RHODIUM GROUP

What Is It Worth?

The State of the Art in Valuing Distributed Energy Resources

Prepared for the U.S. Department of Energy

January 2017

What Is It Worth

The State of the Art in Valuing Distributed Energy Resources

January 2017

John Larsen and Whitney Herndon

Table of Contents

About the Authors

Rhodium Group (RHG) combines policy experience, quantitative analysis and on-the-ground fieldwork to analyze disruptive global trends. Our independent research supports the investment management, strategic planning, and policy analysis needs of clients in the financial, corporate, non-profit and government sectors. RHG has offices in New York, California and Hong Kong, and associates in Washington, Singapore and New Delhi.

John Larsen is a Director at RHG and leads the firm's U.S. power-sector work. Previously, he worked for the U.S. Department of Energy's Office of Energy Policy and Systems Analysis, where he advised on electric power-sector policy design. Prior to working in government, he led federal and congressional policy analysis in the World Resources Institute's Climate and Energy Program. Mr. Larsen is a non-resident Senior Associate in the Energy and National Security Program at the Center for Strategic and International Studies and holds a bachelor's degree in environmental science from the University of Massachusetts at Amherst and a master's degree in urban and environmental policy and planning from Tufts University.

Whitney Herndon is a research analyst at RHG, employing a range of energy and economic models to analyze the impact of policy proposals on the U.S. electricity sector, energy market, and macro economy. Before joining RHG, she was a policy analyst at the Nicholas Institute for Environmental Policy Solutions at Duke University. She holds a bachelor's degree in environmental systems and molecular biology from the University of California at San Diego and a master's degree in environmental management from Duke University.

The authors would like to thank Fred Wellington (Leidos Engineering) and Kristin Igusky (World Resources Institute) as well as staff of the Office of Energy Policy and Systems Analysis at the Department of Energy for their helpful comments and feedback on previous versions of this report.

List of Acronyms Used in this Report

Bulk power system	BPS
Combined heat and power	CHP
Demand response	DR
Department of Energy	DOE
Distributed energy resource	DER
Distribution Locational Marginal Pricing	DLMP
Distribution System Operator	DSO
Distributed System Platform	DSP
Electric Power Research Institute	EPRI
Electric vehicle	EV
Energy efficiency	EE
Independent Distribution System Operator	IDSO
Independent system operator	ISO
Infrastructure-as-a-service	IaS
Kilowatt-hour	kWh
Location Marginal Pricing	LMP
Megawatt	MW
Megawatt-hour	MWh
Net Energy Metering	NEM
Performance Based Ratemaking	PBR
Photovoltaic	PV
Public Utility Regulatory Policies Act	PURPA
Reforming the Energy Vision	REV
Regional transmission organization	RTO
Rhodium Group	RHG
Total Resource Cost	TRC
United States	U.S.
Value of Solar	VOS

Executive Summary

The U.S. electric power sector is in the midst of a significant transition. For much of its ~140 year existence, the U.S. electric system has been based on a foundation of large, centralized baseload power generators connected by transmission and distribution lines to demand loads. During this time electricity flow moved exclusively in one direction, from generators to consumers. The status quo is shifting towards a more decentralized and dynamic two-way system, with increasing amounts of utility-scale and distributed renewable generation. This shift is due to a variety of factors including slowing demand for electricity, persistently low natural gas prices, federal and state environmental regulations, and rapidly declining costs of renewable energy resources, as well as the growth of distributed energy resources (DERs) on the consumer side of the meter. The U.S. Department of Energy (DOE) commissioned Rhodium Group (RHG) to focus on this last driver of change in this report.

DERs have played a relatively minor role in the U.S. power system historically, but their place in the network is changing rapidly. Improvements in technology costs and capabilities, public policy support, and an array of new energy service providers have led to rapid customer adoption and substantial penetration of DERs—in particular solar photovoltaics (PV)—in some markets such as Hawaii and California. In these markets DERs are having tangible effects on distribution system operations and are posing new challenges and opportunities for distribution utilities, regulators, and incumbent market participants. If employed strategically DERs have the potential to help lower costs and improve the reliability of the U.S. electric system. If they are not deployed and integrated properly, DERs could impose new system costs and challenges to reliability. Currently, DERs are not incentivized to provide energy services on the distribution grid in a comprehensive way, nor do they compete on a level playing field with conventional utility- scale technologies. One of the key challenges facing both regulators and market participants associated with DERs is determining what services DERs can or should provide, determining the value of those services, and compensating them accordingly. As more DERs come on line, resolving these issues becomes increasingly critical for planning and operation of the distribution system.

This report explores the latest peer-reviewed literature to provide a broad view of the DER landscape with a focus on current and cutting-edge efforts to value the services that DERs provide to distribution systems and the bulk power system. The goal is to give state and federal regulators, and electric power stakeholders, a deeper understanding of what DERs are, what services they can provide, the options available for quantifying the net value of these services, and regulatory frameworks that could accommodate or potentially hasten the transition to a cleaner and more resilient power system. This report is intended to serve as a resource for power sector decision makers as they wrestle with the ascent of DERs and the broader power sector transition. Based on the research conducted in this report the following key findings were identified:

DERs can contribute to the development of a more flexible, cleaner, and affordable electric power system if they are fairly compensated for the net value of the services they provide, and that net value is fully considered in distribution utility planning and operations. See Chapter 2 for further discussion.

- Different DER technologies can provide different electric services of value to utilities and customers. Where DERs can provide these services at lower net-cost than conventional utility investments and practices they could lower costs for utilities and consumers while maintaining a similar or improved level of service.

- A more flexible and cleaner distribution grid supported by DERs and optimized by system planners could enable long-term deep decarbonization of the U.S. electric power system and broader energy systems.

Current distribution utility regulatory and oversight frameworks either do not value all DER services or do so through inconsistent and incomplete administrative valuation and compensation procedures. Technology neutral, market-based valuation approaches can enable more complete and dynamic assessments of value and appropriate compensation, and could establish a level playing field where DERs can compete alongside other grid resources. See Chapter 3 for further discussion.

- Different valuation and compensation methods are used for different DERs in different contexts. For example, demand response (DR) is often valued through competitive wholesale markets and receives compensation for multiple grid services while energy efficiency (EE) programs are subject to a series of administrative benefit costs tests. Meanwhile, solar PV is compensated primarily through administrative frameworks such as net energy metering (NEM) or sometimes Value of Solar (VOS) tariffs.

- Most administrative valuation and compensation frameworks employ a variation on an avoided cost approach. This leads to over and undervaluation of DERs compared to their actual contribution of grid services and may not lead to the most cost-effective deployment of energy resources from a system-wide perspective.

- The value of and compensation for services provided by DERs can change with different levels of DER penetration. For example, the value of energy generated by solar PV declines as penetration increases because this particular technology tends to put downward pressure on peak wholesale prices. Depending on their design market-based valuation approaches can account for the locational, temporal, and technological profiles of specific DERs. Moving away from administrative compensation and towards market-based approaches will be an important step in establishing price signals that can direct the deployment of DERs to where they are most valuable on the distribution system and can adjust for changing grid dynamics as deployment increases.

- While there is no one-size-fits-all solution, examples of market-based valuation and compensation models currently in use or under development include competitive utility procurement of solar PV energy services, the use of the Infrastructure-as-a-service (IaS) model, and the design and implementation of a Distribution System Operator (DSO) or Independent DSO (IDSO) model that would allow for competitive markets for a variety of energy services within the distribution system.

Revisions to the traditional cost-of-service utility regulatory model may be required to properly value DERs and fully incorporate them into distribution system planning and operations. See Chapter 4 for further discussion.

- The trends behind the surge in DER penetration may continue and could accelerate, leading to a distribution grid that must accommodate two-way flows of electricity. This is a departure from the traditional one-way flow of electricity from central generators to customers. This transition will take years or possibly decades. States experiencing relatively fast penetration of DERs are likely to lead in the area of regulatory reforms.

- The traditional cost-of-service utility regulatory model generally does not place DERs within the core functions of distribution utilities. DERs can erode the two traditional utility revenue sources: rates of return on capital investments and electricity sales. Most state regulatory actions concerning DERs to date have focused on incremental changes to regulatory models to handle specific conflicts with utility cost-of-service revenue streams. However, a handful of states are working on comprehensive revisions that could better accommodate DERs.

- There are several possible options for revising the regulatory model in ways that can place DERs within the core functions of the utility and lead to market-based valuation and fair compensation of DERs. These options include allowing utilities to receive new revenue streams from providing value added services or by incentivizing utilities to create more value from existing and new assets. The ultimate pathway for revising regulatory models will be subject to a particular state's legal and administrative constructs.

Additional research in several areas related to DER valuation and utility regulatory frameworks could provide new and innovative options for utilities and regulators as they consider optimal pathways for integrating DERs into the electric power system.

- DERs are one of several challenges facing utilities and regulators. Other challenges include improving system resilience, protecting the electric power system from cyber and physical security threats, and federal and state policies to reduce power sector CO_2 emissions. Research on planning, operations, and regulatory options for holistically addressing all or most of these issues alongside DER integration could be valuable to a variety of stakeholders.

- The benefits of market-based approaches to DER valuation are clear, but outside of organized markets and competitive procurement few options are currently available to utilities and regulators.

Research into the design of new and innovative methods for market-based valuation of DERs could expand the options available and potentially increase adoption of these approaches.

Alternative regulatory frameworks explored in this report are very different from the typical cost-of-service framework used throughout the US. Identifying intermediate steps in the implementation of revisions to regulatory frameworks and options for easing the transition between steps could minimize friction between stakeholders and potentially increase the adoption of regulatory reforms

CHAPTER I

Introduction

The U.S. electric power sector is in the midst of a significant transition. For much of its ~140 year existence, the U.S. electric system has been based on a foundation of large, centralized baseload power generators connected by transmission and distribution lines to demand loads. During this time, electricity flow moved exclusively in one direction, from generators to consumers. The status quo is shifting towards a more decentralized and dynamic two-way system with increasing amounts of utility-scale and distributed renewable generation. This shift is due to a variety of factors including slowing demand for electricity, persistently low natural gas prices, federal and state environmental regulations, and rapidly declining costs of renewable energy resources, as well as the growth of distributed energy resources (DERs) on the consumer side of the meter. The U.S. Department of Energy (DOE) commissioned Rhodium Group (RHG) to focus on this last driver of change in this report.

DERs have played a relatively minor role in the U.S. power system historically, but their place in the network is changing rapidly. Improvements in technology costs and capabilities, public policy support, and an array of new energy service providers have led to rapid customer adoption and substantial penetration of DERs, in particular solar photovoltaics (PV) in some markets such as Hawaii and California. In these markets DERs are having tangible effects on distribution system operations and are posing new challenges and opportunities for distribution utilities, regulators, and incumbent market participants.

Drivers of DER penetration, in particular technology cost reductions, may persist and accelerate in the near and medium term, leading to greater deployment in additional markets. Meanwhile, as greater amounts of variable renewable generation are added and more baseload, central generation is retired in the bulk power system (BPS), increased operational flexibility will be needed. If employed strategically, DERs have the potential to help lower costs and improve the reliability of the U.S. electric system. If they are not deployed and integrated properly, DERs could impose new system costs and challenges to reliability. They could also potentially play an important role in decarbonizing the grid as well as the broader energy system. Currently, DERs are not incentivized to play these roles on the grid in a comprehensive way, nor can they compete on a level playing field with conventional, utility scale technologies. New designs for markets and electric rates could change this, but only if the value of these DER services can be determined and fair compensation for them can be established.

States and utilities are wrestling with these and other issues, including the need to replace aging grid infrastructure, meet new federal CO_2 reduction requirements, and modernize the grid. Twelve states have opened regulatory dockets to review their current policies regarding DERs.[i] These reviews and other state actions could result in revisions to long standing DER compensation structures, most notably Net Energy Metering (NEM), and possibly revisions to broader utility regulatory models (see Text Box 1). Improved methods for valuing the services that DERs provide have become a key point of focus in New York and California's review processes. These states and others are exploring how to revise distribution utility, regulation planning,

TEXT BOX 1: THE TRADITIONAL COST-OF-SERVICE UTILITY REGULATORY FRAMEWORK

In order to ensure safe and reliable electricity delivery, public utilities have traditionally been regulated as natural monopolies because of the economies of scale and scope. Within this regulatory model public utilities are vertically integrated, owning generation, transmission, and distribution assets and utilities were compensated based on their "cost-of-service." Using cost-of-service regulation, rather than being set by a competitive market, regulators approve the cost of providing electricity and these cost are then passed to rate-payers. The cost of providing electricity includes capital expenditures operation and maintenance, depreciation, taxes, and the rate-of-return required for investment in the public utility. In deregulated states utilities no longer own generation and instead procure energy through competitive markets. Still, the distribution (and sometimes transmission) functions of the utility continue to operate under cost-of-service regulation.

and incentives to more fully integrate DERs in to their power systems.

OBJECTIVES AND APPROACH

One of the key challenges facing both regulators and market participants associated with DERs is determining what services DERs can or should provide and determining the value of those services. As more DERs are coming on line, resolving these issues becomes increasingly critical for planning and operation of the distribution system. This report seeks to provide a broad view of the DER landscape with a focus on current and cutting edge efforts to value the services that DERs provide to distribution systems and the broader U.S. electric power system. The goal is to give state and federal regulators and electric power stakeholders a deeper understanding of what DERs are, what services they can provide, the options available for valuing these services, and regulatory frameworks that could accommodate or potentially hasten the transition to a more flexible grid.

To accomplish that objective this report relies on a variety of public data sources as well as the latest peer reviewed literature from academic, government, and industry sources. This report focuses on foundational and generally applicable research that can provide the broadest base for informed policymaking and is intended to serve as a resource for power sector decisionmakers as they wrestle with the ascent of DERs and the broader power sector transition.

ORGANIZATION OF THIS REPORT

This report is organized as follows:

Chapter 1 (Introduction) describes the objectives and analytical approach used in this report.

