rider RGB Supplementary, Back-up or Maintenance Power, 1.

181 Santee Cooper, https:www.santeecooper.com/pdfs/rates/ratesadjustment/dg-16-rider.pdf.

182 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.

contingency. Since PV generation is concentrated in the early afternoon, and its 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.

If there is a reason for standby and backup service for DER systems, there of course will be a cost of providing it. 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, 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 solar 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 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.[183]

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183 For instance, a recent Wisconsin Dane County Court ruling (Case #: 2015CV000153) overturned the Wisconsin Public Service Commission's previous decision that would have allowed

4. Interconnection Fees/Metering Charges

The interconnection process allows for DERs to connect to the electric grid. In many jurisdictions, the DER owner obtains approval from the local utility and receives authorization to connect, pursuant to that utility's interconnection tariff. The utility may charge an interconnection fee to recover the one-time cost 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, wiring and metering charges, various studies, and system impact reviews.[184] To be clear, interconnection fees are separate from line extension allowances, which involve utility expectations of the customer when the premise was originally connected to the grid. Utilities may need to revisit line extension allowances to ensure that the forecasts used remain accurate. 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 jurisdictions have straightforward procedures for simple interconnections (i.e., for a DER less than a predetermined size, usually around 10 kW–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 benefiting from the interconnection. In California, the interconnection ranges from $75 to $150.[185] Interconnection costs in Massachusetts vary, depending on the size of the interconnection system, and may include an application fee ($0–$7,500), various studies, system

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utility We Energies to impose a standby charge on solar customers, citing a lack of evidence for the charge.

184 EEI Primer, 9; Paul Sheaffer, "Interconnection of Distributed Generation to Utility Systems: Recommendations for Technical Requirements, Procedures and Agreements, and Emerging Issues" (Regulatory Assistance Project, Montpelier, VT, 2011), http://www.raponline.org/document/download/id/4572.

185 *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).

modifications, a witness test, and the cost of installing interconnection facilities).[186] For simple interconnections in Massachusetts, the DER owner generally does not pay an application fee, but may be responsible for other costs to interconnect. Interconnection fees in other jurisdictions vary but are generally set at a flat fee plus a charge per kW.[187] A regulator may consider using the interconnection standards from the most current FERC Small Generator Interconnection Procedures set forth in Order No. 792 as a basis for its process and requirements.[188]

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, Commonwealth Edison and Orange & Rockland (non-residential) impose a separate metering charge to their customers.[189]

The advantages of an interconnection fee or a metering charge are usually 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. By using this approach, other customers will not subsidize the DER owner for costs related to interconnection and metering.

There are also disadvantages of imposing an interconnection fee. For example, if the interconnection fee is a fixed charge, and is greater than the

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186 National Grid U.S., "DG Interconnection Seminar" (National Grid, Waltham, MA, 2016), https://www9.nationalgridus.com/non_html/MA_DG_Seminar.pdf.

187 Sheaffer, "Interconnection of Distributed Generation."

188 *Small Generator Interconnection Agreements and Procedures*, Order No. 792, 145 FERC ¶ 61,159 (2013), clarified, Order No. 792-A, 146 FERC ¶ 61,214 (2014).

189 For ComEd, *see* ComEd, https://www.comed.com/MyAccount/MyBillUsage/Pages/ResidentialBillBack.aspx; for Orange & Rockland, *see* Orange & Rockland, http://www.oru.com/customerservice/frequentlyaskedquestions/aboutbilling/understandingyourbill.html.

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 may be responsible for these costs regardless of the prior DER facilities installed on the distribution system. In this case, the final DER to interconnect is responsible for the total cost of the distribution system upgrade. Hawaii used a mechanism to spread a DER project upgrade to new customers in the interconnection queue to spread the costs across more of the future users of those upgrades.[190] Moreover, an interconnection fee may prevent DER adoption because the additional fee increases the payback period of the DER investment for 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.

B. DER Compensation Options

This section outlines several options that a regulator may consider in determining how to compensate DER. Again, a regulator may ultimately choose an option not described below. This sections goes through the pros and cons of the options.

1. 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

190 *Instituting a Proceeding to Investigate Distributed Energy Resource Policies,* "Decision and Order No. 33258 (Hawaii Public Utilities Commission, Honolulu, HI, October 12, 2015).

difference between two consecutive readings defines the quantity of kWh 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 US 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 meter readings.

NEM developed as a straightforward method for compensation 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 C&I 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 being exported to the grid were 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 the systems on customers' homes. 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 past century, and can be read electronically at very short intervals (five minutes or even shorter). It must also be noted that NEM is predominately used in conjunction with solar PV; whether NEM is compatible in practice with compensating other types of DER remains to be seen, and should be studied carefully by a jurisdiction before implementation.

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 oriented in a way to capture the greatest solar radiance, which typically covers noon to 4 p.m.[191] 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 for themselves. Customer generation, it is argued, reduces utility generation even if the generation occurs at times other than when the customers consume

191 Typically, solar panels face southwest, which allows for the greatest amount of sunlight to power the panels.

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 or upgrades, or both. 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 profit 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 from the customer's system exceeds its consumption. That is to say, at times the meter may run "backward" 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" 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 bill, 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 for 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 that 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 per 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 of energy 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's system. The advent of advanced meters has facilitated the ability to adopt 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, there is 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, or 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 imposes those avoided costs on the nonparticipants. In this view the nonparticipants are subsidizing the NEM participants.

Though NEM is the simplest form of compensation 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 grid operator, such as the distribution utility, to have the ability 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 have little impact on 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 higher costs. Customer-sited solar 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 system 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 generation and adds system costs that then must be paid by all customers.

Finally, although 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 in the highest rate 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.

