U.S. DEPARTMENT OF ENERGY

Smart Grid System Report

2022/2024 Report to Congress

December 2024

United States Department of Energy
Washington, DC 20585

Message from the Secretary

We are pleased to submit the 2022/2024 Smart Grid System Report as required biennially by Title XIII (Smart Grid), Section 1302, of the Energy Infrastructure and Security Act of 2007. The report is focused primarily on the transformation occurring at the grid edge where utilities interface with their customers and third-party merchants to optimize the application of distributed energy resources, an emerging set of assets that complement current resources in the provision of energy services.

Distributed energy resources, represented by such technologies as rooftop photovoltaic, energy storage, and building management systems, provide multiple benefits to utilities and consumers with respect to improving reliability, resilience, and both energy and operational efficiencies. However, they pose challenges to current grid operating practices as they introduce a requirement to dynamically orchestrate potentially millions of new devices at the grid edge at a high level of performance to ensure system reliability. In addition, the fact that they are owned or controlled by a diverse set of players, which may include utilities, utility customers, and third-party merchants, necessitates organized behaviors between them and sets the need to establish rules that govern how they coordinate, as well as how they are regulated.

This report provides an examination of the evolving portfolio of grid-edge resources and a discussion of how key challenges to their effective integration and utilization are being addressed. Essential areas of additional focus include standardizing processes to improve operational coordination, establishing methods to fully value the benefits and provide appropriate compensation for these resources, and articulating grid technology requirements in a system engineering context. This set of challenges are both institutional and technological in nature. Addressing them will require coordinated efforts across governmental jurisdictions and stakeholders to advance current practices for grid planning and operations, as well as to design and implement markets for distributed energy resources.

Pursuant to statutory requirements, this report is being provided to the following Members of Congress:

The Honorable Patty Murray
Chair, Senate Committee on Appropriations

The Honorable Susan Collins
Vice Chair, Senate Committee on Appropriations

The Honorable Tom Cole
Chairman, House Committee on Appropriations

The Honorable Rosa DeLauro
Ranking Member, House Committee on Appropriations

The Honorable Chuck Fleischmann
Chairman, Subcommittee on Energy and Water Development, and Related Agencies
House Committee on Appropriations

The Honorable Marcy Kaptur
Ranking Member, Subcommittee on Energy and Water Development, and Related Agencies
House Committee on Appropriations

The Honorable Patty Murray
Chair, Subcommittee on Energy and Water Development
Senate Committee on Appropriations

The Honorable John Kennedy
Ranking Member, Subcommittee on Energy and Water Development
Senate Committee on Appropriations

If you have any questions or need additional information, please contact me or Ms. Meg Roessing, Deputy Director for External Coordination, Office of Budget, Office of the Chief Financial Officer, at (202) 586-3128.

Sincerely,

Jennifer Granholm

Acknowledgments

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Executive Summary

The U.S. electric grid is undergoing a dramatic structural transformation attributable to Federal and state policies promoting the use of alternative energy resources and measures to improve resilience, as well as to technological advancements supporting the growth of an emerging merchant class providing services to electric companies. The transformation is occurring at a rapid pace at the edge of the distribution grid where utility systems are interfacing with those of utility customers and third-party merchants to integrate and utilize an evolving set of resources. These distributed energy resources (DERs),[a] which include such technologies as rooftop solar, batteries, and electric vehicles, have the potential to complement the set of large-scale generating resources, such as natural-gas power plants and wind or solar farms, situated within the bulk-power electricity system.

DERs can provide electrical energy back to the grid, as well as supplement the electricity needs of residential, commercial, and industrial customers of utilities. As a result, they can help utilities improve the effectiveness and efficiency of providing electrical energy to their customers. They also give utility customers options for the way in which they utilize electrical energy, for example, by helping them reduce or shift their demand for electricity, as well as by providing essential backup power for improving reliability and resilience.

The fact that DERs are owned and/or operated by several entities, which include utilities, their customers, and third-party merchants,[b] greatly changes the paradigm by which grid assets are operated from one of control to one of *both control and coordination*. The shift to multi-party coordination will require advancements in how the grid is designed and operated, especially when considering that the use of DERs introduces a requirement to dynamically orchestrate millions of new devices at the grid edge with high standards of performance. This will require refinements in approaches to system engineering combined with the application of technological innovations, such as energy storage and power electronics devices, to ensure reliable grid operations under dynamic conditions. It will also necessitate organized behaviors among utilities, their customers, and third-party merchants through a set of established rules that govern how they coordinate, as well as how they are regulated to ensure high levels of operational performance.

To illustrate the complex set of relationships emerging at the grid edge, Figure ES-1 shows the partnering arrangement undertaken by Baltimore Gas and Electric Company (BGE) to manage their electric vehicle charging infrastructure, which includes implementation of a managed

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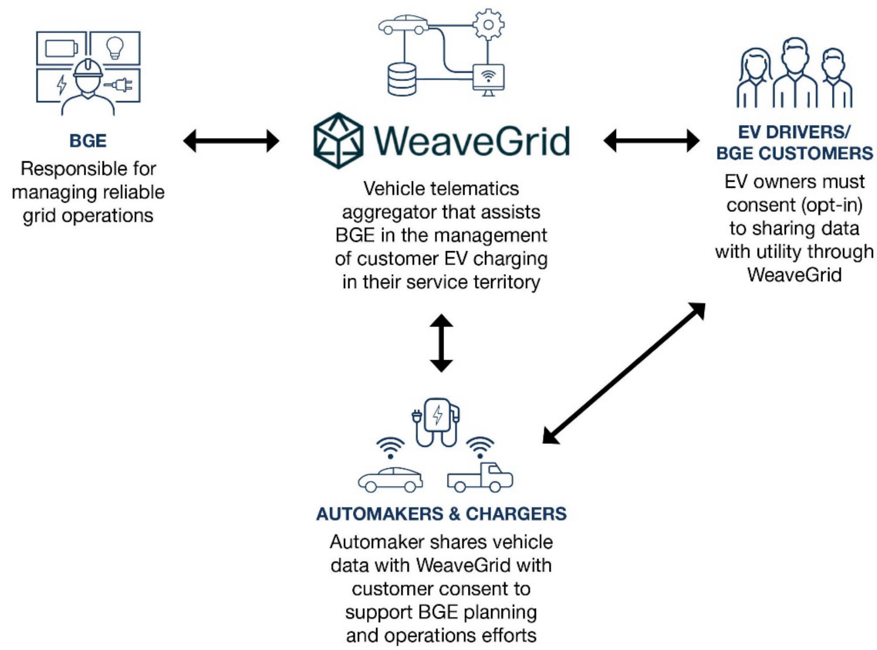
[a] Distributed energy resources (DERs) are resources sited close to customers that can provide all or some of their electric power needs or can be used by the system to either reduce demand (such as improve energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the grid. The resources are small in scale, connected to the distribution system, and physically close to the load. Examples of DER types are solar photovoltaic (PV), wind, combined heat, and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE).

[b] Third-party merchants provide DER technology and associated services to both utilities and their customers.

charging program. This arrangement aims to enable convenient charging by BGE customers and to ensure through managed charging that electricity can be delivered reliably with prudent investments in supporting grid infrastructure. Third-party merchants, such as Weave Grid, Inc. (WeaveGrid), are beginning to serve as aggregators of distributed assets providing an increasingly important role in the management of DERs as partners with utilities.

FIGURE ES-1: PARTNERING ARRANGEMENT FOR MANAGED EV CHARGING AT BGE[1]

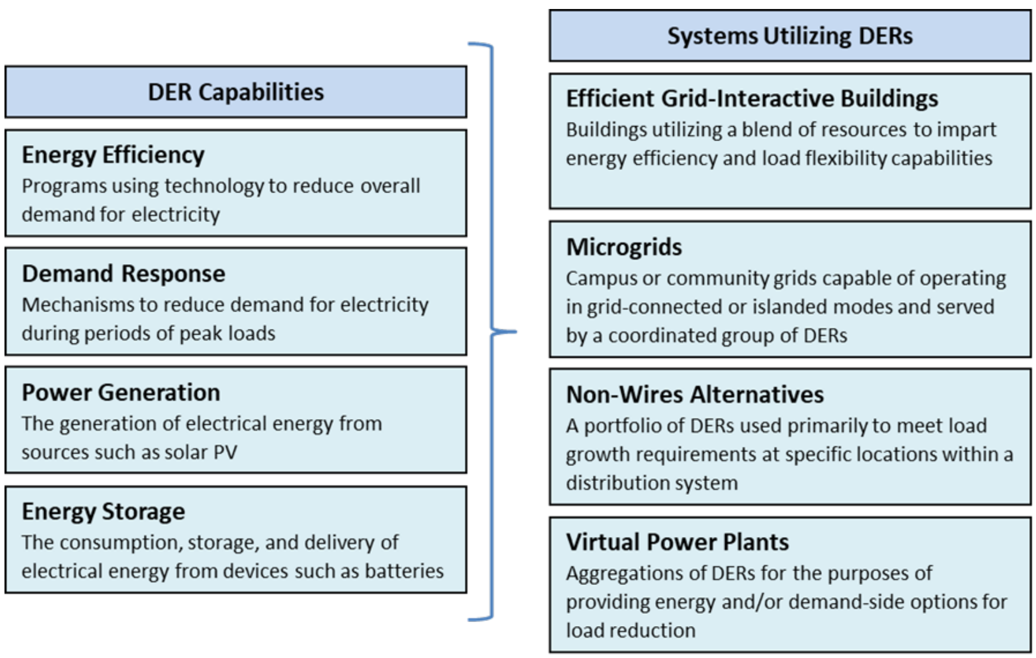


DER Adoption and Related Investments

The four main capabilities that DERs provide are energy efficiency, demand response, distributed generation, and energy storage, as shown in Figure ES-2. Each provides a unique set of services that individually or in combination can provide value to utilities and their customers, as well as to society at large. These services include the provision of electrical energy, the assurance of having sufficient electricity generating capacity to meet all electricity supply-demand scenarios, improvements in resilience (e.g., by providing back-up power), and support for managing electric system parameters such as voltage and frequency. Energy efficiency and demand response programs are particularly useful for reducing overall electricity demand requirements, as well as for reducing load on the system during critical periods; the net effect of these programs is to reduce requirements for additional generation capacity and electricity delivery infrastructure.

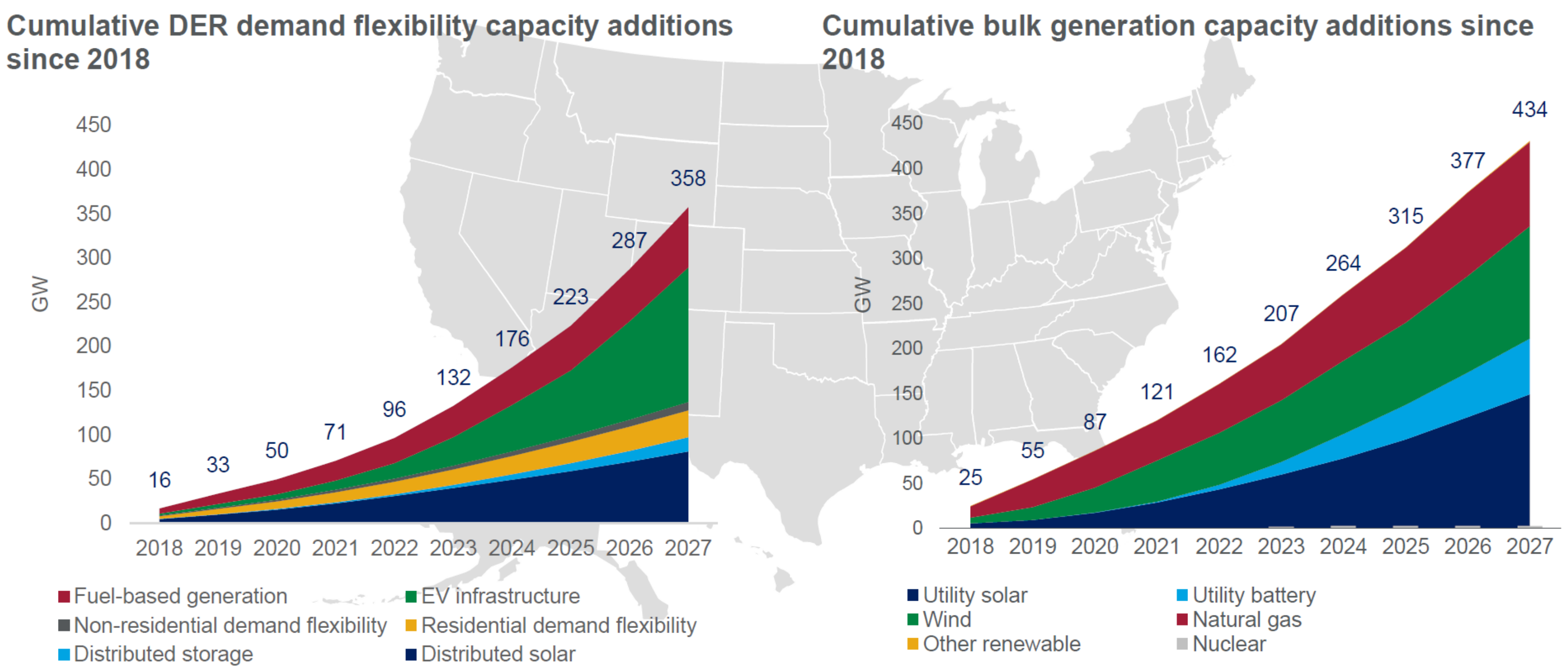
The various configurations of DERs shown in Figure ES-2 are evolving with respect to their rate of adoption, the technological systems needed to support their converged operations with the grid, their financial viability, and the maturity of both institutional and regulatory practices needed to facilitate their implementation. Lack of standardized practices governing the relationships between utility and non-utility entities at the grid edge is a major impediment to more robust application of these systems. However, the industry is working towards identifying issues and standardizing practices, which includes collaborative efforts with the U.S. Department of Energy (DOE), that address utilities' requirements of reliable performance and the financial requirements of customers and third-party merchants. Ultimately, DERs will need to be recognized as core resources that can provide valuable services, including the operational flexibility required for the envisioned dynamic grid. These capabilities are becoming especially relevant as the prospects for electrification of transportation and buildings will necessitate greater use of distributed assets for serving local energy needs.

FIGURE ES-2: DER CAPABILITIES AND SYSTEM CONFIGURATIONS UTILIZING THEM



The deployment of DERs is projected to grow significantly within the U.S. in the coming years. According to Wood Mackenzie,[2] DERs and the demand flexibility they provide are expected to grow by 262 gigawatts (GW) from 2023 to 2027, as shown in Figure ES-3. This will nearly match the 271 GW in bulk generation additions over that same period. For comparison purposes, as of February 2023 the U.S. had nearly 1,300 GW of generating capacity.[3] The U.S. market for DERs is forecast to double from 2022 to 2027, reaching $68 billion per year, with solar and electric vehicles expected to lead DER deployments in the first half of the decade.[4]

FIGURE ES-3: CUMULATIVE DER AND BULK GENERATION CAPACITY ADDITIONS (2018 – 2027)[5]



Utility investments in smart grid technology enable new system capabilities and are needed to integrate DERs with grid operations. They include investments in control systems, such as advanced distribution management systems, substation automation, advanced metering infrastructure, distribution monitoring and control of inverter-based assets,[c] and customer information systems. The level of investment in these systems was estimated to be $9.05 billion in 2023, which represents 2.3% of utilities' total revenues for that year, which approached $400 billion.

Addressing Key Challenges

As the numbers and types of these DERs increase along with evolving business models, the ability to effectively characterize, integrate, utilize, and orchestrate them so that they can function reliably within the operational environment of the electric grid, presents a set of challenges, which are both technical and institutional in nature, as shown in Figure ES-4.

FIGURE ES-4: KEY CHALLENGES TO THE EFFECTIVE INTEGRATION AND UTILIZATION OF DERS

There are many efforts being undertaken across the country to address these challenges, yet they are limited in jurisdictional and geographic scope and have different areas of focus. As noted in an August 2022 report by the Energy Systems Integration Group (ESIG):[6]

> *"Currently, individual states, such as California and New York, are developing their own distribution-level solutions to DER integration. While these efforts are reflective of the*

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[c] Inverter-based assets are devices, such as rooftop photovoltaic systems and energy storage devices, that produce direct electrical current, which must be converted to alternating electrical current accomplished by inverters. This is necessary for integrating DERs into electric power grid operations. Inverters can manage power flow, e.g., adjust voltage and current outputs, to accommodate a variety of grid operating conditions.

> *actions of individual, forward-looking states, this approach is insufficient, as each state has to essentially reinvent the wheel. This situation will lead to a proliferation of disparate standards, terminology and approaches around DER integration across the United States, which in turn will generate confusion and increase costs among manufacturers, developers, and other DER service providers. It will ultimately result in less access to distribution systems for DER providers, higher DER costs, and lower benefits to customers."*

The ESIG paper points to the need for a greater level of coordination across the electricity sector to address specific issues relating to the effective integration and utilization of DERs. This includes maturing practices and processes to achieve a greater level of standardization across the industry.

To enable the performance of the electric grid to match increasing levels of complexity presented by higher levels of DERs, as well as to fully realize the value that they can provide, several key challenges need to be addressed:

1. Integrated planning practices within and across jurisdictions are required that can result in holistic, long-term grid investment strategies which incorporate DERs as core resources.

   Approaches for integrating DERs in integrated distribution system plans and integrated resource plans are evolving and not universally applied across the country. The coupling of these disparate planning processes to support more comprehensive regional planning is beginning to occur, as well as the advancement of needed analytical methods, such as the probabilistic forecasting of customer load and DER adoption. DOE is working with the industry and state governments to advance such planning practices. However, greater alignment between the expectations of state regulators and utilities with regard to required investment strategies is needed.

2. Coordination frameworks are needed that set the respective roles and responsibilities, including data/information sharing requirements, of all participants involved in the provision, orchestration, and oversight of DER services.

   A standardized set of rules, codes of conduct, and performance expectations are necessary for establishing how DER service providers and grid operators, at both the distribution and bulk-power levels, coordinate within an operational environment. Federal Energy Regulatory Commission (FERC) Order 2222[7] which requires Independent System Operators and Regional Transmission Organizations to establish markets for aggregations of DERs has greatly motivated the need for formal coordination frameworks. DOE is working with the industry to develop and institutionalize a set of distribution grid codes to standardize practices relating to requirements for grid engineering, data/information sharing and security, governance and oversight, and the integration and operational use of DERs, including microgrids, electric vehicles, and virtual power plants.

3. Staged technology deployment strategies applying system engineering principles and advanced grid components are needed to realize the capabilities required for enabling the effective utilization of DERs within dynamic operational environments.

   Providing the flexibility needed in a dynamic operating environment will require orchestrating DERs within very fast timeframes. Technological advancements are occurring in the areas of a) dynamic modeling of grid conditions to inform real-time operations, b) sensing and telemetry to provide observability of grid assets and situational awareness, c) enhanced computational and data-processing for operational intelligence, d) secure communications to ensure that the essential flow of information and data needed to support grid operations remains intact under normal and adverse situations, and e) grid components, such as power electronics devices, to manage and optimize power flow within short timeframes. Designs for platforms that can support coordinated operations are also being developed.

4. Greater levels of standardization for addressing interoperability between devices and systems that also ensure cybersecurity are required.

   The increasing number of devices at the grid edge is driving exponential growth in the amount of data that needs to be exchanged and integrated. This growth is driving an urgent need to improve interoperability between devices, software, and utility systems. The challenge of collecting and exchanging data at the grid edge is complicated further by the number of competing strategies and communications protocols. Many different communication protocols exist, and the vendors of devices and systems apply them at their discretion.

   It will not be possible to achieve interoperability unless all devices use the same vocabulary. The Common Information Model (CIM)[8] is the only standard semantic dictionary for describing and naming grid data from the bulk transmission system to the grid edge. Universal adoption of the CIM and other standards, including the application of standard grid codes and requiring DER registration to serve data exchange requirements, is critical to achieving plug-and-play interoperability.

   There are significant ongoing activities to help address cybersecurity challenges at the distribution system level. A noteworthy effort, currently underway by DOE's Office of Cybersecurity, Energy Security, and Emergency Response (CESER) in partnership with the National Association of Regulatory Utility Commissioners (NARUC), is an initiative to set common practices for the industry.[9] This includes the development of guidelines that provide a set of recommended cybersecurity practices for utilities, DER owners and service providers (including aggregators), and vendors supplying distribution utilities with hardware and software. The initiative will also include the formulation of implementation and adoption strategies for the recommended practices.

5. Methods for evaluating the full contribution of DERs combined with straightforward mechanisms for compensating their services are needed to fully realize their value.

   Methods for determining the value of DER services and for providing compensation to entities providing them are evolving and not practiced consistently across the U.S. As a result, DER aggregators and service providers must navigate complex regulatory landscapes that involve compliance with differing wholesale market rules, retail regulations, programs and tariffs, and utility procurement processes. This is in addition to facing high upfront costs for recruiting customers and investing in monitoring and control technology with little certainty in realizing needed revenues. DOE's efforts to standardize practices, e.g., grid codes, between DER aggregators and utilities will help. These efforts include working with the North American Energy Standards Board to establish a standard DER aggregator services agreement model.

   In addition, traditional compensation mechanisms do not always fully account for the value of DERs. For example, some tariff designs, such as net-energy metering, are designed to compensate utility customers and tend to overlook the value they can provide to utility systems. Methods developed by some states, including New York (which has implemented a Value of DER method), have identified several value streams, including those that provide locational and system-wide benefits, for which DERs can be compensated. However, additional work is needed to evolve DER valuation and compensation frameworks that provide value from DERs for both utilities and their customers, and to approach some level of consistency across the country.

Concluding Remarks

Distributed energy resources are emerging as critical assets that provide valuable services for both utilities and their customers resulting in improved operational and energy efficiencies, enhanced reliability and resilience, and reduced emissions of greenhouse gases. These services include providing energy, additional generating capacity to meet peak demand requirements, and enhanced capabilities for managing system parameters, such as voltage and frequency. These services are useful for supporting both bulk-level and distribution system operations, and they provide value to utility customers who may apply them to serve their particular interests. The emergence of DERs and the ability to apply them optimally, especially as they scale in type and magnitude, will fundamentally change the way we plan, design, and operate the electric grid.

The advent of a mixed set of DERs owned and operated by entities other than utilities, such as DER aggregators, has shifted the engineering challenge from one of control to one of both control and coordination requiring disparate organizations to function in a highly organized manner to ensure effective, secure, and reliable grid operations. Coordination frameworks that define the respective roles and responsibilities, as well as data/information sharing requirements, of all participants engaged in the delivery and oversight of services from DERs are nascent and evolving. Standardization of the various aspects of such coordination frameworks would reduce barriers to a more robust and efficient utilization of DERs.

Incorporating DERs as core resources in utility operations will require advancements and more widespread application of integrated planning processes. These planning processes include integrated distribution system planning, as well as more comprehensive regional planning practices, in which the utilization of DERs for providing grid services can be incorporated into holistic grid investment strategies. Currently, integrated distribution system planning is not practiced universally across the country[d] and consideration of DERs in regional planning processes is at an early stage.

In addition, advancements in analytical methods that support these planning processes are needed. For example, techniques for forecasting the adoption rates of DERs and electrification that are sufficiently granular and forward-looking while accounting for uncertainty are evolving and not consistently applied. These planning processes also require system engineering approaches that assess alternatives in grid structures and technology choices, and that enable the formulation of staged, least-regrets, grid investment strategies. These investment strategies will need to incorporate and dictate the demand for technological advancements that will provide the sensing, communications, control, data management, and computational capabilities needed for a more dynamic operating environment.