Chapter 2 (Distributed Energy Resources – The Current and Future Technology Landscape) defines DERs and reviews the array of grid services they can provide. Historical trends in DER deployment to date and the drivers behind these trends are reviewed. Near-term forecasts of DER deployment are also explored and examples of current and possible future commercially available DER technologies are provided.

Chapter 3 (Options and Methods for Valuing DERs) explores general approaches to valuing DERs, how those approaches differ across technologies, and how the value of DERs can change with increasing penetration and at different locations on the distribution system. The potential upside for the electric power system from a standardized, consistent, and technology neutral approach to valuing DERs across technologies is also considered.

Chapter 4 (Operationalizing DER Valuation Through Regulatory Frameworks) builds on Chapter 3 by identifying and exploring regulatory frameworks that can be implemented to incorporate DER value into distribution system and BPS operation and planning decisions. Revisions to electric rate frameworks are also explored. As there may not be a one-size-fits-all regulatory pathway, multiple potential frameworks are explored.

Chapter 5 (Findings and Areas for Future Research) provides key findings for consideration based on this report's review of the literature and identifies areas for further research and exploration.

CHAPTER 2

The Technology Landscape

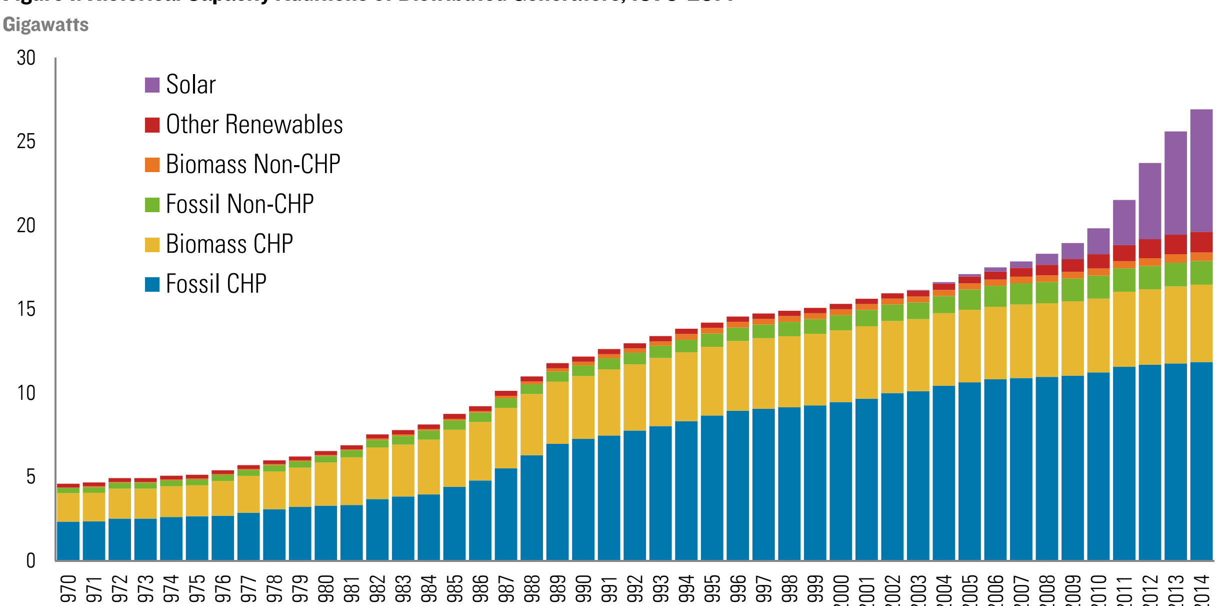
In this chapter a working definition of DERs is established for the purposes of this study. DER literature is reviewed with a focus on the different types of services commercially available DERs can provide to the power system and the value associated with those services. Finally, innovation of DERs is explored to examine how cutting edge technologies could expand the types of services provided to the grid in the not-to-distant future.

WHAT ARE DERS?

This report relies on an inclusive definition of DERs. Specifically any generator, storage, demand control, or energy efficiency technology located "behind the meter" on a customer's premises or connected directly into the local distribution system. This is done in recognition that a variety of different technologies can and are used to fulfill different customer needs.

This definition of DERs includes combined heat and power (CHP) units at commercial and industrial facilities, fuel cells, micro turbines and reciprocating engines, household generators, and other fossil-fuel fired generators. It also includes zero-emitting resources such as battery storage, electric vehicles, distributed solar photovoltaics (PV), and wind, as well as non-generation assets such as demand response and energy efficiency. In relation to resources in the BPS, DERs are small-scale, typically but not always measured in kilowatts of capacity rather than megawatts. DERs are installed by customers, distribution utilities (as discussed later in this paper, where permitted by state law), and by third parties for a variety of reasons depending on the services required by the electric system.

Figure 1: Historical Capacity Additions of Distributed Generators, 1970-2014[ii]



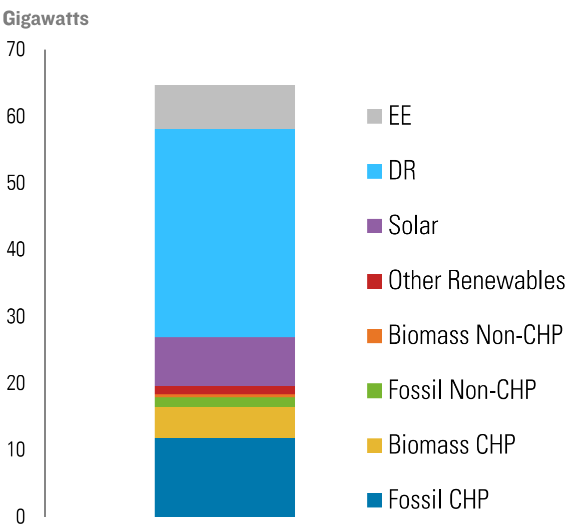
Distributed generation has played a role in the electric power sector for several decades. Historically, these DERs have consisted of dispatchable resources; however the recent increase of non-dispatchable PV capacity marks a change in this tren d.

When thinking about DERs it is important to not only consider a particular technology in isolation. Increasingly one or more DER technologies are being deployed in combination with information and communication technologies. These DER systems have the potential to provide a broad range of electric system services that extend beyond what an individual DER could provide on its own.[iii] For example, the combination of battery storage and rooftop PV with a smart controller can turn variable solar power into a dispatchable generator that is responsive to market signals. DER systems have the potential to expand the capabilities of individual technologies, opening up the possibility of providing a broader array of grid services.

WHAT ROLES DO DERS PLAY IN THE ELECTRIC SYSTEM?

The participation of DERs in the electric power system goes back several decades. From the 1970s through the turn of the century, distributed generation DER largely consisted of CHP at industrial and large commercial sites (Figure 1). While not shown in Figure 1, utility and wholesale market Demand Response (DR) programs as well as energy efficiency (EE) programs have also represented a significant share of total DERs (both generation and non-generation resources) deployed, as illustrated by the fact that they made up a majority of total DER capacity in 2014 (Figure 2). DR programs compensate large distribution utility customers for reducing demand during peak load periods. In recent years, renewable energy technologies, most notably solar PV have been added to the grid at an accelerating pace. Taking this long view, DERs have historically been deployed by customers with large electric demand for the purposes of meeting demand onsite (CHP) or for providing DR resources that can be called upon by grid operators just like generators operating within the BPS. Not included in these data are fossil fuel-fired generators used by residential customers to provide backup power in the event of an outage.

Figure 2: DER Installed Capacity, 2014[iv]



Non-generation DERs such as DR and EE represent the majority of currently available DER capacity.

Customer side distributed generation is not new, but its role in the electric system is changing. For example, the recent rise of PV represents a departure from historical norms in which DERs serving customer load can also sell surplus power into the distribution system through enabling policies such as NEM. Technologies that enable more industrial, commercial, and residential customers to participate in demand response, where load is reduced or shifted in order to minimize constraints on the electric system, are opening up new opportunities for customer pricing and interaction with grid operations.

WHAT DEPLOYMENT CHALLENGES DO DERS FACE?

PV is one example of how DERs have become controversial in some parts of the U.S. The rise of distributed PV is new in two important ways. First, it puts greater demands on grid operators than other common DERs (i.e. CHP and DR) because it is not dispatchable.[v] Second, because it is located behind a customer's electric meter it is typically viewed as a reduction in load rather than a generator. Without additional data systems, utilities and grid operators may not have the information required to "see" the capabilities of these DERs and anticipate how they fit within grid operations.[vi] These attributes of PV explain in part why DERs have become controversial in some power markets in recent years. Another factor is that NEM, the most prevalent compensation framework for distributed PV generation has led to concerns that distribution service costs are being shifted unfairly towards non-PV customers. NEM is explored in more detail later in this report. Increasing amounts of DERs, led by PV, are requiring utilities, grid operators, and regulators to rethink how they manage the electric power system.

Meanwhile, DER deployment is expected to accelerate. Technology costs for a variety of DERs have been declining, fueling their accelerated deployment.[vii] These trends are projected to continue in the near term. For example, distributed solar PV capacity is projected to increase by a factor of four within the next decade.[viii] Incentives such as Federal Tax credits, State Renewable Portfolio Standards and Energy Efficiency Resource Standards have led to the deployment of more DERs into the marketplace.[ix] In addition, increasing innovation in the information technology space is expected to unleash a new wave of building automation and demand control distributed energy systems that could open up new DR and EE opportunities for residential and commercial customers.[x] These new technologies have the potential to both provide value to the electric system or impose new costs depending on how regulatory and market structures evolve or do not evolve to fully incorporate DERs. They also can shift customers to become more proactive managers of where their electricity comes from.[xi] As costs decline for these technologies consumer demand for them is likely to increase.

WHAT SERVICES CAN DERS CURRENTLY PROVIDE TO THE ELECTRIC SYSTEM?

This section explores what services DER technologies can provide to the grid. Without an understanding of these services it is difficult to establish the value of providing them. Within the literature there is no single reference list of energy services or products available. Indeed, scholars argue that there are as few as three and as many as 207 distinct products, services or benefits that DER can provide to the grid.[xii] The reason for the broad spread is the specificity used in describing the products. For example, Tabors, et al. argues that there are three core electric products that are central to the operation of power systems (real energy, reactive power and reserves) with all other products being derivatives or combinations of the first three.[xiii]

The MIT Energy Initiative provides a broader list of electric power system service requirements that can be met with DERs that essentially expands on the three core products (Table 1) both in specificity of services and the perspectives of different stakeholders.[xiv] Beyond energy, voltage control, and reserves, MIT lists more specific services such as increased reliability and outage recovery deferral of system capital investments, reductions in system operating costs, and arbitrage of price differentials. Ancillary services such voltage control and frequency regulation are also included. All of these services could be valuable to utilities, regulators, and ratepayers. Again, different DER technologies can provide different services depending on their capabilities. This point is explored in detail below.

Table 1: Electric Power System Services[xv]

Service	Description
Energy	Electricity produced (MWh).
Power / Capacity	The amount of power (MW) available to the grid from a generating resource at a point in time.
Voltage control	Regulation of the voltage required for transmission and distribution lines to transport and deliver power.
Frequency regulation	Small short-term generation changes on the grid required to maintain a frequency of 60 hertz on transmission lines.
Increased reliability / Resilience to outages	Preventing blackouts in, and maintaining reliable electricity delivery to, distribution circuits.
Black- start / Outage recovery	Providing start up power to generating units after an outage.
Primary Reserves	Generating units or demand resources that respond immediately to stabilize grid frequency in the event of a system disturbance or loss of a generating unit.
Secondary Reserves	Generating units or demand resources that respond within minutes of primary reserves to return grid frequency to nominal levels in the event of a system disturbance or loss of a generating unit.
Tertiary Reserves	Generating units or demand resources that allow primary and secondary reserves to return to their normal reserve state after the event of a system disturbance or loss of a generating unit.
Flexibility / Integration of variable renewables	The ability to provide energy to the grid on a flexible basis which can be useful for balancing the variable generation profile of renewables.
CapEx Investment deferral	The ability to reduce or eliminate a shortfall in energy or capacity so that capital expenditures for upgrades at existing facilities or investment in new centralized resources are not necessary.

Reduction of losses	The reduction of transmission and distribution losses on the grid.
Risk- mitigation	Services to the grid that reduce financial or energy security risks.
Arbitrage of energy price differentials	Buying power at times when power prices are lower or when there is excess generation supply and storing it for the purpose of selling it back to the grid when demand and prices are higher.

The electric power system requires a variety of services to function efficiently and reliably. DERs can provide these services depending on the locational, temporal and technological profiles of specific technologies.

When looking at the array of DERs commercially available today, it is clear that no single technology can provide all services required by electric power system. Table 2 takes an abridged set of information from MIT's assessment of system service needs and compares the capabilities of a leading set of DERs against them. While a comprehensive comparison of services and capabilities is outside the scope of this paper, the table illustrates the point that different DER technologies can play different roles on the grid. The table assesses six DER technologies: Solar PV, Industrial CHP, Residential natural-gas fired sterling and reciprocating engines (generators), Distributed Battery storage, DR (energy management systems), and EV charging. An "X" signifies that a particular service is provided by that DER. Of these six the first four can provide energy to the grid, while DR and EV charging cannot. However, DR and EV charging can help balance load with variable RE generation just as battery storage, CHP, and generators can. The choice of DER to meet specific grid requirements will be dependent on how a technology's service profile matches with these needs.