2. Valuation Methodology

There are two main methods of determining the valuation model for this methodology: value of resource (VOR) and value of service (VOS). Other terms that may also be used to reflect this concept include "buy all/sell all" and "buy all/credit all."[192] In other words, a customer is charged for its consumption at the retail rate and is then separately paid or credited for its generation or other service. Conceptually, a valuation methodology allows for the disconnection of consumption from the provision of a specific service, such as 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 provision of a service, 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

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192 A third way, proposed by the staff of the Michigan Public Service Commission, is based on the real outflow of electricity from a solar PV unit, and the inflow of electricity from the grid, while maintaining a cost-of-service framework. This method utilizes the capability of AMI to measure inflow and outflow of electricity generated and consumed over an hour. The model addresses the netting of total generation and consumption, which may not capture the total amount of electricity generated or consumed, and is typically used in NEM and buy-all/sell-all arrangements. Since this model relies on generation located on customer premises, it may be a consideration if a commission is focused solely on DG. Robert Ozar, "A Reasoned Analysis for a New Distribution-Generation Paradigm: The Inflow & Outflow Mechanism, A Cost of Service Based Approach" (Michigan Public Service Commission, Lansing, MI, August 24, 2016).

regulator. Deciding which path to take may depend on the level of adoption of DER. If the jurisdiction has limited adoption of DER, value of resource may make more sense. On the other hand, if DER is showing significant adoption, then the value of service may be applicable.

a. Value of Resource

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 and benefits to ensure neutrality. This method attempts to recognize potential benefits to the grid, other customers, and society. A few jurisdictions 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 others. Consequently, setting a fixed value for a long period of time may be unwise. Again, the choice of whether to use short-term or long-term costs and benefits is likely an issue in this valuation. 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 benefits and costs are realized and growth of DER occurs. Most methodologies currently being used consider both the positive and negative effects of the following:[193]

1. Avoided energy/fuel
2. Energy losses/line losses
3. Avoided capacity
4. Ancillary services (may include voltage or reactive power support)

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193 It is important that the costs and benefits under this strategy are similar to those afforded to traditional generation resources. If a jurisdiction identifies additional benefits, such a job creation, it should be considered outside the development of the rate itself and can be treated as an adder or compensated for in some other manner.

5. Transmission and distribution capacity (and lifespan changes)
6. Avoided criteria pollutants
7. Avoided CO2 emission cost
8. Fuel hedging
9. Utility integration and interconnection costs
10. Utility administrations
11. Other environmental factors
12. Reliability factors and costs

The benefits of the VOR method are that once a value/rate is determined, it is known and can be relied on as a value of service provided to the grid. Customer generators or other resources can gain certainty regarding the value of their investments (at least for a time). As this provides greater compensation 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, VOR allows for a more equitable consideration of all 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 resources that are included in the Public Utility Regulatory Policies Act.

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, including location, timing, benefits, and costs, to the resource. The following are some examples of states that have engaged in valuing some or many of the items discussed previously:

- Minnesota set a value of solar rate for solar gardens.[194]
- In Texas, Austin Energy has a buy all/sell all value of solar tariff.[195]
- Maine presented a value of solar study to its legislature.[196]

One must use caution, however, to ensure that any value component determined by the VOR is not already being tracked or traded separately. For example, in Nevada, renewable DG is eligible for RECs and customer generators are granted credits based on system output. However, a greater number of RECs 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 and benefits (such as environmental costs, avoided CO2, and avoided pollutants) are separately tracked through issuance of RECs through a recognized tracking mechanism,[197] one should remove them from the VOR list, or else those same benefits or avoided costs would be double counted. Determinations of value should at-

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194 *In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program,* "Order Approving Value-of-Solar Rate for Xcel's Solar-Garden Program, Clarifying Program Parameters, and Requiring Further Filings," Minnesota PUC, Docket No. E-002/M-13-867 (issued September 6, 2016).

195 Austin Energy, http://austinenergy.com/wps/portal/ae/rates/residential-rates/residential-solar-energy-rate/.

196 Maine Public Utilities Commission, "Maine Distributed Solar Valuation Study" (Maine Public Utilities Commission, Augusta, ME, March 2015), http://www.maine.gov/tools/whatsnew/attach.php?id=639056&an=1; http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf (addendum).

197 Two examples are the Western Renewable Energy Generation Information System and the Midwest Renewable Energy Tracking System. Both systems track and facilitate REC transactions in their respective geographical regions.

tempt 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 with any methodology, there are downsides to using VOR. 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. Since this is, in essence, an administratively set price for compensation, it is subject to risks of going through a regulatory proceeding. 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 of the DER 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.

b. Value of Service

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 and 2000s. By introducing services, the distribution utility would be able to identify specific services necessary to maintain grid reliability, and then the distribution utility would be able to procure those services from a 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 dispatchable 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).[198] 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 black start, such as from a microgrid or energy storage resource.[199] 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 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.

The following image illustrates the variety of services that can be provided by some types of DER, in this case energy storage, but can apply to a wide variety of other resources.[200] Additionally, the image illustrates which groups can realize these services.

Importantly, a VOS would focus on services and not on technologies or particular types of resources. If the utility sought black start capability, any resource that was capable of meeting the technical requirements could bid. This would free up additional values from specific resources, even though the VOS process is technology agnostic. Similar to with 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, will be able to respond to fluctuating costs

