



NARUC

**The National
Association
of Regulatory
Utility
Commissioners**

Evolution of the Distribution System & the Potential for Distribution-level Markets: A Primer for State Utility Regulators

**Sharon Thomas
NARUC Research Lab**

January 2018

**With support from the U.S.
Department of Commerce (NIST)**



Acknowledgments and Disclaimers

This report was developed as part of the “NARUC Regulator Smart Grid Engagement, Phase 4” project of the National Association of Regulatory Utility Commissioners (NARUC) Research Lab. The material in this report is based on work supported by the U.S. Department of Commerce, and specifically, the National Institute of Standards and Technology (NIST) under Award Number 70NANB16H220.

The Research Lab authored this report, which includes editorial comments and suggestions from NARUC members. However, the views and opinions expressed herein are strictly those of the author(s) and may not necessarily agree with positions of NARUC or those of the U.S. Department of Commerce.

The Research Lab thanks state public utility commissioners, commission staff, and other industry experts from around the country for their support, guidance, and feedback, including:

- John Howley, *District of Columbia Public Service Commission*
- Lorenzo Kristov, *California Independent System Operator*
- Commissioner Matt Schuerger and Tricia DeBleeckere, *Minnesota Public Utilities Commission*
- Christopher Villarreal, *Plugged In Strategies*
- Commissioner Nick Wagner, *Iowa Utilities Board*

© January 2018 National Association of Regulatory Utility Commissioners

Disclaimer: This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

TABLE OF CONTENTS

SECTION 1: Introduction: Evolution of the 20th Century Electric System into a 21st Century Utility System”	4
SECTION 2: Transactive Energy and DERs	7
SECTION 3: Distribution System Evolution	10
A. Stages of Distribution System Evolution.....	10
Stage 1: Grid Modernization.....	10
Stage 2: DER Integration	11
Stage 3: Distributed Markets	12
B. Types of Markets.....	12
C. Independent versus Distribution Utility DSOs	13
D. Considerations for Market Services and Distribution Market Development	13
E. Market Services and Functions	18
F. Origin of DSO Models and State Exploration of Them	20
G. Overview of What a Platform is & Operational Models for DSOs.....	21
1. Total DSO.....	21
2. Minimal DSO	22
3. Independent Distribution System Operator (IDSO).....	24
SECTION 4: Lessons Learned	25
A. Overview of Notable State Grid Modernization Initiatives	25
New York.....	25
California	26
Arizona	27
Hawaii	29
Evaluation of States’ Distribution System Evolution	31
SECTION 6: General challenges with grid modernization and incorporating high levels of DERs	33
SECTION 7: Guiding Principles and Objectives for State PUCs Undertaking Grid Modernization Initiatives	35
SECTION 8: Questions for Regulators to Consider	40
Types of data and other information needed by regulators:	41
SECTION 9: Conclusion	42
SECTION 10: Appendix	43

SECTION 1

Introduction: Evolution of the 20th Century Electric System into a 21st Century Utility System^{1,2,3}

Traditional electric distribution system planning involves moving electricity generated from centralized power plants, transmitting the electricity over high-voltage transmission lines, and delivering it to end-users at the distribution level. In this model, power flows in one direction, from generation to transmission lines, transmission lines to distribution lines, and ultimately to end-users. State and federal regulatory frameworks, utility business models, reliability and operating standards, planning and investment approaches, and wholesale markets have all been designed for this traditional paradigm. However, the electric industry is undergoing a shift toward a two-way power flow among the bulk electric system, the distribution system, end-users, and distributed energy resources (DERs) located both behind the meter and in front of the meter.

Varying definitions of DERs in industry literature abound. In this paper, we use the definition provided in the 2016 NARUC *Distributed Energy Resources Rate Design and Compensation Manual*,⁴ which says it “is a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include solar photovoltaic, wind, combined heat and power, energy storage, demand response, electric vehicles, microgrids, and energy efficiency.”⁵

Policy initiatives, technological advancements, and changing customer choices are all key drivers in this shift toward greater DER adoption. Policy initiatives include efforts to decarbonize across all sectors of the economy with high-tech shifts aiding these changes and producing smaller, more economical, devices. Decisions at the grid-edge also include customer, community, and city-level adoption of various equipment and energy sources for greater efficiency, resiliency, economic and system benefits, and lower environmental impacts. An underlying assumption of this paper is that the distribution system will evolve in response to these aforementioned drivers.

At the grid-edge, customers and localities are adopting various types of DERs that are changing how electricity is supplied—this shift will eventually encompass the entire electrical system. Distribution systems will need new approaches for interconnection procedures, and coordination with transmission systems and wholesale markets to handle these higher DER penetration rates. In many parts of the country, DER penetration is increasing and having a measurable impact on distribution system planning

¹WM Warwick, TD Hardy, MG Hoffman, JS Homer, “Electricity Distribution System Baseline Report.” July 2016, p. iii, https://www.energy.gov/sites/prod/files/2017/01/f34/Electricity_percent20Distribution_percent20System_percent20Baseline_percent20Report.pdf.

² Lorenzo Kristov, “Policy, Technology and Architecture for a 21st Century Electric System,” PowerPoint presentation at International School for Materials for Energy and Sustainability California Institute of Technology, July 19, 2017.

³ Paul De Martini, Lorenzo Kristov, “Distribution Systems in A High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight.” October 2015, <https://emp.lbl.gov/sites/all/files/lbnl-1003797.pdf>.

⁴ This report will be referred to as the “NARUC DER Manual” hereafter.

⁵ NARUC Staff Subcommittee on Rate Design, *Distributed Energy Resources Rate Design and Compensation*, National Association of Regulatory Utility Commissioners, November 2016, p. 45, <http://pubs.naruc.org/pub/19fdf48b-aa57-5160-dba1-be2e9c2f7ea0>.

and operation, creating operational challenges. This growth is spawning a need for two-way power flows that legacy distribution system equipment was not intended to support.

Grid operators—transmission system operators (TSOs) such as balancing authorities (BA), or regional transmission operators (RTOs), or independent system operators (ISOs) in restructured markets or vertically integrated markets—have limited visibility and control over customer-side resources. As a result, the industry is beginning to re-conceptualize and redefine Distribution System Operators (DSOs) to encompass their changing roles and responsibilities in a more decentralized power system. This new DSO concept has been a part of state-level utility commissions’ grid modernization discussions in both New York and California.

In this report, DSO is defined as the entity responsible for planning and operational functions associated with a distribution system that is modernized for high levels of DERs [this definition is derived from a Lawrence Berkeley National Laboratory (LBNL) report released in 2015].⁶ The DSO denotes a new electric system paradigm and an expanded functional role for the distribution utility. It is important to note that the “DSO” refers to the entity handling operations, whereas later discussions of a “platform” refer to the creation of a distribution-level energy market that energy services can be transacted on (and a platform is not needed to have a DSO). An example of a DSO that is in line with the LBNL definition is the New York Public Service Commission’s (NYPSC) “Reforming the Energy Vision” (REV) proceeding (April 2014) as “representing both the interface among individual customers and the interface between customers and the bulk power system...[and serving]... as [the] Distributed System Platform Provider (DSPP) [that] will actively coordinate customer activities so that the utility's service area as a whole places more efficient demands on the bulk system, while reducing the need for expensive investments in the distribution system as well. The function of the DSPP will be complemented by competitive energy service providers; both generators of electricity and retailers of commodity will expand their business models to participate in Distributed Energy Resources (DER) markets coordinated by the DSPP.”⁷

Designing the future of DSOs hinges upon the development and interface between DERs and the electrical system. Defining and quantifying the costs and benefits of DERs are challenging and therefore difficult to value and compensate. The increasing volume and diversity of DER technologies connected to the electric system requires a new transmission-distribution (T-D) interface coordination framework. The design and management of this interface for large amounts of DERs will need to be done in conjunction with designing any future DSO.

The relationship between transactive energy and DERs is addressed in this report and gives a high-level overview of three stages in the distribution system evolution, along with associated characteristics of each stage. Various types of market services and functions are explained as well. Next, a discussion of three potential operational models for DSOs is provided. Thereafter, examples of grid modernization efforts

⁶ “Distribution System Operator (DSO) is the entity responsible for planning and operational functions associated with a distribution system that is modernized for high levels of DERs. The term DSO is not intended to imply the need for a different entity from the existing utility. Although the term is becoming more widely used in industry discussions, it does not yet indicate a single, well-defined business model, organizational structure or complete set of functional capabilities, nor does it need to. Rather, we adopt the term DSO simply to recognize that distribution operations of the future will have some functional capabilities beyond those of utility distribution operators today, if for no other reason than to be able to plan and operate the system reliably with larger amounts of diverse DER and multi-directional energy flows. Depending on policy choices in each jurisdiction, the DSO may be limited to the minimal functions needed for high-DER operations, or may expand to a more proactive role in guiding DER deployment to meet locational needs or facilitating or “animating” markets for DERs and prosumer energy-related transactions...” (LBNL <https://emp.lbl.gov/sites/all/files/lbnl-1003797.pdf>, p. vi)

⁷ *Reforming the Energy Vision: NYS Department of Public Service Staff Report And Proposal*, April 2014, p. 9, [http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/percent24FILE/ATTK0J3L.pdf/Reforming percent20The percent20Energy percent20Vision percent20\(REV\) percent20REPORT percent204.25.percent2014.pdf](http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/percent24FILE/ATTK0J3L.pdf/Reforming%20The%20Energy%20Vision%20(REV)%20REPORT%204.25.percent2014.pdf).

that have been successful are presented. General challenges involved with incorporating large amounts of DERs are then highlighted. This is followed by an overview of guiding principles and objectives for state PUCs undertaking grid modernization initiatives. Lastly, a set of questions for regulators to consider as they pursue grid modernization efforts in their states. The appendix highlights legislative and regulatory actions that have initiated grid modernization activities in several states.

The evolution of the nation's electrical grid in light of increasing adoption of DERs--and the necessary associated changes to utility business models--is a very broad topic. We attempt to explain and highlight issues that are important for regulators to consider and evaluate. Some additional issues that regulators will want to take into account, but are beyond the scope of this paper, include DER rate design and compensation methodologies, as well as an evaluation of the tradeoffs; DER technologies and their specific characteristics; cybersecurity implications of higher DER levels; data access and privacy concerns; tools for developing architectures for implementing transactive energy techniques; and evaluations of different types of DSO models and the tradeoffs between them.

SECTION 2: Transactive Energy and DERs

The growth in DERs is one of the key drivers of transactive energy. As the smart grid continues to evolve, there will be more opportunities for efficiency improvements through market-based transactions between energy consumers and producers. New economic tools and processes will also be needed to enable these changes. According to the National Institute of Standards and Technology (NIST):

The concept of transactive energy (TE) is being used to describe these interactions, which involve economic and control techniques to manage grid reliability and efficiency.⁸

An overview online from NIST notes that the TE approach provides a way to more closely balance energy supply and demand. NIST also explains that if the value of electricity at particular points in time and geographic locations can be agreed upon by energy providers and consumers, then each party can decide whether or not they want to proceed with the transaction at that price.⁹

A more detailed definition of TE comes from the Grid Wise Architecture Council (GWAC):¹⁰

The term "transactive energy" is used here to refer to techniques for managing the generation, consumption or flow of electric power within an electric power system through the use of economic or market based constructs while considering grid reliability constraints. The term "transactive" comes from considering that decisions are made based on a value. These decisions may be analogous to or literally economic transactions. An example of an application of a transactive energy technique is the double auction market used to control responsive demand side assets in the GridWise.

The NARUC DER Manual describes TE as both:

...a "technical architecture"¹¹ and an "economic dispatch system."¹² TE relies on price signals, robust development of technology on both the grid and customer side, and rules that allow markets to develop; therefore enabling a wide variety of participants to provide services directly to each other. TE facilitates the coordination of customer-sited resources, such as demand response (DR), storage, and other on-site resources, that are responsive to price or other signals.¹³

IEEE's "The Policymaker's Toolkit, Vital Questions to be Addressed About Proposed Transactive Energy Systems," describes the way that TE systems would support development of what IEEE calls a "New Distribution System" as follows:

⁸ "Transactive Energy: An Overview," NIST staff, date accessed 9/22/2017. <https://www.nist.gov/engineering-laboratory/smart-grid/transactive-energy-overview>.

⁹ Ibid, date accessed 9/9/2017. <https://www.nist.gov/engineering-laboratory/smart-grid/transactive-energy-overview>.

¹⁰ Transactive Energy, GridWise Architecture Council staff, date accessed 11/30/2017. http://www.gridwiseac.org/about/transactive_energy.aspx

¹¹ Technical architecture here means an architecture for how a system can be operated.

¹² The economic dispatch system refers to the means to facilitate the exchange of energy services.

¹³ NARUC Staff Subcommittee on Rate Design, *Distributed Energy Resources Rate Design and Compensation*, National Association of Regulatory Utility Commissioners, November 2016, p. 139, <http://pubs.naruc.org/pub/19fdf48b-aa57-5160-dba1-be2e9c2f7ea0>.