Table 2: Technology Assessment for Select DERs and Electric Power System Services[xvi]

	Energy	Power / Capacity	Voltage control	Frequency regulation	Increased reliability / Resilience to outages	Black- start / outage recovery	Primary Reserves	Secondary Reserves	Tertiary Reserves	Flexibility / Integration of renewables	CapEx Investment deferral	Reduction of losses	Risk- mitigation	Arbitrage of energy price differentials
Solar PV	X	X			X							X		X
Industrial CHP	X	X	X	X		X	X	X	X	X				X
Residential / commercial natural gas-fired Sterling engines	X	X	?	?	X			X	X	X		X		X
Distribution system lithium-ion battery storage	X	In agg.	Poss.		X	X		X	X	X	X		X	X
Demand response (home energy management systems)		Poss.					Poss.			Poss.	Poss.	Poss.		
Smart unidirectional EV charging			X	X						X				

This table provides examples of how different DERs could provide different services to the electric power system based on their specific technological capabilities. "In. agg." = In aggregate. "Poss." = Possible

This report primarily relies on this list of services derived from work by MIT in an effort to focus this paper on key policy and market questions related to valuing DERs. The list includes a reasonable level of granularity and breadth, and aligns well with other studies in the literature.[xvii]

WHAT SERVICES CAN DERS PROVIDE IN THE FUTURE?

DERs could potentially provide a broader set of services to the grid with additional technological innovation and regulatory frameworks that enable cutting edge technologies to contribute to distribution system operations. While it is impossible to cover all potential options and developments, a few examples are provided to illustrate what is possible. One example involves smart inverters. Smart inverters can provide ancillary services by adjusting the power factor of the PV system they are associated with.[xviii] This technology has not been widely deployed though it is commercially available; some utility pilot projects are underway.[xix]

Improvements in information and communications technology could enable autonomous load control and vehicle-to-grid capabilities that could allow EVs and buildings to provide grid services revolving around demand flexibility. Demand flexibility is an expanded, more sophisticated type of demand response that allows demand to shift continuously in response to changing market conditions through price signals. These new capabilities could help balance electric loads with variable generation resources including PV and wind, and could also provide ancillary services. One study has found that widespread deployment of demand flexibility in the residential sector could cut grid costs by 10-15% and reduce customer electric rates by 10-40%.[xx]

Finally, combinations of distributed generators, storage, and demand response could be aggregated into dispatchable, remotely controlled virtual peaker plants. This example of a distributed energy system could be operated by a distribution utility or third party aggregator and could compete directly with centralized generators in the BPS in capacity markets. While the technologies that could enable this type of system are not yet available, they hold the potential to by highly disruptive to generation utilities if this type of distributed energy system can provide capacity services at a lower cost compared to traditional generators.[xxi]

Current and future DER service capabilities could play an important role in the U.S. response to mitigating climate change. DERs have the potential to support the long-term decarbonization of the electric power sector through storage and balancing of variable zero-carbon generation and reduced demand from energy efficiency.[xxii] Over the long term if electrification of the majority of energy uses across the economy were to take place, these same services could allow DERs to contribute to the decarbonization of the entire U.S. energy system.[xxiii]

While the potential of DERs is great it won’t be captured without fully understanding the value that DER services provide, and taking the value into account in grid planning and operations. This chapter reviewed the types of services DERs can provide. The next chapter examines options for valuing these services.

CHAPTER 3

Options and Methods for Valuation

With the completion of the review of leading DER technologies and the power system services they provide, this report turns to the process of valuing these services. Approaches to valuing services provided by DERs vary considerably across jurisdictions, components of the electric power system, and DERs themselves. This chapter explores general approaches to valuing DERs, how those approaches differ across technologies, and how the value of DERs can change with increasing penetration and at different locations on the distribution system. The potential upside for the electric power system from a standardized, consistent, and technology-neutral approach to valuing DERs across technologies is also considered.

VALUE OF DERS OCCURS ACROSS THE ELECTRIC POWER SYSTEM

Value in the DER context means different things depending on whether the entire electric system is being considered or only one of its constituent components. Value can also vary depending on the stakeholder perspective (utility, customer, etc.) to which a particular DER is being considered. This report takes a system-wide view, where the value of DERs consists of four components reflecting the constituent parts of the power system plus broader impacts:

- **Generation:** The value of DERs contribution to the power generation system to meet aggregate demand at least cost. Examples include avoided generation or fuel and avoided capacity.

- **Transmission:** The value of DERs in facilitating least-cost delivery of power over the high voltage transmission system. Examples include deferred transmission capacity additions and avoided line losses.

- **Distribution:** The value of DERs in enabling reliable least-cost distribution of power to and between end-use customers. Examples include avoided integration costs and avoided distribution system capacity additions.

- **Customers and Society:** The value of DERs in mitigating externalities associated with the power system. Examples include abatement of air and water pollution, as well as other societal impacts such as increased employment and economic development.

The services required by the electric power system fit within these four constituent parts and can often touch on more than one. The available literature suggests that the value of DERs is found mostly in the generation and transmission components of the power system.[xxiv] This is in line with the historical deployment of DERs, where the majority of DER installations to date have provided either energy or capacity services to the BPS and/or consumers. Indeed, in some markets valuation approaches for DERs are quite sophisticated and leverage competitive markets at least for specific services provided by a specific type of DER. The best example is DR deployed in parts of the country with competitive wholesale markets. In these markets large industrial and commercial consumers can participate in capacity markets or other load management programs by committing to reduce demand by a set amount when called upon. DR providers are compensated for delivery of capacity like power plants. The result is a reduction in peak loads.

Most approaches currently in use pull these various system components and services into a single valuation framework.[xxv] The separate values associated with each service a specific DER provides to each component of the electric power system are aggregated into a single unified value. This reduces the transparency and granularity of DER valuation into a single form of compensation, as opposed to an unbundled approach that considers separate values for services provided at each level of the power system and to society. Maximizing the potential contribution of DERs to the power system will require some unbundling of services to different levels of the power system. Without unbundling distortions may occur that lead to the over or under valuation of specific DER services and/or a lack of accounting for system costs that may be incurred when additional DERs are deployed. This is already occurring in some markets due to the proliferation of PV spurred by NEM policies.

The services typically valued within the generation and transmission components of the electric power system are avoided generation (or power-plant fuel), avoided operations and maintenance, avoided capacity and reserves, and avoided transmission capacity. Value of DERs to the distribution system is primarily represented by avoided distribution capacity investments. Within most valuation approaches these avoided costs are typically calculated based on recent historical data and can be static. They do not get frequently recalculated, as DER penetration and BPS fuel mix change over time. This is not unlike the approach initially used under the Public Utility Regulatory Policies Act (PURPA) in requiring utilities to purchase generation from merchant power plants at a predetermined avoided costs.[xxvi] Tierney argues that initial PURPA avoided cost frameworks led to inefficient and suboptimal outcomes that did not take into account the particular attributes of generators—such as their generation profile and location—leading to under or over compensation for power. Tierney cautions that regulators should quickly transition past bundled, avoided cost based valuation frameworks (including NEM as well as Value of Solar tariffs, discussed in detail below) to market-based frameworks that set compensation and performance requirements for DERs.[xxvii] This issue is explored further below.

DERs can also provide value to society. This can come in the form of reduced air pollution if DERs displace fossil generation on the grid. If DERs lead to lower electric rates through reduced costs of system operations then all consumers receive a financial benefit. The degree to which DERs serve as a potential driver of economic development and/or employment and deliver a benefit society could also be valued.[xxviii]

VALUE OF DER CAN BE EXPRESSED IN MORE THAN JUST MONETARY TERMS

Many services provided by DERs are readily quantifiable in monetary terms, making it relatively easy to incorporate them into a static valuation framework. Avoided energy and capacity costs at the generation, transmission, and distribution level fall into this category. These services are the mainstays of practically all valuation studies in the literature. While direct monetization is the most straightforward and reliable approach to quantifying benefits and costs there are some services that are not readily monetized, but clearly represent potential costs or benefits to the electric power system and/or society. Drawing from the list of service requirements from the previous chapter, examples of some difficult to monetize services include:

- Risk mitigation
- Reduced environmental impacts
- Economic development impacts

Some have argued that services that are not readily monetizable should still be incorporated into DER valuation frameworks.[xxix] In most cases, valuation conventional grid resources do not include the value of non-monetized services. If regulators do choose to consider non-monetized services when valuing DERs without extending those same considerations to all grid resources then DERs may end up being valued on an uneven playing field. In some studies, the value of services where quantitative monetized values aren't available can represent a large component of the total value of DERs. For example, one review of solar PV valuation studies found that incorporating the cost of CO_2 increased the value of solar PV by more than 2 cents/kWh.[xxx] Doing so can require the use of proxy values, alternative metrics, regulator judgement, and other approaches to simplify the challenge of monetizing the value of certain services and incorporating them into broader valuation frameworks. For example, CO_2 benefits can by monetized by using the federal Social Cost of Carbon or market price for CO_2 allowances (in states with cap-and-trade programs).[xxxi] Depending on statutory and regulatory requirements and norms in each state, different approaches to assessing non-monetized values may be more appropriate than others.

VALUE OF DER CAN CHANGE WITH PENETRATION AND LOCATION

As discussed at different points in this chapter, due to their inherent technological profiles the value of specific DERs can change substantially with increased levels of penetration. This fact is often overlooked in administrative, avoided cost based DER valuation and compensation (discussed in detail below). The direction and magnitude of the change in value is specific to a type of DER in a particular electric market, but the general point holds. For example, PV can reduce wholesale marginal prices in the middle of the day when the sun is shining. It does this either through reductions in net load on the grid (in the case of distributed PV) or through bidding energy into wholesale markets (in the case of utility-scale PV) at a price of zero, reflecting the lack of any marginal cost of generation since PV does not have any fuel costs. At low penetrations of PV customers may see a benefit as peak mid-day prices are reduced through lower demand and/or lower marginal wholesale prices. But this benefit shrinks as more PV penetrates the grid. Each additional increment of PV installed can put downward pressure on wholesale prices when the sun is shining. This lowers the price paid to all on the grid including PV and can lead to lower retail electric rates.[xxxii] The result is a reduction in compensation to all PV generators as PV penetration increases. This issue highlights the importance of dynamic valuation and compensation of DER services on the grid that can automatically update as market conditions change.

Without storage to store PV energy for use at other times of day, high penetration of PV could inflict new costs on the grid through requiring fast ramping generation to be available for early evening hours when PV generation does not sync up with peak demand. High PV penetration can also begin to displace baseload generators (such as nuclear units) and lead to curtailment of PV at certain times of day, greatly reducing the value of these resources. One study estimates that the economic value of energy from PV in California at 30% penetration could be 65% lower than the value of PV at 5% penetration.[xxxiii] Indeed, in California expected increases in PV generation are projected to put substantial downward pressure on wholesale prices in light load months such as March. By 2020 prices could be low enough to put substantial pressure on baseload generators and could result in oversupply problems.[xxxiv] Hawaii utilities are already experiencing load ramping challenges due to relatively high PV penetration.[xxxv] This example is specific to PV. Increased penetration of other DERs may yield different results depending on their technological, temporal, and locational profiles.

Related to the changing value of DERs at different penetration levels is the fact that DER values are highly dependent on their location on distribution system. For example, a typical rooftop PV installation on a circuit with no other DERs present is likely to have no negative impact on system costs, as the circuit has ample capacity to accommodate the small amount of power flowing in from the PV customer. However, at much higher PV penetration levels on this same hypothetical circuit, the additional two-way power flow could put a strain on capacity and could accelerate wear and tear on system components, leading to faster replacement and higher system costs. Current valuation frameworks sometimes consider these potential costs associated with DERs, but typically look at them from a system-wide level. Averaging these costs over the system overlooks the fact that DER deployment targeted to where it can produce the greatest benefits could lead to greater net benefits compared to traditional non-locational approaches. ConEdison's Brooklyn/Queens Demand Management project, discussed in greater detail below, illustrates that locational value is also important for comparing DERs against traditional distribution system investments. In this example, a large system capacity requirement was located on the system and a portfolio of DERs targeted at that location was deemed to be the most cost-effective option compared to a new substation. The same portfolio of DERs in a different location on the system may not have provided the same capacity benefits.

VALUATION AND COMPENSATION OF DERS FROM THE UTILITY PERSPECTIVE: ADMINISTRATIVE AND MARKET-BASED APPROACHES

In both planning and operating decisions across the electric power system there are essentially two general approaches used to compensate DERs for the value of the services they provide to the electric system: an administrative approach or a market-based approach. Note that while the administrative approach sets up a proceeding to determine the value of DERs so that they can be adequately compensated, under the market approach value and compensation can be synonymous. In this report the term administrative approach is intended to encompass valuation methods that use an administrative proceeding, such as a Public Utility Commission action, to determine the value of a specific DER or portfolio of DERs in addition to how utilities, third-parties, and/or consumers are compensated for operating them on the electric power system. Typically, market-based approaches to valuing some grid services are more commonly in use in deregulated markets than in regulated ones, though administrative approaches are commonly used if DERs are being compensated at the retail level (e.g. NEM and distributed PV). Administrative approaches usually involve some sort of determination of avoided costs. This is distinct from the market-based approach where competitive procurement or the use of markets determines the value of DERs and associated compensation. While the market-based approach may include administrative actions to enable the use of markets, these actions don't directly determine the value of DERs. DERs have the potential to erode the viability of traditional cost-of-service regulated utility business models.[xxxvi] As such, adequately assessing and applying the value of DERs from the utility's perspective may only go so far without incremental or even fundamental revisions to utility regulation.[xxxvii] This is explored in depth in Chapter 4.

To date, the common practice in assessing the value of DERs across the U.S. has been the use of an administrative approach, one of the most prominent examples being utility-driven EE programs. In EE programs, utilities are required to demonstrate that a specific program meets a benefit-cost screening test framework established by state regulators before it can receive approval to pursue the project. One common EE screening test is the Total Resource Cost (TRC), which is intended to assess whether an EE program will result in a net reduction in costs to all consumers served by the utility in question.[xxxviii] The TRC considers benefits from EE programs including avoided costs of energy, capacity, transmission and distribution, and some difficult to monetize non-energy benefits. It also considers the administration, program (typically financial incentives), and participant costs of the EE program, as well as non-energy costs.