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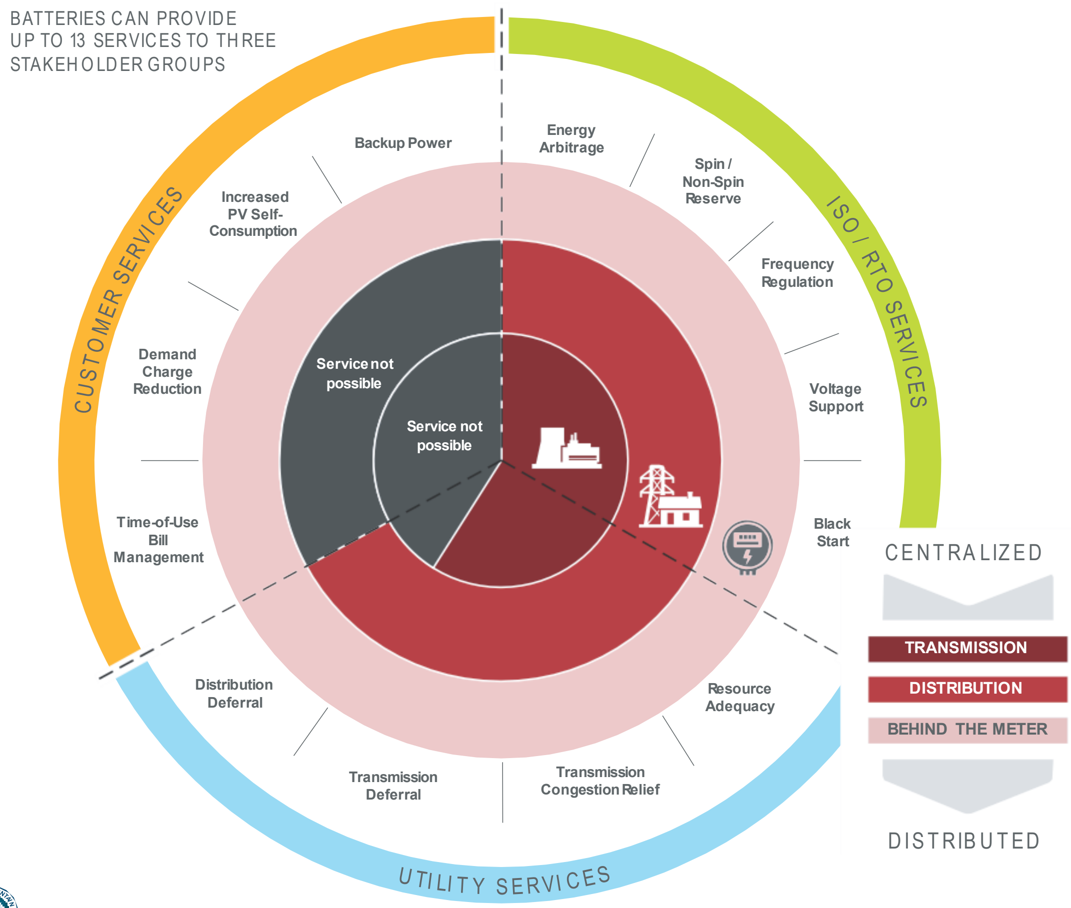
198 Solar City Grid Engineering, "Pathway to the Distributed Grid."

199 Rocky Mountain Institute, "Economics of Battery Energy Storage."

200 *Id.*, 6 (used with permission of RMI).



Source: RMI

to serve across the distribution system 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 II. 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 allow the utility to recover costs through VOS, extra earnings on performance, or allowing a greater rate of return on operational and maintenance.

Aggregation

In some instances, the services and benefits of DER are more valuable when aggregated into larger numbers. Many states, however, do not allow aggregators to participate in their jurisdictions. For example, in the MISO market, only Illinois allows for third-party aggregators to operate in their jurisdiction. In non-organized markets, development of retail markets may be a path; in this instance, a utility would be allowed to procure additional services from a third-party aggregator to meet local, retail needs. A single DR customer may not provide much of a response, but when aggregated with many customers can provide benefits at both the retail and wholesale side. Lastly, aggregation can result in a more direct compensation by tying it directly to wholesale prices or, potentially, a distribution locational marginal price.

c. Transactive Energy

A more future-oriented version of a valuation methodology is Transactive Energy (TE). TE is a concept developed by the GridWise Architecture Council (GWAC) and Pacific Northwest National Labs (PNNL). TE is both a technical architecture and an economic dispatch system highly reliant on 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 GWAC, TE is a means by which customer-sited resources, including DR, 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 GWAC, 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."[201] 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. In other words, the customer or DER could bilaterally contract with another customer, resource, aggregator, or the utility for the product or service it is offering. This would allow DER to have wider benefits than simply to the utility or grid, but to other customers directly connected to the grid seeking additional services or products.

GWAC 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 affect the reliability of the grid, the resources 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. Indeed, TE can be thought of as enabling new compensa-

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201 GridWise Architecture Council, "GridWise Transactive Energy Framework, Version 1.0" (GridWise Architecture Council, Richland, WA, January 2015), 11.

tion models, including fee-based models.[202] 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 recovery of investments, but TE focuses on a series of short-term transactions; ensuring adequate compensation and certainty for investments will need to be proved.[203] Lastly, many jurisdictions have policies limiting the ability of customers to sell excess electricity to other customers, or prohibit aggregators that may be in a better position to optimize a group of resources and integrate them with the utility.[204]

To assist decision makers in better understanding TE, and its practical applications, GWAC has put out a draft "Decision-Maker's Transactive Energy Checklist."[205] The Checklist is designed to be "a tool to help decision-makers evaluate options such as capital asset investments and new information technology opportunities to determine whether they conform to the principles and attributes of transactive energy. Conformance to these tenets will ensure a level playing field for prosumers, utilities, services providers, market operators, and investors, in a framework based on end-to-end interoperability, operational reliability, and economic efficiency. This is a tool that will help

202 *See, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision,* "Order Adopting a Ratemaking and Utility Revenue Model Policy Framework," New York Public Service Commission, Case 14-M-0101 at 46-47 ("First, and at the heart of REV, is the development of new transactive-based revenues between and among DSPs, end-use consumers, and third-party market participants. These revenue opportunities reflect the nascent market and will evolve over time.").

203 A pilot project addressing these issues and developing and testing the feasibility of customer-site load management systems, operational strategies, and retail tariff options is underway in California. *See,* "Retail Automated Transactive Energy System (RATES)," funded by California Energy Commission, EPIC Grant GFO-15-311 (http://www.temix.net/images/GFO-15-311_Retail_Automated_Transactive_Energy_System.pdf).

204 For more considerations, see Nilgun Atamturk, "Transactive Energy: A Surreal Vision or a Necessary and Feasible Solutions to Grid Problems?" (California Public Utilities Commission, San Francisco, CA, October 2014).

205 GridWise Architecture Council, "Decision-Maker's Transactive Energy Checklist" (draft, GridWise Architecture Council, Richland, WA, August 2016).