TE systems would support and require the development of a “New Distribution System” to provide proactive network management (network planning, investments, and operations) to respond to dynamically changing market conditions and manage customer-side resources. This would include changing the traditional role of the distribution utility into a “Distribution System Operator” to perform “Transmission System-like” functions within an Integrated Grid. States and stakeholders should assess how using a TE system framework could help to value system-based investments and operation protocols that could drive distribution utility efficiency and innovation, with a view to shifting from the traditional approach of meeting peak capacity (and building more to profit) to load profiling and optimizing investments; and from measuring megawatts sold to measuring value creation.¹⁴

The flexibility provided by DER resources to utility companies could also assist in avoiding costly infrastructure upgrades. However, developing a TE system requires a significant amount of communications and technology equipment—e.g., advanced metering infrastructure (AMI) is a requirement under TE. Some additional challenges include: unproven levels of customer acceptance of this concept; long-standing public policy on resource planning and procurement relies on long-term recovery of investments, but TE focuses on short-term transactions and proof of adequate compensation, and certainty for investments will be required; and many jurisdictions have policies limiting the ability of customers to sell excess electricity to other customers or aggregators.¹⁵

State PUCs in New York, California, and Hawaii are exploring changes to their grid market structures. A discussion of grid modernization initiatives in these states as well as in Arizona can be found in SECTION 4. As more DERs are added to the distribution systems and more micro-grids and campus networks begin to function as virtual power plants, the potential for these and other entities—such as prosumers¹⁶ and smart buildings and equipment—to interact with each other will increase and give rise to a more decentralized grid.¹⁷

¹⁴ The Policymaker’s Toolkit, Vital Questions to be Addressed About Proposed Transactive Energy Systems. NIST Transactive Energy Challenge: Business and Regulatory Models Working Group. June 2017, pp. 7-8, <http://sites.ieee.org/sagroups-825/files/2017/08/Policymaker-Toolkit-Final.pdf/>

¹⁵ NARUC Staff Subcommittee on Rate Design, *Distributed Energy Resources Rate Design and Compensation*, National Association of Regulatory Utility Commissioners, November 2016, .pp. 140-141, <http://pubs.naruc.org/pub/19fdf48b-aa57-5160-dba1-be2e9c2f7ea0>.

¹⁶ Energy consumers who also sell the excess energy they produce from the DERs they own, as defined by Sharon Thomas.

¹⁷ “GridWise Transactive Energy Framework: Version 1.0,” The GridWise Architecture Council, January 2015, p. 14, http://www.gridwiseac.org/pdfs/te_framework_report_pnnl-22946.pdf.

Additional Resources on this Topic from GWAC:

“The Decision-Maker’s Transactive Energy Checklist”: Helps decision-makers evaluate options such as capital asset investments and new information technology opportunities to determine whether they conform to the principles and attributes of transactive energy.

“GridWise Interim Report: Transactive Valuation Methodology”: this is a document written by PNNL that provides a valuation methodology for transactive systems.

“GridWise Transactive Energy Framework Version 1.0”: provides a method and a set of supporting tools that can be used for developing a range of different architecture for implementing transactive techniques.

“GridWise Transactive Energy Infographics”: Graphical illustration of how transactive energy works, along with accompanying descriptions about why transactive energy is important and what the benefits are.

“GridWise Transactive Energy Principles”: Provides high-level requirements for TE systems that provide an additional point of reference for communicating with stakeholders and identifying common ground within the transactive energy community.

SECTION 3: Distribution System Evolution

A. Stages of Distribution System Evolution

DER adoption in the U.S. is uneven. While certain areas have significant adoption, others barely have any. This uneven adoption, as noted in the introduction, is currently driven by policy, technological cost-effectiveness, local economic factors, and consumer interest.

Figure 1 below comes from a report¹⁸ by LBNL and shows a three-stage evolutionary framework for the distribution system. The framework is based on the assumption that the distribution system will evolve in response to both public policy and increasing customer adoption of DERs. Each level expands on capabilities of the earlier stage and includes additional functionalities to support greater amounts of DER adoption and the level of system integration desired. The result is an increasingly complex system.

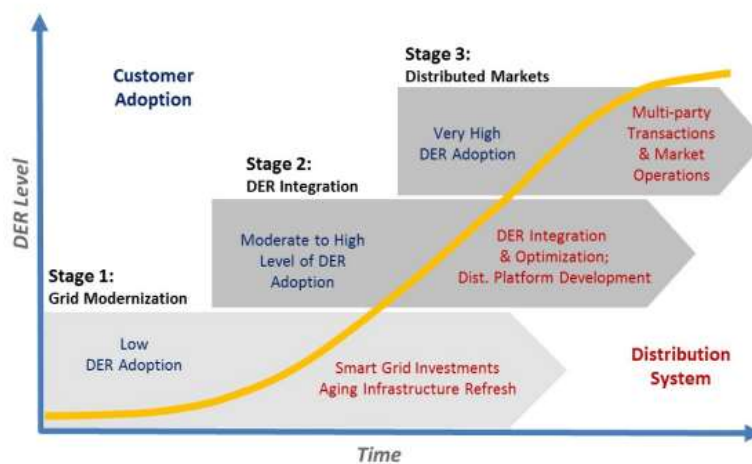


Figure 1. Distribution System Evolution.

We developed a three-stage evolutionary framework for the distribution system driven by its aggregate growth of DERs. The stages are related to the required distribution system changes and potential for DER service transactions at certain thresholds of DER adoption, as experienced in the U.S. and globally to date.

Stage 1: Grid Modernization¹⁹

Stage 1 characterizes a state of the distribution system where utility-grid modernization and reliability investments are currently underway or will be made in the near-term. Customer DER adoption is low in this stage and can be accommodated within the existing distribution system without material changes to infrastructure or operations. DER participation in wholesale markets is very limited or non-existent. Most distribution systems in the U.S. are currently at Stage 1. Distribution systems prior to Stage 1 (10 years ago or more) had low levels of automation and were largely analog systems.

¹⁸ Paul De Martini and Lorenzo Kristov, "Distribution Systems in A High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight," October 2015, P.. 8, <https://emp.lbl.gov/sites/all/files/lbnl-1003797.pdf>.

¹⁹ Ibid.

States in Stage 1 can anticipate greater customer adoption of DERs and the associated increase in interconnection requests as well as necessary changes to their distribution planning. States can begin by analyzing and streamlining rules and procedures for interconnecting DERs to the system, and should consider performing regular engineering assessments of the amount of capacity on various parts of the distribution system to accommodate additional DERs with existing and already-planned facilities (also known as the hosting capacity).

Distribution system planning plays a very important role in supporting operations. Over the decades, distribution system design and planning has not changed much and distribution utilities primarily needed to be good forecasters and planners, focusing mostly on safety and reliability. In the future, distribution utilities will need to plan, operate, and innovate in a variety of new ways to accommodate higher levels of DERs. As such, updates to distribution planning process will be needed to support a reliable, efficient, and robust grid in a changing and uncertain future; new planning efforts should be coordinated with resource and transmission planning to accommodate more DERs and bidirectional power flows. Specific distribution system planning capabilities and distribution grid operations capabilities are described in detail in SECTION 3.D. These efforts should begin in Stage 1.

The increasing impacts of randomness and variability on modern power systems will continue changing, and will continue to dramatically change patterns of system behavior, how systems are planned, how systems are dispatched, and how energy is exchanged. The deterministic approaches typically used by utilities are based on deterministically established dispatch and flow patterns, a few typical stresses, and known congested paths. Consequently, these approaches are becoming increasingly inadequate for dealing with the problem of uncertainty. A new generation of probabilistic methods, reliability, and control performance criteria, tools, and business practices is necessary to address these challenges.²⁰

Assessments that can help states prepare for Stage 2 include performing location-value assessments to identify optimal areas for siting DERs on the distribution system. This assessment can provide such benefits as real-time operational services or deferment of infrastructure investment.

Stage 2: DER Integration²¹

In Stage 2, DER adoption reaches higher levels that require enhanced functional capabilities to maintain reliable distribution system operation. At these levels, DERs also have the potential to provide system benefits. For these reasons, changes to grid planning and operations are required. The Stage 2 DER adoption threshold is based on experience and appears to be when DER adoption reaches beyond nearly 5 percent of the distribution grid peak loading, systemwide. This level of adoption typically results in concentrations of these high adopters in particular neighborhoods and commercial districts, creating the need for enhanced functionality inherent in Stage 2.

Two-way power flows will be needed on high-DER circuits, which will require more advanced protection and control technologies and operations capabilities to ensure safety and reliability. Additionally, the increased level of DERs may provide an opportunity to deliver services to the bulk power system.

²⁰ "Stochastic Operations and Planning," *PNNL*, April 2015, p. iii, https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23680.pdf.

²¹ Paul De Martini and Lorenzo Kristov, "Distribution Systems in A High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight," October 2015, pp. 8-9, <https://emp.lbl.gov/sites/all/files/lbnl-1003797.pdf>.

Distribution utilities can source services from flexible DERs to support or act as alternatives to reliable traditional resources. If DERs can do this, then the distribution operator and the balancing authority would also need to coordinate with each other to ensure reliable operation of the integrated grid.

Stage 2 is concerned with procurement mechanisms for the distribution operator to acquire services from DERs. Thus, Stage 2 markets would have only one buyer—the distribution operator—and would not involve distribution-level energy sales for later resale that could raise federal-state jurisdictional issues.

Stage 3: Distributed Markets²²

Stage 3 is a conceptual stage in which DER providers and prosumers go beyond providing services to the wholesale market and the distribution utility, and seek to engage in energy transactions on a peer-to-peer level. A peer-to-peer system will require regulatory changes to allow retail energy transactions across the distribution system, including ones that are still within a local distribution area (LDA) defined by a single T-D interface substation.

Enabling these kinds of market transactions will require a formal distribution-level market structure to facilitate these peer-to-peer energy transactions. In addition to local markets within each LDA, prosumers may also want to transact between LDAs, using both the transmission system and the distribution system, which places a greater emphasis on coordination between DSOs and TSOs at the T-D interfaces. In this context the DSO role may evolve to include additional market facilitation services, such as financial clearing and settlement. Re-conceptualized roles of the DSO are discussed in SECTION 3.H. Given the regulatory changes and high levels of DER adoption required for Stage 3 to be viable, activities in this stage will likely begin in select areas that already have high-DER penetration. For states that do not currently have significant levels of DERs, but are interested in exploring a Stage 3 distributed market, pilot programs offer one possibility for examining what the potential efficiency gains and local resiliency benefits are of such markets.

B. Types of Markets²³

There are three types of markets that should be distinguished to understand the potential market evolution and related jurisdictional issues over time. These three types of markets are listed below.

1. Wholesale energy and operational markets: Opportunities for DERs to participate in wholesale markets exist today to varying degrees across the country under the Federal Energy Regulatory Commission (FERC) jurisdiction. DERs are increasingly providing a number of wholesale services including energy, generation capacity, transmission capacity deferral, and ancillary services that are needed to operate the electric system. DERs may participate as supply-side or demand-side resources, depending on the nature of the DER and market rules; they may be connected to the utility's distribution grid or at end-user premises; and they may be aggregated to comprise larger "virtual" resources.

2. Distribution operational market: This is a new structure that involves creating opportunities for DERs to be considered as alternatives to utility capital investments or operational expenses. The potential types of services may include: distribution capacity deferral, steady-state voltage management, transient power quality, reliability and resiliency, and distribution line-loss reduction. The distribution utility would procure

²² Ibid, p. 10.

²³ Paul De Martini and Lorenzo Kristov, "Distribution Systems in A High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight," October 2015, pp.. 12-13, <https://emp.lbl.gov/sites/all/files/lbnl-1003797.pdf>.

these services, in place of traditional expenditures, to meet its statutory obligations for a safe and reliable distribution grid. The distribution planning process defines the need for these operational services. This type of market is contemplated to become viable as a characteristic feature of Stage 2.

3. Distribution-level energy market: This is a conceptual structure that involves DER providers, energy services providers, and customers or prosumers buying and selling energy commodities across an LDA (at delivery points that bypass the transmission system, if both sides of the transaction are within the same LDA), or using the transmission system if the two sides are in different LDAs. This type of a peer-to-peer market could involve two structures: a) bilateral forward energy transactions, and b) the creation of an organized residual energy spot market. Both types of structures would likely require statutory and regulatory changes because some energy transactions of this type—for example, when the buyer is a load-serving entity (LSE) rather than an end-user—may be considered to be sales for resale and therefore be subject to FERC jurisdiction.

C. Independent versus Distribution Utility DSOs

A key question regulators will need to consider is whether the new functional requirements of a distribution utility in the high-DER context should be provided by a new independent entity or by adding additional responsibilities and capabilities to the existing distribution utility. A new independent entity, generally referred to as an independent DSO, would be separate from the organization that performs most traditional utility functions, including retail electric service to end-use customers and ownership of the distribution system assets. Various DSO models are discussed in more depth in SECTION 3.H.

This Berkeley Lab report, “Distributed Systems in a High Distributed Energy Resources Future,” includes steps that can help identify the policy or regulatory attributes that guide the choice of an independent or utility DSO (pp. 17-18).

D. Considerations for Market Services and Distribution Market Development

SECTION 3.B, describes three basic types of markets: 1) wholesale energy and operational markets, 2) distribution operational markets, and 3) distribution-level energy markets. Development of these markets requires that the services they offer be clearly defined with regard to specific operational and commercial performance requirements. Many types of DERs will be able to provide operational services to the distribution system as described in Stage 2. This will require their services to be defined, their performance requirements and measurement rules to be specified, and their sourcing and compensation mechanisms to be established. This section identifies capabilities and characteristics of distribution system planning, distribution grid operations, and distribution market operations that will be required of distribution operators to support these types of markets.

1. Distribution System Planning:²⁴

Scalability: The capability of the distribution grid and related operational and market systems to increase capacity with additional resources rather than extensive modification or replacement of the cyber-physical systems, while delivering the same quality of service with no impact to performance, reliability, and interoperability.