Finally, it will be important to institute practices that provide greater levels of certainty in the performance of DERs to ensure the reliable delivery of electricity and associated services. The ability of DERs to provide grid services is evolving. New methods for DER valuation and compensation are necessary to capitalize on this ability and enhance the role of DERs. A reasonable expectation of adequate compensation for both utilities and DER service providers is a necessary predicate for the capture of the benefits of DERs and the success of developing DERs as a reliable resource. A fundamental question is whether DERs should be provided under a market-based or regulated regime. Either regime will necessarily build on an understanding of the intrinsic value that DER brings to distribution and bulk electric system operations. Additional effort is needed to advance DER valuation and compensation methods to enable reliable, equitable, and cost-effective approaches for utilizing DERs.

In summary, the introduction of DERs for the provision of services for both utilities and their customers has introduced a set of challenges that are both technological and institutional in nature. Addressing these challenges will require coordinated efforts across governmental jurisdictions and among stakeholders to advance practices for grid planning, operations, and the design and implementation of markets.

[d] Currently, nineteen states, plus the District of Columbia, require regulated utilities to file some form of distribution plan.

SMART GRID SYSTEM REPORT 2022/2024

Table of Contents

I. Introduction

The U.S. electric grid is undergoing a dramatic structural transformation, in part, due to a set of emerging resources at the edge of the distribution system where utilities interface with customers and third-party merchants. These distributed energy resources (DERs)[e] can provide electrical energy back to the grid, as well as supplement the electricity needs of utility customers. As a result, DERs can provide valuable services to utilities and their customers, an emerging model for enhancing reliable, resilient, and efficient grid operations. However, they pose challenges to current grid planning and operating practices since they introduce a requirement to dynamically orchestrate millions of new devices at the grid edge with high standards of performance. Furthermore, the fact that they are owned or operated by utility customers and third-party service providers, as well as by utilities, necessitates organized behaviors between them and sets the need to establish rules that govern how they coordinate, as well as how they are regulated.

Both Federal and state policies and regulations have encouraged the use of non-utility assets to promote the application of alternative energy resources for the purposes of incentivizing competition, encouraging decarbonization, and improving the efficiency and resilience of the electrical grid. The influence of these policies and regulations, combined with technology-driven innovation and changing consumer preferences, is causing rapid evolution at the grid edge. This is introducing a new set of physical, business, and market structures represented by such technologies as microgrids, electric vehicles, and virtual power plants which will require new approaches for designing and managing the grid to ensure that it continues to function in a reliable and effective manner.

Key considerations for future grid function and structure include providing sufficient flexibility to account for:

- **Diversity** – varying preferences representing jurisdictions and stakeholders,
- **Optionality** – differing institutional, business, and technical approaches,
- **Scalability** – ensuring system performance with increasing levels of myriad resources, and
- **Extensibility** – enabling convergence with other infrastructures and new business structures.

Moving forward to address a new set of challenges posed by the advent of DERs is an urgent matter. Given the ambitious goals of both Federal and state governments to decarbonize and

[e] DERs are resources sited close to customers that can provide all or some of their electric power needs or can be used by the system to either reduce demand (such as improve energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the grid. The resources are small in scale, connected to the distribution system, and physically close to the load. Examples of DER types are solar photovoltaic (PV), wind, combined heat, and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE).

enhance the resilience of the electric grid, with DERs playing a significant role in achieving them, considerable effort is required to modify and advance current institutional, regulatory, and business practices to assure that DERs are integrated into mainstream grid operations in a reliable, secure, safe, equitable, and cost-effective manner. The greatest challenge facing us is to determine how to best organize and structure the conversation amongst stakeholders so that we can address these challenges collectively and move forward in a productive way.

Due to the significance of changes in the way we plan and operate the electric grid posed by these emerging resources, DOE has chosen to focus on the institutional and technological aspects of grid-edge evolution in this 2022/2024 Smart Grid System Report.

Legislative Mandate

The Department's Office of Electricity prepared this 2022/2024 Smart Grid System Report as required by Title XIII (Smart Grid), Section 1302, of the Energy Infrastructure and Security Act (EISA).[10] The EISA directs DOE to submit a biennial report to the U.S. Congress:

> **"…concerning the status of smart grid deployments nationwide and any regulatory or government barriers to continued deployment. [In addition] the report shall provide the current status and prospects of smart grid development, including information on technology penetration, communications network capabilities, costs, and obstacles. It may include recommendations for State and Federal policies or actions helpful to facilitate the transition to a smart grid."**

In addition, Title XIII states that the policy of the United States is to support the modernization of the nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve the following:

- Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid,
- Dynamic optimization of grid operations and resources, with full cybersecurity,
- Deployment and integration of distributed resources and generation, including renewable resources,
- Development and incorporation of demand response, demand-side resources, and energy-efficiency resources,
- Deployment of "smart" technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation,
- Integration of "smart" appliances and consumer devices,
- Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning,
- Provision to consumers of timely information and control options,

- Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid, and
- Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

As expressed in prior reports, DOE continues to work closely with the electric grid industry, including policymakers, regulators, and utilities, to better understand and address both technological and institutional issues related to the advancement of smart grid technology, particularly including in the context of grid edge evolution.

Content of the Report

This report presents trends in DER adoption and utilization and requirements for technological and institutional advancements. The report is subdivided, as follows:

I. **Introduction** – presents rationale for focusing the report on grid-edge evolution.
II. **Smart Grid Advancements** – provides a historical view of advancements in smart grid technology.
III. **Factors Shaping Grid-Edge Development** – provides an examination of drivers for adopting and applying DERs and related smart-grid investments.
IV. **Evolving Portfolio of Grid-Edge Resources** – presents the set of DERs which are providing services to utilities and their customers and includes a discussion on barriers impeding their full utilization.
V. **Addressing Key Challenges** – provides a discussion on how key challenges are being addressed within the industry.
VI. **Conclusion** – provides a summary of key issues with recommendations.
VII. **Appendices** – provides supporting information.

II. Smart Grid Advancements

> **What is being sensed or controlled on the grid?**
>
> While smart grid technology can be complex, the physical phenomena it measures or controls are largely limited to voltage, current, and frequency to ensure the reliable flow and delivery of power derived from electrical energy. Digital devices sense and control these electrical parameters to provide situational awareness for grid operators and to initiate control actions to manage power flow. These devices now include smart inverters to monitor and control DERs through centralized or autonomous means.

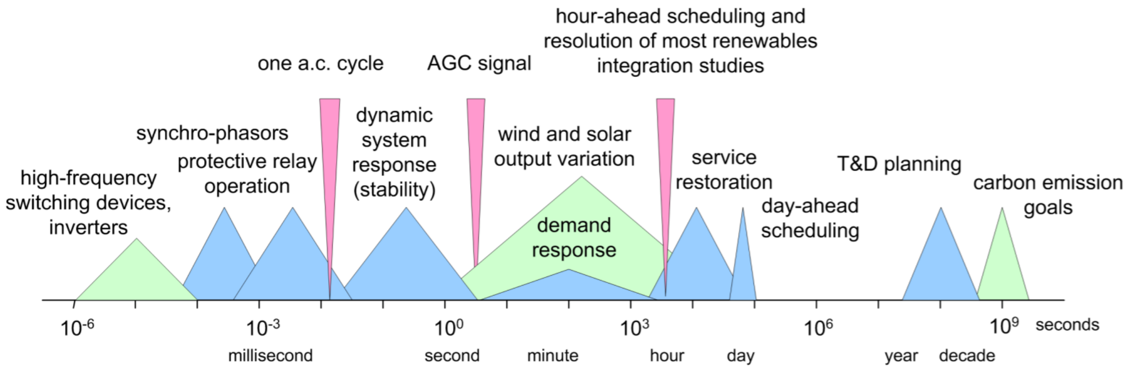
The North American power grid is a vast and complex machine with 1.2 million megawatts of electricity generating capacity[11] that delivers electricity to 335 million people[12] across nearly 700,000 circuit miles of transmission lines and 5.5 million miles of distribution lines.[13] Power flow, the frequency of alternating current, and voltage levels are continuously maintained and adjusted in precise ways across the grid. Managing the generation and delivery of electricity involves thousands of organizations, including over 60 balancing authorities,[14] seven Independent System Operators/Regional Transmission Organizations (ISOs/RTOs),[15,f] four Federal power marketing organizations,[16] and over 3,000 distribution utilities[17] regulated by various entities, namely, the Federal Energy Regulatory Committee (FERC) overseeing interstate transmission of electricity, as well as state public utility commissions, and the boards of local governments and cooperatives. The power grid continues to evolve in response to new demands and requirements.

One aspect of the grid that makes it "smart" is the cyber infrastructure that works with the physical system to perform the functions of sensing, communication, control, coordination, computing, and data management to ensure that its various components, including their integration with utility customer and third-party systems, are functioning together properly. Another key aspect of the smart grid is the intelligence it can provide to human planners and operators for undertaking near- and long-term management decisions. The use of data to provide real-time situational awareness, improve operational effectiveness, and inform plans for future grid investments is a significant and growing activity.

As shown in Figure 1, there are a range of timescales associated with grid planning and operations. Many operations must occur in timescales in the sub-second range requiring systems that can work automatically or autonomously (enabling machine-to-machine interactions without a human interface). The emergence of renewable generation technologies and DERs has created a more dynamic grid due to instantaneous and random fluctuations in the supply and demand for electricity. This is pushing operational decision-making to shorter timescales requiring more sophisticated technological capabilities.

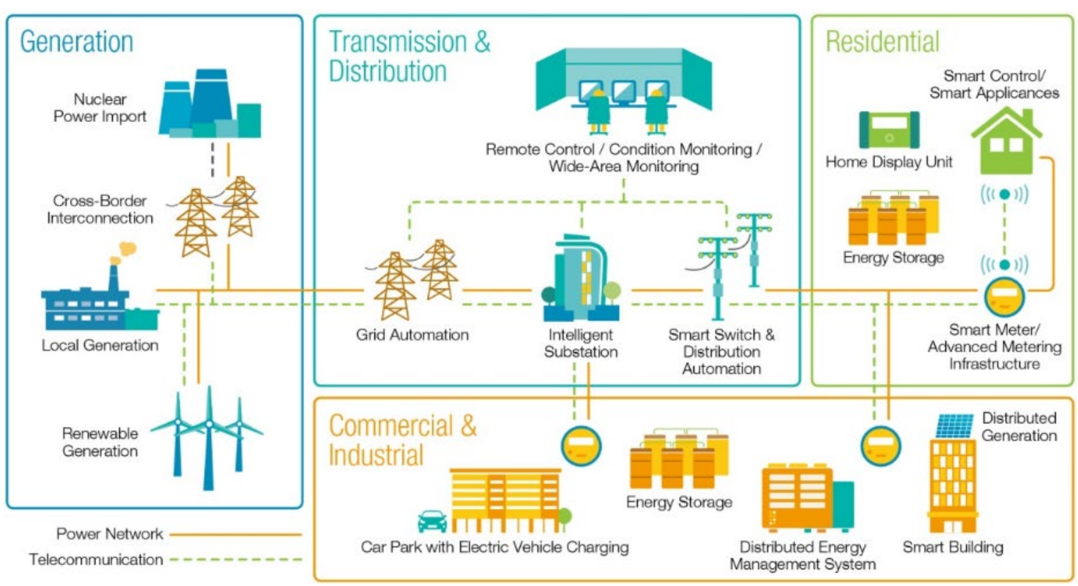
[f] Utilities formed ISOs/RTOs to coordinate, control, and monitor the operation of the interstate grid for regions of the United States.

FIGURE 1: TIMESCALES IN ELECTRIC GRID OPERATIONS[18]



As noted above, the cyber infrastructure has combined with the physical infrastructure of the electric grid to address demands for new functional capabilities. These combined infrastructures continue to co-evolve to take advantage of technological advancements, particularly associated with digital technology and its impact on data management and analytics. These advancements now involve the convergence of utility systems with those of its customers and third-party technology providers. Figure 2 provides a view of the various applications of smart grid technology across the power system, including its intersection with customer and third-party systems. Although the deployment of smart grid technologies varies widely across state and utility footprints, the grid is evolving from a static structure with few participants with centralized control, to a dynamic structure with many participants and complex control and coordination requirements that must be managed by advanced digital technologies and communications infrastructure.

FIGURE 2: OVERVIEW OF SELECT SMART GRID TECHNOLOGIES ACROSS THE POWER SYSTEM[19]



Key Developments in Smart Grid Technology

The integration of digital technology with the grid's electromechanical systems has evolved over several decades, as shown in Table 1. The beginning of this integration occurred in the 1960s when engineers began to deploy supervisory control and data acquisition (SCADA) systems to monitor and control processes associated with complex industrial or manufacturing operations. The introduction of SCADA in transmission and distribution substations began in earnest during the late 1970s. These SCADA systems employed microprocessors that directly interfaced with devices in the physical world, telemetry providing communications, and computers at master stations in transmission and distribution control centers.[20]

Today's SCADA systems have advanced substantially and are integrated into various aspects of utility grid operations that include functions associated with:

- Outage management, including fault location, isolation, and system restoration (FLISR),
- Voltage and reactive power management,
- System monitoring, control, and protection,[g] including state estimation,
- Control of power flow and protection of equipment using devices, such as circuit breakers, field switches, and power electronics equipment,[h] and
- Dispatch and control of inverter-based resources, such as DERs.

The combination of SCADA systems with these other functions is collectively referred to as operations technology (OT), which is responsible for monitoring and controlling field devices connected to the electric grid. OT has advanced from using vendor-based proprietary protocols to applying open communications standards and protocols (e.g., the Internet Protocol Suite[i]), enabling such systems to interface with devices from multiple vendors, as well as to take advantage of advancements in improved techniques for system analysis and operations, although standardization of data exchange processes continues to evolve.

In parallel with OT deployment, utilities have applied enterprise information technology (IT) to manage business processes, such as billing and revenue collection, asset tracking and depreciation, and workforce management. The IT systems, based on company enterprise and personal computing technology, apply software systems that permit many users to access utility-wide data through a variety of applications.

[g] Protective relays are devices designed to trip a circuit breaker when a grid problem occurs. Examples of conditions that a relay can detect include over current, over voltage, reverse power flow, under frequency, or over frequency. Relays can operate very quickly, within 1–2 electrical cycles (16–32 milliseconds).

[h] Power electronics represent a class of devices that apply solid-state technology to manipulate current, voltage, and frequency in electrical systems, thereby managing the character and flow of power.

[i] The Internet Protocol Suite is the conceptual model and set of protocols that enables a standardized approach for supporting communications between devices. IP-based communications (networking) systems can use fiber-optic, radio, and other means for conveying data. Use of the IP suite does not necessarily imply use of the internet itself.

TABLE 1. SMART GRID TECHNOLOGY DEVELOPMENT[j]

Grid Component	Status in 20th Century	21st Century – Smart Grid Developments
Physical infrastructure and Hardware *Examples: Relays, reclosers, circuit breaker*	Well-developed by the early 20th century. Almost all devices and equipment remained electromechanical until 1990s.	Controls moving to digital capabilities for measurement, sensing, local intelligence, and distributed control.
Grid Communications/Networks *Examples: Field area networks, wide area networks*	Use of various limited, one-way analog communications technologies (e.g., frame relay circuits) joined in later century with satellite, cellular, unlicensed radio.	Communications reaching out to customer premises. Two-way digital communications for wide area networks and field area networks.
Data Communications Networks	One-way analog connections from utility to home, whereby meter reader had to manually visit customer premises to determine energy use for billing purposes and restoration.	AMI, internet-connected devices, and cloud solutions enable two-way communications to improve efficiencies and facilitate greater visibility and situational awareness.
Grid Software *Examples: GIS, OMS, DMS, EMS, ADMS, and DERMS*	Limited centralized software for major applications (e.g., security-constrained economic dispatch).	Distributed software pervasive in field devices and systems, Centralized software capabilities greatly increased.
Customer Facing Applications	After advanced metering infrastructure (AMI) was deployed, utilities invested in web portals for customers to pay bills online and view energy use. This was considered a benefit of AMI.	Today's applications are reaching behind the meter. With the proliferation of utility cloud solutions, smartphone apps, and IoT, customers can access devices in the home and optimize their homes energy use with a single click.
DER Interfaces	Traditionally machine to machine connection allowed for grid operators to optimize generation at the edge.	As DER become performance-based assets, the smartphone and customer managed applications play an increasingly critical role, introducing new participants into the grid ecosystem.
Grid-Edge Visibility and Control	Utility visibility and communication at the grid edge consisted of usage data at the customer meter with limited ability to shape load outside the context of traditional energy efficiency and demand response customer programs.	Today's grid-edge extends past the meter into the home and offers an environment to extend grid services, energy management and optimized DER orchestration (e.g., that utilize assets potentially owned by customers and third parties).

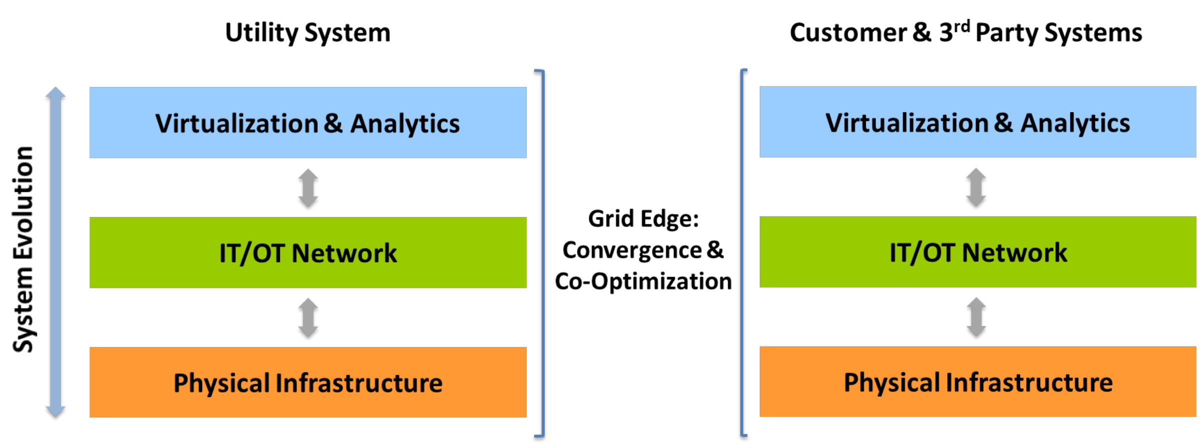
[j] Grid software examples include geographic information systems (GIS), outage management systems (OMS), distribution management systems (DMS), energy management system (EMS), advanced distribution management system (ADMS), and distributed energy resource management system (DERMS).

The convergence of IT and OT systems and the digitization of utility systems and processes has provided new analytical capabilities and significant operational benefits. Digitalization is leading to virtualization where digital representations of the physical infrastructure can facilitate scalable and flexible simulations of large systems, which can inform approaches for optimizing utility operations.

In addition, with increasing complexity in the utility operational environment coupled with the need for more informed and shared decision-making, utilities have turned to using cloud computing services from third parties which can provide scalable solutions for data management and analytics. Through these services, utilities can utilize their own private clouds to maintain the highest level of security and control or choose hybrid systems that give utilities the ability to use a private cloud and host third-party-facing functions within a public cloud. Furthermore, by enabling cloud-to-cloud business interactions, these systems can create convergence between utility, customer, and third-party operations.

As a result of advancements in digital technology, a virtualization and analytical layer that applies system data is emerging, as shown in Figure 3. This provides the ability to model and analyze the cyber-physical system to improve the effectiveness of grid planning and operations. A similar evolution is occurring within customer and third-party systems. The grid edge may be defined as being the convergence of utility systems with customer and third-party systems; converging these systems sufficiently to support the reliable delivery of electrical power will require advancing current institutional, business, and technological processes to optimize interactions between them.

FIGURE 3: CONVERGENCE AND CO-OPTIMIZATION AT THE GRID EDGE



Distribution System Evolution

The ability to integrate, utilize, and orchestrate high levels of DERs requires operational capabilities so that the electric grid can perform reliably under highly dynamic and uncertain conditions. These capabilities will enable utilities to accommodate greater variability and uncertainty in the supply and demand for electricity at the grid edge through operations that work much faster, utilize autonomous functions, and apply adequate reserves. Advancements in technological capabilities and institutional processes are needed to plan, design, and operate a more complex system, particularly at the distribution system level where utility operations will converge with customer and third-party merchant operations.

The operational capabilities needed for coordinated management and control of DER will require a continued evolution of distribution system capabilities as the level of DER adoption continues to increase. Figure 4 below illustrates a three-stage, evolutionary framework for the distribution system.[21] The yellow line represents the adoption of DER overlaid across stages of grid development with capabilities building to address increasingly complex requirements. The red pointer indicates the current stage of many utilities in the U.S. which are witnessing increased rates of DER adoption. The star indicates the level of operational maturity needed to enable the utilization of DERs in bulk-power grids, as mandated by the FERC Order 2222.[k] These stages are characterized, as follows:

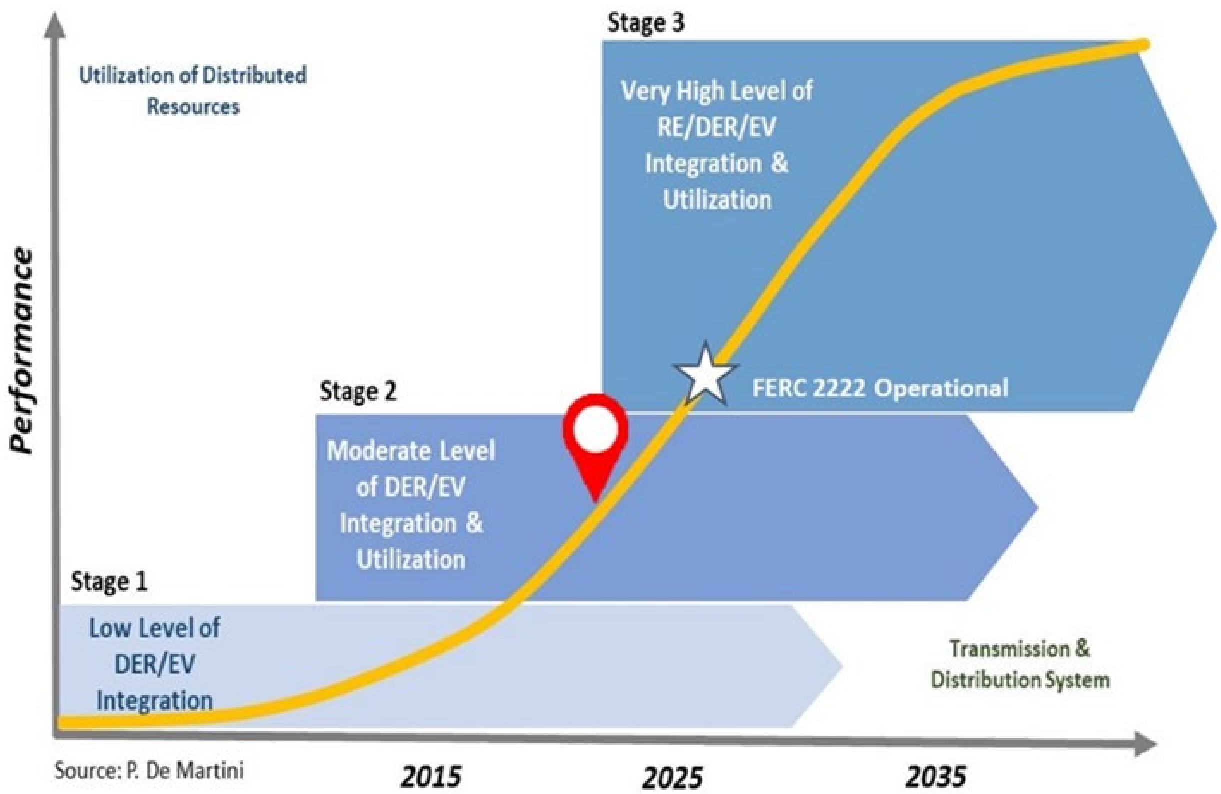
Stage 1 represents a low level of DER adoption where no material changes to grid infrastructure, planning, and operations is anticipated. The primary emphasis, which is carried though every subsequent stage, is to ensure reliability, resilience, and operational efficiency.