Beyond the TRC there are several other screening tests typically used for assessing EE programs, all with slightly different purposes and information on the costs and benefits for different groups. Table 3 provides a summary of standard EE screening test and their implications. They range from the Societal Cost Test, a broad assessment of total costs to society, to more focused procedures such as the Utility Costs Test that determines the impact of a program on the average customer. Different state regulatory bodies use one or more of these tests to determine the overall value of a specific EE program. These same tests can be adjusted to assess whether specific DER deployment programs provide net benefits.

Table 3: Implications of the Standard Energy Efficiency Cost-effectiveness Tests[xxxix]

Test	Key Question Answered	Costs and Benefits Included	Implications
Societal Cost Test	Will there be a net reduction in societal costs?	Costs and benefits experienced by all members of society.	Most comprehensive. Best able to account for all energy policy goals.
Total Resource Cost Test	Will there be a net reduction in costs to all customers?	Costs and benefits experienced by all utility customers, including program participants and non-participants.	Indicates the full incremental costs of the resource. Generally includes full societal costs but not full societal benefits.
Utility Cost Test	Will there be a net reduction in utility system costs?	Costs and benefits to the utility system as a whole, including generation, transmission, and distribution impacts.	Indicates the impact on average customer bills.
Participant Cost Test	Will there be a net reduction in program participant costs?	Costs and benefits experienced by the customer who participates in the program.	Of limited use for cost-effectiveness screening. Useful in program design to understand and improve participation.
Rate Impact Measure	Will there be a net reduction in utility rates?	Costs and benefits that will affect utility rates, including utility system impacts plus lost revenues.	Should not be used for cost-effectiveness screening. Does not provide useful information regarding rate impacts or customer equity impacts.

A variety of cost-effectiveness tests are used for assessing EE, each answers different key questions.

Market-based approaches for valuation and compensation include the use of competitive markets where DERs can directly participate as well as utility competitive procurement and compensation processes. In both options a regulatory or market framework needs to be in place to facilitate DER participation, though the framework need not exclusively focus on DERs. Other traditional distribution system investments and/or generation and transmission technologies may also compete depending on the setting. Market-based applications for valuation may focus on a specific grid services, such as capacity or energy, or it may encompass multiple services depending on the design of the framework. The advantage of the market-based approach over the administrative approach is that markets establish the value of DER services rather than a regulatory proceeding. Market-based approaches are dynamic, allowing DER value to reflect the specific needs of the grid at a given time and, in some cases, can also capture the locational value of DERs. One disadvantage is that in most markets societal benefits are not completely reflected. If the assignment of such societal benefit values is important than they can be incorporated through an administrative approach, though if they are not applied consistently across all grid resources then DERs may potentially be perceived to have an advantage.

One of the largest and most widespread examples of competitive valuation of DERs is the participation of DR (and in some instances EE and EVs) in competitive wholesale markets for energy, capacity, and ancillary services. In regions of the U.S. with competitive wholesale power markets, RTOs have allowed DERs that meet specific requirements to participate and compete alongside generation and transmission assets to provide grid services on a voluntary basis. The Supreme Court recently upheld the Federal Energy Regulatory Commission's order 745, enabling DR participation in RTO markets.[xl] In some cases customers bid into these markets directly. In other instances utilities or third-party aggregators participate by bundling services from multiple customers and distribute market revenues to end users. The value of grid services provided by DERs is determined based on the settlement prices in each market that DERs participate. One substantial advantage of the use of these competitive markets is that whatever DERs clear the market are guaranteed to be least-cost options by virtue of least cost economic dispatch.

Distributed generation DERs such as PV have typically not participated in RTO markets, but that could change. California ISO is working to change its wholesale markets to allow aggregators to consolidate and bid in services from small scale DERs such as rooftop PV.[xli] Importantly, DERs that participate in California NEM programs cannot participate, since that would lead to double compensation of services. Aggregated DERs receive compensation based on performance and location of the services as they enter the BPS. Cal-ISO has also changed its market rules to allow distributed battery storage to participate in its markets.[xlii] In effect, the Cal-ISO market changes expand on its experience with other DERs such as DR.

Competitive procurement of DER grid services is another market-based approach to valuation that is receiving increased attention. In Maine this approach is being investigated as a driver for accelerated deployment of PV to replace NEM.[xliii] In this framework, regulators require or allow utilities to procure specific grid services through competitive solicitations. This is similar to the way in which utilities and competitive retail electric providers conduct competitive solicitations for long-term contracts for energy from wholesale merchant generators. What is different is the focus on DERs and regulators' willingness to allow utilities to earn revenue from the activity. Like the use of markets described above, competitive solicitations avoid the need for administratively determined avoided cost valuations and instead allow for identification of value through competition.

Competitive procurement can also allow for competition between DERs to meet specific needs on the distribution system and can lead to new and innovative alternatives to traditional investments. The most visible example of how this can play out is ConEdison's Brooklyn/Queens Demand Management Program.[xliv] Instead of building a new substation to accommodate increased demand for capacity on its distribution system at a cost of over $1 billion, ConEdison received regulatory approval from the New York PSC to deploy a portfolio of EE, storage, and distributed generation to meet system constraints. ConEdison issued an RFI for innovative solutions that can be secured under firm contracts, and meet specific timing and performance criteria. The result is a project cost of approximately $200 million with a mix of customer-sited and utility-sited DER. While it is unclear if the vast savings from this specific example can be replicated elsewhere, the potential of competitive procurement to bring new and low cost grid solutions to the market is clear.

One theoretical market-based approach that could be used in the future is distribution locational marginal pricing (DLMP).[xlv] DLMPs are very similar in nature to the location marginal pricing (LMP) models used by RTOs to determine the value of wholesale energy at the specific location and time it is delivered on the BPS. In wholesale markets LMPs represent the marginal cost of energy production as well as the cost associated with any congestion on the transmission system. Generators in real-time wholesale markets receive compensation for the sale of energy based on the applicable LMP, depending on time and location. As the distribution system equivalent of LMPs, DLMPs could be a granular market measure of a utility's short-run marginal cost of energy delivery at the specific time and location of energy use.[xlvi] As such DLMPs would require an open competitive market for energy (and potentially other services) within a distribution system, something that currently does not exist in any state. Still, if systems were put in place to allow for competition and DLMP formation the result would be a market-based, technology-neutral DER valuation framework that would compensate DERs in real-time based on their technological capabilities, as well as their temporal and locational generation profiles. DLPMs would be dynamic and responsive to short- and long-term changes on the distribution grid as opposed to the static, avoided cost compensation frameworks used under administrative valuation approaches.

Proponents of the use of DLMPs contend that, if implemented, they could enable greater market access for DERs and support improvements to the efficiency of the distribution system.[xlvii] Several steps are required to make DLMPs a reality and they could take a number of years to put in place. Currently, distribution systems are owned and operated by regulated monopoly utilities. Under utility operation of the system, no competition exists between DERs for supplying energy services, though third-party vendors do compete to provide customers energy services behind the meter.[xlviii]

Changing this framework would require a significant change in regulation of utilities by state regulators and/or new legislation, depending on the state context. Deployment of the information and communication technology infrastructure required will take time. The computational challenges of calculating very granular DLMPs are far more complex than what is currently undertaken at the wholesale level.[xlix] After all the pieces are put in place, it may still take time for a competitive market to take shape and mature. As part of its Reforming the Energy Vision (REV) regulatory process, New York is exploring ways to start the transition to a more competitive distribution system that may support the use of DLMPs in DER valuation. This is further explored in the next chapter.

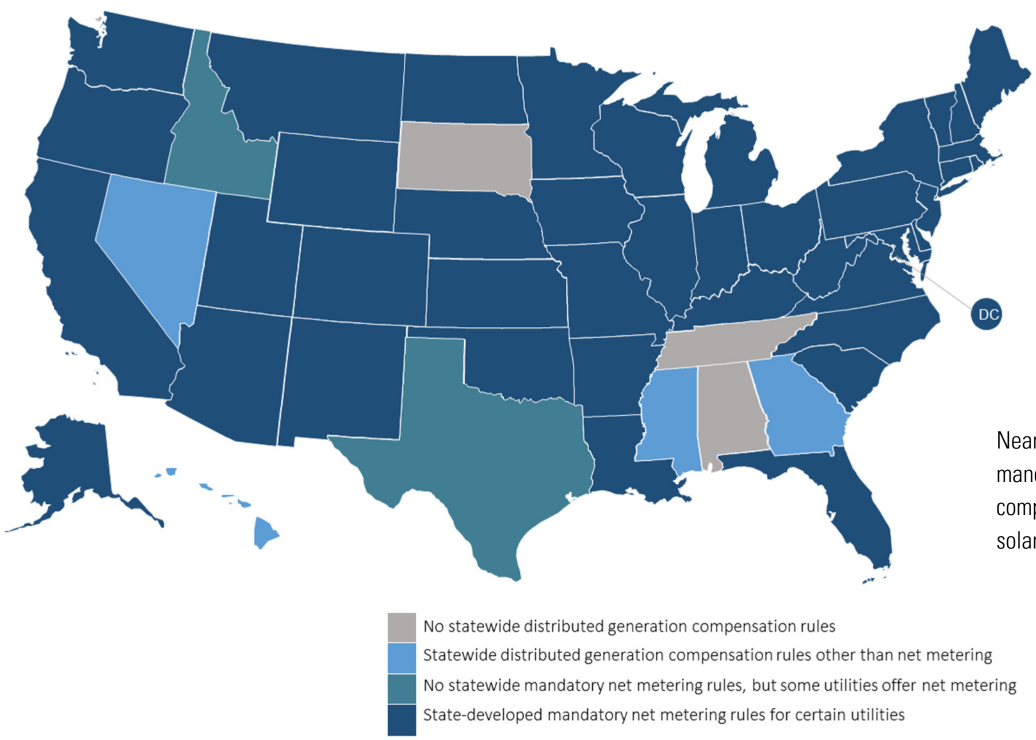
POTENTIAL GAINS FROM A GRANULAR AND DYNAMIC VALUATION AND COMPENSATION APPROACH

Whether using an administrative or a market-based approach, granular assessments hold more potential for transparent and adequate DER valuation and compensation. Methods that account for location on the distribution grid, temporal generation profiles relative to system demand, and the specific grid services provided can produce a more comprehensive picture of DER value. This can enable distribution utilities to spend smarter, avoiding bad capital allocation decisions and inflated tariffs.[l] This comprehensive picture requires much more sophisticated and complex analytics than have traditionally been used in distribution planning and policymaking. However, new frameworks such as the Electric Power Research Institute's (EPRI's) Integrated Grid as well as components of regulatory activities in New York and California are making inroads in this area.[li] As new methods are developed they can be incorporated into utility regulatory proceedings.

VALUATION AND COMPENSATION OF DERS, LEARNING FROM NET ENERGY METERING

NEM has been levered within states in order to incentivize the installations of residential and commercial distributed solar PV. Under these policies, throughout the vast majority of the states in the U.S., owners of distributed solar are compensated per kWh of electricity produced at their retail rate of electricity. Therefore, customers are only charged for the "net" electricity consumed. Existing net metering programs often have caps on commercial and residential customers to limit the total state-wide amount of capacity that can participate in the program. NEM is used for PV compensation in 41 states and the District of Columbia (Figure 3).

Figure 3: Current Net Metering and Distributed Generation Compensation Policies[lii]



Nearly all states rely on mandatory NEM for compensation of distributed solar PV.

The issues associated with using the administrative approach for valuing and compensating DERs are illustrated by NEM. While NEM has been a major driver of solar PVs surge, it has also been referred to as a blunt or imprecise instrument for valuing the services provided by PV.[liii] First, NEM does not charge the PV owner for distribution services provided to accommodate any energy sales to the grid. Second, by compensating PV based on the existing retail rate instead of the actual value of the energy that distributed PV is providing, the locational and temporal aspects that energy are overlooked. The locational aspects of DER deployment are a key component of benefits or costs they provide to the electric power system. Likewise, because nearly all ratepayers in the U.S. pay flat rates for electricity, the temporal profile of PV generation (only available during daytime hours when the sun is shining) and its impact on wholesale electric prices is not considered.[liv] Instead, customers with PV receive the same compensation regardless of the fact that they are only capable of providing power in a discreet timeframe each day. All of these issues have led to concerns from utilities and other stakeholders that NEM is leading towards cross-subsidization of solar by non-solar owning ratepayers. Indeed, from 2015 through the first half of 2016 twenty-two states changed or considered changing their NEM programs in an attempt to address these concerns.[lv]

The data on the net benefits associated with NEM are mixed. Some studies have found that NEM has and could continue to provide net benefits to the electric power system and to all ratepayers. Others have found that NEM has been successful in driving deployment of distributed PV, but the cost could outweigh the benefits for ratepayers. In an analysis of various PV deployment scenarios at prototypical utilities, Muro and Saha found that economic benefits outweigh the costs and impose no significant cost increase for non-solar customers.[lvi] On the other hand, an analysis conducted by E3 of New York's NEM program employing multiple screening tests found that the costs of NEM modestly outweighed the benefits and that there was evidence of cross-subsidization and a shift in grid costs away from PV owners to non-PV ratepayers.[lvii] The E3 study also found that if NEM installations could be targeted to higher value locations on the distribution system then NEM would yield net benefits for all customers. Regardless of the cost and benefits that NEM provides to electricity systems, moving away from compensation approaches that do not take into account the temporal and locational value of PV services will be an important step in establishing price signals that can direct DER deployment to where it can be most useful on the distribution system.

VALUE OF SOLAR (VOS) TARIFFS: MOVING FORWARD ON ADMINISTRATIVE APPROACHES

In an attempt to compensate PV in a way that better reflects its contribution to the grid. Some states are considering Value of Solar (VOS) tariffs as replacements or modifications to NEM for new PV installations. VOS tariffs are in place in Austin Energy's (Texas) service territory for some PV-owning customers and Minnesota allows investor-owned utilities to use a VOS in lieu of NEM if they choose to. The VOS approach builds on EE screening tests and benefit costs analyses of NEM in that it consists of a quantification of many of the same benefits (including avoided energy, capacity, transmission, distribution, avoided pollution, etc.) as well as the costs associated with integrating PV into the electric power system. Under a VOS tariff a solar PV customer receives a fixed price for every kWh sold to the electric grid. Meanwhile, that same customer is billed for their gross electricity consumption according to their rate class.