²⁴ Modern Distribution Grid: Volume I, Customer and State Policy Driven Functionality,” March 27, 2017 (vol. 1.1), pp. 44-45, http://doe-dspx.org/wp-content/uploads/2017/02/Modern-Distribution-Grid_Volume-I_v1.1.pdf.

Accommodate New Business Models: Enables integration of new products and services that may provide additional value beyond traditional electric energy and delivery. This includes non-energy adjacent services providers seeking to create convergent value across critical infrastructure networks as in smart city initiatives, for example.

Transparency: Timely and consistent access to relevant information by market actors, as well as public visibility into planning, market design, and operational performance without putting sensitive information at risk.

Convergence with Other Critical Infrastructure: Integration with other networks such as natural gas, telecommunications, water, and transportation to create a more efficient and resilient infrastructure, as may be reflected in certain microgrids, while supporting economic and environmental policy objectives to achieve societal benefits including applications associated with Smart Cities.

Accommodate Technology Innovation: Facilitates the integration of new grid and DER types that enable net positive benefits for all customers, taking privacy and security concerns into account, and provide access to system, customer, and third-party data (as needed) to encourage market innovation.

Open and Interoperable: Enable active participation by customers, and accommodates all forms of DER, new services, and markets. This is accomplished through transparent planning, operations, and market interactions that adhere to open standard architecture protocols when available, applicable, and cost effective.

Impact Resistance and Resiliency: The ability to withstand environmental hazards or cyber-physical attacks over a period of time while maintaining a required expected level of service, which includes the ability to recover from disruptions and resume normal operations within an acceptable period of time.

Efficient Operations: The activities taken to improve the performance and efficiency of electricity distribution systems. This includes strategies that can be used to get the same or greater capability out of a utility's wires, saving energy and thereby reducing the need for additional investment.

Asset Management: a systematic process of cost-effectively operating, maintaining, and upgrading electrical assets by combining engineering practices and economic analysis with sound business practice.²⁵

2. Distribution Grid Operations:²⁶

Security: Physical and cybersecurity measures include activities that detect and respond to man-made and environmental threats, and mitigate risks. These risks include cyber-attacks, storms, fire, earthquakes, terrorism, vandalism, and numerous other physical threats. This also includes consideration of operations and the reflexive impacts of physical threats on the cyber domain, and cyber threats on the physical domain such as attacks and disruptions to critical communication channels, or compromise of computer or data integrity. This also recognizes the

²⁵ "Utility asset management in the electrical power distribution sector," *IEEE*, July 2005, <http://ieeexplore.ieee.org/document/1611842/> (Accessed: 12/4/2017).

²⁶ "Modern Distribution Grid: Volume I, Customer and State Policy Driven Functionality," March 27, 2017 (vol. 1.1), pp. 45-48, http://doe-dsp.org/wp-content/uploads/2017/02/Modern-Distribution-Grid_Volume-I_v1.1.pdf.

increasing interdependencies between physical and secure information and communication systems.

Privacy & Confidentiality: Privacy and confidentiality allows users to maintain control over the collection, use, reuse and sharing of personal and commercial information as relates to electricity consumption, generation, storage, and/or market activity. At the same time, this includes protection against issues such as identity theft, determination of personal behavior patterns, determination of specific appliance usage and real-time surveillance. These privacy measures in turn enhance and ensure the confidentiality of customer, commercial, and market information.

Contingency Analysis: Contingency analysis involves understanding and mitigating potential failures in a distribution network. Contingency analysis for distribution involves, for example, assessing potential impacts due to changes in system power flows due to real-time variations in net load resulting from DER operation and/or changes in gross load. It also includes assessment of potential impacts due to distribution component reliability and faults in specific system configurations. Contingency analysis involves two basic steps: contingency selection and contingency evaluation.

Management of DER and Load Stochasticity: Management of DER and load stochasticity is the ability to assess and respond to changes with minimal cost and emissions impacts while maintaining reliability.

Reliability & Resiliency Management: Refers to the provision of adequate, efficient, safe, and reasonable service and facilities. It also includes making repairs, changes, and improvements to the service. The service will be reasonably continuous and without unreasonable interruptions or delay. Grid operator will strive to prevent interruptions of electric service and, when interruptions occur, restore service within the shortest reasonable time. Effective reliability and resiliency management includes procedures and systems to achieve the reliability performance benchmarks and minimum performance standards established by applicable authorities.

Operational Risk Management: Examines core operations including energy delivery and reliability as well as DER-provided operational services performance and related distributed platform systems. It encompasses current and future risks and mitigation strategies to manage tangible operational risks related to environmental factors, human interaction (including errors and public safety) and equipment/system failures. Operational risks may also include these complex system risks:

- Randomness risk, associated with stochastic variations inherent in the cyber-physical electric system;
- Knowledge risk, related to a lack of knowledge (known-unknowns) about characteristics of an electric network and connected devices;
- Interaction risk, created by the interaction among customers, DERs, markets and elements of the electric network; and
- Black Swan risk, pertaining to low-probability, high-impact, or unknown-unknowns events occurring.

Situational Awareness: Involves operational visibility into physical variables and events. It also includes forecasting for all grid conditions that may need to be addressed such as normal operation states, criteria violations, equipment failures, customer outages, and cybersecurity events.

Integrated Grid Coordination: Focuses on the physical coordination of real and reactive power flows across the transmission/distribution system interface where the coordination is between the distribution operator and the BA (a utility TSO or an ISO/RTO).

Controllability and Dynamic Stability: Controllability describes the ability of an external input (the vector of control variables) to move the internal state of a system from any initial state to any other final state in a finite time interval. For the grid, this means the ability to make the grid behave as desired within the bounds of grid capability. Dynamic stability is the property of a system by which it returns to an equilibrium state after a small perturbation. For the grid, this means the ability to tolerate and compensate for small disturbances to maintain proper settings of quantities like voltage and power flow. Disturbances would include such things as solar PV power fluctuations due to cloud cover variation, but there are many other possible sources of disturbances, including faults and fluctuating loads. For distribution, the results may differ from bulk systems (local reliability issues instead of cascading failures, for example), but the basic principle of stability is the same.

Attack Resistance / Fault Tolerance / Self-healing: This property is the ability of a system to tolerate asset or function loss, through failure or attack, and act to maintain best available service despite degradation. It can enable the system to maintain its reliability and resiliency, ensuring its robustness. It can add to the security of the system and safety of the distribution grid. It may also include device-level control limiters that prevent a device from being commanded into out-of-band operation.

Control Federation and Control Disaggregation: Control federation is the ability to combine and resolve multiple competing and possibly conflicting control objectives. The problem arises when more than one control process wants to make use of a particular grid resource or asset. Control disaggregation is the ability to decompose broad control commands into forms suitable for local consumption and decision-making while accounting for local constraints. This ability enables the mix of centralized and distributed control to achieve local optimization within global coordination.

Fail-Safe Modes: A fail-safe device/system is expected to fail at some point; when it does, it will fail in a safe manner or be placed into a safe state. Also, a fail-safe device/system may also define what occurs when a user error or loss of communications causes it to behave in an undesired manner, including notifications.

Public and Workforce Safety: This refers to the design, construction, operation, and maintenance for the distribution system—including facilities that do not belong to electric utilities—ensuring adequate service, and secure safety to workers and the general public.

Stochastic Planning: Greater flexibility will be needed from planning and operations to address DER adoption and the associated impacts such as greater variability on the power system. Deterministic planning methods used by utilities are inadequate for dealing with the problem of uncertainty. In light of this, a move from deterministic planning to stochastic planning will be necessary.²⁷

²⁷ "Stochastic Operations and Planning," PNNL, April 2015, p. iii, https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23680.pdf.

3. Distribution Market Operations:²⁸

Market Animation: Involves establishing transparent distribution operational markets to enable viable market development for grid services with deep participation, to achieve a more efficient and secure electric system including better use of the distribution system, as well as the transmission system and bulk generation.

System Performance: This attribute is defined in terms of cost, quality of service, and applicable environmental and societal parameters through optimization of a portfolio of grid and DER-provided services, between the distribution and bulk power systems, and across various timescales.

Local Optimization: The use of DER, integrated grid assets, and related platform technologies, to economically locate, place, manage, and operate a distribution system to meet local performance requirements, including least-cost service, reliability, and power quality. This optimization may include an assessment of the impacts of local actions on the overall system, and vice-versa.

Environmental Management: Involves the use and optimization of DER resources, along with centralized clean resources to meet federal, state, and local environmental targets.

Distribution Investment Optimization: Identification and sourcing of a mix of grid infrastructure and technology assets and DER provided services to enable efficient investment and operational expenditures for a safe, reliable distribution grid addressing needs identified in distribution planning. Investment optimization includes the concept of solving multiple problems with the same investment, such as DER, to simultaneously improve reliability and capacity.

Distribution Asset Optimization: This is the operational utilization of physical grid assets and DER-provided services to manage distribution operations in a safe, reliable, secure, and efficient manner through dynamic optimization.

These capabilities are described further, with an illustration in Figure 25, on page 91 of the Department of Energy's "Modern Distribution Grid, Volume I: Customer and State Policy Driven Functionality" Report."²⁹ Figure 25 maps these capabilities to various functions, such as DER portfolio management, settlements, etc.

Customers and services firms should have access to relevant information so they are informed about the types of services and benefits they can provide to the grid. Additional considerations to address include rules for the physical interconnection of new resources; if principles of "open access" should apply and, if so, how they are specified and enforced; and whether DERs can participate in the wholesale transmission-level market directly or if they must go through a distribution operator or LSE that would provide the wholesale market interface.^{30,31} Distribution market development plans must also incorporate issues

²⁸ Modern Distribution Grid: Volume I, Customer and State Policy Driven Functionality." DOE. March 27, 2017 (vol. 1.1), pp. 48-49, http://doe-dspx.org/wp-content/uploads/2017/02/Modern-Distribution-Grid_Volume-I_v1.1.pdf.

²⁹ "Modern Distribution Grid: Volume I, Customer and State Policy Driven Functionality," March 27, 2017 (vol. 1.1), p. 58, http://doe-dspx.org/wp-content/uploads/2017/02/Modern-Distribution-Grid_Volume-I_v1.1.pdf.

³⁰ PJM and CAISO currently allow DER to participate in wholesale markets.

³¹ Notice of Proposed Rulemaking, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators. November 17, 2016. FERC. ¶ 61,121. 18 CFR Part 35. Docket Nos. RM16-23-000; AD16-20-000. <https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-1.pdf>.

regarding potential market power, which can be an issue in aforementioned Stage 2 when DER services are likely to be concentrated among a few entities on an individual distribution feeder. For example, a distribution feeder may have three DER services firms with sizable amounts of aggregated dispatchable DERs, and any one would be able to influence a local market.³²

E. Market Services and Functions

A number of market services and monetary structures exist, making DER valuable to utility companies, DER owners, and end-use customers. Consideration should also be given to who creates and controls these services. At the distribution level, entities that could create and control these markets include utilities, regulatory authorities, and third parties. Some of these market services may include:

- Aggregation to wholesale markets:^{33,34} In some cases, the services and benefits of DER are more valuable when aggregated into larger numbers. This aggregation would involve assembling a portfolio of DERs, including individual customer response. By doing so, aggregators, be they utilities or third parties, enable smaller resources to participate in wholesale markets in instances where each individual DER might be ineligible, or the costs or complexity of participation prohibitive. However, some states do not allow aggregators to participate in their jurisdictions. For example, in the Midcontinent Independent System Operator, Inc. (MISO) market, only Illinois allows for third-party aggregators to operate in their jurisdiction. In non-organized markets, development of retail markets may be a path. In this instance, a utility would be allowed to procure additional services from a third-party aggregator to meet local retail needs. A single DER customer may not provide much of a response, but when aggregated with many customers, this can provide benefits at both the retail and wholesale levels. Lastly, aggregation can result in a more direct compensation by tying it directly to wholesale prices, or potentially a distribution locational marginal price.
- “Park-and-loan” energy storage-based services:³⁵ The incorporation of energy storage, including park-and-loan offerings, on the distribution system and at customer sites may enable operators to offer new, non-core market-enabling services similar to those provided by natural gas utilities. In a “park-and-loan,” parties may store energy that cannot be delivered immediately and are scheduled for future delivery with the DSO. Similarly, distribution operators may sell or loan short-term energy as needed to make up for deficiencies in scheduled deliveries, or they may use stored energy to smooth an LDA’s net load to minimize variability exported onto the transmission grid.

³² Necessary changes to the operation of the distribution system is not limited to the utility. The role of the regulatory commission may also need to evolve with the utility. For example, development of distribution level markets may require that regulatory commissions take on additional roles providing market monitoring or oversight functions to ensure open access and address market power concerns.

³³ “Modern Distribution Grid: Volume I, Customer and State Policy Driven Functionality,” March 27, 2017 (vol. 1.1), p. 58, http://doe-dspx.org/wp-content/uploads/2017/02/Modern-Distribution-Grid_Volume-I_v1.1.pdf.

³⁴ NARUC Staff Subcommittee on Rate Design, *Distributed Energy Resources Rate Design and Compensation Manual*, National Association of Regulatory Utility Commissioners, November 2016, p. 45, <http://pubs.naruc.org/pub/19fdf48b-aa57-5160-dba1-be2e9c2f7ea0>, <http://pubs.naruc.org/pub/19fdf48b-aa57-5160-dba1-be2e9c2f7ea0> (p.139)

³⁵ Paul De Martini and Lorenzo Kristov, “Distribution Systems in A High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight.” October 2015, p. 26, <https://emp.lbl.gov/sites/all/files/lbnl-1003797.pdf>.