Stage 2 represents moderate levels of DER adoption where integrated planning that addresses grid modernization investment requirements needed to manage bi-directional power flow, as well as more formal approaches for coordinating operations between grid operators and DER service providers, become necessary. The emphasis in this stage and throughout system evolution is to use DERs as load-modifying and energy resources.

Stage 3 represents a high level of DER adoption and includes electrification of transportation and buildings where a significant level of grid modernization is needed to optimize and orchestrate the use of DERs for the provision of grid services, as well as to manage a high level of variability and uncertainty in electricity supply and demand. This stage may apply alternative grid structures and ownership models, including community microgrids. At this stage, formal processes will be needed to support interjurisdictional coordination of markets, planning, and operations.

[k] FERC issued Order No. 2222 in 2020 with updates in 2021, requiring each ISO and RTO to develop a wholesale market participation model that allows DER and DER aggregations to provide and be compensated for wholesale market services; https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf.

FIGURE 4: DISTRIBUTION SYSTEM EVOLUTION[22]



Since DER adoption is a major factor in determining the shape and pace of this distribution system evolution, the rate of DER growth is a key determinant in the need for utility IT/OT investments to enable DER integration, management, and orchestration. As a result, the rate of DER adoption, the factors that impact DER adoption, and the relationships between those interdependent factors are key drivers for system evolution.

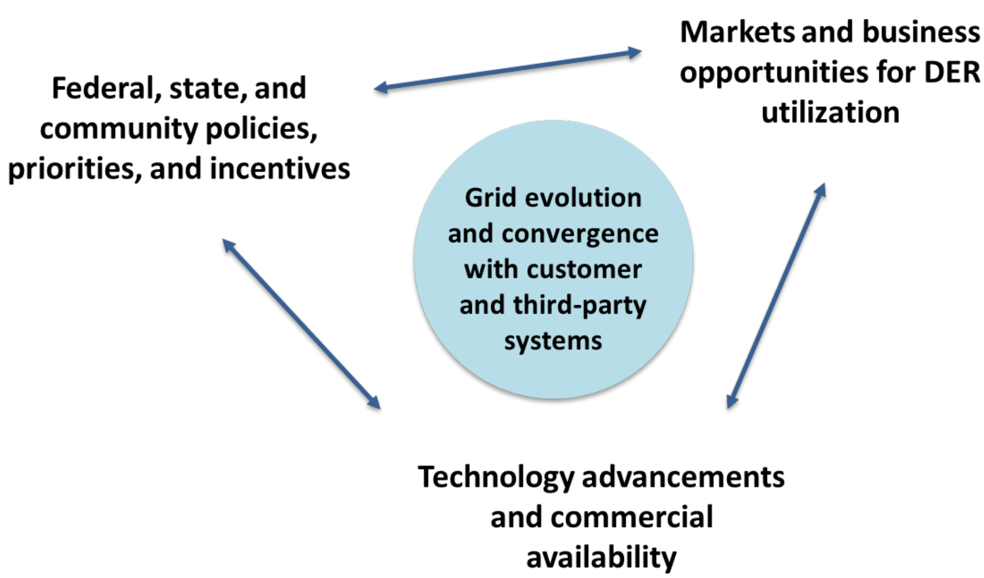
III. Factors Shaping Grid-Edge Development

As shown in Figure 5, three main factors are driving the adoption of DERs and subsequent evolution of the grid. These include:

- Federal, state, and community policies, priorities, and incentives which are directly stimulating increasing deployments of DERs. These include tax credits, targets, procurement mandates, and other incentives that drive DER adoption.
- Current and emerging markets, including tariff designs, that provide compensation to customers and third-party DER service providers, including DER aggregators. These include wholesale market participation models for DER, retail tariffs reflecting the grid value of DER, as well as revenue streams available via utility customer programs.
- Advancements in the performance and cost-effectiveness of technologies leading to making them suitable for commercial application. Such advancements could include research, development, demonstration, and deployment assistance, as well as industrial policies aimed at scaling the manufacturing capacity of new technologies.

Appendix A provides more detailed information regarding the drivers and enablers of DER adoption.

FIGURE 5: FACTORS SHAPING GRID-EDGE DEVELOPMENT



Key Investment Trends

The deployment of DERs is projected to grow significantly within the U.S. in the coming years, as shown in Figure 6. According to Wood Mackenzie,[23] DERs and the demand flexibility they provide are expected to grow by 262 GW from 2023 to 2027. This will nearly match the 271 GW in bulk generation additions over that same period.[24] For comparison purposes, as of February 2023 the U.S. had nearly 1,300 GW of generating capacity.[25] The U.S. market for DERs is forecast to double from 2022 to 2027, reaching $68 billion per year, with solar and electric vehicles expected to lead DER deployments in the first half of the decade.[26]

Utility investments in smart grid technology enable new system capabilities and are needed to make possible the integration of DERs with grid operations. With total U.S. electric power revenues approaching $400 billion, the outlook for utility investments in IT and OT technologies in 2023, including related portions of grid modernization projects, was estimated at 3.6 - 4.0% of the total investment level, as shown in Figure 7, where:[27]

- **Operations technology ($2.8B):** Non-smart-grid transmission and distribution (T&D) control systems, engineering workstations, computer-aided design (CAD), and GIS,
- **Smart-grid-related operations technology ($3.2B):** Control systems, including ADMS, distribution automation (DA) control, and substation automation protection and control,
- **“Pure" smart grid devices/systems ($4.1B):** DA technologies, AMI, T&D monitoring and control devices, renewables interties/inverters,
- **Smart-grid-related administration IT ($1.75B):** Meter data management systems (MDMS), billing, and customer information systems (CIS), and
- **Administration IT ($4.75B):** Non-smart-grid payroll, accounting, and HR systems.

FIGURE 6: CUMULATIVE DER VS. BULK GRID CAPACITY ADDITIONS FROM 2018-2027[28]

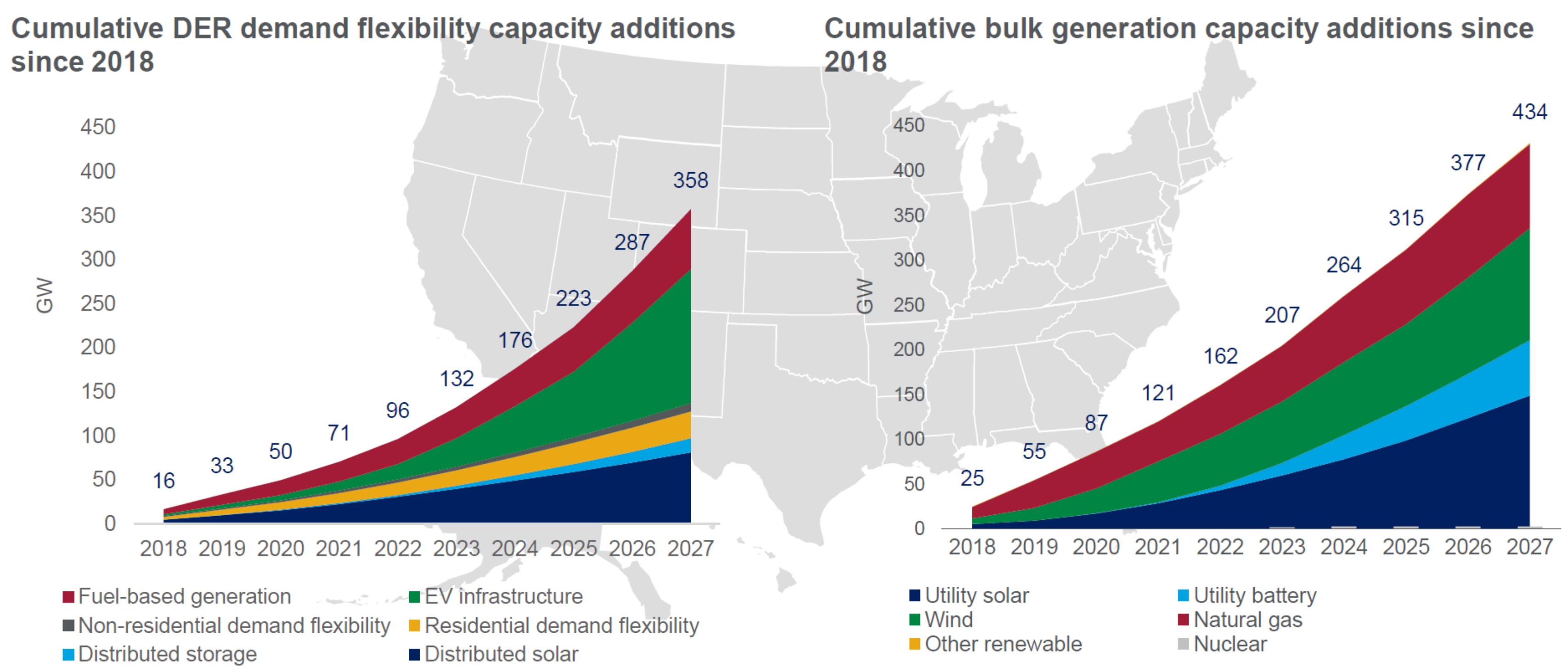
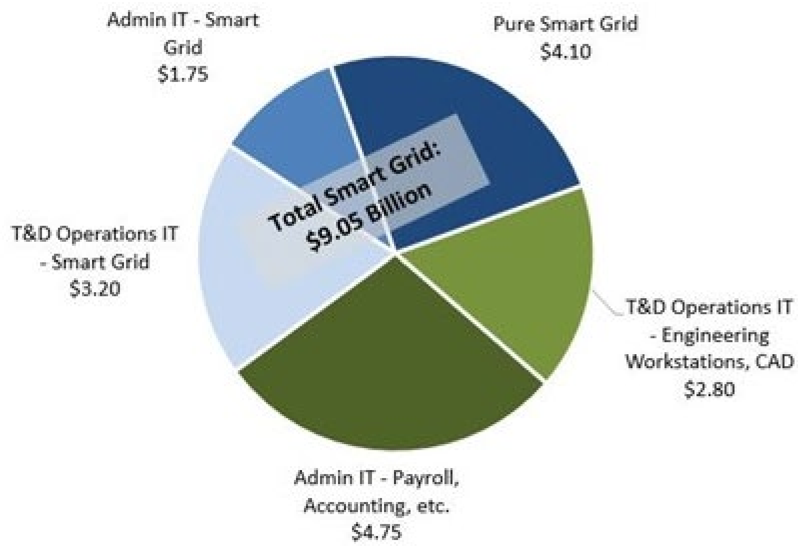
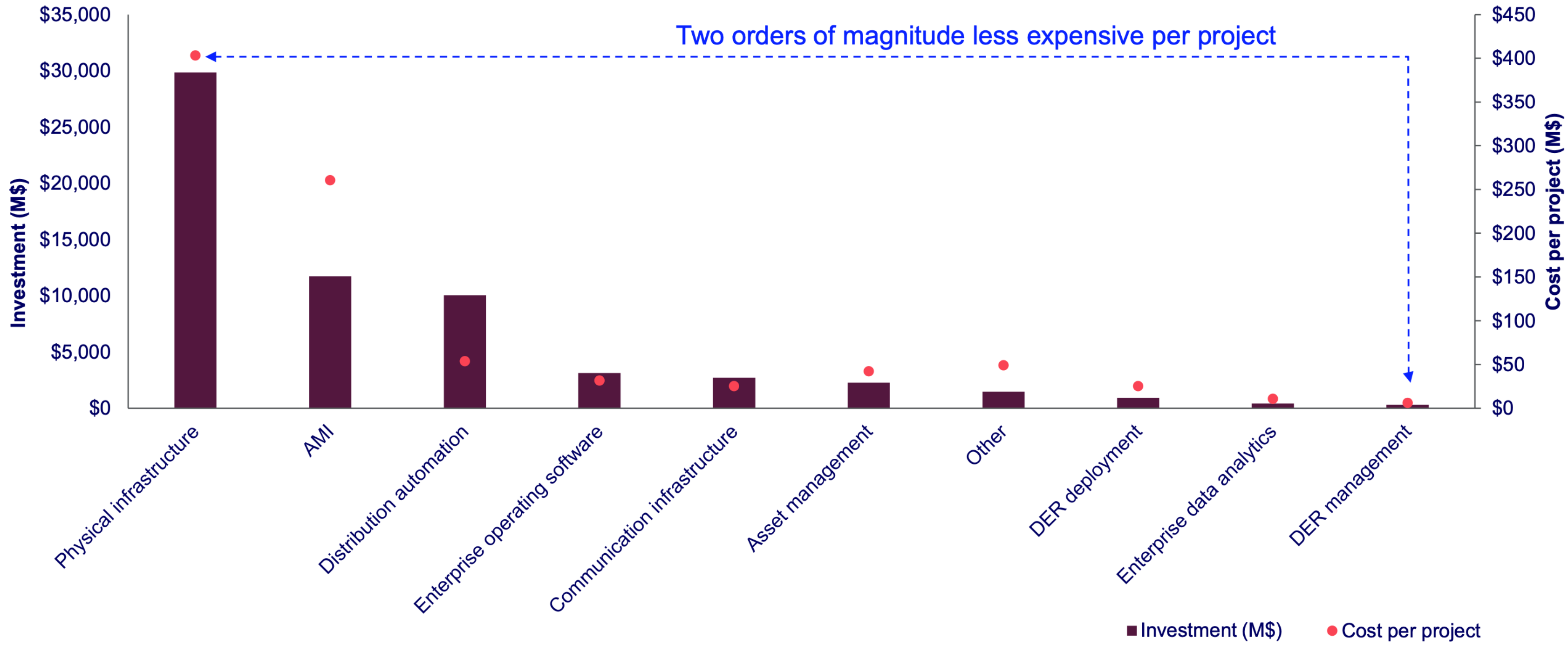


FIGURE 7: ESTIMATED EXPENDITURES FOR IT/OT EXPENDITURES[29]



Also, a review by Wood Mackenzie of 85 regulatory filings submitted by 50 major investor-owned utilities (IOUs), carried over into or filed after 2018, provides additional insight into the grid modernization investment practices of utilities as shown in Figure 8.[30] These plans span several years and represent $62.8 billion in proposed distribution system investments in a variety of areas.

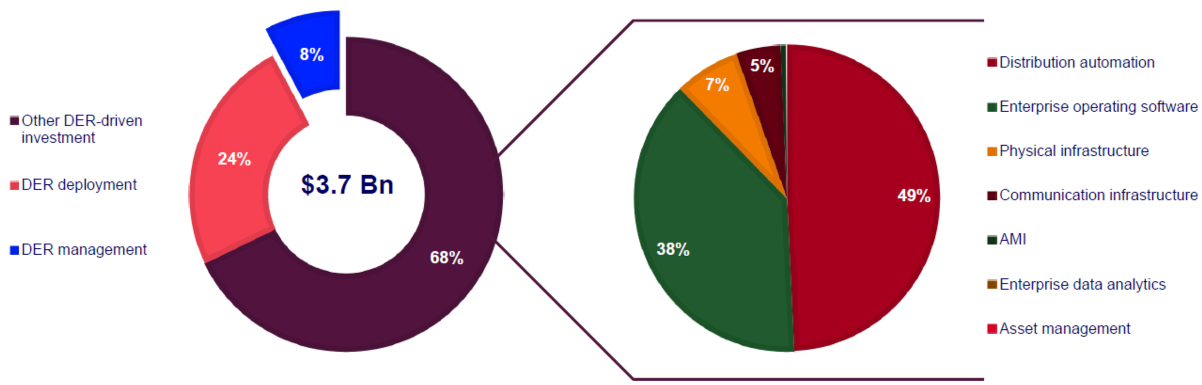
FIGURE 8: GRID MODERNIZATION INVESTMENT AND THE AVERAGE COST PER PROJECT BY CATEGORY.[31]



The largest investment category pertains to physical infrastructure modernization which includes capacity expansion as a result of DER growth and electrification, as well as infrastructure replacement and hardening to address resilience from severe weather or climate-related issues, but excludes investments made for business-as-usual operation of the grid or meeting conventional load growth. A list of these investment categories can be found in Appendix B.

As shown Figure 9, DER-driven investments comprise approximately $3.7 billion and consist of investments in DERs, such as deployments in microgrids, energy storage, and non-wires alternatives, and DER management technologies which include automated DER interconnection tools, distributed energy management systems (DERMs), DER market participation enablement, hosting capacity portals, and vehicle-grid integration systems. Supporting software and hardware systems are also included.

FIGURE 9: DER-DRIVEN INVESTMENTS[32]

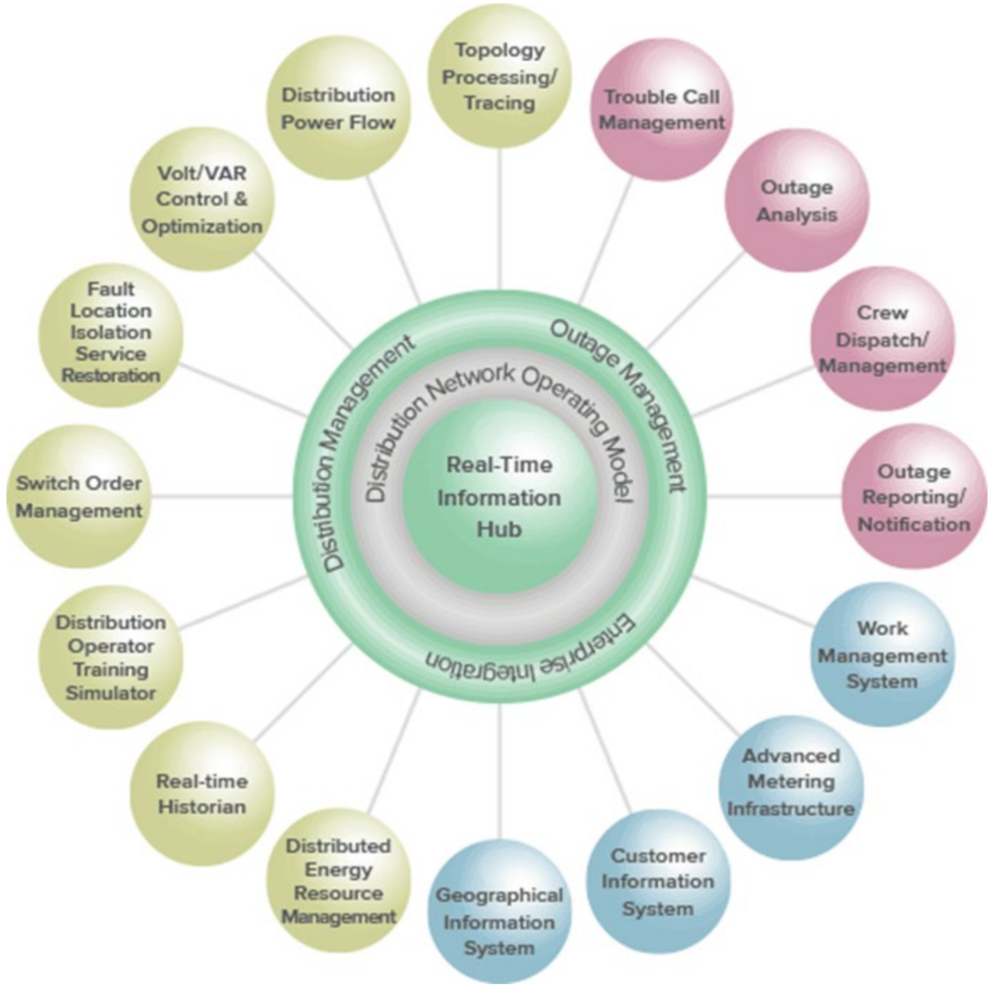


Key findings from the analysis conducted by Wood Mackenzie[33] include the following:

- Annual investments for grid modernization have increased at an annual average growth rate (AAGR) of 72% from 2018 to 2023. Over this period, the investment in distribution system grid modernization has accelerated with an average of $1.7 billion growth year on year.
- Severe weather events, DER adoption rates, and state policies are driving grid modernization investments among the utilities studied. 48% of the total investment is allocated to hardening the physical infrastructure or expanding the capacity to meet DER growth and the new demand resulting from electrification.
- No standardized approach exists to quantify the benefits of grid modernization technologies, making the cost-effectiveness of these investments harder to evaluate for policymakers.
- The studied utilities are filling market gaps by developing solutions in house, for example, by developing modeling and planning tools due to a lack of turnkey advanced planning software.

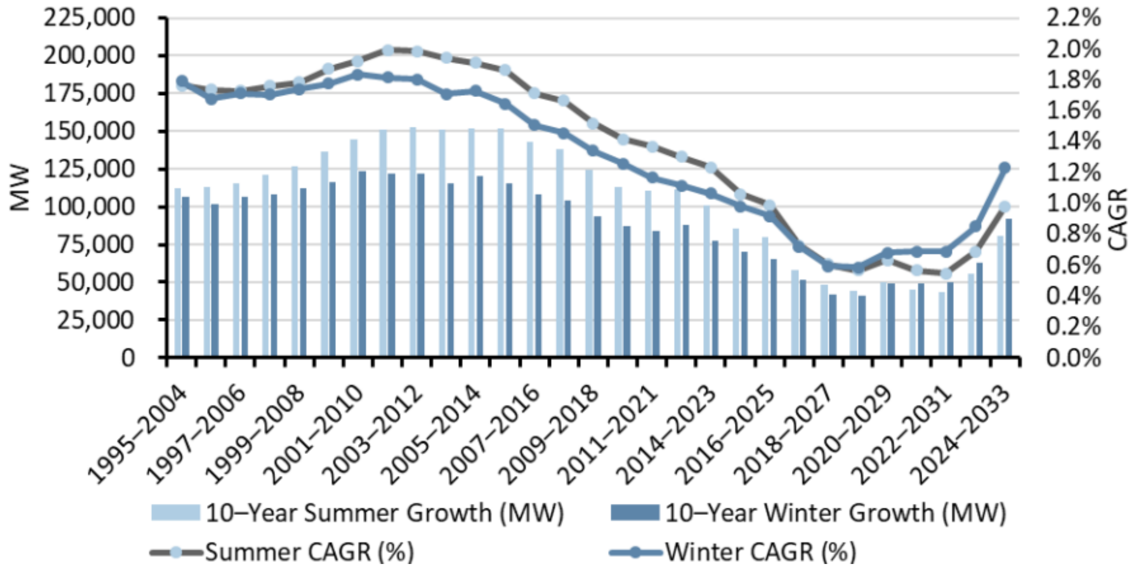
- A new wave of advanced metering infrastructure (AMI) deployments is occurring due to enhanced meter and distributed intelligence functionality (characterized as AMI 2.0). However, the benefits of these new capabilities are difficult to quantify as utilities diverge significantly in their AMI benefit-to-cost analysis due to a lack of a standard approach for quantifying AMI benefits. AMI 2.0 involves using advanced meter functionality to enhance grid operations (e.g., in the areas of outage management, voltage management, and improving visibility to DERs and EVs).
- Utilities are expanding the functional capabilities of advanced distribution management systems (ADMSs) to include fault management, voltage management, and DER management (ADMS-integrated DERMs). Figure 10 provides a view of intended ADMS functions. There is increased investment in DERMS deployment where DER penetration rates are increasing.
- Utilities are modernizing their enterprise asset management systems (EAMS) moving from reactive to predictive and proactive asset maintenance practices.
- Utilities are beginning to invest in holistic data platforms, including cloud-based platforms, to improve asset management processes, data-sharing capabilities with external entities, system operations, planning functions, and business processes.