One review of multiple VOS studies found that the methodologies used are "all over the map."[lviii] This is due in large part to inconsistent inputs and assumptions, as there is no industry standard VOS methodology. Another important factor associated with the VOS studies reviewed is that they do not fully consider the temporal and locational attributes of PV installations. Instead, they rely on averages and discount rates that may or may not coincide with the actual impacts of PV on the grid. The reviewers recommended standardization of methods, and a more sophisticated and granular approach to assessing the temporal and locational attributes of PV. While this could add complexity and lead to different levels of compensation for PV in different applications (e.g. commercial vs. residential) and locations on the distribution grid, it would also help to direct PV deployment to where it could be most useful on the distribution system.

Two other concerns have been raised regarding VOS tariffs and their incorporation of societal benefits. First, they may inconsistently value societal benefits across generating technologies. For example, the benefit of CO_2 reductions from PV is included in a VOS tariff, but is not considered for compensation of utility-scale PV, wind, nuclear, and other zero emitting technologies. Second, "missing money" situations could arise where regulators require utilities to compensate PV owners for the avoided CO_2 costs they provide. However, in the regular operation of providing electric service the utility simply does not incur these costs so they are not actually avoided. In both instances regulators need to consider how to address these inconsistencies if they pursue a VOS tariff.

THE TRANSLATION FROM VALUE TO ELECTRIC RATES

Valuing DERs appropriately and establishing fair compensation based on their true value is an important part of establishing affordable and reasonable electric rates for consumers. Still, it is only one part of the process in determining the prices electric consumers actually pay and respond to. Regulatory frameworks for utilities and how they may change in preparation of a high DER future will represent the deciding factor in establishing the role of DERs on the grid, and how their associated benefits and costs are distributed to consumers. In this chapter current and cutting edge methods for valuing DERs were reviewed. In the next chapter, the traditional regulatory framework and how it could change due to DERs is examined.

CHAPTER 4

Operationalizing Valuation

Valuation of DERs is just one part of the puzzle in tapping their potential contribution to a modern, flexible, low-carbon power system. Getting incentives right for utilities, customers, third-party DER providers and aggregators to minimize costs and maximize benefits for everyone that uses the grid will likely require revisions to the century old distribution utility regulated monopoly framework. This chapter considers how and why that may be the case, and identifies conceptual and applied regulatory approaches that could provide frameworks for a high DER future.

THE TRADITIONAL UTILITY REGULATORY STRUCTURE AND ITS INTERACTION WITH DERS

For over 100 years the distribution system has operated under a regulated monopoly framework.[lix] An entity is granted the exclusive right to own, operate, and maintain an electric distribution system in a defined service territory with the requirement that it provide reliable, affordable electricity to all customers. In exchange the utility can receive a reasonable rate of return on its investments as determined by a regulatory oversight body and recouped through customers electric rates. This framework has proven to be remarkably durable over time and contributed to near universal electric service and high rates of service reliability.

The monopoly model has weathered change before. Prior to the 1990s all distribution utilities were fully integrated with operations in the generation and transmission components of the grid. This is still the case for about one-third of electric customers largely in the south and western U.S.[lx] Corneli and Kihm have observed that technological innovation in the information and power generation spaces gave rise to more efficient operational models for wholesale power generation. These innovations led to utility restructuring in many states where integrated utilities spun off their generation and transmission assets, and gave rise to Regional Transmission Operators (RTOs) and Independent Power Producers. New regulatory frameworks for wholesale markets also were created to manage the evolving bulk power landscape.[lxi]

The traditional distribution regulatory framework is based on a cost-plus model and rewards the utility for making capital investments and selling electricity. In other words it generates revenue by building and maintaining an asset base and through sales of a basic commodity. It earns a rate of return for new capital investments and spreads that cost over fixed volumetric electric rates. The larger the capital cost and/or the more electricity the utility can sell, the more revenue it can receive so long as it secures regulatory approval for rate recovery. Under this arrangement, utilities have an obligation to serve all electric customers and maintain reliability of the distribution system.

This framework presents disincentives for utilities to embrace DER either in their own planning or in accommodating customer and third-party DER systems. In some states, distribution utilities are prohibited from owning generation, including DERs. This serves as an additional disincentive for utilities to incorporate DERs into their planning and operations. Customer sited and third-party owned DERs erode utility revenues by reducing electricity sold by the utility to consumers. Without a realignment of utility incentives under revised regulatory frameworks, utilities have no business case for pursuing or accommodating DERs.

Meanwhile some view grid planning and operations under the traditional utility regulatory framework as out of date.[lxii] Before the recent increase of DERs the grid operated primarily as a one-way system with power sourced from central generators on the BPS, relayed over transmission lines to distribution systems, and from there on to individual customers. Within this paradigm distribution system planning has focused on how to serve increasing customer load over time with little or no consideration of existing or expected customer-side DER deployment.[lxiii] As DER penetration has increased, some parts of the U.S. distribution systems have been experiencing two-way flows of power that legacy equipment was not designed to handle. DERs are also confusing distribution load forecasts, making it more challenging to plan and operate the system using traditional approaches. In addition, most electric grid infrastructure is old and in need of replacement, posing a threat to reliability.[lxiv] As discussed earlier in this report, DER penetration is expected to increase going forward. DERs have the potential to further exacerbate these issues or be part of the solution if revisions to regulatory frameworks are implemented.[lxv]

The mismatch between the current monopoly distribution utility regulatory framework and increased DER penetration has generated clashes in some states. One example is state EE policies that have driven customer electricity savings. EE interferes with the traditional utility business model because it reduces revenues by slowing down the growth in electricity sales. Over time, most states have revised utility regulations in a number of different ways to harmonize utility incentives with energy saving goals. Allowing utilities to receive new revenue, through new channels such as getting compensated for the administration of EE programs or for meeting or exceeding energy savings targets, is one such way. Another example is the decoupling of electric rates from revenues, effectively removing a utility's incentive to sell ever increasing amounts of electricity.

Utilities have been managing DERs on their systems for decades. EE is the most widespread example, but DR and CHP have also been incorporated and accommodated on distribution systems. What is new about the latest wave of DER penetration is that it is centered on generation technologies (as opposed to reductions in demand) and penetration is due in part to a strong customer technological innovation drivers. The former is important because it directly effects grid operations and planning in ways that other DERs have not as discussed above. Regarding the latter, state and federal policies have significantly incentivized (subsidized) DER deployment, and customer preferences are also changing. Technology cost reductions have accelerated adoption with further cost reductions expected, making some DERs competitive with grid electricity even without policy support. Distribution utilities largely lack the experience to plan for greater DER deployment and, without revisions to regulatory frameworks, lack incentives to be proactive about preparing for a high-DER future.

Increasing DER penetration is not the only thing utilities and regulators are tackling. Concerns about system resilience, cybersecurity and physical grid security are presenting new and different challenges to reliability.[lxvi] In addition, concerns about climate change have led to new federal requirements for CO_2 emissions embodied in the EPA's Clean Power Plan. Depending on decisions by state regulators, many of these competing priorities and requirements could be addressed comprehensively in any revision of utility regulatory frameworks.[lxvii]

REGULATORY OPTIONS FOR INCORPORATING DERS INTO UTILITY BUSINESS MODELS

Given the confluence of drivers pressuring the traditional regulated monopoly model, changes will almost certainly be required. With the diversity of circumstances across states and utilities it is likely that there will not be a single one-size-fits all solution. Instead this report largely relies on the organization framework developed by Satchwell et al. that helps to categorize potential utility regulatory models where support for cost-effective DERs becomes a core function of the utility. The two general categories of regulatory models are: 1) the services-driven utility, 2) the value-driven utility.[lxviii] Each of these options is examined below and conceptual and real world examples of models that fit within each category are identified. An additional category is considered where incremental changes to the traditional business cost-of-service model are made to accommodate DERs but DERs support is not a core function of the utility.

Services-driven utility

Service-driven utility regulatory models focus on achieving profits through the provision of value-added services to customers instead of through sales of the electricity commodity, all the while retaining the traditional asset-based utility framework. These services are in addition to, and billed separately from, basic retail electricity service and need not be solely focused on grid services. This model allows for utilities to provide some of the same services provided by third-parties in the power sector today such as financing of DERs through leases or on-bill financing, green power options, energy usage information, and EE programs. Utilities would still have a motivation to profit off of existing and incremental capital investments under this model, just as they always have. Such investments would increasingly be directed towards supporting higher profit achievement from services while maintaining reliability and other core utility functions. Utilities could be well positioned to provide a wide array of value-added services given their incumbent status in electric markets, and existing customer relationships and associated market data that third-party DER providers do not have.

Service-driven utilities could provide services to customers through a variety of different approaches. They could provide a menu of services that customers could pick and choose from. Alternatively they could bundle groups of services from the grid and DERs together in an offering not unlike that seen in the cable industry where phone, television, and internet are provided as a package.[lxix] Service-driven utilities could also take a customer-hosting approach to DER deployment where the utility owns the DERs (e.g. PV, storage, etc.) on a customer's property and pays a rental fee to the customer as compensation. This approach has been piloted in Texas and Arizona, and allows the utility to target DER deployment where it is most valuable to the distribution system and greatest benefit for all customers.[lxx]

Service-driven utilities need not provide services solely to traditional end-use customers. Two potential approaches discussed in the literature present opportunities for the utility to provide services to third-party DER developers and owners in addition to customers. One option is the Infrastructure-as-a-service (IaS) model where the utility provides procurement services by soliciting competitive offers for distribution system capacity, maintenance, and operations solutions from third-party providers and even customer owned DERs.[lxxi] Under the IaS model the utility would conduct distribution system planning, identify system needs, and solicit and secure bids for solutions so long as those solutions are lower cost than conventional solutions. Utilities would receive streams of service income or a rate of return representing fair compensation for administration of the procurement process and operating the distribution system. A good example of IaS is the ConEdison BQDM project discussed elsewhere in this report.

A final example of a service-driven utility model is the Distribution System Operator (DSO) or Independent DSO (IDSO). As discussed previously in this report, a DSO is in many ways analogous to RTOs and ISOs in wholesale markets. Under this model the utility acts as the owner and operator of the distribution grid and is responsible for providing grid services such as grid reliability, system planning, dispatch, and interaction with the BPS. It would also be responsible for operating an open access platform and market mechanisms enabling competition among consumers and third-parties who would provide energy, capacity, and other grid services not provided by the DSO.[lxxii] The utility receives streams of revenue for successfully providing the services under its responsibility through service charges and approved rates of return on capital investments to support these services. The DSO model is attractive from the perspective of DER valuation in that is enables the most granular market-based valuation framework that takes into account the locational, technological, and temporal attributes of all DERs. Still, this is the most complex option and will require deployment of sophisticated communications and energy management technologies on a broad scale, and could take several years to achieve.

Through its REV process, the New York PSC has directed that utilities serve as the DSO [the DSO is called distributed system platform (DSP) in New York.] The PSC further said that if utilities serving this role do not meet REV objectives, it will consider creation of an independent DSP (or IDSO). As described by advocates in the REV proceeding, an IDSO is an independent entity that does not own generation or other physical assets. The IDSO would be similar in concept to the RTO and ISO models of the transmission market. RTOs and ISOs are nonprofit, public benefit organizations that do not own generation or other physical assets.[lxxiii]

The New York PSC identified the IaS as an intermediate step towards the development of a utility DSP model. In the early stages, utilities can earn new revenues from displacing traditional grid investments with DER alternatives. Over time utilities will transition to their new role as DSP earning platform service revenues through operation of the distribution system and the market framework that supports competitive procurement and delivery of energy services by customers and third parties.[lxxiv]

Value-driven utility

Value-driven utility regulatory models focus on motivating utilities to achieve greater profits by meeting specific performance targets. These targets can be designed by regulators to align with broad policy goals such as electric reliability, affordability, environmental performance, energy efficiency and DER integration. Depending on how broadly it is applied, this approach can reduce the cost-of-service model incentive to build new assets to increase revenue and instead motivates the utility to derive as much value as it can out of existing assets. This approach is commonly referred to as Performance Based Ratemaking (PBR) and regulators have experimented with it in incremental and ad hoc ways in a number of states.[lxxv] Under PBR, utilities may gain greater regulatory certainty relative to infrequent rate cases as they have specific targets to meet over time. They are then motivated to find and implement the least cost pathway to meeting the targets.

PBR can be applied to a portion of a utility's revenue, leaving the rest subject to traditional cost of service regulation. For example, utilities could be subject to performance based regulation for meeting specific annual EE targets, but receive the rest of their revenue through a traditional rate case. Alternatively, PBR can be applied holistically to a utilities entire revenue framework. The latter has not yet been implemented in the U.S., however, a collaboration of electric system stakeholders in Minnesota has recommended that that state pursue PBR for its investor owned utilities.[lxxvi] The United Kingdom (UK) implemented holistic PBR for its distribution and transmission utilities in 2010 and it continues to serve as the basis for utility regulation in that country.[lxxvii]

Management of DER penetration and accommodation of broader deployment can be included in PBR through specific DER performance goals and/or DERs can be part of the solution set used by a utility to meet broader performance metrics. Hypothetical examples of DER specific reasonable and achievable goals include setting maximum DER interconnection wait times that get shorter over time or achieving a specific level of DER penetration on the distribution system by a set date. Alternatively, if a utility has a PBR goal to keep distribution system costs level for five years then DERs could be procured or installed directly by the utility (depending on any applicable rules regarding utility ownership of generation) if they are lower costs than conventional solutions. The key is that if regulators set the right goals under PBR then the utility has the profit motivation to find new and innovative ways to bring DERs onto the distribution system to help meet or exceed performance goals. Holistic PBR can be more complex that the traditional regulatory framework, but it can also tailored to a state's specific circumstances and policy goals.[lxxviii]

Other categories of business models

In addition to the two broad categories discussed above Satchwell et al. identify two other categories that are worth discussing. First is the idea of a service- *and* value-driven utility. This hybrid of the two options explored above would involve a utility offering value-added services to customers within the framework of PBR. While most examples are conceptual at this stage, components of New York REV could be seen as possible examples of this model. Specifically, in addition to the DSP (IDSO) service-driven utility role, utilities are also charged with meeting specific performance benchmarks for system efficiency, energy efficiency, customer engagement, interconnection, and affordability.[lxxix] While the goals and associated upside/downside monetary incentives are yet to be specified, utilities in New York could be subject to at least partial PBR alongside a service-driven business model in that state.