- Micro-transaction clearing and settlement services: The settlement process includes calculating credits and charges for DER services and other market activity.³⁶ As the number of energy transactions rises across the distribution system and into the bulk power system, it may be desirable for distribution operators to offer additional non-core micro-transaction clearing and settlement services. Transactions involving DERs may involve complex pricing structures and terms and very small dollar amounts per transaction. These types of micro-transactions will more closely resemble the special tariff and other operating revenue transaction structures that utilities currently support, although at a fraction of the volume of transactions contemplated for a high-DER future.³⁷ A technology that could support these kinds of transactions is Blockchain, which is a shared, encrypted ledger that is maintained by a network of computers that verify transactions. Advocates say the technology could be especially promising in the electric industry where networks of peers, such as electricity producers and consumers, trade energy with one another.³⁸
- DER Sourcing:³⁹ Markets for sourcing non-wires alternatives for distribution may involve using one or a combination of these three general structures:
 - Prices: Time-varying rates, tariffs, marginal pricing, market-based prices;
 - Products: DER products offered to customers that may be operated by the utility or third parties that may be funded by utility customers through retail rates or by the state; or
 - Procurements: DER services sourced through competitive procurements such as request for proposals/offers, bilateral contracts such as power purchase agreements, auctions, etc.
- DER Portfolio Management:⁴⁰ DER portfolio management consists of managing a mix of DER sourced through various mechanisms involving prices, products, and procurements, as well as grid infrastructure investments. This involves optimizing the utilization of these resources to achieve desired performance in terms of response time and duration, load profile impacts, market requirements, and value (based on net of the costs to integrate DERs into grid operations).
- Market Information Sharing:⁴¹ This function encompasses the communication and exchange of market information between the BA or TSO, distribution system, and participating DER, including information on distribution area net demand, net interchanged supply, DER services scheduled by the distribution system, DER forecasts, aggregate output of DERs, and DER services that may be offered to the BA or TSO for wholesale market participation.

³⁶ "Modern Distribution Grid: Volume I, Customer and State Policy Driven Functionality," March 27, 2017 (vol. 1.1), p. 58, http://doe-dspx.org/wp-content/uploads/2017/02/Modern-Distribution-Grid_Volume-I_v1.1.pdf.

³⁷ Paul De Martini and Lorenzo Kristov, "Distribution Systems in A High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight." October 2015. P. 26, <https://emp.lbl.gov/sites/all/files/lbnl-1003797.pdf>.

³⁸ Mike Orcutt, "How Blockchain Could Give Us a Smarter Energy Grid," MIT Technology Review. October 16, 2017. <https://www.technologyreview.com/s/609077/how-blockchain-could-give-us-a-smarter-energy-grid/>

³⁹ "Modern Distribution Grid: Volume I, Customer and State Policy Driven Functionality," March 27, 2017 (vol. 1.1), p. 58, http://doe-dspx.org/wp-content/uploads/2017/02/Modern-Distribution-Grid_Volume-I_v1.1.pdf.

⁴⁰ "Modern Distribution Grid: Decision Guide, Volume III," June 28, 2017, pp. 5, 75, <http://doe-dspx.org/wp-content/uploads/2017/02/Modern-Distribution-Grid-Volume-III.pdf>.

⁴¹ "Modern Distribution Grid: Volume I, Customer and State Policy Driven Functionality," March 27, 2017 (vol. 1.1), p. 59, http://doe-dspx.org/wp-content/uploads/2017/02/Modern-Distribution-Grid_Volume-I_v1.1.pdf.

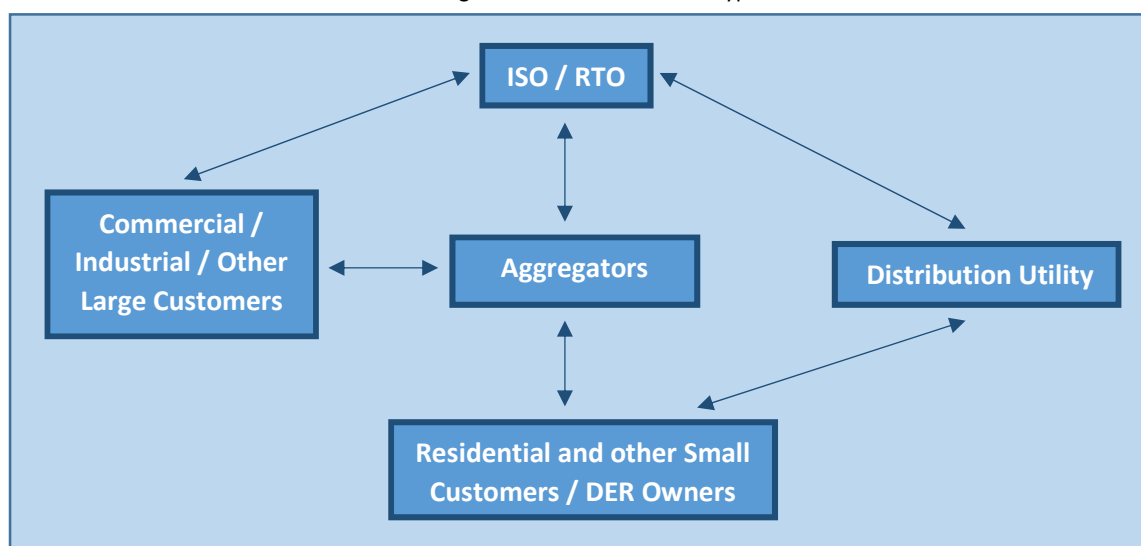
- **Market Oversight:**⁴² The market oversight process includes functions to monitor distribution market activity and assess potential market manipulation, as well as ensure market security, legitimacy and performance. This function also includes the related market participant rules, including terms of the responsibilities and associated requirements. Appropriate compliance mechanisms will collect and transmit data needed for independent market monitoring and controls as required by regulation, where applicable.

F. Origin of DSO Models and State Exploration of Them

The concept of DSOs arose as a result of two key issues: 1) the problem of managing high penetration DER for both bulk system and distribution operations while maintaining reliability; and 2) the emerging problem of passing coordination from one entity (e.g., an aggregator) to another entity (e.g., an ISO/RTO) while skipping an entity in-between (the distribution utility), which leaves the skipped layer unaware of actions that impact its responsibilities in grid systems.⁴³ This has been referred to as “tier bypass.”

An example with aggregated demand response, can help to illustrate the tier bypass issue. In this case, the third-party aggregator and customers (predominantly large ones)⁴⁴ would communicate directly with the ISO. However, the distribution utility is left out of the communication loop and does not have information about the type of aggregation, the location of the aggregation, and whether the ISO has dispatched the resource or not. So if an ISO dispatches a demand response program that has been aggregated within their market, the distribution utility would need to have information about this so they know what the impacts of that dispatch are on the distribution system. Figure 2 provides an illustration of how the issue of tier bypass occurs.

Figure 2: Illustration of Tier Bypass



⁴² [Ibid.](#)

⁴³ “Modern Distribution Grid: Volume I, Customer and State Policy Driven Functionality,” March 27, 2017 (vol. 1.1), p. 35, http://doe-dspx.org/wp-content/uploads/2017/02/Modern-Distribution-Grid_Volume-I_v1.1.pdf.

⁴⁴ When large customers do this, it is less of a problem compared to when aggregators communicate directly with the ISO/RTO since large customers are likely already transmission-connected.

New York has been exploring the idea of transforming utilities into distributed system platform providers (DSPP) that own and operate the grid and serve as neutral gatekeepers between the providers and buyers of energy. To ensure independence in the system, utilities that serve in the DSPP role will be prohibited from owning DER resources. In 2014, California regulators directed the state's investor owned utilities to develop distribution resource plans that include programs allowing for two-way energy flows, enhanced customer choice for DERs, and increased opportunities for DERs on the grid-edge. State regulators aim to "begin the process of moving the IOUs toward a more full integration of DERs into their distribution system planning, operations, and investment,"⁴⁵ as stated in a California Public Utilities Commission (PUC) distribution resource planning ruling issued in 2014.

G. Overview of What a Platform is & Operational Models for DSOs

A platform or distribution-level market for transacting energy service, is a business ecosystem that matches producers with consumers, who transact directly with each other using resources provided by the ecosystem itself. The DSO would work in conjunction with the platform to facilitate the provision of market services. The platform ecosystem provides outside parties with easy access to products or services through an infrastructure and a set of rules designed to facilitate interactions among users. A platform's overarching purpose is to consummate matches among users and to facilitate the exchange of goods and services, thereby enabling value creation for all participants. Platform components include hardware, software, and service modules, along with an architecture that specifies how they fit together. Platform rules coordinate network participants' activities. They include standards that ensure compatibility among different components, protocols that govern information exchange, policies that constrain user behavior, and contracts that specify terms of trade and the rights and responsibilities of network participants.⁴⁶

An overview of three distribution operational models is provided next that illustrate different ways to distinguish roles and responsibilities around the T-D interface between the DSO and the BA or TSO. The focus in these models is on the distribution system portion of the utility company, aside from its functions of supplying retail energy to end users or managing other energy-related services for consumers. The reason for doing this is to focus more specifically on challenges associated with distribution system planning, market design, and operations of the grid in a high-DER future.

1. Total DSO⁴⁷

In the "Total DSO" model, the distribution utility essentially takes on the functions of an ISO, but at the distribution level. The DSO and TSO act as balancing authorities and engage with each other, as BAs normally do, by sharing information about what is occurring on the system. For example, the DSO and TSO would share information about net electricity flows across their system, with the goal that each system is settling and dispatching what they need to, within their authority. This sharing of information between the DSO and TSO helps facilitate the operation of the system at certain T-D interfaces (i.e. substations).

In this model, the DSO expands its current roles and responsibilities to include functions, such as:

⁴⁵ DRP.R.14-08-013 (Calif. 2014), p. 5, <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M146/K374/146374514.PDF>.

⁴⁶ Tabors Caramanis Rudkevich (TCR), White Paper on Developing Competitive Electricity Markets and Pricing Structures. Prepared for NYSDA. April 2016, p. 34, <https://www.bu.edu/pcms/caramanis/NYPSC%20TCR%20WhitepaperApril2016.pdf>.

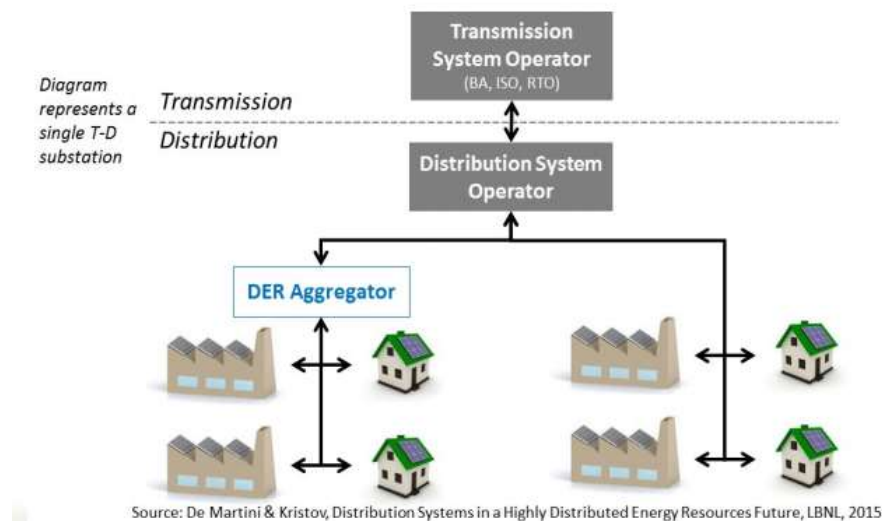
⁴⁷ Lorenzo Kristov, "Modernizing transmission-distribution interface coordination for a high-DER future," March 29, 2017, Slide 10, https://energy.gov/sites/prod/files/2017/04/f34/2_T-D%20Interface%20Panel%20-%20Lorenzo%20Kristov%2C%20CAISO.pdf.

- DER aggregation for wholesale market participation;
- Optimizing local DER to provide transmission grid services;
- Balancing supply-demand locally; and
- Managing DER variability to minimize impacts at T-D interface.

An additional role is operating distribution-level markets, where the DSO provides a single aggregated bid to a BA or TSO at each T-D interface, and multi-use applications are simplified because the DSO manages DER response to grid operator dispatch.

DSO directly integrates all DER for the LDA at each T-D Interface. The DSO also coordinates T-D interchanges with the BA or TSO, so that the BA or TSO only sees a single resource at each T-D interface and does not need visibility to the DERs. Additionally, the DSO would manage all intra-distribution area transactions, schedules, and energy flows.