LMP+D

In the New York REV proceeding, the New York Public Service Commission sought greater clarity in the value of DER utilizing an LMP+D model, where LMP is the locational marginal price on the wholesale side and D is the value of the resources on the distribution grid. As stated by the New York Public Service Commission, the value of D "can include load reduction, frequency regulation, reactive power, line loss avoidance, resilience and locational value as well as values not directly related to delivery service such as installed capacity and emission avoidance." (***Petition for Relief Regarding Its Obligation to Purchase Net Metered Generation Under Public Law §66-j***, "Order Establishing Interim Ceilings on the Interconnection of Net Metered Generation, Case 15-E-0407, New York PSC at 9 (October 16, 2015).) In this solution, "the value of D when added to the location-based marginal price of energy (LMP) will constitute the full value of DER to the system, or the LMP+D." (***Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision***, "Staff White Paper on Ratemaking and Utility Business Models," New York Public Service Commission, Case 14-M-0101 at 75 (July 28, 2015).) A recent New York Public Service Commission staff report describes the variety of tariffs, values, and services that supports this direction, and the technologies currently available to support this move. The staff report describes the goal of this effort is to "develop accurate pricing for DERs that reflect the actual value DERs create." Furthermore, in describing the need to move to a more value-based model, the staff report notes that a move away from NEM to a "more precise DER valuation and compensation is necessary." New York Department of Public Service, ***In the Matter of the Value of Distributed Energy Resources***, "Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding," Case No. 15-E-0751 (State of New York, Albany, NY, October 27, 2016), 4-5.

embody and assess the best long-term value for all parties."[206] Use of the checklist can assist regulators in determining if TE is an appropriate option to consider for meeting some need, and how to enhance value for all parties connected to the grid.

206 GridWise Architecture Council, "Decision-Maker's Transactive Energy Checklist," 1.2.

VI. A Path Forward for Regulators

A. Decision Framework

The majority of content in this Manual reflects the traditional role of the regulator: determine utility costs, authorize recovery of prudent costs, determine which customers will pay for which costs, and set rates for an opportunity to recover those costs. The impetus for this Manual is the changes occurring in the industry. Some of the changes, like improved communications and sensor technology, continue to enhance visibility into the grid and have added cost-effective choices for serving customers. What is completely new is that the customer is no longer simply a passive taker of electricity. This fundamental change allows a customer to produce its own electricity, invest in technology to take more control over its own usage, send electricity or provide other services to the grid, and have more flexibility and responsiveness to changing prices and supply of electricity. This section provides an overview of information and questions a regulator may need to address to effectively use this Manual to best meet the needs of the particular jurisdiction. The section starts by outlining some high-level questions, data needs, and distribution system planning before outlining some indicative rate design, compensation, and cost–benefit questions.

1. Questions to Support a Regulator

Below is an initial, indicative set of questions that a regulator may ask to gauge the status of DER adoption in the state, the level of preparedness at the utility to integrate or utilize DER, how the existing rate design affects DER generally and certain DER specifically, and considerations for next steps. This is by no means an exhaustive list.

Assessing the current situation:

- What is the current adoption level of DER in the jurisdiction?
  - ◊ What is the number of interconnection agreements?
  - ◊ What is the number of EVs on EV-specific rate designs?

◊ What is the number of customers on a DR program or the amount of available DR from the utility or aggregators, or both?

- Where is the DER located?
- Does the regulated utility have sufficient visibility into its distribution grid to monitor impacts of certain types of DER on its system?
- What issues, if any, have already come to the utility's or regulators' attention concerning the effect of DER on the grid and regulation?
- When was the last class cost-of-service study performed? Does the regulator have sufficient information about rate and cost impacts from DER on customer classes?
- How are the different types of DER currently treated in rate design, compensation, planning, and so forth?
- On a prospective basis, how does any policy or regulation address DER investments that lead to DER benefits, if any?

Exploring DER rate design and compensation:

- What role is expected of DER in the short and long term? What is the regulator's vision regarding how these changes affect the industry?
- How does that role affect utility planning, revenue recovery, and investment decisions?
- What does different DER provide in the context of the utility's duty to provide generation, transmission, and distribution while satisfying environmental and other public policy requirements?
- How should a jurisdiction analyze costs and benefits of any particular DER technology or service?
- How does the jurisdiction minimize harm and optimize benefits?
- How does a jurisdiction address these questions—does a jurisdiction open one generic proceeding, or does a jurisdiction address them piece by piece?
- How does a regulator address the asymmetry of information inherent in utility regulation when discussing the grid?
- How do the different scenarios of DER adoption rates affect utility and

regulatory processes?

- Does the utility have access to the data necessary to inform itself and the regulator about its system, costs, and hosting capacity? How can these data be shared with other stakeholders in a way that is both useful but also appropriately protects the data?
- How should the jurisdiction ensure that all stakeholders participate in any proceeding? Traditional participants in regulatory proceedings may no longer capture the full views of stakeholders.
- When, and at what pace, should the jurisdiction act?
- Are the regulators moving away from traditional utility regulation and rate making—for instance adopting a so-called performance-based distribution system as a platform (e.g., New York REV), or a Transactive Energy regulation? If so, how does DER fit into, or drive, that vision?

In reviewing any particular proposal, a jurisdiction may consider the following:

- Does the proposed DER compensation mechanism accurately and objectively assess the costs, benefits, and risks of DER?
- To what extent does the proposed rate structure account for core infrastructure costs and impacts relating to the grid?
- Do the projected benefits of the DER outweigh the likely costs to the utility, to other customers, and to society at large? Benefits might include bill impacts and compliance with environmental mandates; costs might include cost shifts, impacts on utility planning, and possible reliability implications.
- Does the proposal result in a cost shift?
- Are possible cost shifts minor, reasonable, and non-regressive? To what extent any cost-shift is acceptable.
- If costs arise as a result of DER deployment, will the rate structure ensure that the causer of the cost pays?
- Does the proposal ensure equitable access to benefits, such as decreases in electric bills?
- Are there alternatives to realizing the core public policy objectives at

issue in the proposed DER compensation mechanism? Are there alternative paths to the public good at issue?

- Should a regulator consider a separate class for DER customers?
- Does the proposal further core notions of regulatory neutrality and parity? Does the proposal endorse a particular technology or business model, or does it create opportunities for an array of market participants?
- To what extent are regulators formally expanding their distribution system planning process in their jurisdiction? Does the regulator already have, or is there an adequate level of, visibility into the utility's planning process and operations?

DER, by definition, primarily affects the distribution system since that is where it is located. That is not to say DER cannot impose costs on, or provide benefits to, the broader generation and transmission systems. However, for the most part, the costs and benefits manifest themselves at the local level, and as such that is where DER is forcing regulators and utilities to focus.