The other category of business models is one where DERs are not incorporated as core function of the utility and instead incremental regulatory adjustments are made in an effort to accommodate the increase of DERs. This category represents much of the state regulatory reform experience over the last few years as DERs have increased penetration in some states. In this model the traditional cost-of-service model is preserved. Rates and utility compensation are re-designed to address concerns about lost utility revenue or cost shifting between customers due to DERs (primarily PV). Regulatory changes considered and/or implemented include increases to fixed customer charges, revisions to NEM compensation rules, and lost revenue adjustments.[lxxx] While regulatory changes in this category can allow utilities to better incorporate the value of DERs into their planning and operation, they do not fundamentally change the cost-of-service model. The incentives that drive the utility towards greater electricity sales and large capital investments may run counter to broad and deep DER adoption in the distribution grid.[lxxxi]

TEXT BOX 2: THE POTENTIAL ROLE OF AGGREGATORS

Although individual DERs alone can provide services to the electricity grid, a third-party entity can coordinate, control and even own a group of individual DERs, and can provide a variety of services on the grid. First, on the distribution level, aggregation of DERs into a distributed energy system can alleviate the need for the centralized electricity grid. This is useful in times of grid power outages, but also for those areas that need transmission upgrades to get centralized power to the distribution nodes. Alternatively, aggregators provide the opportunity for DER resources to collectively bid into organized electricity markets. The precedent for this is the U.S. is the role DR aggregators have made to making DR a successful player in PJM Interconnection's capacity market. Eventually, aggregators can utilize more extensive communication systems so DERs can also play a role in reserve markets or other markets for ancillary services. Similarly, regulated utilities can competitively procure the services provided by DER aggregators to meet their system requirements needs.

Other considerations

One commonality across all models discussed is that distribution planning is improved to incorporate state of the art tools and techniques for anticipating the deployment of DERs and considering them as alternatives to traditional system investments. These processes will evolve over time and adoption will occur at different rates across the country based on local circumstances.[lxxxii] Without improved planning utilities will not be able to proactively harness innovative and potentially lower cost alternatives to traditional grid investments, nor will they be well positioned to accommodate increasing DER penetration on their systems.[lxxxiii] The level of planning sophistication required will depend on the current and expected levels of DER penetration in a given jurisdiction.[lxxxiv]

Another important consideration for regulators is the allowable level of competition with third parties such as aggregators (see Text Box 2) and energy service companies in providing services to consumers. Regulators could do one of three things: 1) grant utilities a monopoly over specific services, 2) prevent utilities from participating in competitive delivery of specified services leaving the provision of those services to third parties, or 3) utilities could compete directly with third parties. Option 1 may reduce innovation depending on the regulatory framework. Option 2 will require the utility to maintain reliability of the distribution system and might still require the utility to provide standard offer backstop service. Option 3 may require safeguards to prevent giving the utility an unfair advantage in the market arising from its exclusive knowledge of the distribution system and access to customer data. Regulators have substantial experience with these issues (e.g. through the adoption of affiliate codes of conduct). If regulators allow third parties to provide services then the sharing of system and customer data by the utility may be required, and should be done in a manner than maintains security and customer privacy.[lxxxv] Conversely, utilities may require information from third-party providers to enable effective distribution planning discussed above.

ALIGNING RATE DESIGN WITH DER VALUE

Like the traditional utility regulatory model, the most common types of retail electric pricing provide little or no incentive for DERs to be deployed and operated at the times and places that provide the greatest benefit to the electric system and consumers.[lxxxvi] Revisions to standard electric pricing approaches could lead to shifts in how distribution costs are distributed among users and how customer-sited DERs are compensated. Tierney argues that as regulators, utilities, and stakeholders explore options for revising electric rate frameworks, the principles of fairness and efficiency remain centrally important to any attempts to reform electric rates. Meanwhile others have argued that the typical volumetric, bundled, block rates applied to broad customer classes are no longer fair in large part due to the increasing penetration of DERs.[lxxxvii]

Transforming electric pricing to better reflect the temporal and locational aspects of electricity use and production on the distribution grid while equitably distributing costs will take time and will require a tradeoffs against the hallmark rate design principle of simplicity.[lxxxviii] Traditional volumetric pricing attempts to aggregate the entire bundle of grid services a customer uses in a single cents/kWh rate that reflects system costs averaged over geography and time. Just as market-based frameworks can provide dynamic valuation of services provided by DERs, electric rates can be revised to provide similar price signals to customers. Glick et al. recommend increasing the sophistication of electric rates along three axes: attributes (or grid services), time, and location. For example, customers could be billed separately for energy, capacity, and ancillary services. These attributes could vary in price depending on the time of day a customer uses them and where on the distribution system the customer is located. If a customer owns DERs on site they could receive revenue for each grid service provided by that DER in the same way. If successful, new rate frameworks can help to direct DER deployment to where it can provide the most value for all customers connected to a distribution system. As part of its REV process, New York is exploring alternative rate structures that could lead to payments for unbundled energy services, and with prices differentiated based on time and location. Some utilities are already experimenting with time-of-use rates that vary the price of electricity depending on wholesale prices at any given time.

Any transition from traditional volumetric rates to more sophisticated approaches is likely to be gradual and take time. Options for smoothing the transition include grandfathering customers into current rate structures for a set amount of time and allowing customers to opt-in to new rate structures. Another option is to require more sophisticated rate structures for customers who opt to install DERs while giving all other customers the opportunity to opt-in. These strategies are being used in California and Chicago where time-of-use rates are currently available as a customer option, but are not yet default rate framework.[lxxxix] The difference between the programs in these two jurisdictions is that in California time-of-use rates will become the default rate framework for all customers in 2019.[xc]

THE TRANSITION WILL NOT HAPPEN OVERNIGHT

While the rise of DERs have helped to spur utility regulators and other stakeholders to revisit regulatory and ratemaking frameworks, it is not clear if it will take years or decades for a complete, nationwide transition to new and different high-DER regimes. First, the transition will not happen everywhere at once. California and Hawaii are at the forefront of this transition in large part because these states have some of the highest DER penetration.[xci] Across the rest of the country where DER penetration is still relatively low, most states (with the exception of New York) are far from considering similar changes to regulatory and ratemaking frameworks. If DERs continue along current deployment trends, then as other states experience higher levels of penetration they may begin to explore reforms as well. At that point they will have the advantage of learning from the experience of first-mover states. The other reason why this transition is likely to take time is because reforming decades-old utility regulation models and responding to DER penetration takes time. Introducing new roles and business models for utilities and getting ratepayers accustomed to new ways of thinking about their electric bill will not occur over night. States that are proactive in this space can get ahead in the effort to harness the potential of DERs in creating a modern, clean, and flexible grid.

CHAPTER 5

Findings and Areas for Future Research

This report provides an overview of the literature related to DERs and focuses on current and state-of-the-art methods of DER valuation. Regulators, utilities, and other stakeholders can use this report as a resource as they determine whether and how best to respond to the challenges and opportunities presented by the rise of DERs in the electric power system. Key findings and recommendations for areas of future research are presented below.

KEY FINDINGS

DERs can contribute to the development of a more flexible, clean, and affordable electric power system if they are fairly compensated for the net value of the services they provide and that net value is fully considered in distribution utility planning and operations.

- DERs including combined heat and power (CHP), energy efficiency (EE) and demand response (DR) have played a role on U.S. distribution systems for decades. Accelerated deployment of new and different DERs such as solar PV and to a lesser extent energy storage have created challenges and opportunities for utilities, regulators, and stakeholders in recent years.

- Different DER technologies can provide different electric services of value to utilities and customers. The degree to which DERs can provide these services at lower net-cost than conventional utility investments and practices will determine how much they can lower costs for utilities and consumers while maintaining a similar or improved level of service.

- A more flexible and cleaner distribution grid supported by DERs and optimized by system planners could enable deep decarbonization of the U.S. electric power system and broader energy systems.

Current distribution utility regulatory and oversight frameworks either do not value all DER services or do so through inconsistent and incomplete administrative valuation and compensation procedures. Technology neutral, market-based valuation approaches can enable more complete and dynamic assessments of value and appropriate compensation, and could establish a level playing field where DERs can compete alongside other grid resources.

- Different valuation and compensation methods are used for different DERs in different contexts. For example, demand response (DR) is often valued through competitive wholesale markets and receives compensation for multiple grid services while energy efficiency (EE) programs are subject to a series of administrative benefit costs tests. Meanwhile, solar PV is compensated primarily through administrative frameworks such as net energy metering (NEM) or sometimes Value of Solar (VOS) tariffs.

- Most administrative valuation and compensation frameworks employ a variation on an avoided cost approach. The distinct technological capabilities of different DERs, their temporal generation profile, and their location on the distribution grid are considered in an inconsistent and incomprehensive way, if at all. This leads to over and undervaluation of DERs compared to their actual contribution of grid services and may not lead to the most cost-effective deployment of energy resources from a system-wide perspective.

- The value of and compensation for services provided by DERs can change with different levels of DER penetration. For example, the value of energy generated by solar PV declines as penetration increases because this particular technology tends to put downward pressure on peak wholesale prices. Depending on their design, market-based valuation approaches can account for the locational, temporal, and technological profiles of specific DERs. Moving away from administrative compensation and towards market-based approaches will be an important step in establishing price signals that can direct the deployment of DERs to where they are most valuable on the distribution system and can adjust for changing grid dynamics as deployment increases.

- While there is no one-size-fits-all solution, examples of market-based valuation and compensation models currently in use or under development include competitive utility procurement of solar PV energy services under discussion in Maine and the use of the Infrastructure-as-a-service (IaS) model in New York and California. The design and implementation of a Distribution System Operator (DSO) or Independent DSO (IDSO) model that would allow for competitive markets for a variety of energy services within the distribution system is progressing in New York and being actively discussed in California.

Revisions to the traditional cost-of-service utility regulatory model may be required to properly value DERs and fully incorporate them into distribution system planning and operations.

- The trends behind the surge in DER penetration may continue and could accelerate leading to a distribution grid that must accommodate two-way flows of electricity. This is a departure from the traditional one-way flow of electricity from central generators to customers. This transition will take years or possibly decades. States experiencing relatively fast penetration of DERs are likely to lead in the area of regulatory reforms, though utilities and regulators may choose to be proactive in considering the costs and benefits of DERs to the distribution system.

- The traditional cost-of-service utility regulatory model generally does not place DERs within the core functions of distribution utilities. DERs can erode the two traditional utility revenue sources: rates of return on capital investments and electricity sales. Most state regulatory actions concerning DERs to date have focused on incremental changes to regulatory models to handle specific conflicts with utility cost-of-service revenue streams. However, a handful of states including California, Hawaii, Minnesota, and New York are working on comprehensive revisions that could accommodate DERs and allow them to contribute towards the development of a cleaner, more reliable, and more affordable electric power system.

- There are several possible options for revising the regulatory model in ways that can place DERs within the core functions of the utility and lead to market-based valuation and fair compensation of DERs. These options include allowing utilities to receive new revenue streams from providing value-added services or by incentivizing utilities to create more value from existing and new assets. Under new regulatory models DERs can be incorporated to help utilities harness these new revenue streams at least cost. The ultimate pathway for revising regulatory models will be subject to a particular state's legal and administrative constructs.

AREAS FOR FURTHER RESEARCH

Area 1: Design of new and innovative methods for market-based valuation of DERs at the distribution system level beyond what is already available.

- Research and design of new options could provide more tools for DER valuation that could be specialized for specific grid needs and/or DER types. This could potentially increase the adoption of market-based valuation in distribution grid planning and operations.

Area 2: Identification of pathways that provide a smooth transition to utility models that fully consider and incorporate the DER value.

- Alternative regulatory frameworks that incorporate DER value explored in this report are very different from the typical cost-of-service framework used throughout the U.S. Identifying intermediate steps in the implementation of revisions to regulatory frameworks and options for easing the transition between steps could minimize friction between stakeholders and increase the adoption of regulatory reforms.

- Research that identifies additional options for making DERs a core function for utilities without a major overhaul of the cost-of-service regulatory framework could be useful. The findings could inform state regulatory proceedings where a complete transition to a value-driven or service-driven utility framework is politically or otherwise infeasible.

Area 3: New distribution system planning and operation approaches that can adapt to changing DER penetration, technology innovations, and customer behavior.

- As DER technologies evolve, improve, and increase in penetration, distribution system planners and operators will need new, sophisticated tools to capture the full value to the grid. Development of new and improved best practices and sharing of these practices across the industry should be explored.

- Development of probabilistic and dynamic tools that can help planners anticipate where DER are likely to be installed and how they can be accommodated at least cost should also be considered by distribution utilities.

Area 4: Computational approaches that can be leveraged to support IDSO platforms.

- RTOs have deployed and continue to improve sophisticated computational systems to support wholesale electric service markets. Analogous markets at the distribution level are expected to be far more complex. Development of new more powerful computing and software platforms to support IDSO markets should be explored.

Area 5: Regulatory approaches that can address the multiple issues faced by utilities and regulators.

- DERs are one of several challenges facing utilities and regulators. Other challenges include improving system resilience, protecting the electric power system from cyber and physical security threats, as well as federal and state policies to reduce power sector CO_2 emissions. Research on planning, operations, and regulatory options for holistically addressing these issues alongside DER integration could be valuable to a variety of stakeholders.