Figure 3⁴⁸: Total DSO Illustration



2. Minimal DSO⁴⁹

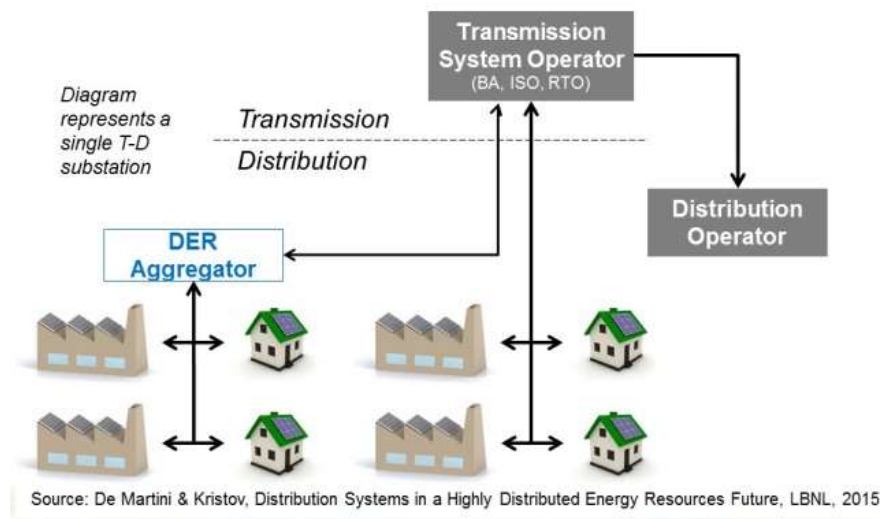
The Minimal DSO model is another approach. In this model, the DSO maintains its current distribution utility role of operating the distribution system, with enhancements only as needed to ensure reliability with high-DER volumes. DER would engage in multiple-use applications, providing services to end-users, the DSO, and the wholesale market. Additionally, the BA or TSO would directly integrate all DER for both transmission and distribution system operations, meaning that all these products and services would go directly into the wholesale market or to the TSO. This would also require the BA or TSO to incorporate a distribution grid network model and have complete real-time distribution grid-state information. Figure 3 shows a graphical representation of the Minimal DSO model and Table 1 on the following page provides

⁴⁸ Lorenzo Kristov, "Modernizing transmission-distribution interface coordination for a high-DER future," March 29, 2017, Slide 13, https://energy.gov/sites/prod/files/2017/04/f34/2_T-D_interface_Panel_percent20Lorenzo_percent20Kristov_percent20CAISO.pdf.

⁴⁹ Lorenzo Kristov, "Modernizing transmission-distribution interface coordination for a high-DER future," March 29, 2017, Slide 10, https://energy.gov/sites/prod/files/2017/04/f34/2_T-D_interface_Panel_percent20Lorenzo_percent20Kristov_percent20CAISO.pdf.

a comparison of power system design elements between a Minimal DSO and a Total DSO model. However, it is important to note that the Minimal DSO model comes with a significant policy and technological challenge as it would require the TSO to have near real-time visibility from the TSO level, through the distribution grid, and into the consumer level and their meters.

Figure 4⁵⁰: Minimal DSO Graphical Illustration



Design Element	Minimal DSO	Total DSO
Market structure	Central market optimization by ISO with large numbers of participating DER	DSO optimizes local markets at each T-D substation; ISO market sees a single virtual resource at each T-D interface
Distribution-level energy prices	Locational energy prices based on LMP plus distribution component (e.g., LMP +D)	Based on value of DER services in local market, including LMP for imports/exports
Resource/capacity adequacy	As today, based on system coincident peak plus load pocket & flexibility needs; opt-out allowed for micro-grids	Layered RA framework: DSO responsible for each T-D interface area; ISO responsible to meet net interchange at each interface
Grid reliability paradigm	Similar to today	Layered responsibilities; e.g., DSO takes load-based share of primary frequency response
Multiple-use applications of DER (MUA)	DER subject to both ISO and DSO instructions Rules must resolve dispatch priority, multiple payment, telemetry/metering issues	DER subject only to DSO instructions, as DSO manages DER response to ISO dispatches & ancillary services provision
Regulatory framework	Federal-state jurisdictional roles similar to today	Explore framework to enable states to regulate distribution-level markets
Comparable to existing model	Current distribution utility roles & responsibilities, enhanced for high DER	Total DSO is similar to a balancing authority

Table 1: A comparison of power system design elements between a Minimal DSO and a Total DSO model.⁵¹

⁵⁰ Ibid., Slide 12

⁵¹ Lorenzo Kristov, "Modernizing transmission-distribution interface coordination for a high-DER future," March 29, 2017, Slide 11.

3. Independent Distribution System Operator (IDSO)⁵²

Another model option was proposed by former FERC Chairman Jon Wellinghoff, which is to have a neutral independent distribution system operator (IDSO). Proponents of this view assert that the distribution system should be owned by utilities, but operated and regulated by an outside entity, similar to an RTO on the transmission grid. Under this model, utilities would still own the poles and wires on the distribution grid, as they do on the transmission system, but would turn over operations to the IDSO, which would be under the jurisdiction of the state utility regulators.

Distribution Owner Functions: a discussion about whether some of the distribution system operational and planning functions should remain with the owner of the distribution system assets (the distribution owner, or DO), irrespective of the entity responsible for the other functions under the various DSO models we describe, can be found on p. 32-34 of this LBNL report: <https://emp.lbl.gov/sites/all/files/lbnl-1003797.pdf>

The utility will be a stakeholder in the planning and operational processes of the independent entity, as they are at the RTO level, Wellinghoff told *Utility Dive* in an interview,⁵³ “but they won’t operate the system and they won’t plan for upgrades to the system. That will be done independently.”

An assessment of the alternative operational models and the pros and cons of creating an independent DSO to perform the DSO functions versus expanding the responsibilities of the distribution utility to include these functions is beyond the scope of this white paper, but you can find one on p. 36 – 56 of this LBNL report: <https://emp.lbl.gov/sites/all/files/lbnl-1003797.pdf>

⁵² Gavin Bade, “Who should operate the distribution grid?” *Utility Dive*, March 19, 2015, <http://www.utilitydive.com/news/who-should-operate-the-distribution-grid/376950/>.

⁵³ “Modern Distribution Grid: Volume I, Customer and State Policy Driven Functionality,” March 27, 2017 (vol. 1.1), p. 58, http://doe-dspx.org/wp-content/uploads/2017/02/Modern-Distribution-Grid_Volume-I_v1.1.pdf.

SECTION 4: Lessons Learned

A. Overview of Notable State Grid Modernization Initiatives

This section provides an overview of state grid modernization and DER integration initiatives that have been steadily progressing. States included in this discussion are: New York, California, Arizona, and Hawaii.

New York^{54,55,56}

In 2003, the governor of New York, along with governors from eight other states in the region, began discussions to develop a regional cap-and-trade program addressing carbon dioxide emissions from power plants.⁵⁷ These discussions resulted in the creation of the Regional Greenhouse Gas Initiative (RGGI), the first mandatory market-based program in the U.S. to reduce greenhouse gas emissions. RGGI was implemented in 2009 and serves as a cooperative effort among the states of New York, Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, Rhode Island, and Vermont to cap and reduce CO₂ emissions from the power sector. In this program states sell nearly all emission allowances through auctions and invest proceeds in energy efficiency, renewable energy, and other consumer benefit programs. After a comprehensive 2012 Program Review, the RGGI states implemented a new 2014 RGGI cap of 91 million short tons. The RGGI CO₂ cap then declines 2.5 percent each year from 2015 to 2020. The RGGI CO₂ cap represents a regional budget for CO₂ emissions from the power sector.⁵⁸

Then in April 2014, the New York Department of Public Service initiated the Reforming the Energy Vision (REV) proceeding, which proposes having an entity perform the role of a “distributed system platform (DSP) provider” to facilitate the deployment of DERs and demand management as an alternative to their traditional infrastructure. In order to encourage buy-in from utilities that are accustomed to earning a rate-of-return on new infrastructure projects, the framework in REV would allow utilities to earn a rate tied to investing in DER, while also achieving the state’s societal and energy goals.

A goal of New York regulators is to create new performance incentives and market-based earnings to spur the development of distribution-level electricity markets that would allow end-users to be compensated in real-time based on the location and temporal value of the DER they own on their premises.

New York’s REV is divided into two tracks. Track 1’s goal is to develop DER markets and establish the utility as the DSP provider. REV defines new operational functions for utilities as the DSP provider, including new grid and market facilitation services. Track 2 centers on reforming rate-making practices for utilities and revenue streams for the DSP provider model, which involves changes in regulatory, tariff, and incentive structures. The Market Design and Platform Technology Working

⁵⁴ “Report of the Market Design and Platform Technology Working Group,” *MDPT Working Group*, August 17, 2015.

http://nyssmartgrid.com/wp-content/uploads/MDPT-Report_150817_Final.pdf.

⁵⁵ Steve Fine, Paul De Martini, and Matt Robison, “On the Grid’s Bleeding Edge: The California, Hawaii, and New York Power Market Revolution.” *ICF International*. July 2015. http://www.ourenergypolicy.org/wp-content/uploads/2015/07/California_Hawaii_New_York_Power_Market_Revolution.pdf

⁵⁶ Krysti Shallenberger, “The top 5 states for utility grid modernization and business model reform,” *Utility Dive*, April 3, 2017.

<http://www.utilitydive.com/news/the-top-5-states-for-utility-grid-modernization-and-business-model-reform/439550/>.

⁵⁷ Regional Greenhouse Gas Initiative, <http://www.rggi.org/design/history/mou> (accessed: September 3, 2017).

⁵⁸ Regional Greenhouse Initiative, <https://www.rggi.org/> (accessed: September 4, 2017).

Group developed a 2015 report,⁵⁹ with recommendations for commissions on the planning, operations, market mechanisms, and technology to create a DER-enabling platform envisioned in Track 1.

The Market Design and Platform Technology Working Group report explained the basic market structure is not expected to change significantly during the initial implementation phase. It described several staged improvements to distribution system planning, market operations, grid operations, and data access. The Working Group defined these development stages in a way that considers tradeoffs in planning the evolution of the DSP market.

In October 2016, the New York Department of Public Service released its staff report⁶⁰ on the value of distributed energy, which represents a move away from traditional Net Energy Metering (NEM). It notes that NEM is a powerful tool for supporting an emerging market, but that when combined with traditional volumetric rate structures, NEM provides an imprecise and incomplete signal of the full value and costs of DERs. One recommendation states that existing solar projects should receive the full retail-rate NEM credit for 20 years from the date of installation. Another recommendation calls for preserving retail-rate NEM for new residential and small commercial projects through 2020, then stepping down the credit until it aligns with the ultimate LMP+D⁶¹ value in the DER docket, which is consistent with a settlement agreement reached between several utility and solar stakeholders earlier in 2016.⁶²

For the past three years, regulators, utilities, and other stakeholders in New York have been filing proposals for the Distribution Service Implementation Plans (DSIP) process and conducting pilot programs within the state. In the first few months of 2017, New York regulators issued a series of orders to find a new compensation structure for DERs, guide the development of DSIPs, and deploy two grid-scale battery storage systems.⁶³ Time-of-use rates are also offered by utilities in New York.

California^{64,65,66}

California has been working to integrate DERs since the late 1990s. The state has a set of policy objectives related to the environment and the role of DERs that are driving California's efforts. California's objectives for DERs have evolved over time from meeting ambitious climate change goals to a more implementation-driven approach involving proactive planning for DER integration. In 2002, California first established a renewable portfolio standard (RPS). Most recently in 2015, this

⁵⁹ "Report of the Market Design and Platform Technology Working Group," MDPT Working Group, August 17, 2015.

http://nyssmartgrid.com/wp-content/uploads/MDPT-Report_150817_Final.pdf.

⁶⁰ "Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding: 15-E-0751." NYS Department of Public Service. October 27, 2016. [https://s3.amazonaws.com/dive_static/editorial/Staff+Report+and+Recommendations+10-27+\(1\).pdf](https://s3.amazonaws.com/dive_static/editorial/Staff+Report+and+Recommendations+10-27+(1).pdf).

⁶¹ "LMP" is the locational marginal price of electricity, or what any wholesale generator in that location would earn for an equivalent kilowatt-hour. "D" is the value of the resource to the distribution system or in other words, the additional value of the asset being distributed. <https://www.greentechmedia.com/articles/read/how-to-find-compromise-on-net-metering/> (accessed: 9/22/2017).

⁶² Katherine Tweed, "New York Resets Distributed Energy Rates, Maintains Residential Net Metering," *Green Tech Media*. October 28, 2016, <https://www.greentechmedia.com/articles/read/new-york-resets-distributed-energy-rates-maintains-residential-net-metering>.

⁶³ A policy that compensates end-users for excess energy produced by their DERs when it is sold back to the distribution grid.

⁶⁴ Krysti Shallenberger, "The top 5 states for utility grid modernization and business model reform," April 3, 2017.

<http://www.utilitydive.com/news/the-top-5-states-for-utility-grid-modernization-and-business-model-reform/439550/>.

⁶⁵ "51st State Perspectives: Distributed Energy Resources Integration: Policy, Technical, And Regulatory Perspectives From New York and California," December 2016, p. 8, http://www.scottmadden.com/wp-content/uploads/2016/12/SEPA-ScottMadden-51st-State-Report_DER-Integration-CA-NY.pdf.

⁶⁶ John Bernhardt, "California adopts nation's first advanced inverter standards," January 6, 2015, <http://www.utilitydive.com/press-release/20150106-california-adopts-nations-first-advanced-inverter-standards/>.

was updated to require publicly owned utilities to procure 50 percent of their electricity from eligible renewable energy resources by 2030.

A series of dockets comprise the state's grid modernization proceedings, with some focused on rate reforms and valuation of DERs, and others on more comprehensive efforts that seek to ease the integration of DERs. Two noteworthy dockets that are designed to encourage DER implementation in the state are the Distribution Resource Plan (DRP)⁶⁷ proceeding and the Integrated Distributed Energy Resources (IDER)⁶⁸ proceeding.

The DRP proceeding asks the state's three investor-owned utilities to explore opportunities for siting, valuing, and integrating DERs, and simultaneously work to delineate their roles and business opportunities on the distribution grid; whereas the IDER proceeding requires utilities to manage DERs on the distribution grid by using demand-side management. A number of other proceedings enhance these dockets by addressing rate-reform, incentives for electric vehicles, energy storage, and DER management. Other proceedings bolstering these dockets include: a DER incentive proposal and numerous filings for electric vehicles, energy storage, and Distributed Energy Resource Management Systems (DERMS).