These trends seem to generally require regulators to have more visibility into and oversight of the planning of a utility's circuits and broader distribution system. They often require the utilities themselves to have far greater visibility into their own systems. Fortunately, the smart grid technology driving these improvements should represent opportunities for more efficiencies to benefit utilities and customers alike.

What data are needed by regulators? Below is a partial list for thinking about types of data or other information for this analysis:

- Does the regulator have access to the number of DER, different types of DER, and locations; number of customers who have adopted DER, the costs and benefits associated with those DER; a recent cost of service study; or, an indication or study showing any cost-shifting, by class, geography, or socio-economic?
- What is the hosting capacity on various parts of the distribution system? Also, what are the unique, localized circumstances that drive opportunities or barriers to increased benefits from DER adoption?
- How are transmission, generation, and distribution costs and benefits

identified, determined, and accounted?

◊ What is the proper level of granularity in data to examine and ensure efficient accounting of DER?

◊ What is the best way to examine and set which costs and benefits should be socialized and which should be borne by the individual customer?

- How can the regulators help society efficiently allocate investment resources, especially between regulated utilities and independent consumers? How can the regulators encourage efficient acquisition of DER?
- What additional data or analyses are needed for the proper visibility and planning for the grid and DER?

Below are examples of potential types of data a regulator may want to obtain, ensure that a utility is collecting, or make available to stakeholders to

Data to Foster Engagement in Grid Needs and Planned Investments

DATA NEED	DESCRIPTION
Grid Need Type	The type of grid need (e.g. capacity, reactive power, voltage, reliability, resiliency, spinning/nonspinning reserves, frequency response)
Location	The geographic (e.g. GPS, address) and the system location (e.g. planning area, substation, feeder, feeder node) of the grid need
Scale of Deficiency	The scale of the grid need (e.g. MW, kVAR, CAIDI/SAIDI deficiency)
Planned Investment	The traditional investment to be deployed in the absence of an alternative solution (e.g. 40 MVA transformer, 12kV reconductor, line recloser, line regulator)
Reserve Margin	Additional capacity embedded within the planned investment to provide buffer for contingency scenarios)
Historical Data	Time series data used to inform identification of grid need (e.g. loading data, voltage profile, loading versus equipment ratings, etc.)
Forecast Data	Time series data used to inform identification of grid need and specification of planned investment (e.g. loading, voltage, and reliability data). Forecast to include prompt year deficiency (i.e. near-term deficiency driver), as well as long-term forecast (i.e. long-term deficiency driver)
Expected Forecast Error	Historical data that includes forecasts relative to actual demands for relevant grid need type in similar projects. Data to be used to evaluate uncertainty of needs and corresponding value of resources with greater optionality (e.g. lead times, sizing, etc.)

Data to Foster Engagement in General Grid Design and Optimization

DATA NEED	DESCRIPTION
Circuit Model	The information required to model the behavior of the grid at the location of grid need.
Circuit Loading	Annual loading and voltage data for feeder and SCADA line equipment (15 min or hourly), as well as forecasted growth
Circuit DER	Installed DER capacity and forecasted growth by circuit
Circuit Voltage	SCADA voltage profile data (e.g. representative voltage profiles)
Circuit Reliability	Reliability statistics by circuit (e.g. CAIDI, SAIFI, SAIDI, CEMI)
Circuit Resiliency	Number and configuration of circuit supply feeds (used as a proxy for resiliency)
Equipment Ratings, Settings, and Expected Life	The current and planned equipment ratings, relevant settings (e.g. protection, voltage regulation, etc.), and expected remaining life.
Areas Served by Equipment	The geographic area that is served by the equipment in order to identify assets which could be used to address the grid need. This may take the form of a GIS polygon.

assist in analyzing grid needs, planned investments, or general grid design and optimization.[207]

B. Role of Technology

Advanced technologies can not only support the operations of a grid, but also support regulators in making decisions about rate design. Communication abilities are being coupled with advanced technologies, providing the utility, and potentially the regulator as well, with data that can be used to make informed decisions about DER 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 (e.g., meter, bus, feeder, circuit). With this information the regulator can also make more accu-

207 Solar City, "Comments to the NARUC Staff Committee on Rate Design Regarding the Draft *Manual on Distributed Energy Resources Compensation*" (Solar City, San Mateo, CA, September 2, 2016), 11–12.

rate cost and benefit analyses of DER; can evaluate the current rate design methodology; and can continuously reevaluate the proper methodology as levels of adoption 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. By 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.

As discussed elsewhere, certain advanced technology investments are required to implement the several methodologies described above. For example, without an advanced meter, implementing an option like TE 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 on total benefits. In other words, specific investments should provide greater benefits than simply enablement of a specific methodology. Many technologies 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. These data can then be used to identify potential changes needed for existing rate design choices. Additionally, these 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 collect information on an hourly or 15-minute basis. Furthermore, meters connected to a customer's Home Area Network (HAN) can be read in real time in increments as frequent as eight 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 options.

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 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 finding 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. Process for Working through the Questions

Ultimately, in determining appropriate rate design or compensation, a regulator will need to balance the various principles and goals of rate design and regulation. As a part of that process, a jurisdiction will have to weigh its unique legacy policies and technology and current situation in considerations related to impacts on utilities, DER customers, and non-DER customers, and other policy considerations of potential changes to rate design or compensation methodologies.

This Manual provides two high-level examples below that may assist a jurisdiction in balancing these considerations. As more jurisdictions gain greater experience in working through these issues, and more data become available, this section may evolve in response to this experience. What follows is a framework that jurisdictions can use to guide them through this process.