FIGURE 10: ILLUSTRATIVE ADMS INTEGRATION OF DISPARATE SYSTEMS, FUNCTIONS, AND DATA[34]



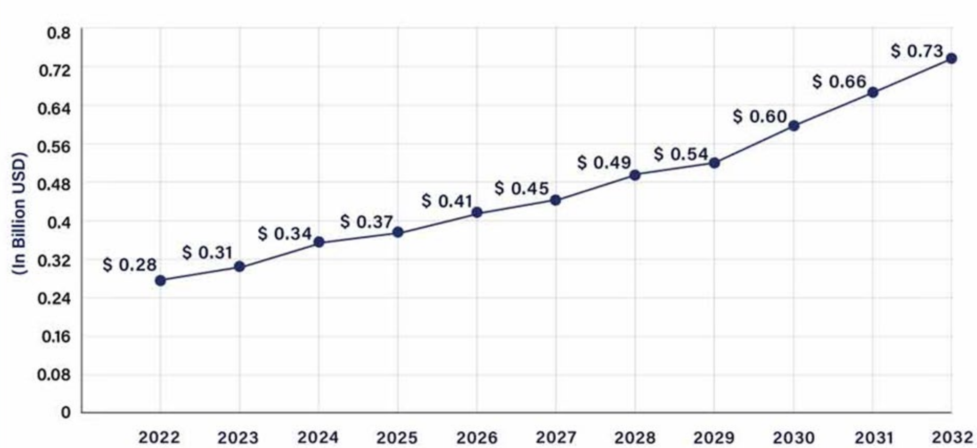
Another important trend impacting utility investment is the recent resurgence in demand growth, as seen in Figure 11. Recently, several major utilities have announced increases in near-term electricity demand stemming from industrial development, data centers, transportation electrification, and building electrification.[35] Entities such as FERC and the North American Electric Reliability Corporation (NERC) have increased their load forecast projections as well. The figure demonstrates that NERC's 2023 Long-Term Reliability Assessment projects energy growth over the next 10 years will be higher than at any point in the past decade. The rapid increase in load will necessitate the use of local resources, such as DERs, to meet electricity demand requirements, if adequate transmission from bulk-power generators cannot be built.

FIGURE 11: THE 10-YEAR SUMMER AND WINTER PEAK DEMAND GROWTH AND RATE.[36]



In addition, the provision of cloud services is a growing segment within the energy sector. As shown in Figure 12, the U.S. cloud computing market size for energy services was valued at $280 million in 2022 and is estimated to surpass $730 million by 2032, growing at a compound annual growth rate (CAGR) of 10% from 2023 to 2032. North America led the global market with the highest share of 44% in 2022.[37] It is expected that utilities and other companies within the energy infrastructure sector will increasingly use services from cloud providers to get access to specialized workers that can provide analytical support to improve their business and operational capabilities. This trend is projected to continue with 60% of organizations projected to offload some IT functions to cloud providers by 2030.[38]

FIGURE 12: U.S. CLOUD COMPUTING MARKET SIZE (2022 – 2032).[39]



Workforce Trends and Considerations

The energy sector added nearly 300,000 jobs, increasing from 7.8 million total energy jobs in 2021 to more than 8.1 million in 2022.[l] A survey undertaken and reported by DOE[40] revealed several findings related to job growth associated with grid modernization activities, including the following:

- In 2022, there were 3.1 million "clean energy" jobs addressing DOE's net-zero aligned goals.[m] This represents an increase of more than 114,000 since 2021, or growth of 3.9%.
- Jobs in the energy efficiency sector reached 2.2 million at the end of 2022 representing an increase of 7.4% since 2020.
- Jobs in clean energy vehicles, including battery and hybrid electric vehicles reached 38,200 jobs representing an increase of 20.9% from 2021 to 2022. The growth in battery electric vehicle (BEV) employment was almost 17 times faster than the increase in gasoline and diesel vehicle employment.
- Grid-scale battery storage jobs increased to 72,928 (which includes 13,6000 jobs in battery manufacturing) in 2022 adding 3,225 jobs and representing an increase of 4.6% since 2021.
- Jobs related to the smart grid (advanced grid technologies), microgrids, and EV charging increased to 24,916, 19,845, and 2,229, respectively, in 2022. This represents an increase of approximately 4% since 2021.

As discussed above, the trend towards increasing digitalization in the electric utility industry is requiring a new set of skills associated with technological advancements in the IT/OT layer, the emergence of data management and analytics capabilities, and the integration of utility systems with customer and third-party systems. These skills will augment and add to the traditional skills of utilities and their service providers. A survey conducted by the Center for Workforce Development[41] reported on utility sector jobs relating to the generation and distribution of electrical energy generated by renewable means, advanced metering, advanced utility or utility of the future, the development of statistical models, machine learning models, artificial intelligence applications, and electric fleet management and maintenance. They found that, although the overall numbers of these jobs are relatively small percentage of the total

[l] The energy sector represents activities associated with electric power generation, transmission, and distribution; the extraction, manufacturing, delivery, and storage of fuels; the manufacture, distribution, and repair of motor vehicles and their components, including electric and hydrogen-powered vehicles; energy efficiency product manufacturing and services to reduce energy consumption; and construction activities supporting the above.
[m] "Clean energy" jobs include jobs in the technologies that align with DOE's "net-zero" greenhouse gas goal, i.e., reaching net-zero greenhouse gas emissions in the energy sector by 2050, and include those related to renewable energy; grid technologies and storage; traditional electricity transmission and distribution for electricity; nuclear energy; a subset of energy efficiency that does not involve fossil fuel burning equipment; biofuels; and plug-in hybrid, battery electric, and hydrogen fuel cell vehicles and components.

(2.6%),[n] it has increased sharply, growing approximately 4x from 2021 to 2023. They also found that the aging workforce "gap" of years past, as expressed in the 2020 Smart Grid System Report,[42] has largely been addressed and replaced with a new challenge of developing a younger workforce. However, they note that while still a relatively small portion of the overall workforce, these emerging technology jobs show significant growth, potentially requiring recruitment and retraining.

Seventy-five percent of the utilities surveyed by DOE,[43] indicated that it was somewhat or very difficult to find qualified workers. The reasons they cited included a) competition for workers and recruitment from a small applicant pool (42%), b) insufficient qualifications relating to certification credentials and education (39%) and c) lack of experience, training, or technical skills (25%). A holistic workforce strategy that engages state policymakers and regulators, communities, utilities, labor unions, and DER service providers may be necessary to recruit, train, and retain skilled workers. Creating quality jobs and investing in career-track workforce development are key considerations when accounting for societal considerations and impacts associated with grid modernization implementation plans.[44]

As electrical infrastructure and smart grid technologies are deployed to meet grid modernization requirements, leveraging existing training resources, as well as established job quality, skills, and safety standards and ongoing and active engagement of labor and other stakeholders in planning processes, will be integral for recruiting, preparing, and retaining a qualified workforce to meet the needs of evolving and complex technological systems. For example, leveraging established industry programs, including notably union and registered apprenticeship and labor management training programs, can be utilized and expanded. Along these lines, there are several existing industry training programs to train workers on advanced grid solutions such as those administered by the International Brotherhood of Electrical Workers, the Electric Power Research Institute, and the Center for Energy Workforce Development.

[n] The percentage is based on a sample size of 315,000 jobs captured in their survey of utilities (compared to the 570,000 total utility jobs captured in the 2023 United States Energy & Employment Report by the U.S. DOE).

IV. Evolving Portfolio of Grid-Edge Resources

The grid edge has evolved considerably over the past few decades beginning with customer-facing utility programs designed to implement energy-efficient practices and progressing towards more advanced methods for utilizing customer-based resources to shape customer demand and provide grid services. Efforts to utilize customer resources are meant to reduce demand (both energy and peak demand) in order to defer the building of additional generation and grid infrastructure capacity, as well as to provide energy and related services. Table 2 provides a list of grid services available from DERs that can serve bulk-power, distribution, and customer or third party-owned systems.

TABLE 2: GRID SERVICES PROVIDED BY DERS

Services	Description
Energy	Generation of electric power over a period of time, expressed as kilowatt-hour (kWh), megawatt-hour (MWh), or gigawatt-hour (GWh).
Capacity	Total energy available from a resource, expressed as kilowatts (kW), megawatts (MW), or gigawatts (GW). Nameplate capacity may differ from useful capacity over time since resources may be taken out of service for maintenance, provide variable output (e.g., solar and wind resources), or can only discharge energy over a limited time (e.g., battery storage).
Plus, Ancillary Services	
Operating Reserves	Reserve capacity is used to address fluctuations in generation and load over a variety of time periods and may be required to provide additional energy when customer demand is increasing rapidly relative to generation output (e.g., to serve system ramping or fluctuations over short time periods).
Frequency Response	The provision of energy (or reduction in energy demand) with a response time in milliseconds to adjust the frequency of the alternating current in the electric grid, which maintained at 60 hertz (cycles per second).
Voltage and Reactive Power Management	The adjustment of voltage to optimize the efficient transfer of electrical power in alternating currents under normal and contingency conditions. Voltage must be kept within strict limits requiring adjustments in real and reactive power.
Resilience	The provision of energy to serve customer demand when electricity service is disrupted, e.g., to serve as back-up power or support microgrid operations when disconnected from the main grid.
Black Start	The provision of energy needed to restore a de-energized electric grid.

It is important to note that utilities and their customers are becoming more reliant on services provided by DERs. This trend may become increasingly important for serving local needs for reliable energy as may be needed to enhance resilience or to provide sufficient power to meet electrification requirements for both transportation and building purposes. To address electrification, obtaining power from local resources will become essential if the U.S. cannot build sufficient transmission capacity to serve load from bulk-level generating resources. Hence, ensuring that we can access needed services from DERs is an important consideration.

Figure 13 provides a look at a portfolio of capabilities obtainable from DERs and the systems that may use them singly or in combination to enable enhanced levels of supply-demand flexibility and resilience for both utilities and their customers. This report will explore these capabilities in more detail. Figure 14 presents a historical view of the use of grid-edge resources.

FIGURE 13: PORTFOLIO OF DER CAPABILITIES AND SYSTEMS

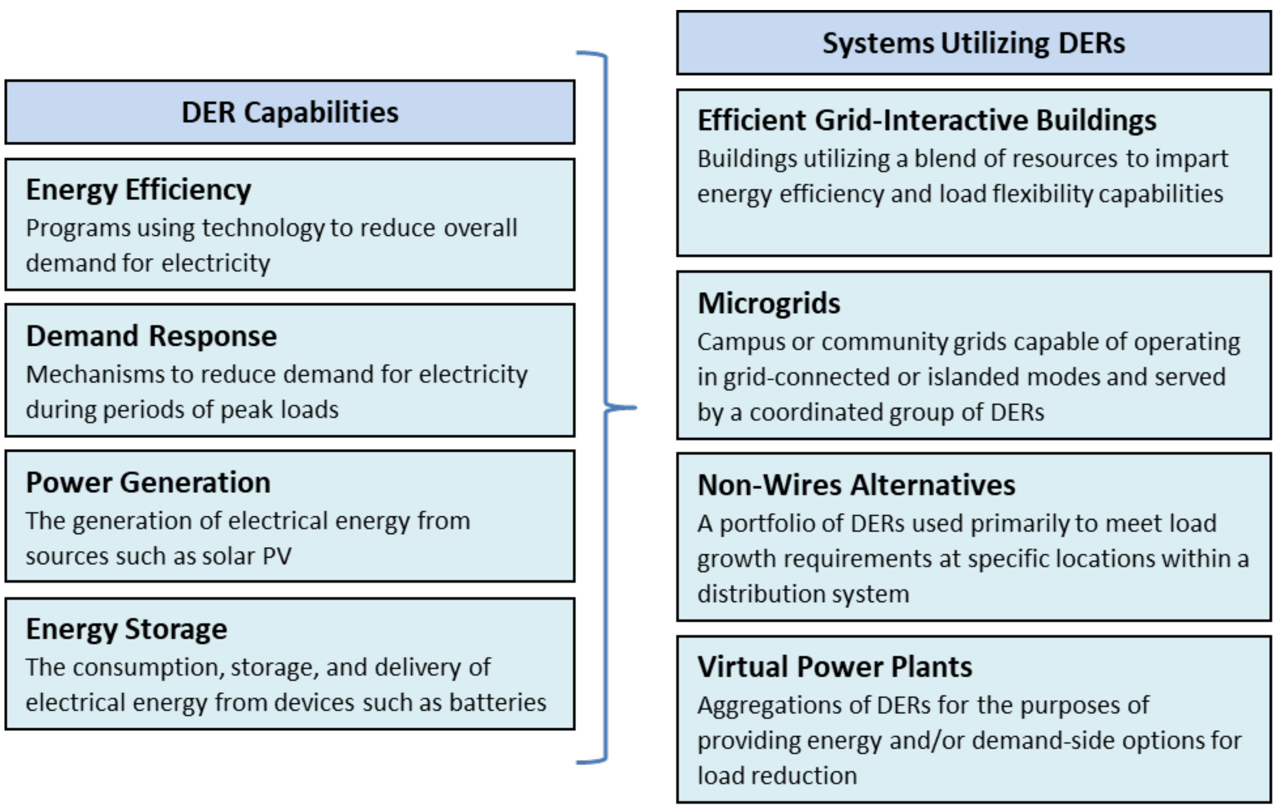
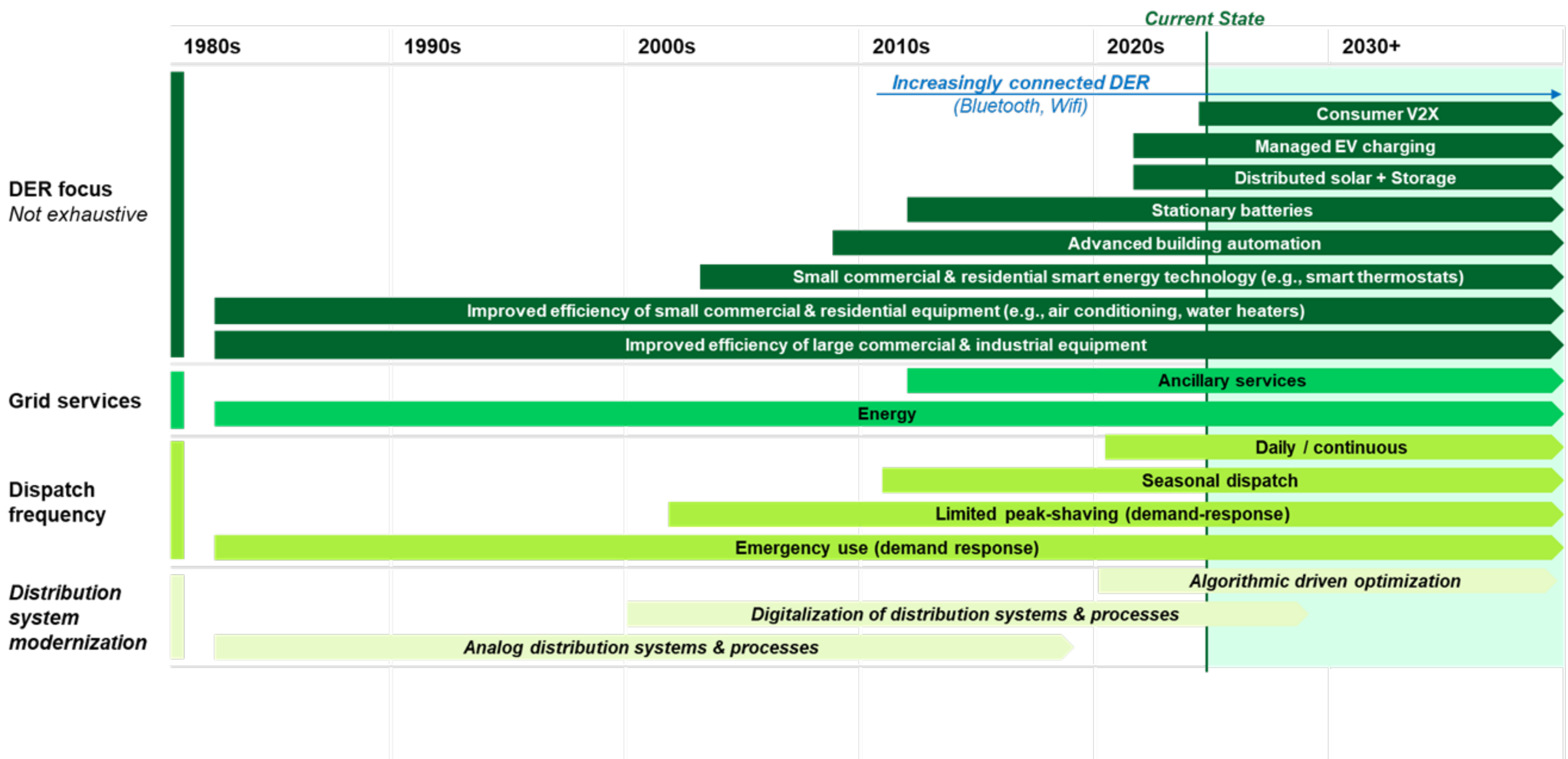


FIGURE 14: EVOLUTION OF DER UTILIZATION[45]



DER Types and Capabilities

The four main categories of DERs are energy efficiency, demand response, distributed generation, and energy storage. These technologies may be situated behind the customer meter (BTM) where they are owned and/or operated by utility customers or third-party service providers; distributed generation and energy storage may also be situated in front of the customer meter (FTM) where they are either owned by a utility or by a third-third party merchant under contract to a utility. Collectively, these resources can reduce the electrical load on the grid, supply electrical power to the grid, or store electrical energy to be used at another time. Given the appropriate incentives, these resources can provide tremendous value to the grid and consumers.

ENERGY EFFICIENCY[o]

Early efforts by the Federal Government to institute practices for conserving energy and implementing efficiency standards for appliances and certain types of equipment occurred in response to two energy crises that occurred in the 1970s.[p] These early efforts included the establishment of utility programs designed to help their customers conserve electricity use, and such programs grew rapidly as a result of state energy efficiency mandates. In the 1980s these efforts, which were originally focused mainly on conserving energy, shifted into the practice of demand-side management (DSM) in which energy efficiency became identified as a resource that could be influenced and managed within utility resource portfolios and factored into their assessment of energy resource requirements, e.g., through integrated resource planning (IRP) processes.[46,47]

Nearly every state has established utility programs to promote the use of energy efficiency practices and technologies, many of which have been advanced through Federal efforts, such as improvements in building technologies, advancements in appliance and equipment efficiency standards, and funding to states to help low-income households weatherize their properties. In addition, more than 25 states have mandatory statewide energy efficiency resource standards, while additional states and the District of Columbia reported savings from utility and public benefits programs in 2021 totaled 0.68% of sales, or 26 million MWh. However, since most efficiency measure generate savings for residents and businesses for years after they are installed, the total impact of utility energy efficiency programs in 2021 was a savings of more than 290 million MWh in 2021, as shown in Figure 15. These large-scale savings are equivalent to approximately 7.63% of 2021 electricity consumption and equivalent to the electricity

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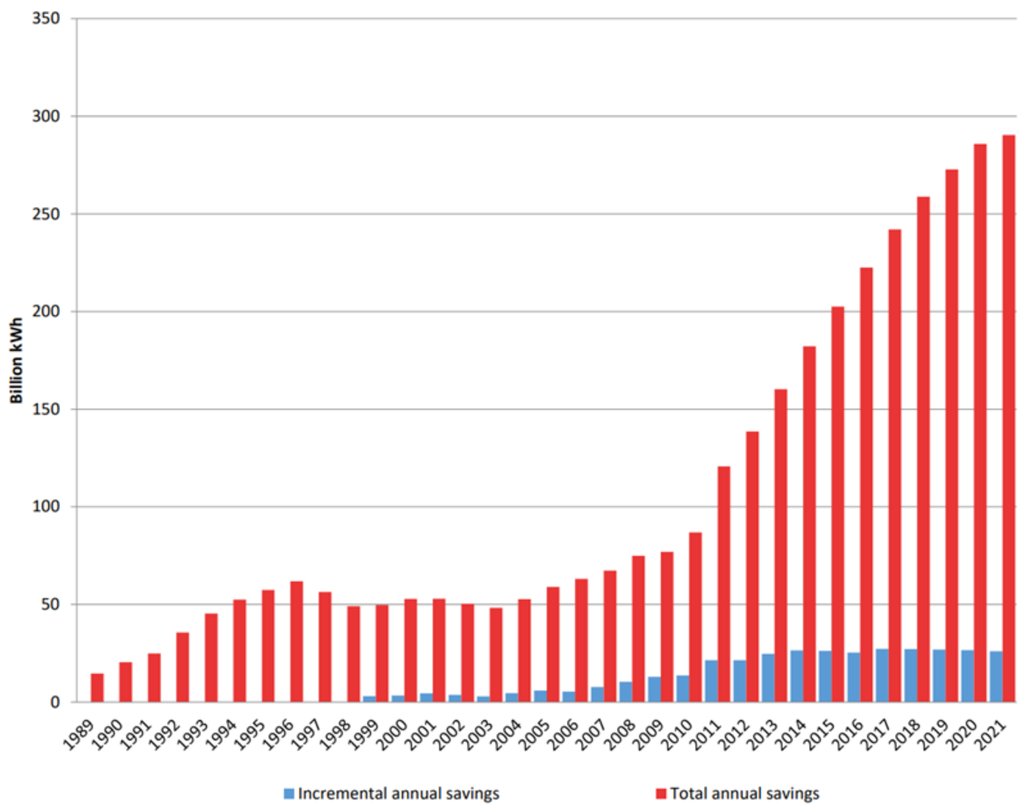
[o] The American Council for an Energy-Efficient Economy (ACEEE) defines energy efficiency as measures that result in producing the same or better levels of amenity or service (e.g., light, space conditioning, motor drive power, etc.) using less energy.

[p] The Organization of Petroleum Exporting Countries (OPEC) declared an oil embargo in 1973 at the time of the Yom Kippur War quadrupling the price of oil with consumers facing gasoline price hikes and shortages, and the second oil crisis occurred in 1979 as a result of a drop in oil production in the wake of the Iranian Revolution doubling the price of oil, https://www.onlyelevenpercent.com/a-brief-history-of-energy-efficiency/.

requirement of approximately 27 million homes.[48,q] According to the U.S. Energy Information Administration (EIA) residential customers accounted for about 47% of the total annual electricity savings from utility energy efficiency programs and commercial customers accounted for 44% of the energy efficiency savings in 2020.[49]

FIGURE 15: ELECTRIC SAVINGS FROM UTILITY ENERGY EFFICIENCY PROGRAMS, BY YEAR[50]

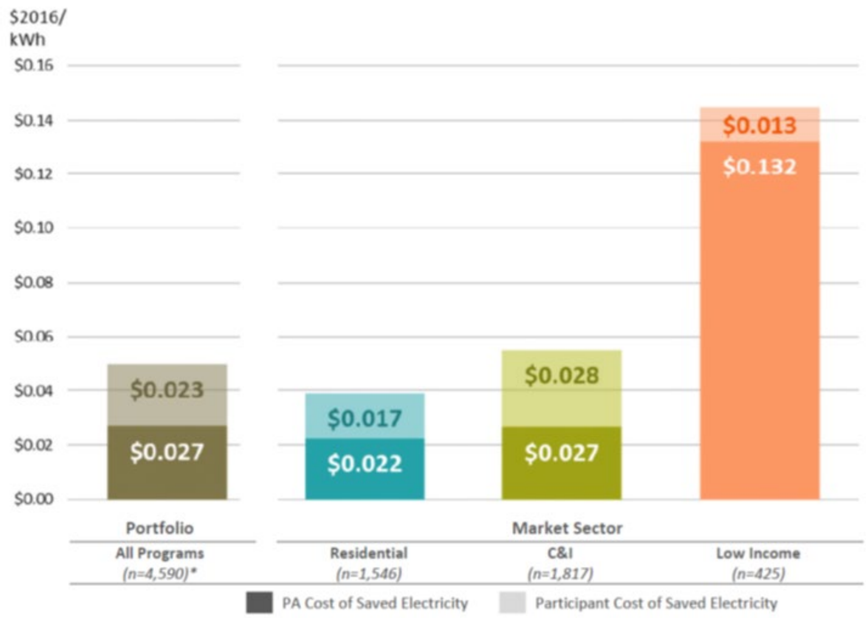


Energy efficiency is a reliable, cost-effective resource as the costs for applying energy efficient practices and technologies result in energy reduction outcomes that are fairly predictable and usually less expensive than purchasing electricity. Avoided energy and capacity costs are the primary yardsticks utilities use to determine, which energy efficiency programs are cost-effective for their customers. Figure 16 shows that the total cost of energy efficient improvements borne by both utilities and their customers (residential, commercial, and industrial) is less than what it costs to purchase an equivalent amount of electricity on a kWh-per-kWh basis, except perhaps for low-income customers who usually require additional support to implement energy efficiency measures.[r]

[q] According to EIA, the average American home uses 10,632 kWh of electricity per year.