Utilities in the state are working to increase DER deployment at the distribution level through pilot programs. The programs will allow utilities to collect four percent on their expenses annually if they can demonstrate that the investments can defer traditional infrastructure investments.

California still has NEM in place, but in 2016 the state issued a "NEM 2.0 rate structure," an extension of the state's previous NEM policy. NEM 2.0 eliminates a cap on the number of homes that could sell distributed solar back to the grid and includes TOU rates. NEM 2.0 is intended to be an interim solution and will be revisited in 2019. In January 2017, the CPUC issued a decision⁶⁹ that will guide how these general rate cases end up influencing the value of solar, energy efficiency, and technologies like demand response and energy storage.⁷⁰

California has additionally been working on establishing new standards for advanced inverters. In December 2014, the CPUC adopted "Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources,"⁷¹ which establishes new smart inverter standards under the state's electric interconnection tariff called Rule 21. This ruling makes California the first state to require the use of advanced inverters with DERs.

⁶⁷ PUC. R.14-08-013 (Calif 2014). <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M103/K223/103223470.pdf>

⁶⁸ PUC. R.14-10-003 (Calif. 2014). <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M116/K116/116116537.PDF>

⁶⁹ PUC. R.15-12-012 (Calif. 2015). <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K250/171250399.PDF>

⁷⁰ Jeff St. John, "With Net Metering Secure, California Solar Now Faces Uncertainty From Time-of-Use Changes," *Green Tech Media*, February 16, 2017, <https://www.greentechmedia.com/articles/read/with-net-metering-secure-california-solar-now-faces-threat-from-time-of-use>.

⁷¹ "Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources: Smart Inverter Working Group Recommendations," Public Utilities Commission, State of California, January 2014. http://www.energy.ca.gov/electricity_analysis/rule21/documents/recommendations_and_test_plan_documents/Recommendations_for_updating_Technical_Requirements_for_Inverters_in_DER_2014-02-07-CPUC.pdf.

Arizona^{72, 73, 74, 75, 76}

In 2006, the Arizona Corporation Commission (ACC) approved the Renewable Energy Standard and Tariff (REST), requiring that regulated electric utilities generate 15 percent of their energy from renewable resources by 2025. Each year, Arizona's utility companies are required to file annual implementation plans describing how they will comply with the REST rules. In December 2016, the ACC voted to end retail NEM for its solar customers and replace it with a lower amount, still to be determined.⁷⁷

ACC Chairman Doug Little opened a docket⁷⁸ to revise Arizona's REST by modernizing and expanding it in August 2016. The Chairman's suggestions included increasing the state's 15 percent renewable energy mandate by 2025 to 30 percent by 2030. At the end of November 2016, the state's Residential Utility Consumer Office, tasked with protecting ratepayer interest, introduced a white paper named, "Evolving the RPS: A Clean Peak Standard for a Smarter Renewable Future,"⁷⁹ to enhance the mandate by adding a directive for a certain percentage of energy used to meet peak-load demand, to be derived from clean sources.

The paper notes that while RPSs have been effective in giving a boost to clean energy, the simple megawatt-hour (MWh) based approach for traditional RPS policies "does not differentiate between each renewable MWh based on its value to the grid or for reducing fuel consumption."⁸⁰ The white paper authors propose "building upon the traditional RPS framework by adding one or more new supplemental components that would work in parallel with the foundational MWh-based retail sales component. The first and foremost of these new components would be the clean peak standard (CPS)," whereby a certain percent of energy delivered to customers during peak-load hours must be derived from clean energy sources. For example, a 30 percent clean peak standard would mean that 30 percent of the MWh delivered to customers during a defined peak period would need to come from qualifying renewable resources."⁸¹ Additional design features can be included in the implementation of the CPS, the paper explains, including tradable compliance credits, locational adders, multi-part peak periods, and periodic updates to align new investments with system needs. The paper's authors assert that if the proposed RPS framework works as it is intended to, it can help to achieve clean energy resource procurement that is

⁷² "Renewable Energy Standard & Tariff," Arizona Corporation Commission. <http://www.azcc.gov/divisions/utilities/electric/environmental.asp> (accessed August 20, 2017).

⁷³ Herman K. Trabish, "Updated: Arizona proposal seeks to mandate renewable generation during peak demand hours," *Utility Dive*, December 9, 2016. <http://www.utilitydive.com/news/updated-arizona-proposal-seeks-to-mandate-renewable-generation-during-peak/432031>.

⁷⁴ Julian Spector, "This Upgrade to Renewable Portfolio Standards Could Make Them a Lot More Effective at Grid Balancing," *Green Tech Media*, December 2, 2016. <https://www.greentechmedia.com/articles/read/upgrade-renewable-portfolio-standards-peak-capacity-arizona>.

⁷⁵ "Commission Approves APS Rate Case Which Offers Rate Options, Low-income Assistance, and Incentivizes the Use of New Technology," Arizona Corporation Commission, August 16, 2017. <http://www.azcc.gov/Divisions/Administration/news/2017Releases/2017-8-16%20Commission%20Approves%20APS%20Rate%20Application.asp>

⁷⁶ Krysti Shallenberger, "Arizona Regulatory Judge Recommends Approval of APS, Solar Settlement," *Utility Dive*, July 27, 2017. <https://www.utilitydive.com/news/arizona-regulatory-judge-recommends-approval-of-aps-solar-settlement/448062/>.

⁷⁷ Robert Walton, "Arizona regulators approve new rates, solar fees for Tucson Electric Power," *Utility Dive*, February 10, 2017. <http://www.utilitydive.com/news/arizona-regulators-approve-new-rates-solar-fees-for-tucson-electric-power/435926/> (accessed: September 21, 2017).

⁷⁸ Docket E-00000Q-16-0289 (Ariz. 2016) <http://edocket.azcc.gov/Docket/DocketDetailSearch?docketId=19621>.

⁷⁹ Zoe Fishman, "Evolving the RPS: A Clean Peak Standard for a Smarter Renewable Future," *Strategen Consulting*, December 1, 2016. <https://www.strategen.com/new-blog/2016/12/1/evolving-the-rps-a-clean-peak-standard-for-a-smarter-renewable-future>.

⁸⁰ Lon Huber, Edward Burgess, "Evolving the RPS: A Clean Peak Standard for a Smarter Renewable Future," *Arizona's Residential Utility Consumer Office*, December 2016, p. 3, <https://static1.squarespace.com/static/571a88e12fe131211f1f6e6/t/58405ac4d2b85768c5e47686/1480612551649/Evolving+the+RPS+White+paper.pdf>.

⁸¹ Ibid.

aligned with a more comprehensive set of grid services that electric power system operators need to supply.⁸²

In June 2016, Arizona Public Service (APS) requested a \$165.9 million base rate increase. Shortly after this, in December 2016, retail NEM ended in Arizona. In March 2017, APS filed a rate design settlement agreement; by August 2017, the ACC approved the March settlement agreement between APS, Commission staff, industry representatives, and solar advocates. Key parts of the settlement include:

- An \$87.25 million annual revenue increase;
- Expansion of the AZ Sun program, a utility-owned rooftop solar program for low and moderate income customers;
- More rate design options including new TOU and demand rates; and
- Grandfathering of existing NEM customers for 20 years so they can stay on their current, more favorable rate plan; and establishment of a transitional step down rate for new customers as follows:
 - In year one, new NEM customers will receive 12.9 cents/kWh for energy exported to the grid (slightly below the existing retail NEM rate of 13 to 14 cents/kWh) and will be grandfathered under that rate for 10 years; and
 - In year two, new NEM customers will receive 10 percent less (e.g., 11.6 cents/kWh) for energy exported to the grid and will be grandfathered under that rate for 10 years.

Hawaii^{83,84}

In 2001, Hawaii passed its first RPS, and NEM additionally went into effect, which led to stark increases in solar PV and solar-powered hot water systems. The RPS was initially voluntary, but became binding by 2004. Substantial change, however, did not happen until a stakeholder group aligned with leadership from the utilities, legislature, governor's office, and various civil society groups (known as the Hawaii Clean Energy Initiative⁸⁵). The group created a stronger set of RPSs with a goal of 40 percent by 2009. In 2015, Hawaii signed into law a 100 percent renewable energy mandate that the state must meet by 2045. In general, Hawaii's approach has included a variety of catalysts, including financial incentives, tax credits, and regulatory pushes.⁸⁶

By 2015, one out of every eight homes in Hawaii reported having solar panels, which led to overvoltage and utility restrictions to solar photovoltaic (PV) additions. In response, Hawaii's Public Utility Commission (PUC) issued four orders, including Order No. 32052 that requires utilities to file distributed generation

⁸² Ibid..

⁸³ Gavin Bade, "Getting to 100 percent renewables: How Hawaii plans to get fossil fuels off the grid," *Utility Dive*, March 23, 2016. <http://www.utilitydive.com/news/getting-to-100-renewables-how-hawaii-plans-to-get-fossil-fuels-off-the-gr/416176/> (accessed: September 2, 2017).

⁸⁴ Steve Fine, Paul De Martini, and Matt Robinson, "On the Grid's Bleeding Edge: The California, Hawaii, and New York Power Market Revolution," ICF International, 2015, p.3. http://www.ourenergypolicy.org/wp-content/uploads/2015/07/California_Hawaii_New_York_Power_Market_Revolution.pdf.

⁸⁵ About the Hawaii Clean Energy Initiative: an unprecedented effort to transform the entire Hawaii economy from getting 95 percent of its energy, including most electricity, from imported oil today, to meeting the state's energy needs from 70 percent clean energy (primarily indigenous renewables and efficiency) by 2030. <https://energy.gov/oe/services/electricity-policy-coordination-and-implementation/state-and-regional-policy-assistance-2> (accessed: September 2, 2017).

⁸⁶ Gavin Bade. "Getting to 100 percent renewables: How Hawaii plans to get fossil fuels off the grid," *Utility Dive*, March 23, 2016. <http://www.utilitydive.com/news/getting-to-100-renewables-how-hawaii-plans-to-get-fossil-fuels-off-the-gr/416176/>

interconnection plans (DGIPs) to upgrade distribution and integrate more solar PV. Hawaii also has enacted state legislation (HB1943) that will maximize the interconnection of solar PV and require changes to distribution planning, modernization of the grid, and compensation for DER provided services. Hawaii's regulators have responded with a sense of urgency to adapt to market changes as part of its proceeding investigating DER policies. On March 31, 2015, the Hawaii PUC established a requirement for utilities to submit a plan within 90 days for "a) proposed revisions to applicable interconnection-related tariffs to mitigate near-term DER technical integration challenges, expedite interconnection process, and standardize technical specifications for fast-track approval of customer self-supply systems; b) new tariff systems; and for customer self-supply c) proposed DER 2.0 transition plan, including tariff for grid-supply systems."⁸⁷ Concerns about shifting costs of grid maintenance onto non-solar customers led the Hawaii PUC to end NEM in October 2015 and replace it with the self-supply and grid-supply programs, which went into effect in 2016 and are described further below:^{88,89}

- Self-Supply Program
 - Solar PV customers with energy storage are eligible for expedited approval of their systems; and
 - Customers do not get compensated for their energy exports since these systems are not designed for exports.

However, due to issues involving permitting, battery cost, and technical issues, this program has not gained much momentum.

- Grid-Supply Program
 - Solar PV customers are compensated for energy exports at the wholesale rate, which is half the price of the retail rate (wholesale prices are 15-28 cents/Kwh)

Hawaii experiences a load curve even more exaggerated than the "Duck Curve," well known to California utilities, which refers the timing imbalance between peak demand and renewable energy production. The state's largest utility, Hawaiian Electric Co., is trying to address this problem by either shifting renewable energy to fit customer demand, or reshaping customer demand to better align with the renewable energy generation.

Hawaiian Electric recognized that to realize the dual potential of DERs to address generation and demand challenges, it needed a better understanding of which resources were connected to its distribution grid and at a granular level to provide a holistic view and control over the 75,000 rooftop solar systems and other DERs on its grid. A recent grant from the Department of Energy seeks to fix this oversight issue by implementing a System to Edge-of-Network Architecture and Management System (SEAMS), which combines short-term forecasting and weather predictions to provide grid-responsive controls linking DERs with the larger utility systems.

⁸⁷ Steve Fine, Paul De Martini, and Matt Robinson, "On the Grid's Bleeding Edge: The California, Hawaii, and New York Power Market Revolution," ICF International, 2015, p.3, http://www.ourenergypolicy.org/wp-content/uploads/2015/07/California_Hawaii_New_York_Power_Market_Revolution.pdf.

⁸⁸ Customer Self-supply and Grid-Supply Programs," Hawaiian Electric. <https://www.hawaiianelectric.com/clean-energy-hawaii/producing-clean-energy/customer-self-supply-and-grid-supply-programs>.

⁸⁹ Krysti Shallenberger, "Growing Pains: Hawaii Solar Sector Howls as Grid-Supply Incentives Hit Caps," *Utility Dive*, September 13, 2016. <https://www.utilitydive.com/news/growing-pains-hawaii-solar-sector-howls-as-grid-supply-incentives-hit-caps/426149/>.

The state is also reforming utility rate structures so that consumers of all types are encouraged to reduce their energy use during peak hours and shift a portion of their usage to times when more renewable energy is generated. A common example of this method is using TOU. While TOU rates are helping to provide more accurate valuation of DERs, the state is still working to address rate-structure issues.

Overall, Hawaii's approach to DER integration is a more incremental one—comparable to the California model. Hawaiian Electric's current business model is that of a vertically integrated utility where it earns money through traditional cost-of-service ratemaking, and the state seems comfortable maintaining this current model as long as it can meet its regulatory requirements and the 100 percent RPS.