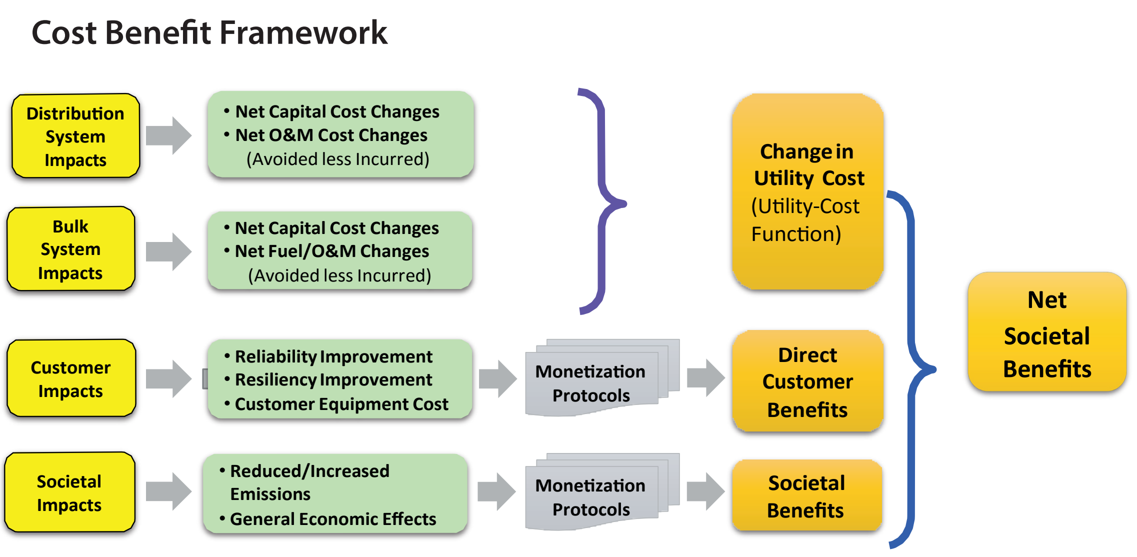
1. Rate Design and Compensation

A regulator may consider the following questions regarding rate design and compensation:

- Once jurisdictions have identified the nature of costs and benefits, how should this information affect rate structures and compensation mechanisms and inform the regulatory compact?
- To what extent should fixed costs be collected through fixed charges? To what extent can alternatives fulfill the same purpose for the public good?
- What amount of revenue responsibility shifting is acceptable, given that there are always intra- and inter-class subsidies?
- To what extent should demand-related costs be collected through demand charges? While collecting these costs through demand charges may result in decreased intra-class subsidies, is the potential for confusion or the difficulty in responding to such price signals a consideration that outweighs the subsidy reduction and potential efficiency gain? To what extent can alternatives fulfill the same purpose for the public good?
- To what extent should costs imposed on the system or previously paid by DER customers be directly attributed to DER customers as opposed to being borne by all customers? Relatedly, to what extent should benefits to the utilities system due to DER installation accrue to DER customers and to what extent should other customers share in these benefits? How and to what extent could a jurisdiction help facilitate investment in DER that benefits all customers?
- To what extent should a jurisdiction take into account external benefits? While economic theory states that prices should reflect all externalities to result in the most efficient outcomes, federal and state incentives may already be taking some of these externalities into account (though perhaps in a less efficient way). A jurisdiction may prefer to rely on society at large to price these externalities, rather than levying that price on ratepayers of a utility.

2. Costs and Benefits

Decisions on an appropriate rate structure and how compensation



Source: EPRI

policies affect, both for DER and non-DER customers, rely to a great extent on a jurisdiction's opinions on the nature of costs and benefits. EPRI's Cost Benefit Framework as related to DER offers a quick overview of one way to consider this question.[208]

The yellow column represents the types of impacts as a source of outputs from the distribution and bulk power system. The gray column identifies measurable impacts from each type, which includes costs and physical impacts to be monetized. The orange column represents those benefits that are to be monetized, which includes customer and societal impacts (bottom two boxes in fourth column). All are then combined to total the net societal benefits. According to EPRI, this "framework supports a variety of perspectives on DER accommodation. . . . the benefit-cost analysis distinguishes between net costs incurred by the utility (the utility cost function) and are therefore collected in rates, and benefits that accrue to customers and society and affect resource

208 EPRI, *Integrated Grid*, 9-3 (used with permission of EPRI).

utilization—but are not priced by the market or administratively and are therefore not included in utility revenue requirements."[209]

A jurisdiction must carefully consider the evidence on the nature of costs and benefits, and decide several key issues.

Another way to analyze these issues is through the California SPM. The following graph is a summary of each cost-effectiveness test.[210] The full SPM provides a breakdown of each test, including the pros and cons of each method. The commonly utilized "Societal Cost" test is treated as an offshoot of the "Total Resource Cost" test; in other words, while using the Total Resource Cost test, the regulator can add a value for costs or benefits to society, such as a social cost of carbon.

Primary	Secondary
Participant	
Net present value (all participants)	Discounted payback (years) Benefit-cost ratio Net present value (average participant)
Ratepayer Impact Measure	
Lifecycle revenue impact per Unit of energy (kWh or therm) or demand customer (kW)	Lifecycle revenue impact per unit Annual revenue impact (by year, per kWh, kW, therm, or customer)
Net present value	First-year revenue impact (per kWh, kW, therm, or customer) Benefit-cost ratio
Total Resource Cost	
Net present value (NPV)	Benefit-cost ratio (BCR) Levelized cost (cents or dollars per unit of energy or demand) Societal (NPV, BCR)
Program Administrator Cost	
Net present value	Benefit-cost ratio Levelized cost (cents or dollars per unit of energy or demand)

The SPM is used across the country for cost-effectiveness testing for a

209 EPRI, *Integrated Grid*, 9-3–9-4.

210 California Public Utilities Commission, *California Standard Practice Manual*, 5.

variety of demand-side resources, primarily energy efficiency.

In thinking about determining costs and benefits, a regulator may consider the following:

- To what extent does the grid provide benefits that are not captured by traditional measures of use? If a jurisdiction believes that the grid provides many benefits not captured by usage, whether volumetric or demand-related, that jurisdiction may lean toward changing rate structures to better reflect those benefits.
- To what extent does DER lower utility costs? If DER provides significant cost reductions or avoids significant costs for the utility, that evidence should affect decisions on appropriate rate structures and compensation.
- To what extent does DER benefit society at large? Identification and the attempted quantification of these benefits should also inform rate design and compensation structures.
- To what extent do rates currently, and to what extent will they in the future, reflect the nature of costs and benefits?