[r] Determined from a sampling of 116 IOUs and other program administrators in 41 states. See The Cost of Saving Electricity through Energy Efficiency Programs Funded by Utility Customers: 2009 – 2015, Lawrence Berkeley National Laboratory, June 2018, https://eta-publications.lbl.gov/sites/default/files/cose_final_report_20200429.pdf.

FIGURE 16: TOTAL COST OF SAVED ELECTRICITY FOR UTILITY EFFICIENCY PROGRAMS BY SECTOR[51]



Utility energy efficiency programs are evolving to support a broader set of state policies, including those associated with decarbonization and equity. However, utilities have identified multiple barriers impeding their energy efficiency programs from achieving their full potential. These include increased difficulty in constructing cost-effective portfolios, supply-chain issues, lack of skilled contractors, legislative or regulatory barriers, and low customer awareness of and interest in the programs.[52]

Please note that energy efficiency can also be improved by applying practices for reducing energy losses as electrical power is conveyed through transmission and distribution systems, although not discussed above. These practices include applying technologies to adjust real and reactive power on the electrical grid through the application of techniques such as integrated volt/VAR management, as well as adjusting voltage and current levels through smart inverters.[s]

DEMAND RESPONSE

Like energy efficiency, demand response is a practice aimed at reducing electricity usage by utility customers, particularly during periods when system peaks are high, as a way to reduce load when wholesale prices are unusually elevated, or when there is a shortfall of generation or transmission capacity to meet demand, or during unexpected emergency grid operating conditions. As a result, demand response is a resource for maintaining system reliability, especially over short periods of time to alleviate system stress (i.e., when electricity demand is

[s] Smart inverters provide the electrical control interface between the grid and many DERs (i.e., inverter-based resources, such as solar photovoltaics and battery storage).

unusually high compared to the available supply of electricity), as well as for reducing the long-term need for providing additional generating capacity principally used to satisfy peak demand.

Demand response resources are made available through retail and wholesale programs[t] and can apply price-based and direct-control mechanisms. For example, they may include voluntary interruptible tariff programs in which large commercial and industrial customers will curtail their use of electricity when requested (e.g., via an alert, by a utility or system operator). They can also include the installation of load-control devices on residential water heaters and air conditioners enabling a utility to directly modify home energy use.[53] These programs are typically voluntary, and customers are compensated in exchange for conducting and, sometimes, just committing to curtail their load.[54]

Demand response has become an integral part of grid operations through retail programs (i.e., serving distribution grid operators) and via wholesale electricity markets managed by RTOs/ISOs to balance supply and demand and to reduce the cost of dispatching additional generation. FERC reported a "potential peak demand savings"[u] from retail demand response programs in 2020 of 15,098 MW and demand response resource participation of 32,421 MW in RTO/ISO markets.[55] As shown in Table 3, the resources serving these markets can represent a significant percent of peak demand in various parts of the country and contribute to reducing the need for building or deploying additional power plants to mainly serve peak load.

TABLE 3: DEMAND RESPONSE RESOURCE PARTICIPATION IN RTOS/ISOS (2020 & 2021)[56]

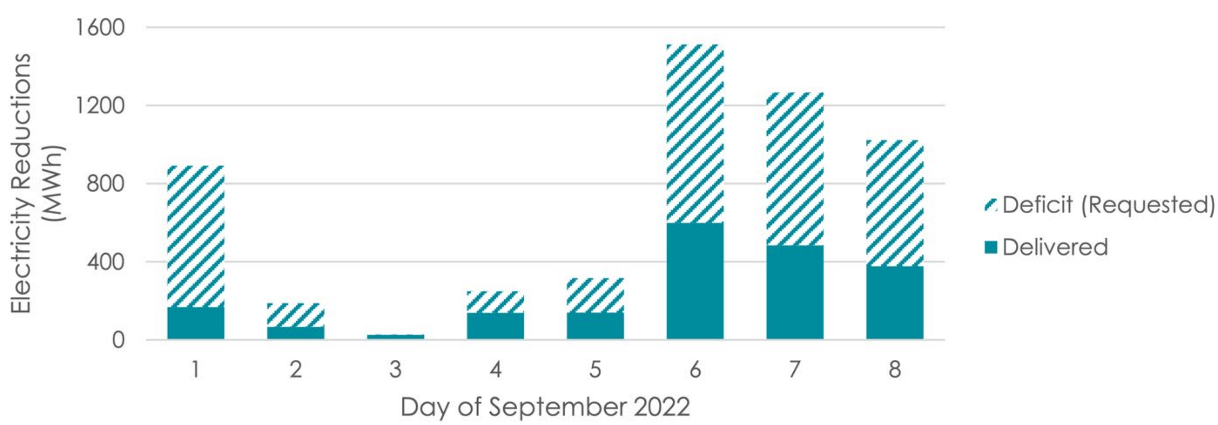
RTO/ISO	2020		2021		Year-on-Year Change	
	Demand Resources (MW)	Percent of Peak Demand	Demand Resources (MW)	Percent of Peak Demand	MW	Percent
CAISO	3,290.0	7.0%	3,900.0	8.9%	610.0	18.5%
ERCOT	3,774.0	5.1%	4,354.5	5.9%	580.5	15.4%
ISO-NE	423.4	1.7%	533.7	2.3%	110.4	26.1%
MISO	12,877.0	11.0%	12,197.0	10.2%	-680.0	-5.3%
NYISO	1,274.1	4.2%	1,345.5	4.4%	71.4	5.6%
PJM	8,915.0	6.3%	9,914.0	6.8%	999.0	11.2%
SPP	34.2	0.1%	176.2	0.3%	142.0	415.2%
Total	**30,587.7**	**6.3%**	**32,421.0**	**6.6%**	**1,833.3**	**6.0%**

[t] Retail programs generally serve distribution utilities, while wholesale programs serve bulk-power systems, which are managed typically by ISOs/RTOs.
[u] The term "potential peak demand savings" refers to "the total demand savings that could occur at the time of the system peak hour assuming all demand response is called." See Form EIA-861 Instructions, Schedule 6, Part B: Demand Response, Energy Information Administration, U.S. DOE, https://elecidc12c.eia.doe.gov/2017%20EIA-861%20Instructions.pdf.

Demand response aggregation, in which a third-party company bundles the DER assets of many smaller customers to participate in wholesale markets, is also occurring in many states as a result of FERC Orders 719 (issued in 2008) and 2222 (issued in 2020). The third-party aggregators have reported significant compensation to DER owners through these demand response programs. However, ten states have instituted a full ban on the practice of demand response aggregation for serving wholesale markets, as the FERC Orders offer "opt-out" provisions for states. Reasons for opting out of demand response aggregation are based on lack of clarity on regulatory control of such programs and market risks. Some states have instituted a partial ban to gain a greater level of certainty on the effectiveness of these programs.[57]

It is important to note that the California Public Advocates Office reported that the state's portfolio of demand response has underperformed and, as a result, can jeopardize system reliability. For example, during the Summer of 2022 when electricity use was high, the California Independent System Operator (CAISO) documented that demand response aggregators only supplied 36% of the reduced demand that they had promised to provide. Figure 17 illustrates the performance of demand response aggregators during a critical 8-day stretch in September 2022 when text alerts were sent out from the California Office of Emergency Services.[58] Uncertainty in the performance of assets not owned by utilities, yet depended upon to provide services when needed, may become a larger issue as we begin to depend on the use of customer and third-party resources.

FIGURE 17: THIRD-PARTY DEMAND RESPONSE PROVIDERS' DAILY REQUESTED ENERGY (5PM TO 9PM) COMPARED TO DELIVERED ENERGY FROM SEPTEMBER 1 – 8, 2022[59]



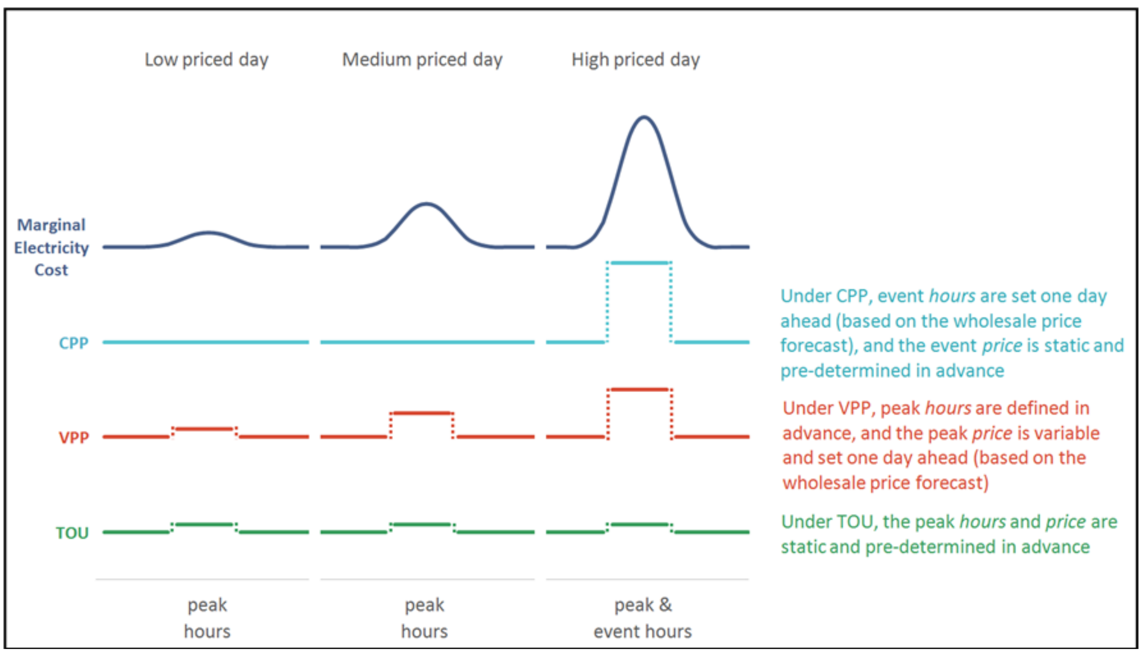
Time-Based Rates

Time-based (or time-varying) rate programs are a form of demand response and constitute part of a demand-side management strategy. Time-based rates are electricity prices that vary with time, typically over the course of a day, and are intended to provide utility customers with price signals that better reflect the time-varying costs of producing and delivering electricity. They are especially useful for managing peak demand.

A myriad of financial benefits inures utilities and their ratepayers when customers take service under and respond to time-based rates. The value associated with lowering peak demands is often at its highest when reductions in consumption coincide with times that the local or regional power system is experiencing its highest level of demand (i.e., the coincident system peak demand). Such reductions in electricity demand at these times can lead to deferrals of new investments or upgrades in electric generation, distribution, and transmission facilities, and/or avoidance of higher prices from wholesale power suppliers. These results can lead to reductions in the utility's overall cost of service, which can benefit all customers when the reductions are passed on through retail rates.

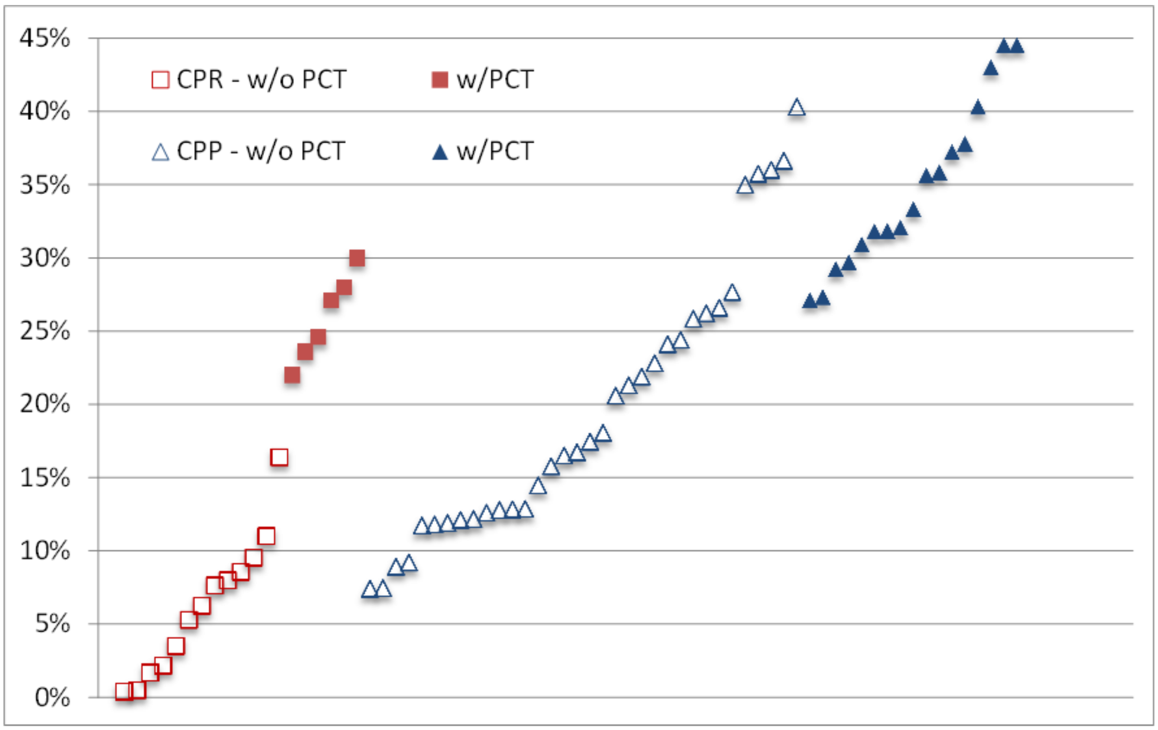
Figure 18 shows the impact of alternative time-based rate designs on lowering peak demand. The alternative rates shown in the figure, critical peak pricing (CPP), variable peak pricing (VPP), and time-of-use (TOU), all seek to reflect at a more aggregate level the average of the marginal cost of producing electricity during various periods of time.

FIGURE 18: AN ILLUSTRATION OF SEVERAL TIME-BASED RATE DESIGNS[60]



There is significant evidence from deployments of time-based rate programs showing that they can yield benefits to utility customers. For example, under the Smart Grid Investment Grant Program (which ran during the years 2010 – 2015), the U.S. DOE partnered with ten electric utilities to conduct a variety of time-based rate studies, which applied randomized and controlled experimental designs. Peak demand reductions resulting from groups that applied either critical-peak rebate or critical peak pricing rate designs with and without the use of programmable controllable thermostats (PCTs) are shown in Figure 19. As an example, the Oklahoma Gas & Electric SmartHours Program, which includes a variable rate design (up to $0.46 per kWh during peak times) in which customers respond to price signals during the non-holiday weekday hours of 2:00 PM – 7:00 PM during the summer months, have helped to reduce peak demand by more than 100 MW.[61]

FIGURE 19: AVERAGE PERCENT DEMAND REDUCTIONS FOR CUSTOMERS ON CPP AND CPR WITH AND WITHOUT PCTS BY TREATMENT GROUP[62]



Time-based rate programs are enabled by utility investments in AMI, which applies smart meters and supporting communications networks to monitor and share electricity usage information with customers. According to EIA-861 Survey, 97.7 million households have smart meters, which represents about 69% of total residential electric meters in 2021.[63] However, only 12.3 million households are enrolled in a time-based rate program, which is about 9% of the total number of residential households. Hurdles to large-scale implementation of time-based rates are largely due to the following issues:[64]

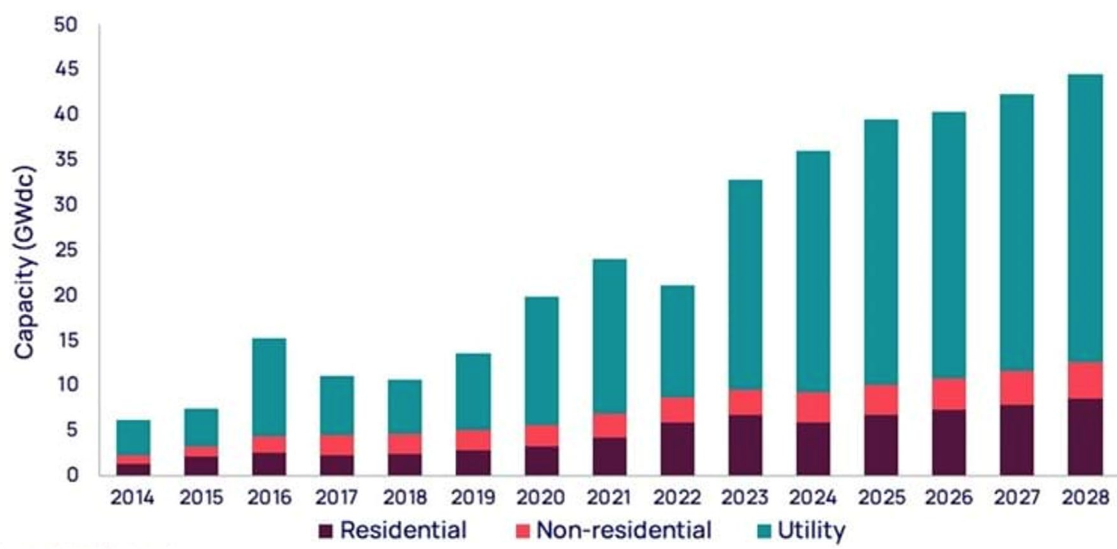
- Regulators, utilities, and customers are not convinced that benefits to a broader group of customers would be realized through full-scale deployment beyond pilot studies,
- Additional investments in time and resources are needed to address customer dissatisfaction and backlash if first-time customers experience bill increases, and

- The extraordinary attention needed to be paid to special needs and disadvantaged customers.

POWER GENERATION

Much of the power injected into the electric grid from grid-edge resources comes from solar technologies.[65] Capital investment in distributed solar grew 130% from the period 2017 to 2022. Current and projected capacity additions are provided in Figure 20. Residential solar, the largest source of distributed solar experienced its seventh consecutive year of record levels of installations.[66] The passage of the Inflation Reduction Act increased projections for deployments significantly. Guidance on the implementation of programs will be a critical part of market and deployment projections.

FIGURE 20: U.S. SOLAR PV INSTALLATIONS AND FORECASTS BY SEGMENT[67]



Community solar is a form of solar energy generation that aims to enable community members of all types to access meaningful benefits of renewable energy, including reduced energy costs, low- to moderate-income household access, increased resilience, community ownership, and equitable workforce development and entrepreneurship.[68] Community solar is a growing U.S. distributed energy sector, with over 6.2 GW of installed systems, with an additional 6 GW of capacity additions estimated in the next five years.[69]

ENERGY STORAGE

Energy storage technology provides a significant new capability for grid operations as it can serve as a buffer for addressing imbalances between the supply of and demand for electricity. This new capability enables the ability to store and deliver electrical energy when needed, which makes possible a variety of applications that are useful to both grid operators and their customers, as shown in Table 4. In this table, energy storage applications are characterized by the duration and magnitude of energy they can provide[v] and whether they primarily serve utilities or their customers, which is often determined by their location, i.e., whether they reside in front of or behind customers' meters (FTM vs BTM). Key applications include:

- Regulating system frequency and voltage within very short timescales,
- Smoothing fluctuations in the supply and demand for electricity; such fluctuations are becoming more extreme due to variable power output from renewable energy resources, as well as increasingly dynamic demand requirements of customers (e.g., caused by the electrification of transportation and buildings),
- Enabling energy arbitrage in electricity markets,
- Providing backup power to serve local needs, and
- Deferring the need to build additional infrastructure by enhancing the hosting capacity of the grid.

As a result, energy storage systems (ESS) can provide many grid services. However, their use is typically compensated through programs that favor one or a few of the applications; hence, opportunities to compensate them for their full value are seldom realized. For example, batteries are usually compensated either through demand response programs or through the sale of grid-supporting services. The term, value stacking, refers to the practice of applying multiple grid services, when possible, to maximize revenue to an ESS owner or to maximize grid benefits of an ESS. There are two primary motivations for value stacking. First, since energy storage is still a relatively expensive tool, the ability to value stack can increase the likelihood that a project can provide a positive net benefit, which is important for developers. Second, some applications like the deferral of investments in transmission and distribution infrastructure may only require charging/discharging as little as a few hours per year to provide the required benefit making an ESS available for the rest of the year to provide other services, which can further improve a project's net benefit.[70]

Annual deployments of ESS by utilities for grid-scale applications and utility customers for residential, commercial, and industrial applications[w] have increased significantly since 2017, as shown in Figure 21, due to reductions in the cost of the technology, the policies and incentives of states (e.g., legislative mandates and favorable tariffs) and Federal programs (e.g., the solar investment tax credit of the Inflation Reduction Act), and sustainability goals of communities and corporations. Grid-scale deployments constitute approximately 85% of the total. In addition, half of the total grid-scale market share is represented by solar-paired storage

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[v] Short-duration applications (e.g., seconds to minutes), often referred to as power applications (measured in MW), are typically used to maintain grid stability (e.g., for frequency and voltage regulation), while longer-term applications (e.g., measured in minutes to hours), often referred to as energy applications (measured in MWh), are used to provide reserve energy and the more effective use of resources.

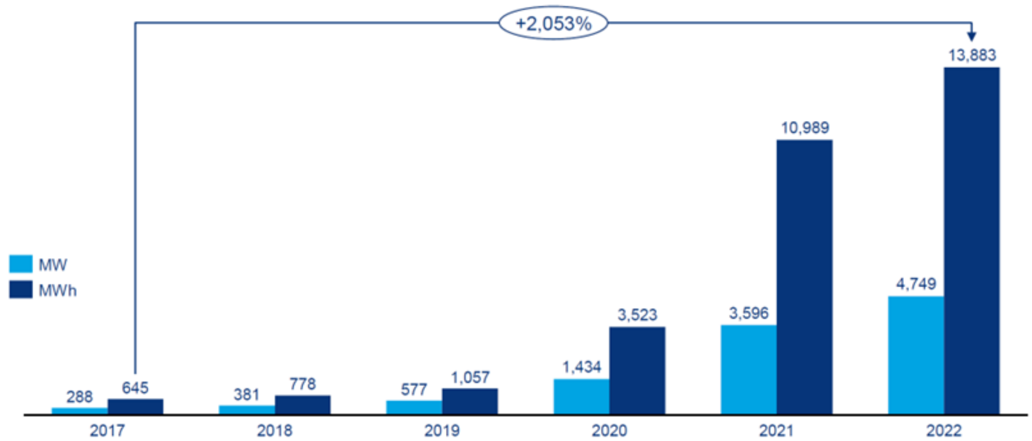
[w] Grid-scale storage is defined as an application in which the off-taker of the power is a utility, a third-party power supplier, or a commercial/industrial entity (only if the project is connected to the transmission system); otherwise, the off-takers are residential, commercial, industrial, and community entities.

deployments.[71] Deployments of ESS are expected to increase dramatically in future years due to anticipated cost reductions in the technology combined with the realization of additional benefits for both utilities and their customers.