Evaluation of States' Distribution System Evolution

Here, we provide a general characterization of the stage at which the four states described in SECTION 4.A are at in their distribution system evolution. The LBNL report⁹⁰ that discusses these stages use DER penetration as an illustrative indicator of the transition from Stage 2 to Stage 3. The stages of the distribution system evolution used in the following discussion refer to those described in SECTION 3.A.

DER penetration levels on the basis of peak load can provide an illustrative sense of the DER integration challenges, but a more comprehensive assessment of system attributes would be needed to fully encompass where a utility or state is with respect to their progress through a given stage.⁹¹ It is also important to acknowledge that progress is often not uniform throughout an entire state (e.g., some utilities in a given state might be at a Level 1, whereas others might be at a Level 2), so the Stages used to describe New York, Arizona, California, and Hawaii below are meant to provide an overarching characterization.

In New York's November 2016 Supplemental DSIP filing, the state's utilities asserted they are already in Stage 2: "During the next five years, the individual utility DSIPs and this Supplemental DSIP will accelerate Stage 1 progress and move the utilities deeper into Stage 2, thus building the capabilities needed to move into Stage 3. Those capabilities include understanding how to integrate DER while maintaining a safe and reliable system, how to optimize DER integration, and how to develop a working distribution services platform."⁹²

According to the LBNL report's use of DER penetration level as an indicator of the transition from one stage to the next, one could reasonably characterize Arizona as also being well into Stage 2. The pace at

⁹⁰Paul De Martini and Lorenzo Kristov "Distribution Systems in A High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight," October 2015., p.8, <https://emp.lbl.gov/sites/all/files/lbnl-1003797.pdf>.

⁹¹ *Modern Distribution Grid Report, Volume I: Customer and State Policy Driven Functionality*, US Department of Energy, Version 1.1, March 27, 2017. http://doe-dsp.org/wp-content/uploads/2017/02/Modern-Distribution-Grid_Volume-I_v1.1.pdf.

⁹² Joint Utilities of New York, "Supplemental Distributed System Implementation Plan," Case 16-M-0411 in the Matter of Distributed System Implementation Plans. November 1, 2016, p. 20, <http://jointutilitiesofny.org/wp-content/uploads/2016/10/3A80BFC9-CBD4-4DFD-AE62-831271013816.pdf>.

which utilities pursue various aspects of their progression will depend on a variety of factors such as utility structure, system design, regulatory requirements, and customer expectations.⁹³

California and Hawaii are in Stage 2 based on DER adoption and public policy decisions, according to the previously mentioned LBNL report.⁹⁴ Both of these states require an evolution in their integrated grid planning process that involves analyzing a wider and more complex range of economic and engineering valuation issues in an integrated and multidisciplinary way. California's DRP order also requires the creation of new services and the use of various pricing, programs, and procurements to competitively source DER services—referred to as “animating markets” in New York. Hawaii similarly recognizes the value of distributed resources requiring compensation for “...electric grid services and other benefits provided by distributed generation customers and other non-utility service providers.”⁹⁵

⁹³“Integrated Distribution System Planning,” ICF International, Prepared for the Minnesota Public Utilities Commission, August 2016. <https://energy.gov/sites/prod/files/2016/09/f33/DOE%20MPUC%20Integrated%20Distribution%20Planning%208312016.pdf>.

⁹⁴ Paul De Martini and Lorenzo Kristov, “Distribution Systems in A High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight,” October 2015, p. 9, <https://emp.lbl.gov/sites/all/files/lbnl-1003797.pdf>.

⁹⁵ Steve Fine, Paul De Martini, and Matt Robison, “On the Grid’s Bleeding Edge: The California, Hawaii, and New York Power Market Revolution,” *ICF International*. July 2015, .pp 4-5, http://www.ourenergypolicy.org/wp-content/uploads/2015/07/California_Hawaii_New_York_Power_Market_Revolution.pdf.

SECTION 6: General challenges with grid modernization and incorporating high levels of DERs

Several states have begun moving toward a new utility business model and their experiences are instructive. However, each state has different statutory and regulatory guidelines that can promote and impede practices relevant to achieving progressive energy goals. In order for a regulatory commission to better prepare itself to address these opportunities, an initial set of questions and challenges on this topic are noted below:

- Smaller utilities with fewer financial resources face a cost barrier to adopting advanced grid technologies.
- Utilities receive a rate-of-return when they build new infrastructure. If utilities integrate high levels of DER and regulators extract as much as possible out of these resources at the lowest cost, then there is no new infrastructure from which utilities can capitalize—leaving them without an incentive to partake in such a system.
- Integrated systems modeling tools are complex and costly.
- Better frameworks are needed to more accurately value the benefits and costs of DER to the distribution system.
 - Least cost ratemaking frameworks may not accurately capture the total benefits that may be enabled. A jurisdiction may want to consider a net benefit ratemaking framework to recognize additional benefits that may be enabled by a certain investment.
- Many states are faced with statutory and regulatory rules unique to their state. A one size fits all approach will not work. Choosing the right model for each state is a challenge.
- State interconnection policies—which, in some states, can be just as lengthy for smaller-scale systems as it is for larger systems—can sometimes create unintended barriers for distributed generation (DG) projects. Excessive or expensive procedures can overwhelm project costs to the point of making clean DG uneconomical.⁹⁶
- DER benefits are very temporal and location-specific.
 - The temporal nature of DERs refers to the fluctuating value associated with weather, seasonal conditions, or the time of day the DER is producing electricity. Demand response contracts, for example, may limit use to a certain number of hours, days, or events per year. The locational value of DERs refers to the variable value associated with a specific distribution substation, an individual feeder, a section of a feeder, or a combination of these components.
 - Different locations of DERs have different impacts on the distribution grid. DERs, such as electric vehicles and energy storage devices, can draw large amounts of power from the grid that can lead to voltage levels dropping below acceptable levels, causing flickering lights, momentary outages, or even blackouts. Other DERs, such as rooftop solar panels, can export too much power onto the grid, causing voltage rises above acceptable levels, which can lead to burnt out equipment and eventually power

⁹⁶ “Energy and Environment Guide to Action: State Policies and Best Practices for Advancing Energy Efficiency, Renewable Energy, and Combined Heat and Power, 2015 Edition,” *U.S. Environmental Protection Agency*. Chapter 7.3, p.1, https://www.epa.gov/sites/production/files/2015-08/documents/gta_chapter_7.3_508.pdf.

outages. Having policies in place to mitigate these circumstances, via tariffs, prices, or other initiatives, will be important to ensure that these resources do not negatively impact reliability, but are also appropriately integrated into the system.

- Variable energy generation from renewable resources and associated issues of tripping offline are also a challenge. Smart inverters can help with this. IEEE 1547 (2017) is the relevant interconnection standard, and is nearing finalization; UL 1741 is the relevant safety standard and was completed in 2016; IEEE 2030.5 is the relevant communication standard.⁹⁷
- Jurisdictional issues for DSOs: Commissions may need to address and examine how new technologies are impacting their regulatory processes and authority. These technologies, such as energy storage, have different attributes than the electricity technologies that existed in the past and may blur the bright lines between federal and state authority. These differing attributes have driven, and continue to drive, new jurisdictional issues and tensions, such as:
 - When end-users adjust their retail demand in response to price signals in wholesale markets or to provide a wholesale service (such as capacity), which side of the federal-state line does that adjustment fall on?
 - When residential customers install rooftop solar panels and provide any generation beyond their immediate needs to the local utility company, do the customers become subject to federal utility regulation?
 - When a distributed generation resource, energy storage asset, or other new technology is capable of providing both retail and wholesale services simultaneously, can it provide those services across both state and federal regulatory structures?⁹⁸

⁹⁷ "Regulatory Challenges to Deploying Distributed Energy Resources," Smart Grid Interoperability Panel, April 2015, <http://www.sqip.org/wp-content/uploads/Regulatory-Challenges-WP-APRIL-2015.pdf>.

⁹⁸ Jeffery S. Dennis, Sudeen G. Kelly, Robert R. Nordhaus, and Douglas W. Smith, "Federal/State Jurisdictional Split: Implications for Emerging Electricity Technologies," December 2016, pp. v-vi, <https://emp.lbl.gov/sites/all/files/lbnl-1006675.pdf>.

SECTION 7: Guiding Principles and Objectives for State PUCs Undertaking Grid Modernization Initiatives

This section provides an overview of the motivators behind state PUCs' grid modernization programs by specifically looking at the guiding principles and objectives of grid modernization that have been provided by states. Guiding principles from Minnesota, New York, and California are first outlined. Thereafter, objectives from ten states and the District of Columbia are detailed.

Guiding Principles from Minnesota, New York, and California

*Minnesota:*⁹⁹

In 2016, the Minnesota Public Utilities Commission (MN PUC) released its Staff Report on Grid Modernization. This report was initiated by the MN PUC in 2015 through a proceeding to consider development of policies related to grid modernization with a focus on distribution system planning. The resulting report identifies the actions in the proceeding, including a definition of grid modernization for the state, principles to guide grid modernization efforts in Minnesota, and proposes a three-phase approach to continue policy development of grid modernization in the state. The principles enumerated in this report for Minnesota are to:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs;
- Facilitate comprehensive, coordinated, transparent, integrated distribution system planning.

*New York:*¹⁰⁰

In 2015, the New York State Energy Planning Board issued the "New York State Energy Plan," which is a comprehensive roadmap to build a clean, resilient, and affordable energy system. This report coordinates New York's REV initiative, as well as other energy policies and initiatives. A core component of this plan is a set of principles that are being applied to the execution of all of the REV elements. These principles are:

Community Engagement: One of the fundamental REV strategies will be for the state agencies to engage with the state's diversity of communities to assist them with developing and implementing clean energy solutions.

Customer Value and Choice: REV aims to empower customers with tools to efficiently manage their power from the grid or distributed resources, and enable competitive markets to encourage the entry of private firms to provide the services and energy options those customers value.

⁹⁹ Minnesota Public Utilities Commission, "Staff Report on Grid Modernization," March 2015, p. 14, http://morethansmart.org/wp-content/uploads/2015/06/MNPUC_Staff_Report_on_Grid_Modernization_March2016.pdf.

¹⁰⁰ "2015 New York State Energy Plan Volume 1," *New York State Energy Planning Board*. 2015, pp. 49-54.

Innovation and Technology: REV will align energy innovation with market demand. New York State Energy Research and Development Authority (NYSERDA) and New York Power Authority (NYPA) will partner with the state's academic research institutions and the private sector to support development of next generation clean energy technology solutions and innovative business and financing models, as well as training the next generation of talent to support growth of the clean energy economy. NYSEDA and NYPA will also work with the clean tech innovation sector outside of New York to help import leading solutions from elsewhere and to help export NY's solutions to receptive markets outside the state.

Private Sector Investment: REV will look to increase the leverage of private sector capital investment by working through the NY Green Bank to develop innovative public/private partnerships and financing models that bridge clean energy finance market gaps. REV will also develop price signals to better reflect the value of clean energy and guide the market's development of DERs, products, and services.

Market Transformation: REV, regulatory reforms, and programs will focus on market transformation, enabling the clean energy supply chain to engage in a new, integrated, and self-sustaining private sector driven clean energy market. To accelerate market transformation, REV initiatives will focus on removing common market barriers to help facilitate development of competitive markets, enhancing data sharing and transparency efforts, supporting outreach and education, and encouraging demonstration projects.

Efficiency: The "New York State Energy Plan" report notes that efficiency is about minimizing waste, and outlines the following specific ways to reduce waste:

- *Technological Efficiency:* a more efficient light bulb or HVAC system requires less energy to produce the same amount of light or heating and cooling.
- *Building Efficiency:* energy efficient buildings incorporate a combination of energy conservation measures to waste less energy (both electric and thermal) while delivering the same level of comfort and services to their occupants. Net zero energy buildings are designed to a level of efficiency that enables them to satisfy all of their energy demands (on an annual basis) through on- or off-site clean energy generation.
- *System Efficiency:* improving the energy and capital efficiency of the State's entire electrical grid (e.g., deploying distributed energy resources to modify the system's load shape to reduce peak demand) reduces the need for new delivery infrastructure investments, allowing New York to accelerate its transition to a clean energy economy without overburdening residential, commercial, and industrial ratepayers.
- *Market Efficiency:* in most circumstances, and recognizing the need for appropriate utility sector regulatory oversight, sustainable private sector-driven competitive markets are the most efficient capital allocation mechanisms.
- *Government Efficiency:* more efficient delivery of government energy programs and services means eliminating redundancies, reducing waste, facilitating shared services, and helping State and local governments balance budgets without increasing taxes.

*California:*¹⁰¹

In California, state legislation passed in 2013 that required electric corporations to file distributed resource plan proposals with the California PUC. With help from the More Than Smart¹⁰² Initiative, the CPUC then issued guidance on the components to be included in the plans. The More Than Smart Report developed the guiding principles for distribution planning listed below. On July 1, 2015, six utilities filed Distributed Resource Plan Applications.

More than Smart's guiding principles for California are below:

- 1) Distribution planning should start with a comprehensive, scenario driven, multi-stakeholder planning process that standardizes data and methodologies to address locational benefits and costs of distributed resources.
- 2) California's distribution system planning, design and investments should move toward an open, flexible, and node-friendly network system (rather than a centralized, linear, closed one) that enables seamless DER integration.
- 3) California's electric distribution service operators (DSO) should have an expanded role in utility distribution operations (with CAISO) and should act as a technology-neutral marketplace coordinator and situational awareness and operational information exchange facilitator while avoiding any operational conflicts of interest.
- 4) Flexible DER can provide value today to optimize markets, grid operations, and investments. California should expedite DER participation in wholesale markets and resource adequacy, unbundle distribution grid operations services, create a transparent process to monetize DER services, and reduce unnecessary barriers for DER integration.