Endnotes

[i] National Regulatory Research Institute. Distributed Energy Resources: Status Report on Evaluating Proposals and Practices for Electric Utility Rate Design. By Tom Stanton. 15-08. (Silver Spring, MD: National Regulatory Research Institute 2015), 14. http://nrri.org/download/nrri-15-08-rate-design-for-der/

[ii] Solar and other renewables data sourced from OpenEI Transparent Cost Database http://en.openei.org/apps/TCDB all other data sourced from Energy Information Administration, Form 861 database. (Washington, DC: Energy Information Administration, 2016).

[iii] MIT Energy Initiative in partnership with IIT-Comillas. The MIT Utility of the Future Study-White Paper. By Ashwini Bharatkumar et al. (Cambridge, MA: MIT Energy Initiative, 2013), 9. http://mitei.mit.edu/system/files/UOF_WhitePaper_December2013.pdf

[iv] Solar and other renewables data sourced from OpenEI Transparent Cost Database http://en.openei.org/apps/TCDB; CHP all other data sourced from Energy Information Administration, Form 861 database. (Washington, DC: Energy Information Administration, 2016). Note: EE includes reported incremental peak demand savings achieved by utility driven programs and DR values represent potential peak demand savings Note that DR values represent potential peak demand savings, EE values represent reporting year incremental annual peak demand savings.

[v] MIT Energy Initiative. The Future of Solar Energy Study: An interdisciplinary MIT study. By Richard Schmalensee et al. (Cambridge, MA: MIT Energy Initiative, 2015), 153 http://mitei.mit.edu/system/files/MIT%20Future%20of%20Solar%20Energy%20Study_compressed.pdf

[vi] Dora Nakafuji, "EnVisioning the Future Grid 3.0" (Presentation from DistribuTECH Conference and Exhibition, Orlando, Florida, February 9-11, 2016), 12.

[vii] Bloomberg New Energy Finance in partnership with the Business Council for Sustainable Energy. 2016 Sustainable Energy in America Factbook. By Zindler et al. (New York, NY: Bloomberg Finance LP; Washington, DC: Business Council for Sustainable Energy, 2016), 87, 90 and 138. http://www.bcse.org/sustainableenergyfactbook/

[viii] Energy Information Administration. Annual Energy Outlook: 2016 Early Release. By Sieminski et al. (Washington, DC: Energy Information Administration, 2016), 33. http://www.eia.gov/forecasts/aeo/index.cfm

[ix] National Renewable Energy Laboratory. Historical and Current U.S. Strategies for Boosting Distributed Generation. By Lowder, et al. 6A20-64843. (Golden, CO: National Renewable Energy Laboratory, 2015), 28. http://www.nrel.gov/docs/fy16osti/64843.pdf

[x] Rocky Mountain Institute. The Economics of Demand Flexibility: How "flexiwatts" create quantifiable value for customers and the grid. By Bronski, et al. (Boulder, CO: Rocky Mountain Institute. 2015), 16, 17. http://www.rmi.org/electricity_demand_flexibility

[xi] SolarCity Grid Engineering. A Pathway to the Distributed Grid. (SolarCity 2016), 21. http://www.solarcity.com/sites/default/files/SolarCity_Distributed_Grid-021016.pdf

[xii] Tabors Caramanis Rudkevich, Inc. White Paper on Developing Competitive Electricity Markets and Pricing Structures. By Tabors, et al. (Boston, MA: Tabors Caramanis Rudkevich, Inc. 2016), 9. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B7912D587-DB8D-420F-B6A6-4A1AF57B77E9%7D Rocky Mountain Institute. Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size. By Lovins, et al. (Boulder, CO: Rocky Mountain Institute, 2002), 2. http://www.rmi.org/Knowledge-Center/Library/U02-09_SmallIsProfitableBook

[xiii] Tabors Caramanis Rudkevich, Inc. White Paper on Developing Competitive Electricity Markets and Pricing Structures. By Tabors, et al. (Boston, MA: Tabors Caramanis Rudkevich, Inc., 2016), Page 9. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B7912D587-DB8D-420F-B6A6-4A1AF57B77E9%7D

[xiv] MIT Energy Initiative in partnership with IIT-Comillas. The MIT Utility of the Future Study-White Paper. By Ashwini Bharatkumar et al. (Cambridge, MA: MIT Energy Initiative, 2013), 13. http://mitei.mit.edu/system/files/UOF_WhitePaper_December2013.pdf

[xv] MIT Energy Initiative in partnership with IIT-Comillas. The MIT Utility of the Future Study-White Paper. By Ashwini Bharatkumar et al. (Cambridge, MA: MIT Energy Initiative, 2013), 13. http://mitei.mit.edu/system/files/UOF_WhitePaper_December2013.pdf

[xvi] MIT Energy Initiative in partnership with IIT-Comillas. The MIT Utility of the Future Study-White Paper. By Ashwini Bharatkumar et al. (Cambridge, MA: MIT Energy Initiative, 2013), 162. http://mitei.mit.edu/system/files/UOF_WhitePaper_December2013.pdf

[xvii] See for example: Tennessee Valley Authority. Distributed Generation – Integrated Value: A Methodology to Value DG on the Grid (Knoxville, TN: Tennessee Valley Authority, 2015), 4. https://www.tva.gov/Energy/Renewable-Energy-Solutions/Distributed-Generation%E2%80%93Integrated-Value-Report; Electricity Innovation Lab. A Review of Solar PV Benefit and Costs Studies. By Hansen, et al. (Boulder, CO: Rocky Mountain Institute 2013) 2013, 13. http://www.rmi.org/elab_empower Synapse Energy Economics for Advanced Energy Economy Institute (AEEI). Benefit Cost Analysis for Distributed Energy Resources: A framework for accounting for all relevant costs and benefits. By Woolf, et al. (Cambridge, MA: Synapse Energy Economics, 2014), 20. http://www.synapse-energy.com/sites/default/files/Final%20Report.pdf

[xviii] MIT Energy Initiative in partnership with IIT-Comillas. The MIT Utility of the Future Study-White Paper. By Ashwini Bharatkumar et al. (Cambridge, MA: MIT Energy Initiative, 2013), 18. http://mitei.mit.edu/system/files/UOF_WhitePaper_December2013.pdf

[xix] Solar Electric Power Association and the Electric Power Research Institute. Rolling out Smart Inverters: Assessing Utility Strategies and Approaches. By Ryan Edge, Ben York and Nadav Enbar (Washington, DC: Solar Electric Power Association, 2015), 4.

[xx] Rocky Mountain Institute. The Economics of Demand Flexibility: How "flexiwatts" create quantifiable value for customers and the grid. By Bronski, et al. (Boulder, CO: Rocky Mountain Institute. 2015), 30. http://www.rmi.org/electricity_demand_flexibility

[xxi] MIT Energy Initiative in partnership with IIT-Comillas. The MIT Utility of the Future Study-White Paper. By Ashwini Bharatkumar et al. (Cambridge, MA: MIT Energy Initiative, 2013), 20. http://mitei.mit.edu/system/files/UOF_WhitePaper_December2013.pdf

[xxii] National Renewable Energy Lab. Renewable Energy Futures Study Executive Summary (Golden, CO: National Renewable Energy Lab. 2012), 23. http://www.nrel.gov/docs/fy13osti/52409-ES.pdf

[xxiii] Sustainable Development Solutions Network and the Institute for Sustainable Development and International Relations. Pathways to deep decarbonization in the United States. By Williams, et al. (Paris, Sustainable Development Solutions Network 2014), 15. http://deepdecarbonization.org/wp-content/uploads/2015/11/U.S._Deep_Decarbonization_Technical_Report.pdf

[xxiv] See for example: Electricity Innovation Lab. A Review of Solar PV Benefit and Costs Studies. By Hansen, et al. (Boulder, CO: Rocky Mountain Institute 2013) 2013, 22 http://www.rmi.org/elab_empower; The Analysis Group. The Value of "DER" to "D": The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability. By Susan Tierney (Boston, MA: The Analysis Group, 2016), 10. http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/Thought_Leaders_Events/Tierney%20White%20Paper%20-%20Value%20of%20DER%20to%20D%20-%203-30-2016%20FINAL.pdf

[xxv] The Analysis Group. The Value of "DER" to "D": The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability. By Susan Tierney (Boston, MA: The Analysis Group, 2016), 9. http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/Thought_Leaders_Events/Tierney%20White%20Paper%20-%20Value%20of%20DER%20to%20D%20-%203-30-2016%20FINAL.pdf

[xxvi] The Law Offices of Carolyn Elefant. Reviving PURPA's Purpose: The Limits of Existing State Avoided Cost Ratemaking Methodologies in Supporting Alternative Energy Development and a Proposed Path to Reform. By Carolyn Elefant (Washington, DC: The Law Offices of Carolyn Elefant, 2012), 4. http://www.recycled-energy.com/images/uploads/Reviving-PURPA.pdf

[xxvii] The Analysis Group. The Value of "DER" to "D": The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability. By Susan Tierney (Boston, MA: The Analysis Group, 2016), 14. http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/Thought_Leaders_Events/Tierney%20White%20Paper%20-%20Value%20of%20DER%20to%20D%20-%203-30-2016%20FINAL.pdf

[xxviii] The Analysis Group. The Value of "DER" to "D": The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability. By Susan Tierney (Boston, MA: The Analysis Group, 2016), 4. http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/Thought_Leaders_Events/Tierney%20White%20Paper%20-%20Value%20of%20DER%20to%20D%20-%203-30-2016%20FINAL.pdf

[xxix] Synapse Energy Economics for Advanced Energy Economy Institute (AEEI). Benefit Cost Analysis for Distributed Energy Resources: A framework for accounting for all relevant costs and benefits. By Woolf, et al. (Cambridge, MA: Synapse Energy Economics, 2014), 36. http://www.synapse-energy.com/sites/default/files/Final%20Report.pdf

[xxx] Electricity Innovation Lab. A Review of Solar PV Benefit and Costs Studies. By Hansen, et al. (Boulder, CO: Rocky Mountain Institute 2013) 2013, 38. http://www.rmi.org/elab_empower

[xxxi] For more on the social cost of carbon see Interagency Working Group on the Social Cost of Carbon. Technical Support Document: - Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis -

Under Executive Order 12866 (Washington, DC: U.S. Government, 2013) https://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf

[xxxii] MIT Energy Initiative. The Future of Solar Energy Study: An interdisciplinary MIT study. By Richard Schmalensee et al. (Cambridge, MA: MIT Energy Initiative, 2015), 106. http://mitei.mit.edu/system/files/MIT%20Future%20of%20Solar%20Energy%20Study_compressed.pdf

[xxxiii] Ernest Orlando Lawrence Berkeley National Laboratory. Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California. By Andrew Mills and Ryan Wiser. LBNL-5445E (Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory, 2012), 71. https://emp.lbl.gov/sites/all/files/lbnl-5445e.pdf

[xxxiv] California Independent System Operator. What the Duck Curve Tells Us About Managing the Grid (Folsom, CA: California Independent System Operator, 2016) https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

[xxxv] Dora Nakafuji, "EnVisioning the Future Grid 3.0" (Presentation from DistribuTECH Conference and Exhibition, Orlando, Florida, February 9-11, 2016), 12.

[xxxvi] Lawrence Berkeley National Laboratory. Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future. By Steve Corneli and Steve Kihm. LBNL 1003823 (Berkeley, CA: Lawrence Berkeley National Laboratory, 2015), 6. https://emp.lbl.gov/sites/all/files/lbnl-1003823_0.pdf

[xxxvii] Ernest Orlando Lawrence Berkeley National Laboratory. A Framework for Organizing Current and Future Electric Utility Regulatory and Business Models. By Satchwell et al. LBNL 181246 (Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory, 2015), 16. https://emp.lbl.gov/sites/all/files/lbnl-181246_0.pdf

[xxxviii] Synapse Energy Economics for Advanced Energy Economy Institute (AEEI). Benefit Cost Analysis for Distributed Energy Resources: A framework for accounting for all relevant costs and benefits. By Woolf, et al. (Cambridge, MA: Synapse Energy Economics, 2014), 36. http://www.synapse-energy.com/sites/default/files/Final%20Report.pdf

[xxxix] Synapse Energy Economics for Advanced Energy Economy Institute (AEEI). Benefit Cost Analysis for Distributed Energy Resources: A framework for accounting for all relevant costs and benefits. By Woolf, et al. (Cambridge, MA: Synapse Energy Economics, 2014), 10. http://www.synapse-energy.com/sites/default/files/Final%20Report.pdf

[xl] Federal Energy Regulatory Commission. Demand Response Compensation in Organized Wholesale Energy Markets. Order 745 (Washington, DC: Federal Energy Regulatory Commission, 2011). http://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

[xli] California Independent System Operator. Tariff Amendment Distributed Energy Resource Provider Initiative. (Folsom, CA: California Independent System Operator, 2016), 2.

https://www.caiso.com/Documents/Mar4_2016_TariffAmendment_DistributedEnergyResourceProvider_ER16-1085.pdf

[xlii] California Independent System Operator. Energy Storage and Distributed Energy Resources Phase 2. Straw Proposal. ESDER 2 (Folsom, CA: California Independent System Operator, 2016), 4. https://www.caiso.com/Documents/StrawProposalforEnergyStorageandDistributedEnergyResourcesStakeholderInitiativePhase2.pdf

[xliii] State of Maine Office of the Public Advocate. A Ratepayer Focused Strategy for Distributed Solar in Maine (Augusta, ME: State of Maine, 2016), 6. http://www.maine.gov/meopa/news/Maine%20VOS%20White%20Paper%20V2%202.pdf

[xliv] ConEdison "Brooklyn Queens Demand Management Program" (Project Update Presentation New York, NY, August 28, 2015) https://www.coned.com/energyefficiency/pdf/BQDM-program-update-briefing-08-27-2015-final.pdf

[xlv] Tabors Caramanis Rudkevich, Inc. White Paper on Developing Competitive Electricity Markets and Pricing Structures. By Tabors, et al. (Boston, MA: Tabors Caramanis Rudkevich, Inc. 2016), 19. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B7912D587-DB8D-420F-B6A6-4A1AF57B77E9%7D

[xlvi] Richard Tabors "Valuing Distributed Energy Resources (DER) via Distribution Locational Marginal Prices (DLMP)" (presentation from Department of Energy Valuation Workshop, Washington, DC, May 3, 2016) 2016.