TABLE 4: SUMMARY OF ENERGY STORAGE APPLICATIONS[72]

Applications	Power or Energy?	FTM or BTM?	Grid-connected or Off-grid?
General Energy Applications			
Energy Arbitrage in Electricity Markets	Energy	FTM	Grid-connected
Renewable Energy Time-shift (Renewable smoothing and firming)	Energy	FTM and BTM	Grid-connected and Off-grid
Ancillary Services			
Frequency Regulation	Power	FTM	Grid-connected
Operating Reserve (spinning, non-spinning, supplementary)	Energy	FTM	Grid-connected
Frequency Response and Virtual Inertia	Power	FTM	Grid-connected
Voltage support	Power	FTM	Grid-connected
Ramp support	Power	FTM and BTM	Grid-connected
Black Start	Power	FTM	Grid-connected
Transmission Services			
Transmission Upgrade Deferral	Energy	FTM	Grid-connected
Transmission Congestion Relief	Energy	FTM	Grid-connected
Stability Damping Control	Power	FTM	Grid-connected
Distribution Services			
Peak shaving and Upgrade Deferral	Energy	FTM and BTM	Grid-connected
Voltage regulation	Power	FTM and BTM	Grid-connected
Reliability and Resilience	Energy and Power	FTM and BTM	Grid-connected
End-user Services			
Time-of-use, demand charge and net-metering management	Energy	BTM	Grid-connected
Power Quality	Power	BTM	Grid-connected
Resilience (Back-up power)	Energy	BTM	Grid-connected and Off-grid

FIGURE 21: U.S. ENERGY DEPLOYMENTS ACROSS ALL MARKET SEGMENTS, 2017 - 2022[73]



There exist several impediments to more robust deployment of utility-scale ESS.[74] The most prominent are associated with:

- Uncertainties associated with project timeline delays and implementation costs, as ESS projects must meet Federal, state, and local zoning, interconnection, testing, and safety requirements for successful deployment. These processes involve approvals from multiple authorities and local communities to ensure compliance with safety and noise requirements, especially in densely populated areas. Supply chain issues associated with ESS equipment, such as transformers, may also impact project schedules.
- Variation across regions and states with regard to available markets, incentives, and profit potential for ESS developers. State policies vary widely with regard to energy storage procurement targets, regulatory requirements, financial incentives, interconnection policies, and support for demonstration programs.[75]
- Lack of mechanisms to quantify and fully monetize the reliability and resilience benefits of ESS either through markets or via IRP processes. For example, predictable compensation for the provision of resource adequacy benefits would support the business case for investments. Unlocking this value would require changes to modeling methodologies currently used to determine resource adequacy.

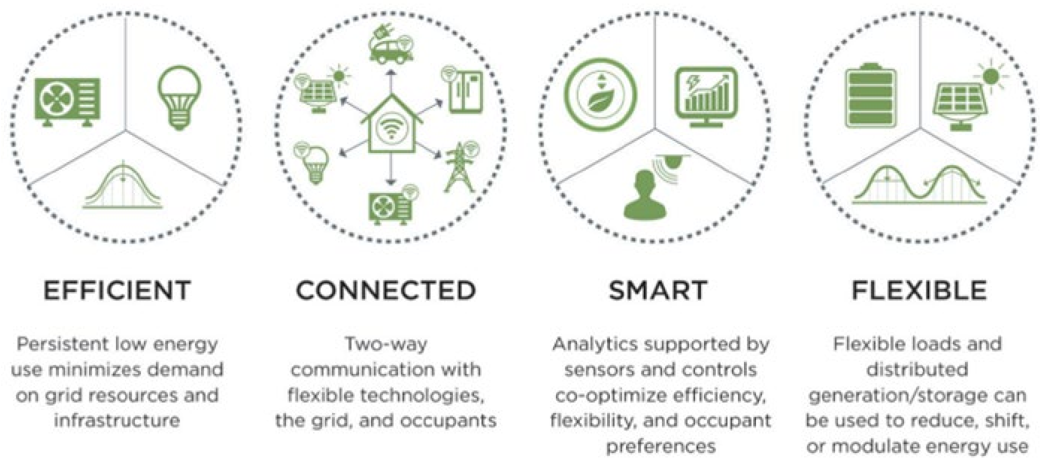
Systems That Apply DERs

DERs are applied in various configurations that include grid-interactive buildings, microgrids, non-wires alternatives, and virtual power plants, which are discussed here. These configurations provide reliability, resilience, efficiency, and cost-savings benefits to utilities and their customers. However, many technological and institutional challenges yet remain to implement these systems in a more robust manner, as is described below. DER configurations and ownership structures are anticipated to evolve as the industry adapts to the application of new technologies. Appendix C provides three examples of how utilities are coordinating with DER aggregators.

GRID-INTERACTIVE EFFICIENT BUILDINGS

Expanding on traditional demand response, grid-interactive efficient buildings (GEBs) utilize state-of-the-art sensors and controls paired with existing equipment and on-site DERs, with the goal of co-optimizing for energy cost, grid services, and occupant needs and preferences, in a continuous and integrated way. Buildings consume approximately 75% of U.S. electricity demand and drive up to 80% of peak power demand in some regions.[76] Grid-interactive efficient buildings offer a vast potential to increase grid flexibility, resulting in significantly reducing energy costs to consumers and facilitate the transition to a decarbonized economy, as shown in Figure 22.

FIGURE 22: KEY CHARACTERISTICS FOR GRID-INTERACTIVE EFFICIENT BUILDINGS[77]



Advanced controls and communications enable buildings to adjust power consumption to meet grid needs through a variety of control strategies applied to existing equipment, such as lighting and heating, ventilating, and air conditioning (HVAC), along with on-site DERs. These control strategies may include reducing energy consumption, shifting energy to another time period, adjusting the power draw, or even increasing energy consumption to store for later use. Control strategies are intended to be automated, as well as be responsive to real-time price controls when serving markets. For this reality to manifest, millions of sensors, meters, smart appliances, loads, and distributed generation need to seamlessly communicate and coordinate.

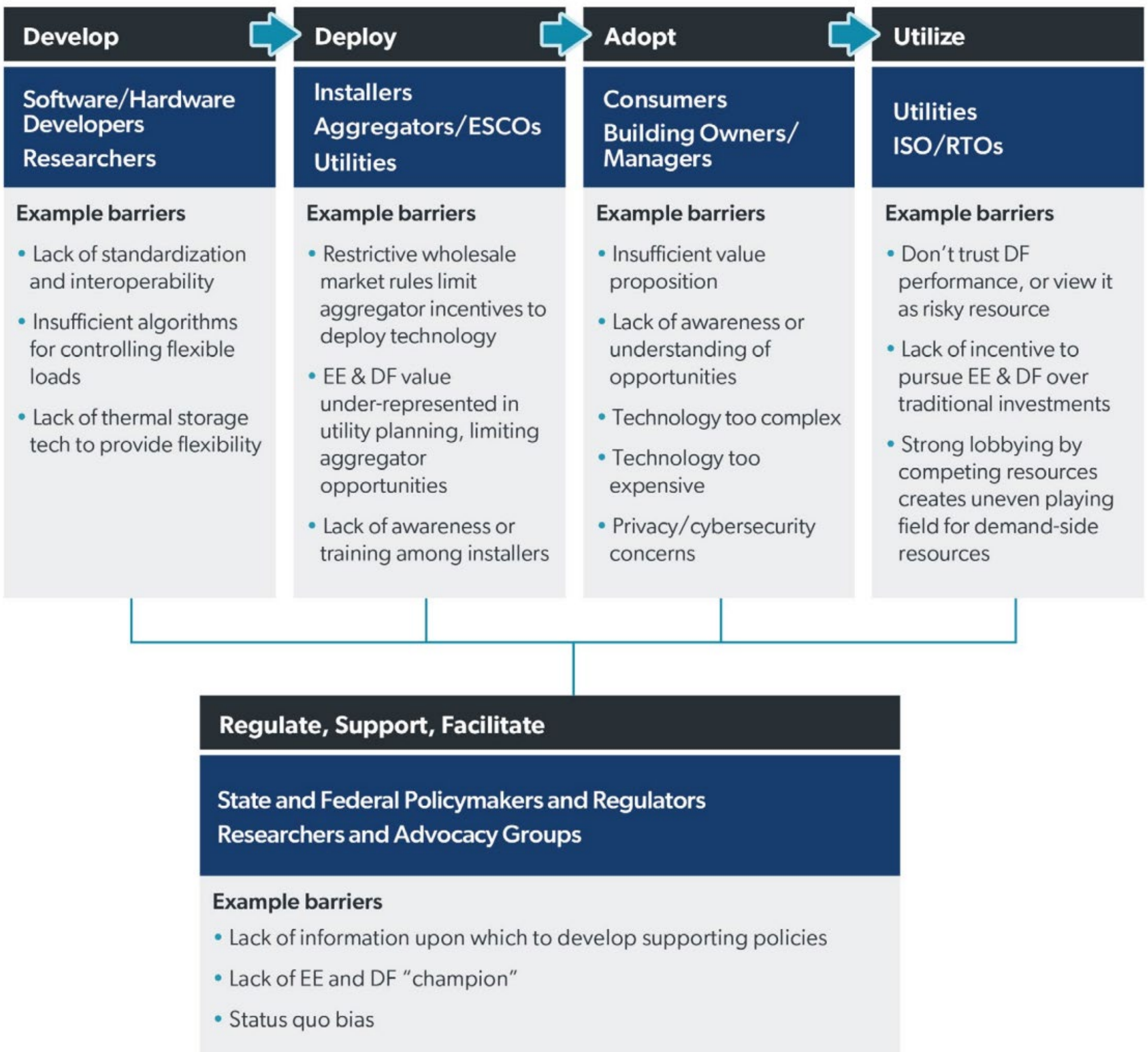
As shown in Table 5, the demand flexibility potential from commercial and industrial facilities is significantly greater than that available from residential buildings. Residential potential is much smaller but growing segment due to increased smart thermostat penetration and expected adoption of grid-interactive water heaters.[78]

TABLE 5: DEMAND FLEXIBILITY POTENTIAL FROM GRID-INTERACTIVE BUILDINGS[79]

Cumulative installed capacity (MW)	**2017**	**2018**	**2019**	**2020**	**2021E**	**2022E**	**2023E**	**2024E**	**2025E**	**2026E**
Demand flexibility potential - Residential	13,568	18,422	24,665	28,645	34,454	40,431	46,244	51,916	57,320	62,282
% total DER cumulative installed capacity	4%	5%	6%	7%	8%	9%	10%	10%	10%	11%
Demand flexibility potential - C&I	285,496	288,121	290,966	291,912	295,664	299,656	312,193	320,091	324,283	329,095
% total DER cumulative installed capacity	82%	79%	77%	74%	71%	68%	65%	62%	59%	56%

There are significant barriers, which impact the optimal use of demand flexibility from GEBs. The National Roadmap for Grid-Interactive Efficient Buildings[80] notes that meaningful barriers limit the development of technologies, deployment, adoption, and utilization of GEB technologies. Figure 23 below outlines barriers at each stage of the process.

FIGURE 23: GRID INTERACTIVE BUILDING VALUE CHAIN AND KEY BARRIERS[81]



Top barriers identified include:[82]

- **Lack of interoperability** – Seamless connectivity of devices in buildings is not widespread, resulting in expensive integration efforts and discouraging adoption or optimal use of technologies,
- **Energy efficiency and demand flexibility not included in planning activities** – Relatively few utilities IRPs consider new incremental energy efficiency additions or demand

flexibility as a resource option. Cost effective opportunities may be disregarded, increasing costs to consumers, and limiting opportunities to provide services,

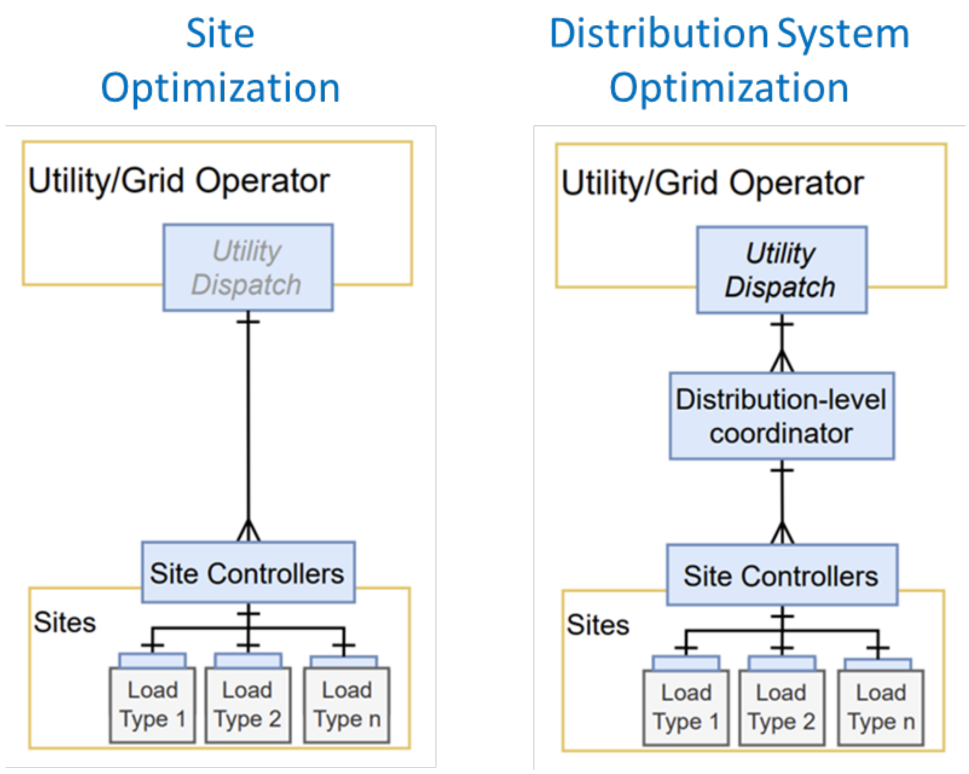
- **Technology is too costly or complex** – Consumers are hesitant to adopt energy-efficient technologies due to upfront costs, particularly in commercial buildings. Perceptions of complexity by building energy managers and lack of awareness leads to lower adoption rates,
- **Consumers lack understanding or incentives** – Consumer perceptions of costs and risks may limit technology adoption. Financial incentives are primary motivators for adoption, and
- **Utilities and system operators may not trust demand flexibility, lack adequate regulatory incentives** – Utilities may have perceptions of operational difficulties and may not have sufficient incentives to utilize demand flexibility offered by buildings.

Current efforts undertaken by DOE include projects with communities, utilities, and vendors to develop control architectures to investigate how grid services from DERs are dispatched, coordinated, and controlled. The DOE Connected Communities program, supported by the Lawrence Berkeley National Laboratory, aims to establish best practices and drive innovation that will enable groups of buildings to coordinate electric load control, integrate distributed energy resources, and provide flexible grid services, while also incorporating energy-efficiency improvements of 30% or more over baseline energy use.[83]

Figure 24 provides examples of two different control architectures, one in which the operation of DERs is optimized to serve a site, e.g., a building owner or campus, and the other depicts how the DERs support the optimization of distribution system operations. Being able to optimize locally at a site and at a system level, as well as shift between them, i.e., multi-layer optimization, presents a challenging, yet achievable, objective in the design of control architectures. This work complements additional efforts within DOE for examining coordination frameworks needed for the integration of DERs into grid operations and for developing reference designs to enable them.[x]

[x] The DOE Office of Electricity is working with the industry to develop standard guidelines for coordination between DER service providers and grid operators, as well as distribution system reference designs.

FIGURE 24: OPTIMIZATION OF DER ASSET UTILIZATION [84]

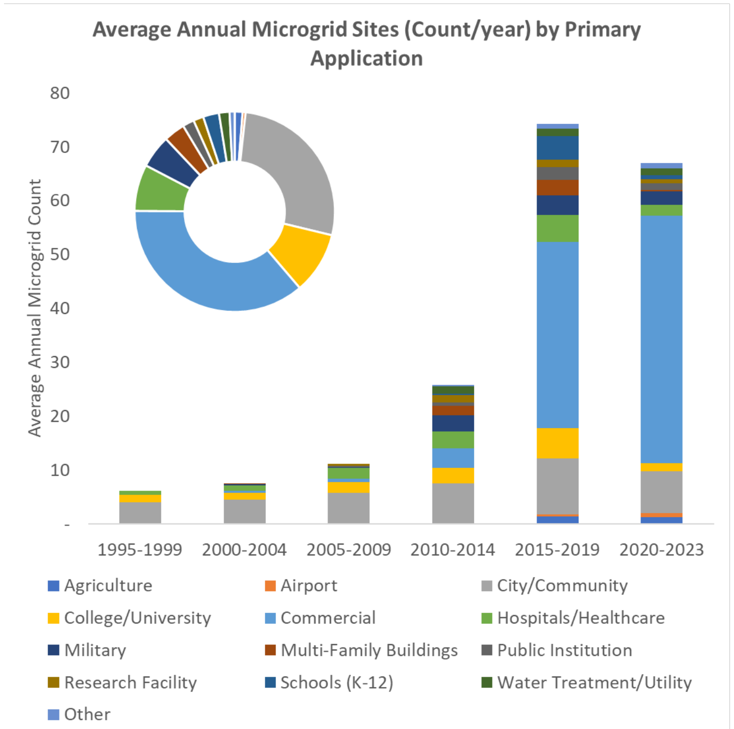


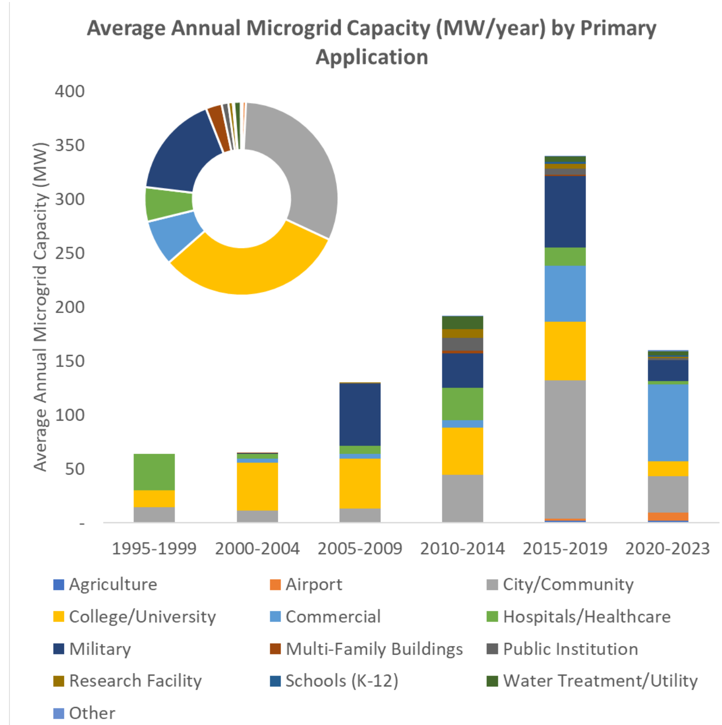
MICROGRIDS

A MICROGRID CAN BE DEFINED AS A COORDINATED GROUP OF DERS THAT SERVE A SET OF CUSTOMER LOADS WITH THE CAPABILITY TO OPERATE IN A GRID-CONNECTED OR ISLANDED MODE. MICROGRIDS USE LOCALLY AVAILABLE RESOURCES, SUCH SOLAR AND ENERGY STORAGE, AND OFFER ENHANCED RESILIENCE TO UTILITY CUSTOMERS BY PROVIDING CONTINUOUS POWER WHEN THE GRID IS EXPERIENCING AN OUTAGE. MICROGRIDS CAN ALSO PROVIDE SERVICES TO GRID OPERATORS THROUGH DEMAND RESPONSE MECHANISMS AND PROVIDING ANCILLARY SERVICES SUCH AS VOLTAGE AND FREQUENCY REGULATION. WITH ADDITIONAL COORDINATION, MICROGRIDS EQUIPPED WITH ENERGY STORAGE, WHICH MAY INCLUDE BATTERY STORAGE AVAILABLE FROM ELECTRIC VEHICLES, HAVE THE POTENTIAL TO INCREASE FLEXIBILITY FOR THE MAIN GRID. AS SHOWN IN

Figure 25, microgrid deployments have increased significantly in the U.S.

FIGURE 25: MICROGRID DEPLOYMENT PATTERNS (DEPARTMENT OF ENERGY MICROGRID INSTALLATION DATABASE)[85]





(Note that the last column spanning 2020 – 2023 covers approximately 4 years of deployments as compared to the prior periods, which cover 5 years each. Hence as microgrid deployments are generally increasing nationwide, this latter period will not necessarily reflect the anticipated increase as it covers a shorter timeframe.)

As shown in Figure 26, patterns of microgrid deployment in the United States are influenced by state policies, both statutory and regulatory in nature, and self-initiated community and private consumer efforts. Many of these deployments are undertaken to address resilience concerns. State policymakers and regulators are advancing a combination of institutional instruments to develop standard procedures to facilitate the deployment of microgrids. These instruments include microgrid tariffs, procedures to quantify the resilience value of microgrids and DERs, and funding programs to support microgrid development. In the absence of legislative and regulatory policies, state institutions (such as state energy offices and commerce departments) are making efforts to promote microgrids, and communities and utilities are undertaking self-initiated actions, as well.[86]

FIGURE 26: MICROGRID DEPLOYMENT WITHIN POLICY PATTERNS[87]

	States	Number of Microgrid Sites	Average Microgrid Size (MW)
Legislation	CA, CO, CT, HI, ME, OR, TX	418	3.63
PUC Initiated	D.C., NJ, WI	24	3.73
Other Institutions	AK, KY, MA, MD, MO, NY, VA, WA	151	11.57
Self-Initiated	AL, AZ, DE, FL, GA, IA, ID, IL, IN, KS, LA, MI, MN, MS, MY, NC, ND, NE, NH, NM, NV, OH, OK, PA, SC, TN, UT, VT, WV	101	13.44

Microgrids introduce a variety of possible alternative grid configurations, which may incorporate cellular and fractal designs,[y] and ownership models requiring greater levels of coordination and control. It is possible to distinguish microgrids into two main types:

[y] A fractal design is characterized as having smaller grids nested within larger grids while a cellular design is characterized as having neighboring microgrids.

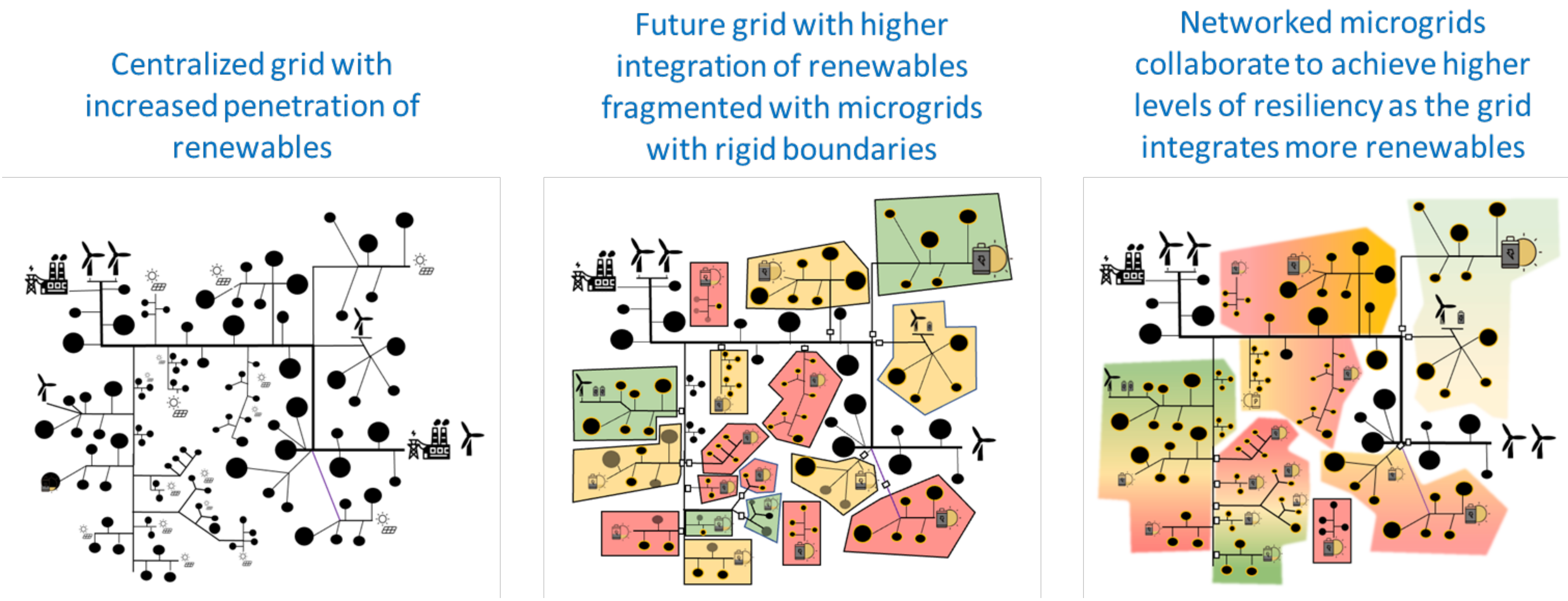
- A **single customer or campus microgrid** has one or more points of common coupling with the utility distribution system at the customer's metered service connection. As such, these microgrids do not use the utility distribution system within the electrical boundary of the microgrid.
- A **partial feeder or community, multi-customer microgrid** uses a portion of a utility distribution feeder to create a microgrid that encompasses more than one customer. They are increasingly being pursued to address enhancing community resilience by states, local governments, and utilities in recognition of the vulnerability of distribution systems during natural disasters. These microgrids often use distribution generation/battery storage that is directly connected to a distribution feeder ("in front of the meter") or uses DER resources behind the customer meter to export energy to other customers that are within the microgrid boundary during islanded operation.