Once these issues have been decided, the most appropriate potential options for rate design and compensation should be clearer. The choice, then, is which of the potential options that achieve some or all of a jurisdiction's goals can or should be used. Certain options, such as time-varying rates and demand charges, require AMI or interval metering to utilize. Without such enabling technologies, a regulator may select another rate design or compensation option that achieves many of the same goals as its preferred option without the technological requirements. Effects of the choice on customers, both DER and non-DER, must also be taken into account when weighing options that achieve a regulator's goals. Equity considerations between income levels, existing and future customers, classes, and technologies should also be taken into account. The delicate balance of all considerations such that the public interest is maximized is at the discretion of regulators in each jurisdiction, and multiple reasonable outcomes are possible.

Whether to Act Based on Adoption Levels

While it is important to take the time to accurately assess the appropriate structure of rates for DER (as well as other) customers, regulators should not tarry too long in establishing what they feel is an appropriate rate structure and compensation mechanism for DER customers. A very important factor in customers' decisions on DER installation is the price signals sent by the rate design. If those price signals do not appropriately reflect a jurisdiction's policies on cost-causation, the result will likely be an economically or socially inefficient amount of DER. Waiting too long to set up an appropriate pricing structure can also make grandfathering and equity considerations between future and existing DER customers more of an issue than they otherwise would be. Setting up an appropriate pricing and compensation structure should be done as soon as feasible, but there should not be so much urgency that the decision is made without all of the appropriate information. The results from such uninformed actions could be worse than no action at all. Adoption levels may, however, affect the amount and types of costs and benefits that accrue from DER installations. It is important to decide if different rate structures and compensation methodologies are appropriate for different stages of adoption, or if a single structure should be put in place that can deal with the differential impacts of various penetration levels. To the extent that it is decided that different rate structures are appropriate at different adoption levels, it should be made clear to customers whether grandfathering will apply so that the decisions on DER installation can take into account the potential for future rate changes.

VII. Conclusion

This Manual is intended to support and help jurisdictions understand, plan for, and develop appropriate policies associated with the growth of DER. As noted throughout the Manual, DER is not simply solar PV or energy storage, and not only could be one type of DER, but could be a suite of technologies. Putting in place the appropriate tariffs, rate designs, and compensation schemes that best utilize these investments, while also ensuring recovery of the prudent costs of maintaining the grid is, ultimately, the task for the regulator. This Manual has attempted to provide jurisdictions with information, current as of the time of this writing, to help answer that question. There will likely be many possible solutions to this question, and the regulator can use a variety of rate designs and compensation schemes to best meet the needs of its jurisdiction.

There are a number of related tasks that this Manual does not fully address. Topics that jurisdictions may also wish to address include, but are not limited to, distribution planning, utility compensation, business models, and data access. Each of these topics is worthy of its own exposition, and the Manual leaves it others to provide detail and support to jurisdictions. Already we see several commissions undertaking proceedings examining all parts of the regulatory and utility model and relationship. This Manual can assist in those proceedings and will hopefully be used to inform those jurisdictions on the DER rate design and compensation portion of those discussions. If a jurisdiction wishes to investigate hosting capacity, making the associated analyses, scenarios, and numbers available to developers and those seeking to interconnect will be extremely important to interconnect those resources efficiently; however, it is not the purpose of this document to answer the question of what should go into a hosting capacity policy or under what circumstances hosting capacity should be made available.

This Manual is not the end of this process, however. Additional research on costs and benefits of DER will continue to be completed. A better understanding of impacts of certain rate designs on customers will continue to be developed. Costs of existing technologies will continue to decline while new technologies will be discovered. New business models and compensation schemes will be developed. With this experience comes new information, which can be used to update this Manual and to provide more specific and practical advice to regulators. With low adoption rates of certain types of DER, such as energy storage, EVs, and solar PV, we are still only at the beginning stages of this evolution. However, this is not a reason for a jurisdiction to wait to start its investigation. Each jurisdiction can start investigating and developing policies that best fit its jurisdiction. Current low adoption rates do not mean that a jurisdiction should wait; in fact, it is a perfect time to start its investigation. With more jurisdictions opening proceedings and investigating these questions, future revisions to this document can include more lessons learned and best practices, and make appropriate revisions where there is evidence to support such changes.

The common themes of this document include the following questions:

- What are fixed costs?
- How does a utility recover its approved revenue requirement?
- How are costs allocated?
- How are benefits and values identified and determined?
- How can technology be used to plan, integrate, and monitor the changing nature of the grid?
- How can adoption rates be used to better plan for and meet this evolution?

Using the guidance provided in this Manual to understand how these themes play out in the jurisdiction and how a regulator responds to these themes can effectively address the growth of DER across the country in a proactive manner. Doing so with representation from many actors and interests, the process described herein can provide regulators with a framework and a time frame for responding. While the future remains unwritten, an outline is beginning to form.

Appendix 1

March 2016 Stakeholder Survey Questions

Thank you for your participation in this survey for inputs into the NARUC Rate Design Staff Subcommittee Distributed Energy Resources Compensation Manual. The response to each question is limited to 1,500 characters, except question 5, which does not have a character limit. Please note that your responses to this survey may be subject to public disclosure. Please direct inquiries to responses@naruc.org.

NARUC will consider each point of input, however we are seeking a broad range of ideas, rather than large volumes of duplicative responses. Quantity of response is unimportant in this survey, and if there are many responses sharing the same ideas and perspectives they will have the same weight as a single well-considered response.

1. What currently used rate designs or methodologies should be explored in the context of the DER Compensation Manual (e.g., flat, inclining block, time-variable)? What examples of fully implemented rate designs or methodologies exist?

2. What are the current rate design and compensation challenges for DER that should be explored in the writing of the Manual?

3. What DER compensation methodologies should be considered in the writing of the Manual (e.g., NEM, value of solar, services model, transactive energy)? Briefly explain examples of fully implemented DER compensation methodologies.

4. What are the most important state and federal cases, orders, judgments, research, papers and other resources that should be considered in the writing of the Manual? Links to such resources can be provided.

5. Please provide any other information, including links to documents, that could assist in the drafting of the Manual. This question does not have a character limit. If you would like to send a document that does not have a link, contact responses@naruc.org.