[xlvii] Sotkiewicz, Paul and Vignolo, Jesus. "Nodal Pricing for Distribution Networks: Efficient Pricing for Efficiency Enhancing Distributed Generation." Working Paper. (2005), 3. https://www.hks.harvard.edu/hepg/Papers/Sotkiewicz_NodalPricing_9.05.pdf

[xlviii] In some jurisdictions other entities own and operate the distribution system such as rural cooperatives and public power utilities. Even in these instances the entities operate with exclusive control of the distribution system and there is no competition.

[xlix] Anya Castillo "Current and Future Distribution System Outlook" (presentation from Department of Energy Valuation Workshop, Washington, DC, May 3, 2016); Nkatou, Elli and Caramanis, Michael. "Spatiotemporal Marginal-Cost-Based Retail Electricity Markets: Efficiency, Structure and Feasibility." Working Paper. 2015, 1. http://www.bu.edu/pcms/caramanis/ElliDistr.pdf

[l] ICF International. The Value in Distributed Energy: It's All About Location, Location, Location. By Fine et al. (Fairfax, VA: ICF International, 2015), 2. http://www.icfi.com/insights/white-papers/2015/value-in-distributed-energy

[li] See Electric Power Research Institute. The Integrated Grid: A benefit-cost framework. 3002004878 (Palo Alto, CA: Electric Power Research Institute, 2015). http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002004878; New York Public Service Commission. Order Establishing Benefit Cost Analysis Framework. CASE 14-M-0101 (Albany, NY: New York Public Service Commission, 2016) http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bF8C835E1-EDB5-47FF-BD78-73EB5B3B177A%7d

[lii] NC Clean Energy Technology Center. 50 States of Solar Q1 2016 Quarterly Report. By Proudlove, et al. (Raleigh, NC: NC Clean Energy Technology Center, 2016), 13 https://nccleantech.ncsu.edu/wp-content/uploads/50-SoS-Q1-2016_Final.pdf

[liii] The Analysis Group. The Value of "DER" to "D": The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability. By Susan Tierney (Boston, MA: The Analysis Group, 2016), ES-1. http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/Thought_Leaders_Events/Tierney%20White%20Paper%20-%20Value%20of%20DER%20to%20D%20-%203-30-2016%20FINAL.pdf

[liv] ICF International. The True Value of Solar. By Fine, et al. (Fairfax, VA: ICF International, 2014), 4 http://www.icfi.com/insights/white-papers/2014/true-value-of-solar

[lv] NC Clean Energy Technology Center. 50 States of Solar Q1 2016 Quarterly Report. By Proudlove, et al. (Raleigh, NC: NC Clean Energy Technology Center, 2016), 11 https://nccleantech.ncsu.edu/wp-content/uploads/50-SoS-Q1-2016_Final.pdf

[lvi] "Rooftop solar: Net metering is a net benefit by Muro and Saha" accessed June 20, 2016. http://www.brookings.edu/research/papers/2016/05/23-rooftop-solar-net-metering-muro-saha

[lvii] Energy and Environmental Economics, Inc. The Benefits and Costs of Net Energy Metering in New York. By Patel, et al. (San Francisco, CA: Energy and Environmental Economic, Inc., 2015), 71. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF4166D6E-CBFC-48A2-ADA1-D4858F519008%7D The tests used were a Participant Cost Test and a Non-participants plus Societal Costs test.

[lviii] ICF International. The True Value of Solar. By Fine, et al. (Fairfax, VA: ICF International, 2014), 1 http://www.icfi.com/insights/white-papers/2014/true-value-of-solar

[lix] Throughout this report we refer to regulated distribution utilities, which encompass all investor owned utilities but may not include other entities such as municipal utilities and cooperatives depending on state regulatory frameworks. While municipal and cooperatives are not regulated utilities in the same way investor owned utilities they still have exclusive rights to provide power to customers within a specified service territory. Overseers of municipal and cooperative utilities can make revisions to the business models of their utilities in the same manner as regulators of investor owned utilities.

[lx] "The Role of ISOs and RTOs" accessed June 15, 2016. http://www.isorto.org/about/irchistory

[lxi] Lawrence Berkeley National Laboratory. Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future. By Steve Corneli and Steve Kihm. LBNL 1003823 (Berkeley, CA: Lawrence Berkeley National Laboratory, 2015), 13. https://emp.lbl.gov/sites/all/files/lbnl-1003823_0.pdf

[lxii] Edison Electric Institute. Future of U.S. Electric Distribution. By Paul De Martini (Washington, DC: Edison Electric Institute, 2012), 2. http://www.eei.org/about/meetings/Meeting_Documents/2012Jul-FutureofElectricDistribution_EEIFutureofDistributionPaper.pdf

[lxiii] Black & Veatch and Solar Electric Power Association. Planning the Distributed Energy Future: Emerging Electric Utility Distribution Planning Practices for Distributed Energy Resources. By Andy Colman, Dan Wilson and Daisy Chung (Washington, DC: Solar Electric Power Association, 2016), 4. https://www.solarelectricpower.org/media/439751/proactive-der-planning.pdf

[lxiv] Edison Electric Institute. Future of U.S. Electric Distribution. By Paul De Martini (Washington, DC: Edison Electric Institute, 2012), 6. http://www.eei.org/about/meetings/Meeting_Documents/2012Jul-FutureofElectricDistribution_EEIFutureofDistributionPaper.pdf

[lxv] Lawrence Berkeley National Laboratory. Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future. By Steve Corneli and Steve Kihm. LBNL 1003823 (Berkeley, CA: Lawrence Berkeley National Laboratory, 2015), 18. https://emp.lbl.gov/sites/all/files/lbnl-1003823_0.pdf

[lxvi] Edison Electric Institute. Future of U.S. Electric Distribution. By Paul De Martini (Washington, DC: Edison Electric Institute, 2012), 7 and 8. http://www.eei.org/about/meetings/Meeting_Documents/2012Jul-FutureofElectricDistribution_EEIFutureofDistributionPaper.pdf

[lxvii] Resources for the Future. The Clean Power Plan and the "Future-Ready" Utility. By Joseph Kruger. DP 16-05 (Washington, DC: Resources for the Future, 2016), 27. http://www.rff.org/research/publications/clean-power-plan-and-future-ready-utility

[lxviii] Ernest Orlando Lawrence Berkeley National Laboratory. A Framework for Organizing Current and Future Electric Utility Regulatory and Business Models. By Satchwell et al. LBNL 181246 (Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory, 2015), 23-29. https://emp.lbl.gov/sites/all/files/lbnl-181246_0.pdf

[lxix] Lawrence Berkeley National Laboratory. Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future. By Steve Corneli and Steve Kihm. LBNL 1003823 (Berkeley, CA: Lawrence Berkeley National Laboratory, 2015), 45. https://emp.lbl.gov/sites/all/files/lbnl-1003823_0.pdf

[lxx] Tracy Idell Hamilton, "CPS Energy seeks partners for rooftop solar expansion," CPS Energy Press

Release, Feb. 9, 2015. Julia Pyper, "Arizona Utilities Get Approval to Own Rooftop Solar," GreenTech Solar, Dec.26, 2014.

[lxxi] SolarCity Grid Engineering. A Pathway to the Distributed Grid. (SolarCity 2016), 19. http://www.solarcity.com/sites/default/files/SolarCity_Distributed_Grid-021016.pdf

[lxxii] Farrokh Rahimi and Sasan Mokhtari, "From ISO to DSO," Public Utilities Fortnightly, June 2014. Accessed May 18, 2016. http://www.fortnightly.com/fortnightly/2014/06/iso-dso

[lxxiii] Jon Wellinghoff, Katherine Hamilton and Jeffrey Cramer. "Comments of Jon Wellinghoff, Stoel Rives, LLC and Katherine Hamilton and Jeffrey Cramer 38 North Solutions, LLC." Comments submitted before the New York Public Service Commission Proceeding on the Motion of the Commission in Regard to Reforming the Energy Vision Case No. 14-M-0101, Albany, New York, July 18, 2014. 2014. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={7DAD3252-DE4E-4A2A-8C35-EB9C707C7195}

[lxxiv] New York Public Service Commission. Order Adopting a Ratemaking and utility Revenue Model Policy Framework. CASE 14-M-0101 (Albany, NY: New York Public Service Commission, 2016). http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BD6EC8F0B-6141-4A82-A857-B79CF0A71BF0%7D

[lxxv] Utility of the Future Center. New Regulatory Models. By Sonia Aggarwal and Eddie (Tempe, AZ: Utility of the Future Center, 2014), 17. http://energyinnovation.org/wp-content/uploads/2014/06/SPSC-CREPC_NewRegulatoryModels.pdf

[lxxvi] e21 Initiative. Phase I Report: Charting a Path to a 21st Century Energy System in Minnesota. (Minneapolis, MN: Great Plains Institute for Sustainable Development. 2014), 1-11. http://www.betterenergy.org/e21-Phase1-Report

[lxxvii] Peter Fox-Penner, Dan Harris, and Serena Hesmondhalgh 2013. "A Trip to RIIO In Your Future: Great Britain's latest innovation in grid regulation," Public Utilities Fortnightly, October 2013. Accessed June 5, 2016 http://www.fortnightly.com/fortnightly/2013/10/trip-riio-your-future?page=0%2C1

[lxxviii] Lawrence Berkeley National Laboratory. Performance Based Regulation in a High Distributed Energy Future. By Mark Newton Lowry and Tim Woolf. LBNL 1003823 (Berkeley, CA: Lawrence Berkeley National Laboratory, 2016), 9. https://emp.lbl.gov/sites/all/files/lbnl-1004130_0.pdf

[lxxix] New York Public Service Commission. Order Adopting a Ratemaking and Utility Revenue Model Policy Framework. CASE 14-M-0101 (Albany, NY: New York Public Service Commission, 2016). http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BD6EC8F0B-6141-4A82-A857-B79CF0A71BF0%7D

[lxxx] National Regulatory Research Institute. Distributed Energy Resources: Status Report on Evaluating Proposals and Practices for Electric Utility Rate Design. By Tom Stanton. 15-08. (Silver Spring, MD: National Regulatory Research Institute 2015), 12. http://nrri.org/download/nrri-15-08-rate-design-for-der/

[lxxxi] Ernest Orlando Lawrence Berkeley National Laboratory. A Framework for Organizing Current and Future Electric Utility Regulatory and Business Models. By Satchwell et al. LBNL 181246 (Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory, 2015), 22. https://emp.lbl.gov/sites/all/files/lbnl-181246_0.pdf

[lxxxii] Black & Veatch and Solar Electric Power Association. Planning the Distributed Energy Future: Emerging Electric Utility Distribution Planning Practices for Distributed Energy Resources. By Andy Colman, Dan Wilson and Daisy Chung (Washington, DC: Solar Electric Power Association, 2016), 23. https://www.solarelectricpower.org/media/439751/proactive-der-planning.pdf

[lxxxiii] More than Smart Initiative. More than Smart: A Framework to Make the Distribution Grid More Open, Efficient and Resilient (Pasadena, CA: Resnick Institute, 2014), 8. http://morethansmart.org/wp-content/uploads/2015/06/More-Than-Smart-Report-by-GTLG-and-Caltech-08.11.14.pdf

[lxxxiv] More than Smart Initiative. "MTS Walk, Jog, Run Framework." Accessed May 26, 2016. http://morethansmart.org/mts-walkjogrun-framework/

[lxxxv] Ernest Orlando Lawrence Berkeley National Laboratory. A Framework for Organizing Current and Future Electric Utility Regulatory and Business Models. By Satchwell et al. LBNL 181246 (Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory, 2015), 20. https://emp.lbl.gov/sites/all/files/lbnl-181246_0.pdf

[lxxxvi] Electricity Innovation Lab. Rate Design for the Distribution Edge: Electricity pricing for a distributed resource future. By Glick et al. (Boulder, CO: Rocky Mountain Institute, 2014), 15. http://www.rmi.org/PDF_rate_design

[lxxxvii] Edison Electric Institute. Future of Retail Rate Design. By Eric Ackerman and Paul De Martini (Washington, DC: Edison Electric Institute, 2013), 3. http://www.eei.org/issuesandpolicy/stateregulation/Documents/Future%20of%20Retail%20Rate%20Design%20v4%20021713%20eta%20-%20pjd2.pdf

[lxxxviii] Electricity Innovation Lab. Rate Design for the Distribution Edge: Electricity pricing for a distributed resource future. By Glick et al. (Boulder, CO: Rocky Mountain Institute, 2014), 7. http://www.rmi.org/PDF_rate_design

[lxxxix] See for example:

ComEd. "About | ComEd's Hourly Pricing Program." Accessed June 7, 2016. https://hourlypricing.comed.com/about/; PG&E. "Time-of-use. Learn what Time-of-Use rate plans mean for your business." Accessed June 7, 2016. http://www.pge.com/en/mybusiness/rates/tvp/toupricing.page?WT.mc_id=Vanity_TOU

[xc] California Office of Ratepayer Advocates. "California Residential Electric Rate Redesign." Accessed June 7, 2016. http://www.dra.ca.gov/general.aspx?id=2444

[xci] More than Smart Initiative. Building the Plug & Play Grid: A guide to help states plan for electricity distribution system upgrades. By Brunello, et al. (MTS, 2016), 2. http://morethansmart.org/wp-content/uploads/2016/03/BrunelloDeMartini_Building-the-PlugPlay-Grid_March-2016.pdf