Community microgrids, compared to single customer microgrids, involve greater technical complexity and additional statutory and regulatory issues. For example, community microgrids will require:

- Service rules, often driven by statutory and/or regulatory requirements, which identify the respective roles and responsibilities of the utility and microgrid owner/operator during normal and islanded operations,
- Additional distribution system upgrades, which would include reclosers to enable islanding, as well as protection relays, grid controls, and high-speed communications to ensure safe operation, and
- Special considerations for customers who may not wish to participate in the microgrid.

As the use of microgrids evolves, more complex interactions are envisioned. For example, the Oak Ridge National Laboratory (ORNL) is designing a microgrid "orchestrator" technology that enables microgrids to collaborate with each other rather than operate as individual islands with rigid boundaries.[88] Under this approach, the local microgrid controllers would keep full control of their assets while the orchestrator would permit the transactive exchange of power between neighboring microgrids based on their respective needs for energy and resilience. ORNL is developing this technology to support microgrid deployments in Puerto Rico. Evolution to this type of configuration is shown in Figure 27.

FIGURE 27: TRANSITION TO NETWORKED MICROGRIDS[89]



NON-WIRES ALTERNATIVES

Non-wire alternatives (NWAs) have gained recognition over the past several years as a strategy to apply cost-effective opportunities for DERs that can economically defer, mitigate, or replace investments in traditional infrastructure, e.g., power lines, substations, and transformers. NWAs typically utilize a portfolio of distributed energy resources, e.g., energy-efficient technologies, rooftop solar, and energy storage, to support energy needs at specific locations within a distribution system. The potential to avoid distribution costs is highly concentrated in locations where loads are growing, components are highly loaded, and there is little or no capacity to accommodate additional growth.[90]

The concept of NWAs was spurred by technology improvements and advanced through state and ISO-RTO policies requiring consideration of NWAs within the distribution and transmission planning processes.[91] State jurisdictions that mandate the consideration of NWAs in grid planning include California, Colorado, Delaware, Hawaii, Maine, Michigan, Minnesota, Nevada, New Hampshire, New York, and Rhode Island, plus the District of Columbia; several additional states have related proceedings, pilots, or studies underway.[92]

Despite tangible successes, such as the Brooklyn-Queens Demand Management Project in New York,[z] NWA scalability has remained elusive. Given the promise of NWAs, relatively low numbers of NWAs have been implemented. Industry analysis indicates that from 2014-2020 only 41 of 279 proposed NWA projects were ultimately pursued, with cost and reliability concerns noted as main factors. 72% of these project implementations were located in California and New York – jurisdictions with strong NWA policies and processes.[93]

The viability of NWA solutions has depended upon the ability to cost-effectively procure DERs within the timeframes needed to meet utility needs for addressing load growth. The process is complex and involves many steps that test the prudency of favoring an NWA solution over a traditional approach. In addition, requiring a portfolio of DERs to defer the need for a traditional investment sets a challenging performance standard that will need to be met by non-utility assets. Various hurdles within the process are provided in Figure 28.

[z] The New York Public Service Commission (PSC) adopted incentives to encourage Con Edison to utilize non-wire alternatives (NWAs) to alleviate congestion on its grid and avoid building a $1.2B substation. The Brooklyn Queens Demand Response program (BQDR) utilized third party aggregators to apply local resources, such as integrated renewables including battery and solar, as well as DR programs, to help meet the utility needs and avoid excess costs.

FIGURE 28: CHALLENGES ACROSS STAGES IN NWA PROJECT DEVELOPMENT[94]

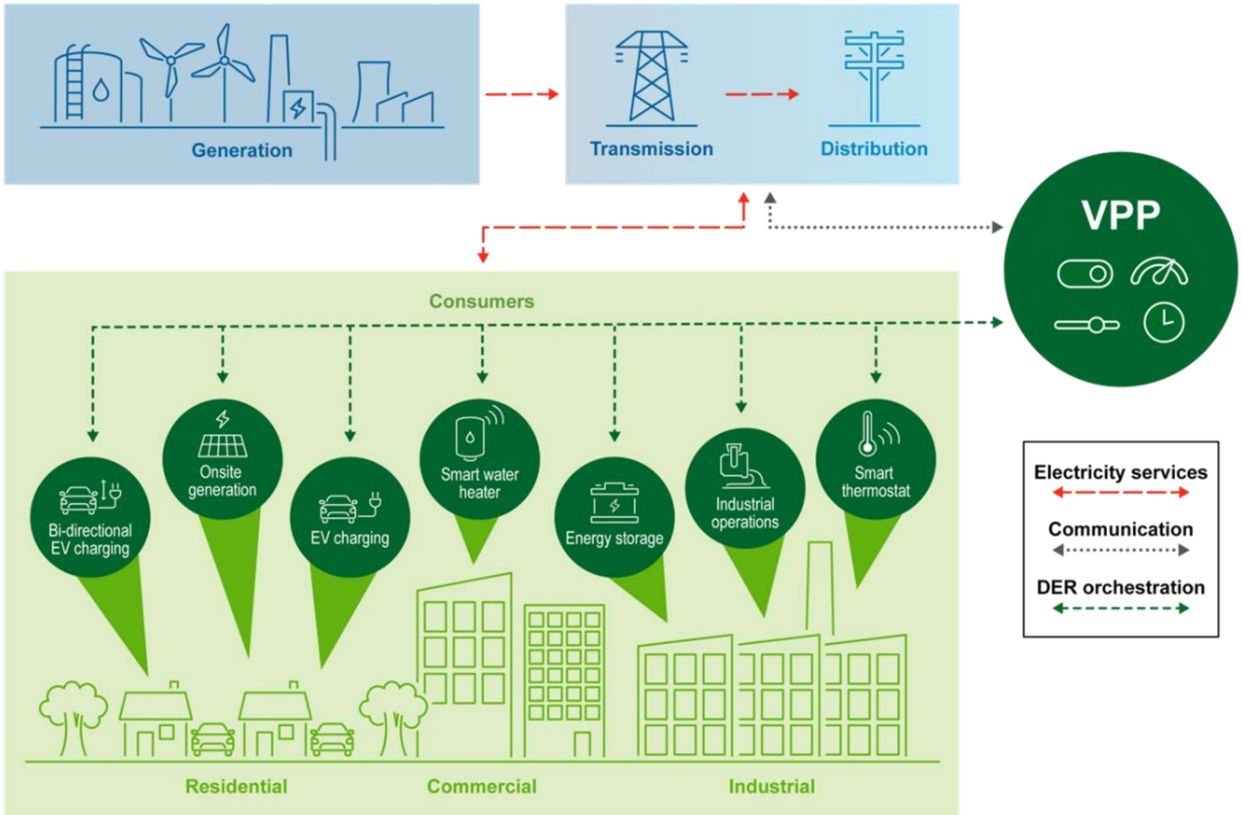
Stages	Challenges
NWA Opportunity Assessment	• Uncertainty in forecasting load growth and DER adoption • Locational net-value analyses are evolving
Procuring DER Services	• Meeting technical feasibility requirements • Acceptance of terms and conditions, and financial risk, by DER service providers • Meeting cost-effectiveness criteria
Regulatory Approval	• Approval of projects based on feasibility and reasonableness • Projects serving multiple jurisdictions face differing priorities • Value stacking may not fit traditional regulatory frameworks
Implementation	• Navigating the practical challenges of permitting, interconnection, equipment procurement, construction, and recruiting customers who can contribute DER services within a required timeframe

Although the implementation of NWA projects has not achieved the level of success initially envisioned, the experience gained to date has provided the means for utilities to explore how to consider the use of DERs more effectively in their core planning processes, how to implement such solutions in combination with traditional infrastructure investments, and how to work collaboratively with regulators and stakeholders, such as DER service providers, to incentivize and standardize this practice. Although NWAs are not currently a widespread solution, they have paved the way for expanding the use of DERs for the provision of grid services.[95]

VIRTUAL POWER PLANTS

VPPs are aggregations of distributed energy resources, such as rooftop solar, energy storage systems, electric vehicles (EVs), energy efficient practices and technologies, and smart buildings containing controllable equipment, which can be operated to supply electrical power like a traditional power plant or reduce customer load via demand response mechanisms. VPPs are operated by an aggregator, which utilizes DER assets owned by utility customers, including residential, commercial, and industrial electricity customers, in a variety of participation models that offer rewards for contributing to reliable and efficient grid operations.[96] VPPs are like NWAs in that both aggregate DERs to provide grid services. However, NWAs are used primarily to offset traditional grid investments to meet local system demands. In contrast, VPPs apply the same concept, but can now serve broader electricity markets, including bulk-level markets administered by ISOs/RTOs, as depicted in Figure 29.

FIGURE 29: CONCEPT OF A VIRTUAL POWER PLANT[97]

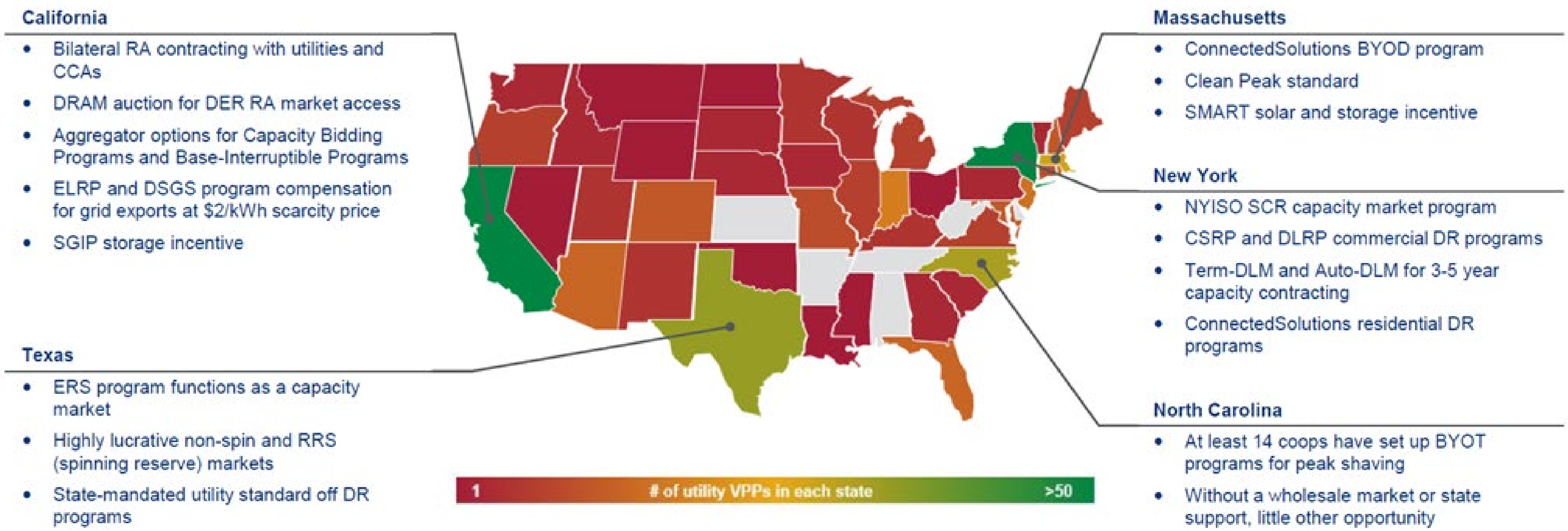


Industry definitions for VPPs range considerably. A working definition, offered by Wood Mackenzie, is the following:[98]

> *An aggregation of behind-the-meter load and DERs, and optionally front-of-the-meter DERs, that:*
>
> - *Aggregation: Are electrically located behind more than one utility meter,*
> - *Heterogeneity: May include more than one technology and technology platform provider,*
> - *Orchestration: Presents itself to a utility or power market as a single resource, such that its internal asset composition is irrelevant,*
> - *Dispatchability: Is dispatchable, offering at least an all-call instruction, but may be subject to time- and weather-dependence, and*
> - *Maximality: Represents the largest collection of DERs that meets the prior criteria.*

Given this definition, VPPs are concentrated where there are favorable wholesale markets, as well as state-driven programs, particularly in California, New York, and Texas, as shown in Figure 30.[99]

FIGURE 30: STATUS OF VPP DEPLOYMENTS ACROSS THE U.S. [100]



Although VPPs are a recent application of DERs, they offer a means to extract value from them through the use of DER aggregators, which can optimize their operation. As a result, VPPs have the potential to address multiple grid challenges, including:

- Contributing to the resource mix by providing an ability to reduce demand or supply electricity to augment power produced by bulk-level resources. Given retirements of fossil fuel plants combined with load growth (particularly from electrification and data centers), a potential nationwide shortfall of 200 GW of electricity generating capacity needed to meet peak demand requirements are estimated to occur by 2030.[aa]
- Supporting local needs for energy, generating capacity, and other grid services. With anticipated load growth due to electrification, combined with difficulties in constructing additional transmission capacity, relying on local DER resources to maintain grid reliability may become essential.
- Providing a source of flexible load management to balance the supply and demand for electricity more effectively, given increased dependence on renewable technologies and variable loads. The potential contribution of distributed resources to the overall flexibility need is significant. For example, a 2019 Brattle Group report identified a consumer flexible resource potential of 200 GW by 2030, an increase of 140 GW over existing capacity in the U.S.[101] The Brattle Group estimated the national benefits of DER flexibility could exceed $15 billion per year by 2030 through reduced needs for additional generating capacity to meet peak load requirements.

Given these potential benefits, VPPs face considerable hurdles with regard to applying them at a large scale for the provision of services for supporting grid operations and associated markets. These include:[102, 103]

- Lack of compensation in current mechanisms for the full range of beneficial services that VPPs could provide,
- Planning frameworks and supporting analytical tools that do not adequately consider DERs as core resources,
- Insufficient standardization of coordination requirements governing the operations of DER service providers, including VPPs, with grid operators at both the bulk-power and distribution system levels,
- Grid infrastructure that is not fully advanced to provided needed visibility and control of DER assets, and

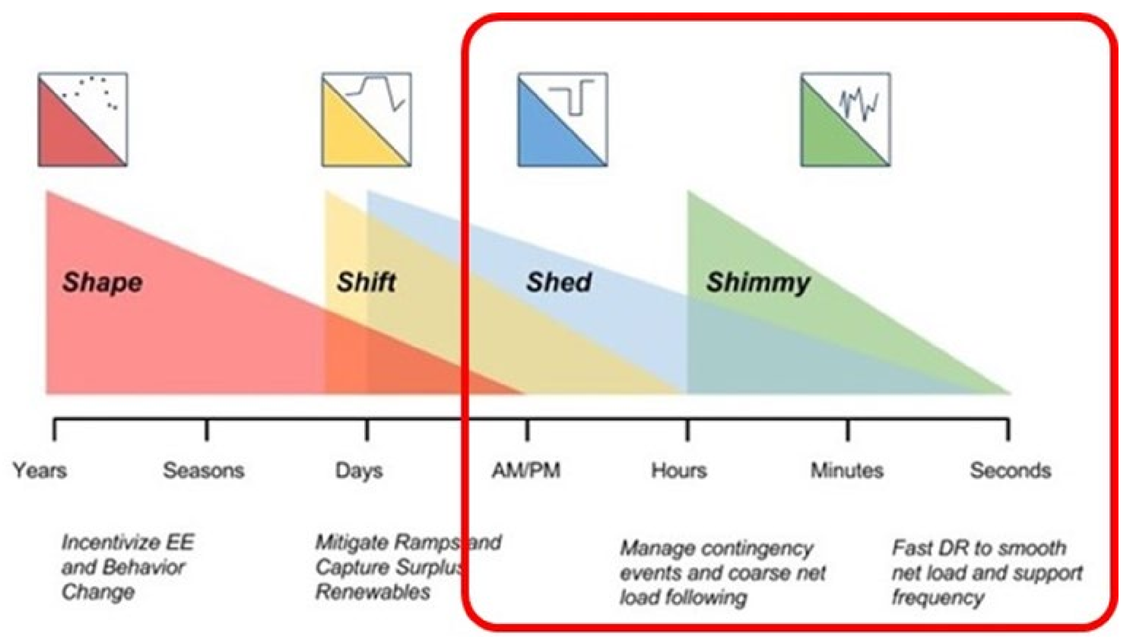
[aa] Peak demand in the U.S. is expected to grow approximately 8% in the U.S. between 2023 and 2030 – from 743 GW to 802 GW—and incremental 59 GW (estimated by The Brattle Group based on total electricity consumption projections from Office of Policy National Energy Modeling System mid-case electrification scenario). It is estimated 162 GW to 183 GW of generation will be retired between 2023-2030. If retiring assets were operating at full capacity, the retirements combined with peak demand growth would imply a supply gap of 221 to 242. However, the majority of recent and expected retirements are aging coal plants, with some oil and natural gas plants retiring as well; retiring assets will likely be operating below full capacity. For this reason, the supply need is estimated conservatively to be ~200 GW.

- Interoperability standards and practices that have not yet sufficiently matured within the industry to enable compatibility between devices and systems while maintaining data privacy and cybersecurity.

Flexible Load Management and Consumer Participation

The potential for DER to "shape, shift, shed, and shimmy" consumers' net electricity consumption, as shown in Figure 31, will provide a real-time, continuous load management capability that when applied strategically can significantly reduce the need for additional infrastructure and generating capacity that would otherwise be required to meet forecasted electricity demand. For example, strategic load management would significantly reduce infrastructure requirements anticipated to serve forecasts of electricity demand due to electrification. To illustrate this point, a recent study by Kevala undertaken for the California Public Utilities Commission (CPUC) estimated that without considering new real-time dynamic rates and flexible load management strategies, the estimated cost for distribution system investments to accommodate anticipated high adoptions of DER, including transportation and building electrification, by 2035 would cost approximately $50 billion. The more effective use of DERs to provide load management would reduce the estimated costs. A second study (Part 2) will examine costs under varying scenarios that will include the use of advanced DER controls and flexible load management, as well as the implications of managed DER growth.[104]

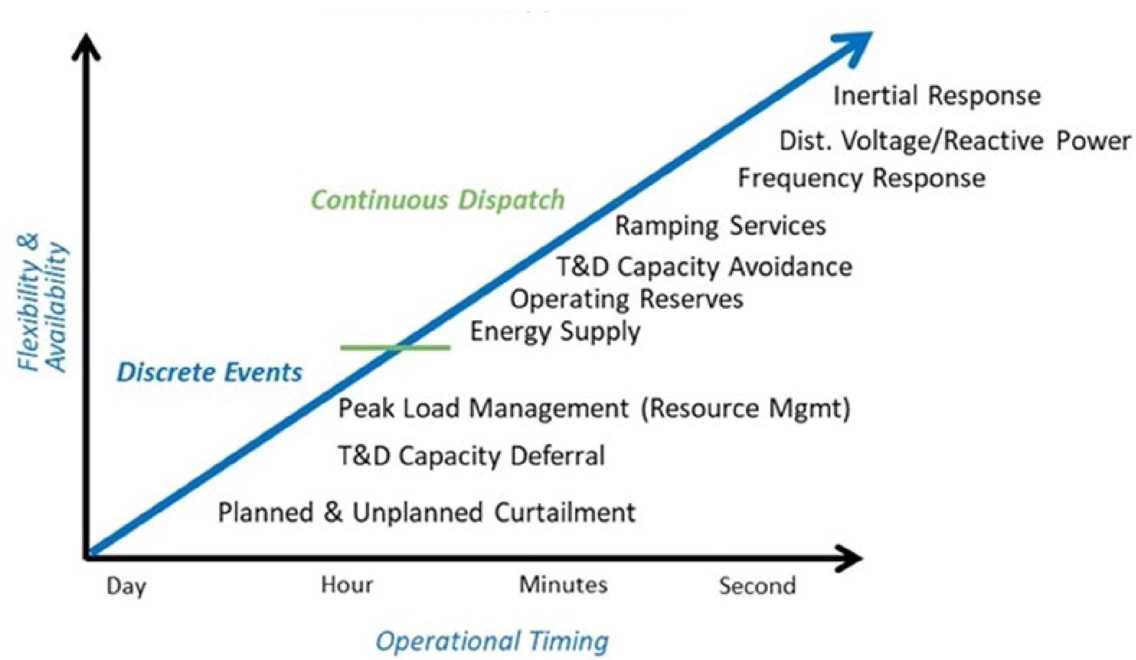
FIGURE 31: FLEXIBLE CONSUMER RESOURCE MANAGEMENT SPECTRUM[105]



The ability to provide flexible services on a continuous basis implies that DERs become operational assets, i.e., they function in real-time with utility operations, as shown in Figure 32.

As many of these DER are owned by utility customers, it will become necessary to determine their willingness to participate and how participation might be best achieved. Such a partnership model embodies a "co-production" relationship, which would involve actively engaging consumers and/or communities that own resources in the design, commissioning, and operation of flexibility services. Doing so is essential for understanding the diversity of the range consumers' (e.g., residential, and small commercial) and communities' interests. By examining these considerations, policy makers, regulators, consumer advocates, DER aggregators, utilities, market operators, and other stakeholders will have a greater appreciation of the changes needed to more effective engage consumers.[106]

FIGURE 32: POTENTIAL FLEXIBLE DER APPLICATIONS[107]



Furthermore, markets and pricing methods for consumer resource response will increasingly be challenged to operate on shorter time cycles required for real-time operations. Human-in-the-loop based methods in which grid operators, aggregators, and customers would actively take part in decisions to deploy DER services will be too slow in such an environment. This issue was highlighted in a Brattle report, which examined demand response effectiveness:[108]

> *"It is evident that requiring consumers to respond directly to prices is suboptimal and results in behavior that cannot be explained by conventional economic models. This is a clear argument for the use of extensive automation for demand response, both to reduce the burden of price response on consumers and to ensure a more predictable and efficient response from demand."*

The above discussion also hints at the tension that exists between utilities, which are responsible for ensuring grid reliability (i.e., "keeping the lights on"), and third parties, such as DER aggregators, who wish to provide grid services, but may not be held to the same standard.

To maintain reliability, utilities prefer the firm commitment of resources to meet their operational requirements, while DER service providers will require revenue certainty. It is useful to point out that the presence of DER not owned by the utility changes the problem from one of control to one of *control and coordination*. Reliance on customer-owned DERs provides a level of uncertainty that will need to be managed and factored into technology deployment and compensation strategies that consider the respective needs of utilities, DER service providers, and DER owners. The industry is currently working to resolve these issues.

V. Addressing Key Challenges

As discussed in this report, the U.S. electric system is undergoing a dramatic structural transformation, particularly at the edge of the distribution system where a range of assets, many of which are owned or managed by consumers and third-party merchants, can serve as resources for providing energy and related services to both utilities and their customers. As the numbers and types of these DERs increase along with evolving business models, the ability to effectively integrate, utilize, and orchestrate them so that they can function reliably within the operational environment of the electric grid, presents a set of challenges, which are both technical and institutional in nature, as shown in Figure 33.