6. Please list your contact information if there is further clarification needed:
   a. Name
   b. Company
   c. City/Town
   d. State/Province
   e. ZIP/Postal Code
   f. Country
   g. Email Address
   h. Phone Number

Appendix 2

Notice of Comment Period and Agenda for July 23, 2016 NARUC Town Hall

On July 21, 2016, the draft of the NARUC Distributed Energy Resources Compensation Manual was released and posted on the NARUC website. Development of the document began in late 2015 and the final Manual is projected to be completed in early November 2016. There will be two opportunities for public feedback on the draft Manual: at a July 23 Town Hall held in conjunction with the NARUC Summer Committee Meetings in Nashville, Tennessee, as well as through the submission of written comments.

Please find the draft here: www.naruc.org/ratedesign

Oral Comment Period

NARUC has announced the holding of a Town Hall at the Summer Meeting to act as a public forum for high-level comments on the draft DER Compensation Manual. The Town Hall will be held on Saturday, July 23, from 2 PM until 5 PM Central in the Broadway F Meeting Room at the Omni Nashville Hotel (250 Fifth Avenue South) in Nashville, Tennessee. The agenda is as follows:

2:00 PM Central	Welcome – NARUC President Travis Kavulla Introduction and Agenda Overview – Chris Villarreal
2:30 PM Central	Overview of Chapter 2 "what is the Rate Design Process" and Chapter 3 "What is DER?" – Chris Villarreal
2:45 PM Central	Overview, Comment, and Q&A on Chapter 4 "Rate Design and Compensation Considerations, Questions, and Challenges" – Chris Villarreal
3:05 PM Central	Overview, Comment and Q&A on Chapter 5 "Compensation Methodologies" – Chris Villarreal
3:30 PM Central	Break
3:45 PM Central	Overview, Comment, and Q&A on Chapter 6 "Technology, Services, and the Evolving Marketplace" – Chris Villarreal
4:15 PM Central	Comment and Q&A on overview, conclusion, and other remaining comments – Chris Villarreal

To facilitate the discussion, NARUC requests that speakers sign up in advance to speak on specific chapters; there will be an opportunity to discuss the document as a whole at the end of the session. A sign-up sheet will be available near the entrance of the room. During the Comment and Q&A portion of each chapter, the moderator will call the names of those who have signed up. When the name is called, the individual will approach one of the standing microphones, and, depending on the number of interested speakers, there may be a time limit. Please keep in mind that the drafters are seeking feedback on the chapters and request that oral comments during the chapter Comment and Q&A be limited to responding to the specific chapters. Please hold high-level, overview, conclusion, or other remaining comments until the last session (at 4:15 PM).

Written Comments

In addition to the Town Hall, written comments on the draft Manual will be accepted until close of business on Friday, September 2. Submissions will only be accepted and considered if submitted to responses@naruc.org. Please refrain from sending comments to the Staff Subcommittee, the Chair, or other NARUC members and staff. Writers are specifically interested in feedback on the questions listed below; however, written comments need not be limited to these questions.

Questions

1. Has the draft Manual addressed the issue in a comprehensive and useful manner?

2. Are there any other considerations not included in the draft Manual that impact Distributed Energy Resources?

3. Are there other compensation options not included in the draft Manual?

4. How could the Manual be written in a way that is more useful to regulators?

5. Should the draft Manual include a discussion of distribution system planning or distribution system operators?

6. Does the draft Manual provide sufficient discussion on considerations of equitable treatment between customers in the context of ratemaking?

7. Since the initial survey and request for information was released in March 2016, have there been any new developments that the Staff Subcommittee should take into account in this draft Manual?

8. Is the draft Manual missing any key technologies that should be included?

Appendix 3

Roster of Members and Observers of Staff Subcommittee on Rate Design

Christopher Villarreal
Minnesota Public Utilities Commission

Jamie Barber
Georgia Public Service Commission

Rajnish Barua, Observer
National Regulatory Research Institute

Todd Bianco
Rhode Island Public Utilities Commission

Daniel Blair
Michigan Public Service Commission

Thomas Broderick
Arizona Corporation Commission

Venkata Bujimalla
Iowa Utilities Board

Jim Busch
Missouri Public Service Commission

Daniel Cleverdon
Public Service Commission of the District of Columbia

Kenneth Costello, Observer
National Regulatory Research Institute

Kim Cox
Missouri Public Service Commission

Anne-Marie Cuneo
Public Utilities Commission of Nevada

Sharon Daly
Massachusetts Department of Public Utilities

Sue Daly
Public Utilities Commission of Ohio

Natelle Dietrich
Missouri Public Service Commission

Patrick Donlon
Public Utilities Commission of Ohio

Catherine Eastwood
North Carolina Utilities Commission

Brian Edmonds
Public Service Commission of the District of Columbia

David F. Gillich
Connecticut Department of Energy and Environmental Protection

Rachel Goldwasser, Observer
New England Conference of Public Utilities Commissioners, Inc.

Matt Hartigan
Delaware Public Service Commission

Grace Hu, Ph.D.
Public Service Commission of the District of Columbia

Tracy Izell
Oklahoma Corporation Commission

Norman Kennard
Pennsylvania Public Utility Commission

Jon Kucskar
Maryland Public Service Commission

Emily Luksha
Massachusetts Department of Public Utilities

Eddy Moore
Arkansas Public Service Commission

Alan Nault
Rhode Island Public Utilities Commission

Jeffrey Orcutt
Illinois Commerce Commission

David Parsons
Hawaii Public Utilities Commission

Paul Phillips
California Public Utilities Commission

Liliya Randt
New York State Public Service Commission

Nicholas Revere
Michigan Agency for Energy/ Michigan Public Service Commission

Will Rosquist
Montana Public Service Commission

Sam Shannon
Wisconsin Public Service Commission

Corey Singletary
Wisconsin Public Service Commission

Stephen St. Marie, Ph.D.
California Public Utilities Commission

Thomas Stanton, Observer
National Regulatory Research Institute

Neil Templeton
Montana Public Service Commission

Dale Thomas
Indiana Utility Regulatory Commission

Tamara Turkenton
Public Utilities Commission of Ohio

Cynthia Wilson-Frias
Rhode Island Public Utilities Commission

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