Grid Modernization Objectives of 10 States & D.C.:¹⁰³

The Department of Energy's Modern Distribution Grid, Volume I report did an analysis of ten states around the country and the District of Columbia. The states analyzed were California, Florida, Hawaii, Illinois, Massachusetts, Minnesota, New York, North Carolina, Oregon, and Texas, to represent both regional and regulatory diversity. For most of the states, the objectives for grid modernization were drawn directly from legislative or regulatory documents. In the cases of North Carolina and Florida, grid modernization legislation or regulation leaves the definition of objectives open to utilities, and so the literature sources in these two states also include utility filings related to grid modernization technology deployment.

¹⁰¹ Minnesota Public Utilities Commission, "Staff Report on Grid Modernization," March 2015, pp. 5, http://morethansmart.org/wp-content/uploads/2015/06/MNPUC_Staff_Report_on_Grid_Modernization_March2016.pdf.

¹⁰² More than Smart (MTS) is a non-profit organization whose mission is to support policy-makers and stakeholders pursuing cleaner, more reliable, and more affordable electricity service through the integration of distributed energy resources into electricity grids. MTS brings industry, non-profit, and policy experts together to develop innovative approaches to upgrade state electricity distribution systems in high DER growth scenarios.

¹⁰³ *Modern Distribution Grid Report, Volume I: Customer and State Policy Driven Functionality*, US Department of Energy, Version 1.1. March 27, 2017, pp. 19-20. http://doe-dsp.org/wp-content/uploads/2017/02/Modern-Distribution-Grid_Volume-I_v1.1.pdf.

Descriptions of the objectives of these states and the District of Columbia are below:

Affordability: Provide efficient, cost-effective, and accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies.

Reliability: Maintain and enhance the safety, security, reliability, and resiliency of the electrical grid at fair and reasonable costs, within accepted standards and consistent with the state's energy policies.

Customer Enablement: Support greater empowerment, engagement, technology options and information for customers to manage their energy bills, including related infrastructure investment to accommodate two-way flows of energy.

System Efficiency: Enhance the operation of the physically connected generation, transmission, and distribution facilities, which are operated as an integrated unit typically under one central management or operating supervision.

Enable DER Integration: Ensure that the grid can integrate or host DER with the necessary communication and cyber and physical security protocols, in order for DER to be dispatched and controlled, while providing engineering and economic benefits.

Adopt Clean Technologies: Enable customer adoption of new and clean technologies (e.g., energy storage, DER, electric vehicles, microgrids, etc.) to facilitate greater customer choice, reduce emissions, improve reliability and resource diversity, and enhance customer experience.

Reduce Carbon Emissions: Reduce carbon dioxide emissions emitted from the electricity sector. For example, this may result from: meeting new generation needs with renewable or other clean sources of energy; displacing fossil fuel use in generation with renewable power or other clean sources of energy; making more efficient use of fossil-fuels; increasing building efficiency and taking other conservation or energy efficiency measures; and increasing electrification of the transportation sector.

Operational Market Animation: Monetize DER services, reduce barriers for DER integration, and provide greater opportunities for realizing benefits of distributed energy resources through the provision of grid services.

Table 2 shows the grid modernization objectives of each of the 10 states, as well as the District of Columbia in this study:

Objectives	CA	DC	FL	HI	IL	MA	MN	NC	NY	OR	TX
Affordability	•	•	•	•	•	•	•	•	•	•	•
Reliability	•	•	•	•	•	•	•	•	•	•	•
Customer Enablement	•	•	•	•	•	•	•	•	•	•	•
System Efficiency	•	•	•	•	•	•	•	•	•	•	•
Enable DER Integration	•	•	•	•	•	•	•	•	•	•	•
Adopt Clean Technologies	•	•	•	•	•	•		•	•	•	•
Reduce Carbon Emissions	•	•	•	•				•	•	•	•
Operational Market Animation	•	•		•		•	•		•		

Table 2:¹⁰⁴ Grid modernization objectives of ten states and the District of Columbia.

The appendix in SECTION 10 provides an overview of legislative and regulatory actions that have initiated grid modernization efforts in several states.

¹⁰⁴ *Modern Distribution Grid Report, Volume I: Customer and State Policy Driven Functionality*, U.S. Department of Energy, Version 1.1, March 27, 2017, .pp 20, http://doe-dsp.org/wp-content/uploads/2017/02/Modern-Distribution-Grid_Volume-I_v1.1.pdf.

SECTION 8: Questions for Regulators to Consider

The questions in this section are drawn from the NARUC DER Manual¹⁰⁵ as well as discussions with state public utility commissions. Regulators may want to consider these questions as they are seeking to gain a sense of the level of DER adoption in their states and how prepared utilities are to integrate DER. The list below is not exhaustive.

Assessing the current situation:

- What is the current adoption level of DER in the jurisdiction?
 - What is the number of interconnection agreements?
 - What is the number of customers on a DER program or the amount of available DER from the utility or aggregators, or both?
- Where is the DER(s) located?
- Does the regulated utility have sufficient visibility into its distribution grid to monitor the impacts of certain types of DER on its system?
- What issues, if any, have already come to the utility's or regulators' attention concerning the effect of DER on the grid and regulation?
- When was the last class cost-of-service study performed? Does the regulator have sufficient information about rate and cost impacts from DERs on customer classes?
- How are the different types of DERs currently treated in rate design, compensation, planning, etc.? What types of scenarios are the utilities considering in their planning processes?
- On a prospective basis, how does any policy or regulation address DER investments that lead to benefits, if any?
- How does a regulator address the asymmetry of information inherent in utility regulation when discussing the grid?
- To what extent are regulators formally expanding their distribution system planning process in their jurisdiction?
- Does the regulator already have, or is there an adequate level of, visibility into the utility's planning processes and operations? If not, which technologies will be needed to understand the system in real-time and then optimize and dispatch resources in real-time?

¹⁰⁵ NARUC Staff Subcommittee on Rate Design, *Distributed Energy Resources Rate Design and Compensation*, National Association of Regulatory Utility Commissioners, November 2016, pp. 143-148, <http://pubs.naruc.org/pub/19fdf48b-aa57-5160-dba1-be2e9c2f7ea0>.

- How can contracts be developed with third parties to ensure response? How can the utility and regulator ensure that if a resource is non-compliant with a bid, that ratepayers are not left having to cover those costs?
- Will there be an increased risk of cyber-attacks as the scale of DERs providing distribution services increases? If so, what is needed to address this?
- How do the utility and the regulator balance the trade-off between economic efficiency and reliability? Maximizing economic efficiency can introduce operational risks. On the other hand, over-investing to create a highly resilient distribution system could be prohibitively expensive.
- Is an independent DSO needed? Can existing distribution system operators take on new roles, functions, and services that are associated with higher DER levels and an evolving distribution system?
- Can states regulate “sales for resale” that occur within a local transactive market without using transmission?

Types of data and other information needed by regulators:

- Does the regulator have access to:
 - Number of DER, different types of DER, and locations;
 - Number of customers who have adopted DER, the costs and benefits associated with those DERs;
 - A recent cost-of-service study; or
 - An indication or study showing any cost-shifting by class, geography, or socio-economic stature?
- What is the hosting capacity on various parts of the distribution system?
- What are the unique, localized circumstances that drive opportunities or barriers to increased benefits from DER adoption?
- How are transmission, generation, and distribution costs and benefits identified, determined, and reported?
 - What is the proper level of granularity in data to examine and ensure efficient accounting of DER?
 - What is the best way to examine and set which costs and benefits should be socialized and which should be borne by the individual customer?
- How can regulators help society efficiently allocate investment resources, especially between regulated utilities and independent consumers? How can the regulators encourage efficient acquisition of DER?
- What additional data or analyses are needed for the proper visibility and planning for the integration of DERs into the grid?

SECTION 9: Conclusion

The electrical distribution system is evolving. As DERs continue to gain popularity and use, jurisdictions will need to understand, plan for, and develop appropriate procedures, regulations, and systems to accommodate their use. As discussed in this paper, there are a number of markets and market services that states and utility companies will need to determine to proceed. Additionally, policy, operation, and functional considerations for distribution system planning need to be taken into account by regulators as they are embarking on grid modernization initiatives in their states. Distribution systems will need innovative approaches for system operation, grid planning, interconnection procedures, and coordination with transmission system and wholesale markets to handle higher DER penetration rates, and still remain secure and reliable.

As the smart grid continues to evolve, there will be more opportunities for efficiency improvements through market-based transactions between energy consumers and producers, and new economic tools and processes will be needed to enable these changes. One-size does not fit all and states need to decide what measures to take given their unique jurisdictional landscape, policy objectives, and customer needs.

SECTION 10: Appendix

Actions That Have Initiated Grid Modernization in the States:

This section provides an overview of specific legislative and regulatory measures and actions that helped to jump-start grid modernization investigations and/or activities.

California:

Action: Legislative (renewable energy mandate - RPS; Assembly Bill 327) & Regulatory (Rule 21 for smart inverters)

Since 2002, California has had an RPS and in 2015, this was updated to require publicly owned utilities to procure 50 percent of their electricity from eligible renewable energy resources by 2030. Additionally, in 2013 California's Assembly Bill 327¹⁰⁶ became law and ordered its three dominant investor-owned utilities – Southern California Edison, Pacific Gas and Electric, and San Diego Gas and Electric – to optimally locate DER in their distribution systems. Lastly, in 2014, the CPUC established new smart inverter standards under the state's electric interconnection tariff called Rule 21.

Hawaii:

Action: Legislative (renewable energy mandate - RPS; NEM)

In 2001, Hawaii passed its first RPS and NEM laws, which led to sharp increases in solar resources. In 2015, a new RPS was signed into law, calling for 100 percent renewable energy by 2045. Hawaii's approach has included a variety of catalysts, including financial incentives, tax credits, and regulatory pushes.¹⁰⁷

Illinois:

Action: Legislative (Future Energy Job Acts) & Regulatory (NextGrid Initiative)

In June 2017, the Illinois legislature passed the Future Energy Jobs Act, which included key provisions such as energy efficiency, renewable energy, and job training and payment help. Additionally, the Illinois Commerce Commission recently began its NextGrid¹⁰⁸ Initiative, which is an 18-month consumer focused study to address critical issues facing Illinois' electric utility industry in the next decade and beyond. The study will examine the use of new technologies to improve the state's electric grid while minimizing energy costs to consumers. Additionally, the study will focus on innovation, technological advancements, economic development, environmental considerations, and education.

Minnesota:

Action: Regulatory (MN PUC Staff Report)

In May 2015, the Minnesota Public Utilities Commission initiated a proceeding to consider development of policies related to grid modernization with a focus on distribution system planning. The Commission held three workshops to gather information on distribution system planning and grid modernization, and to identify specific actions, technologies, and policies that could support and enable grid modernization. In March 2016, the Minnesota Public Utilities Commission Staff Report on Grid Modernization was

¹⁰⁶ https://leginfo.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327.

¹⁰⁷ Gavin Bade, "Getting to 100 percent renewables: How Hawaii plans to get fossil fuels off the grid," *Utility Dive*, March 23, 2016. <http://www.utilitydive.com/news/getting-to-100-renewables-how-hawaii-plans-to-get-fossil-fuels-off-the-gr/416176/>.

¹⁰⁸ <https://nextgrid.illinois.gov/index.html>.

released. The staff report summarizes the actions in the proceeding to date, identifies aspects of the stakeholder comments identified as important for discussion of grid modernization, and proposes a process for continuing the development of policies related to grid modernization.

New York:

Action: Regulatory (RGGI; NY REV; and NY DPS Value of DER Staff Report)

In 2009, New York joined RGGI and enacted regulatory measures to comply with this program.¹⁰⁹ New York's REV initiative was initiated by the New York DPS in 2014. In October 2016 the NY DPS issued the Staff Report and Recommendations¹¹⁰ for the first phase of a regulatory approach to valuing DER products and designing rates for DER providers.

District of Columbia:

Action: Regulatory (DC PSC MEDSIS staff report)

The DC Public Service Commission (PSC) issued Order No. 17912 in June 2015, which opened Formal Case No. 1130, Investigation into Modernizing the Energy Delivery System for Increased Sustainability (MEDSIS). In January 2017, the DC PSC established the MEDSIS staff report to identify technologies and policies that can be implemented to modernize the distribution energy delivery system in the District of Columbia.

Arizona:

Action: Regulatory (renewable energy mandate – REST; NEM)

In 2006, the Arizona Corporation Commission (ACC) approved the Renewable Energy Standard and Tariff (REST), requiring that regulated electric utilities generate 15 percent of their energy from renewable resources by 2025. In 2016, the ACC opened a docket to revise REST to increase the state's renewable energy mandate to 30% by 2030.

In 2009, Arizona began its NEM policy. By 2016, the ACC voted to end NEM and replace it with a lower amount. By August 2017, the ACC approved a settlement agreement between APS, Commission staff, industry representatives, and solar advocates. Key parts of the settlement include a rate increase, expansion of the AS Sun program, more rate design options including new TOU and demand rates, grandfathering of existing NEM customers for 20 years; and establishment of a transitional step down rate for new customers.

¹⁰⁹ <https://www.rggi.org/design/regulations>.

¹¹⁰ <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/C12C0A18F55877E785257E6F005D533E?OpenDocument>.