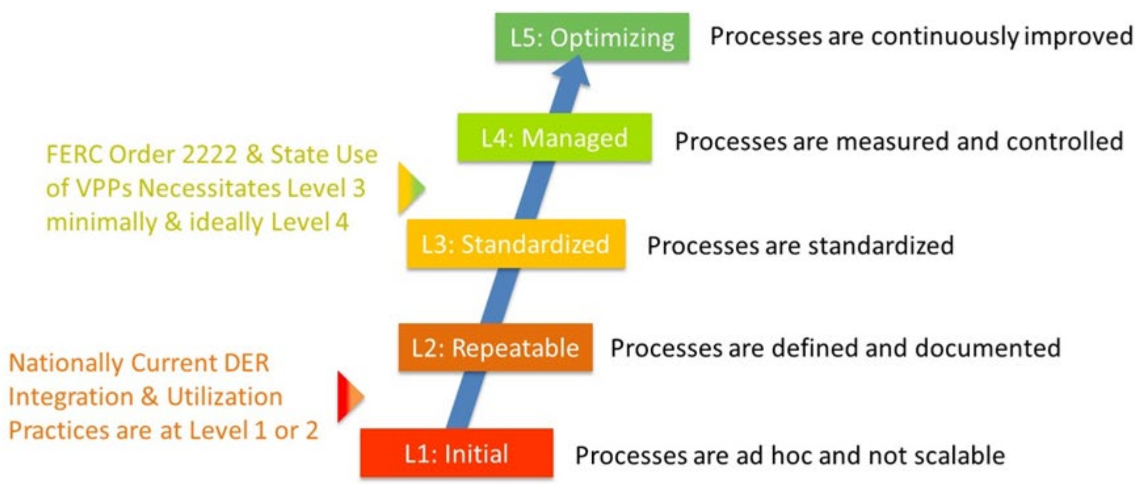
FIGURE 33: KEY CHALLENGES

There are many efforts being undertaken across the country to address these challenges, yet they are limited in jurisdictional and geographic scope and have different areas of focus. As noted in an August 2022 report by the Energy Systems Integration Group (ESIG):[109]

> *"Currently, individual states, such as California and New York, are developing their own distribution-level solutions to DER integration. While these efforts are reflective of the actions of individual, forward-looking states, this approach is insufficient, as each state has to essentially reinvent the wheel. This situation will lead to a proliferation of disparate standards, terminology, and approaches around DER integration across the United States, which in turn will generate confusion and increase costs among manufacturers, developers, and other DER service providers. It will ultimately result in less access to distribution systems for DER providers, higher DER costs, and lower benefits to customers."*

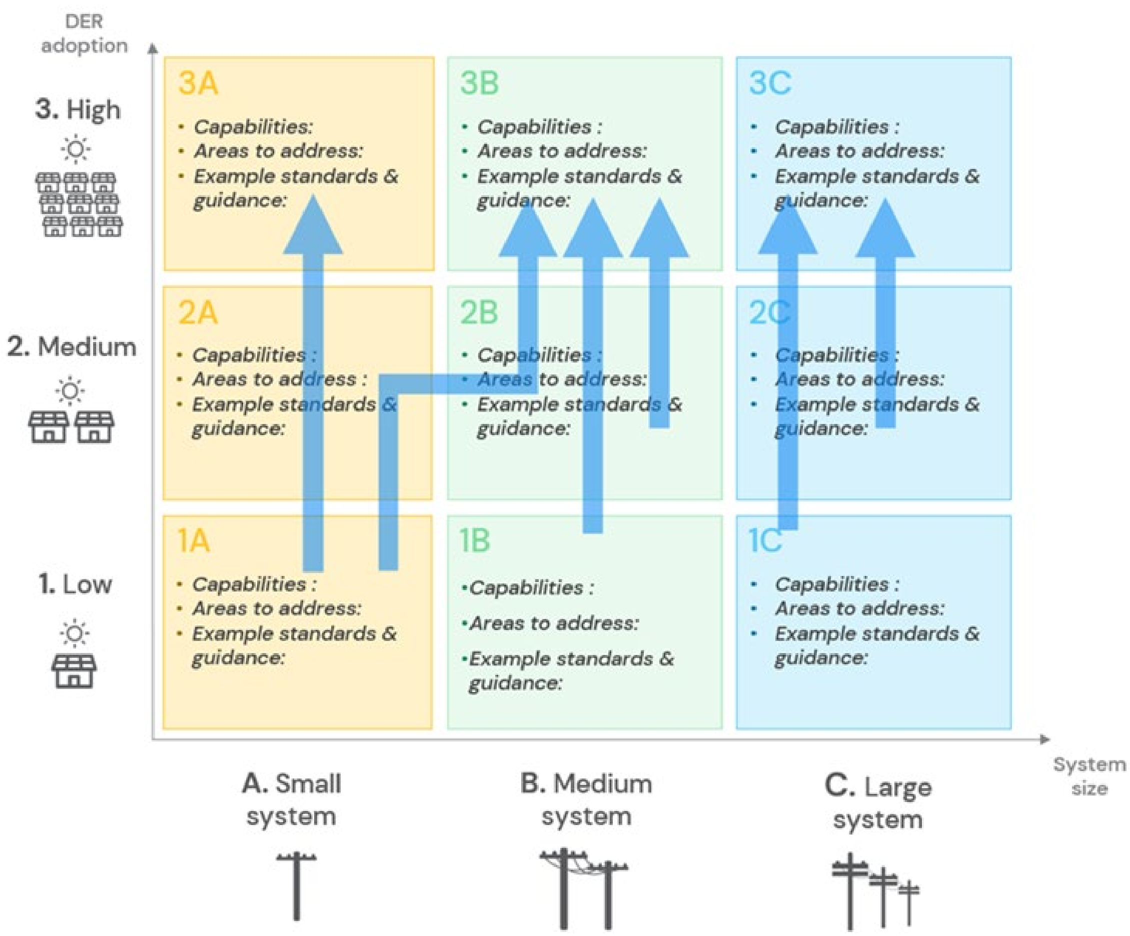
The ESIG paper points to the need for a greater level of coordination across the electricity sector to address specific issues relating to the effective integration and utilization of DERs. This includes maturing practices and processes to achieve a greater level of standardization across the industry, which are particularly focused on grid-edge interactions. The Capability Maturity Model, shown in Figure 34, which was developed by the Software Engineering Institute at Carnegie Mellon University, serves an effective framework for examining the state of current processes and for targeting efforts to mature them, in this case, to reduce barriers to the effective integration and utilization of DERs.

FIGURE 34: CAPABILITY MATURITY MODEL[110]



Furthermore, the pace and scale of DER integration and utilization ranges widely across the country and is shaped by several factors including local policies and priorities, as well as customer preferences. As a result, charting a pathway toward an electric system with a higher penetration of DERs will vary by location and, in addition, depend on the level of expected DER adoption and use, as well as the size of the utility and its capabilities. Smaller and mid-sized utilities have a more limited set of capabilities as compared to large companies, which employ a significantly higher number of personnel, have greater resources available, and frequently execute large and complex infrastructure and IT projects. As a result, as shown in Figure 35, multiple pathways for DER integration can exist for the various permutations of system size and DER penetration. These pathways will need to utilize, as needed, the advanced practices and processes developed for addressing the key challenges mentioned above.

FIGURE 35: MULTIPLE PATHWAYS FOR MATURING UTILITY CAPABILITIES[111]



To enable the performance of the electric grid to match increasing levels of complexity presented by higher levels of DERs, several key challenges need to be addressed:

1. Integrated planning practices within and across jurisdictions are required that can result in holistic, long-term grid investment strategies that incorporate DERs as core resources,
2. Coordination frameworks are needed to set the respective roles and responsibilities, including information sharing requirements, of all players involved in the provision, orchestration, and oversight of DER services,
3. Systems engineering approaches and supporting tools (e.g., grid system models) are needed to assist in the formulation of "least-regrets" technology deployment strategies while accounting for:
    a. The complexity of grid operations required to orchestrate myriad DERs and multiple entities in the operational environment of the electric grid,
    b. The need to address a variety jurisdictional policies and priorities, as well as a range of possible grid configurations and evolving market/business structures,
    c. The ability to scale from managing a few to many DERs and DER owners/operators, and

   d. Uncertainty in the adoption rates of DERs and their performance in supporting grid operations and supporting markets.
4. Greater levels of standardization for addressing interoperability between devices and systems are required, for example, through the adoption of technical standards (such as the IEEE 2030 and 1547 series), standard data-sharing protocols, and cybersecurity practices, to improve the efficiency and security, while reducing the costs, of integrating DERs with utility networks, and
5. Methods for evaluating the full contribution of DERs combined with straightforward mechanisms for compensating their services are needed to fully realize their capabilities.

These challenges are discussed in more detail below.

Integrated Planning

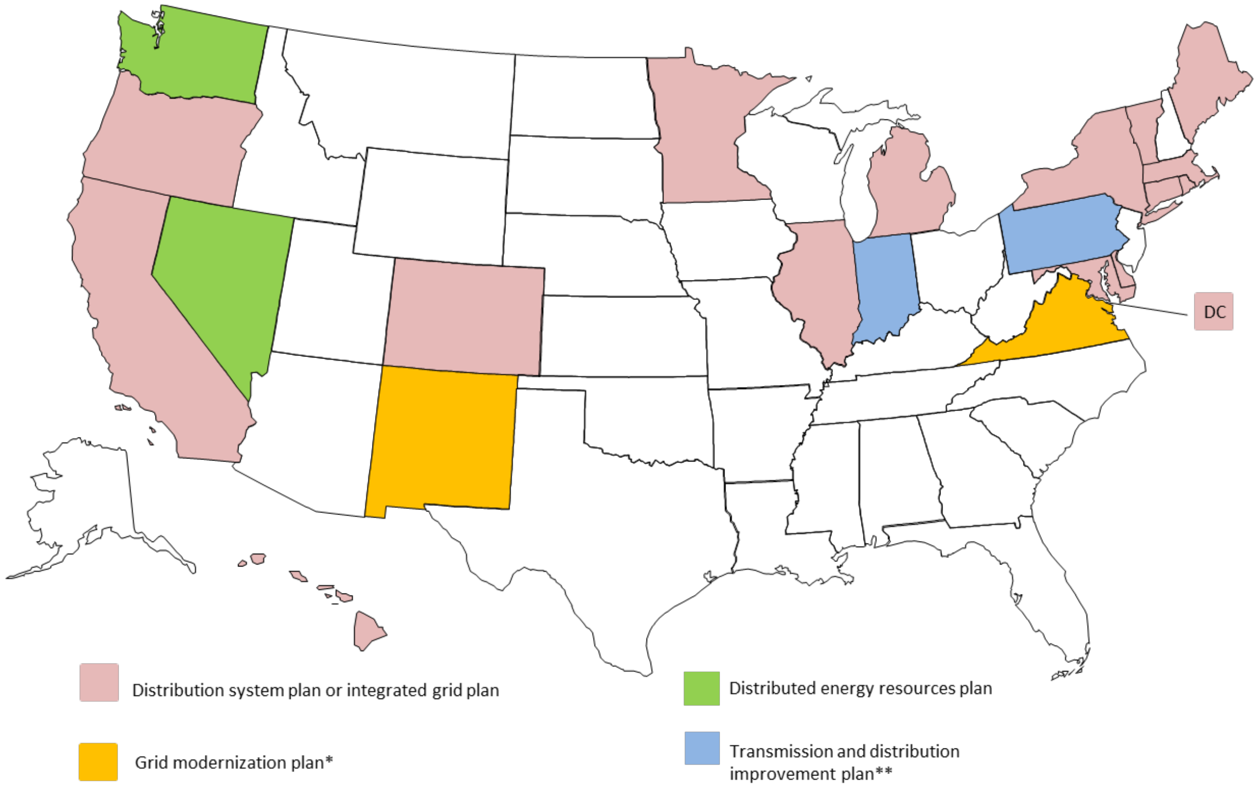
Integrated planning provides a framework for developing holistic and forward-looking strategies for investments in energy resources and grid infrastructure. Two types of integrated planning processes currently exist; one is focused on determining investment requirements for distribution systems and the other is focused on understanding energy resource requirements to meet projected energy demand for a state, region, and/or utility service territory. These two processes, each applying different analytical approaches, are beginning to share information on energy and capacity contributions from DERs, as well as other input assumptions, such as climate impacts. However, they are not applied universally and consistently across the US.

INTEGRATED DISTRIBUTION SYSTEM PLANNING

The convergence of utility, customer, and 3rd-party systems will require coordinated planning processes that address grid modernization needs and distribution system upgrades to enable the integration and utilization of DERs. As shown in Figure 36, the practice of integrated distribution system plans (IDSP) that considers such investments is evolving, yet not universally applied across the U.S. Furthermore, there is a continuing mismatch between what utilities are proposing for their grid investment strategies and what state regulators are willing to approve for a variety of reasons, which includes the desire to keep electricity rates affordable.[bb] What is required are consistent and shared approaches for translating the policies and priorities of communities and states into responsive strategies for grid investments.

[bb] Based on research conducted by the North Carolina Clean Energy Technology Center, there were 498 grid modernization-related policy and deployment actions in 48 states in Q3 2021, but regulators approved only $904.4 million (6.2%) of the $14.7 billion in proposed utility investments. Some $12.7 billion was held for closer scrutiny, with $1.1 billion rejected. See: https://www.utilitydive.com/news/duke-sce-other-grid-mod-proposals-confronted-big-cost-questions-in-2021-a/610977/.

FIGURE 36: STATES REQUIRING REGULATED UTILITIES TO FILE DISTRIBUTION PLANS WHICH CONSIDER USE OF DERS[112]



*Some states that require distribution system plans also require grid modernization plans (e.g., Minnesota and California).
**Indiana also includes storage.

In addition, processes for incorporating socio-economic considerations, such as resilience, equity, and local economic development, into distribution system plans are nascent and evolving. As shown in Figure 37, such processes will require highly coordinated interactions between state policymakers, regulators, consumer advocates, communities, labor representatives, DER service providers, and the public to set objectives, metrics, and priorities to guide grid investment decision-making. Considering the application of DERs, such as microgrids and grid-interactive buildings, to better serve the needs of communities will become an important aspect of the planning process. The work undertaken by the Hawaii Resilience Working Group, which conducted a threat-based risk assessment to determine resilience metrics and priorities provides a good example of a process for integrating resilience considerations into a utility planning process.[113]

FIGURE 37: COORDINATION REQUIRED FOR INCORPORATING SOCIO-ECONOMIC CONSIDERATIONS INTO DISTRIBUTION PLANNING PROCESSES

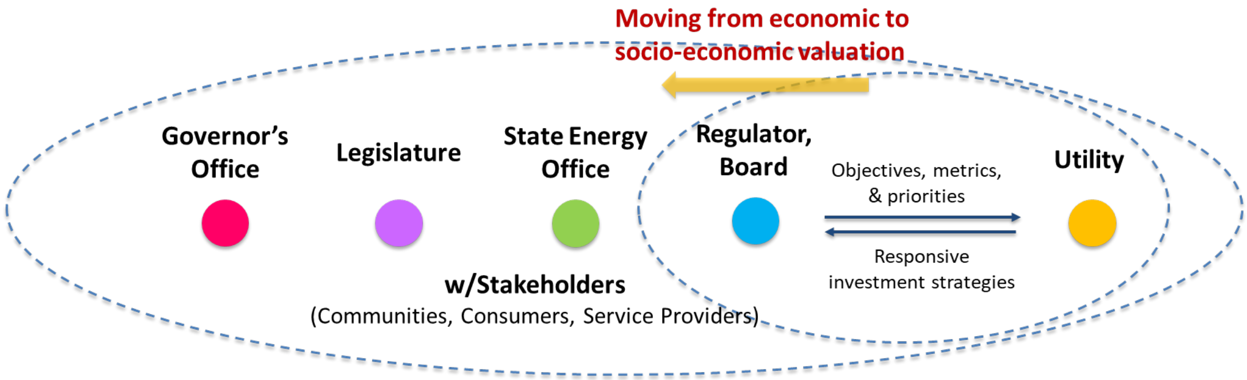
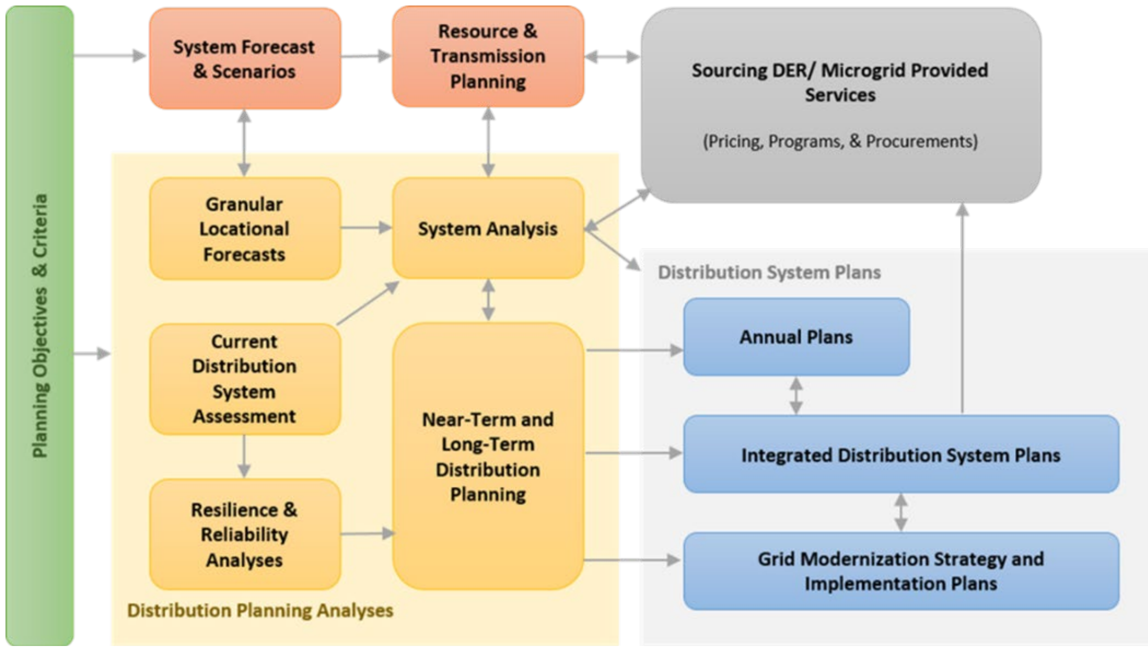


Figure 38 provides an idealized decision framework for an IDSP process. DOE and others have been working with states and utilities across the nation, including providing training to state energy officials and regulators, to both inform and advance the practice of IDSP to better address reliability, resilience, and equity concerns, as well as evolution at the grid edge. Important areas where advancements are being made, yet are still evolving and not universally applied or accepted, are:

- Stakeholder engagement processes that define community and state priorities, particularly around resilience and equity, which can then be translated into planning objectives and priorities,
- Probabilistic forecasting techniques to ascertain load growth and DER adoption rates (including electrification projections) with sufficient granularity for informing investment requirements at the utility feeder level,
- Climate modeling with forecasting of key parameters, such as temperature, to inform asset management strategies,
- Hosting capacity analysis to determine system upgrades needed to accommodate DERs combined with locational net-value analysis to determine where DERs may best provide system value, plus modeling tools to support them and explore options,
- Approaches for determining staged strategies for grid modernization investments to enable DER integration and that also address risk and uncertainty,
- Guidelines for utilizing DERs to meet utility and customer needs through a combination of pricing, program, and procurement mechanisms,
- Multi-objective decision analysis to prioritize investments given funding and other constraints, and
- Approaches to coordinate distribution system planning more effectively with regional resource and transmission planning processes.

FIGURE 38: INTEGRATED DISTRIBUTION SYSTEM PLANNING PROCESS [114]



COMPREHENSIVE GRID PLANNING

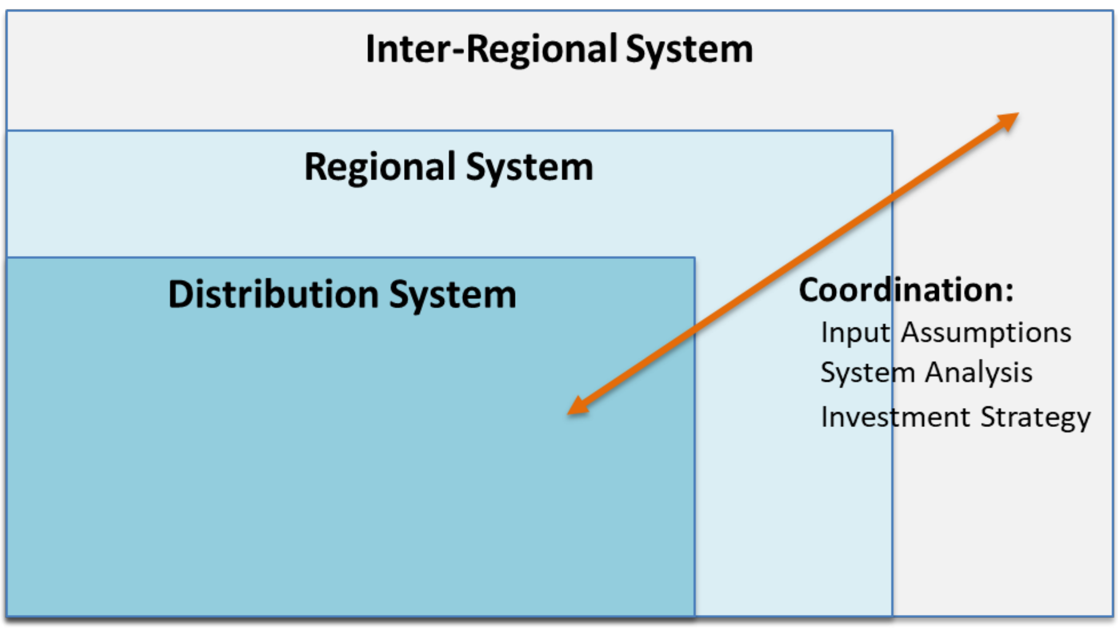
The emergence of DERs as a significant contributor to the overall resource mix changes the analysis for determining grid investments at a multi-state, regional scale. There is some progress being made as many utilities are now including DERs in their IRPs and ISOs/RTOs are continuing to develop bulk-power markets to apply DER services, spurred by several FERC orders, as described in Appendix D. However, more comprehensive planning, which incorporates DER services and approaches for managing them is needed to provide a more holistic understanding of grid investment requirements at a regional level. Specific considerations in the planning analysis include:

- Understanding the extent to which DERs and the way they are operated, e.g., via managed electric vehicle (EV) charging practices, can address forecasted projections of load growth due to electrification with such concerns amplified, especially among local and state governments, if transmission capacity remains insufficient to move power from bulk-generation resources to serve those needs,
- Determining the extent to which DERs can reduce peak demand and corresponding requirements for bulk-power and transmission capacity,
- Assessing the reliability or "firmness" of DER services when called upon to provide energy, reserve capacity, or ancillary services for use in distribution or bulk-level operations,

- Ascertaining the extent to which DERs can serve local needs for resilience, e.g., through microgrids and back-up services, to reduce reliance on the delivery of power from bulk-level resources, and
- Establishing the extent to which DERs can provide grid flexibility, including via frequency response and ramping services, which would otherwise need to be addressed through other investments.

Such integrated planning will require coordination among states and regional planners to establish common objectives and share assumptions, such as forecasts of load, DER adoption, and trends in weather parameters, for example, temperature rise. They will also require more advanced modeling and simulation tools, which can apply stochastic methods to examine and compare options for technology deployment strategies, as well as for determining reserve capacity requirements. As shown in Figure 39, cross-jurisdictional coordination of planning, operations, and market designs is needed to fully integrate DERs into the resource mix.

FIGURE 39: CROSS-JURISDICTIONAL COORDINATION REQUIREMENTS FOR PLANNING PURPOSES



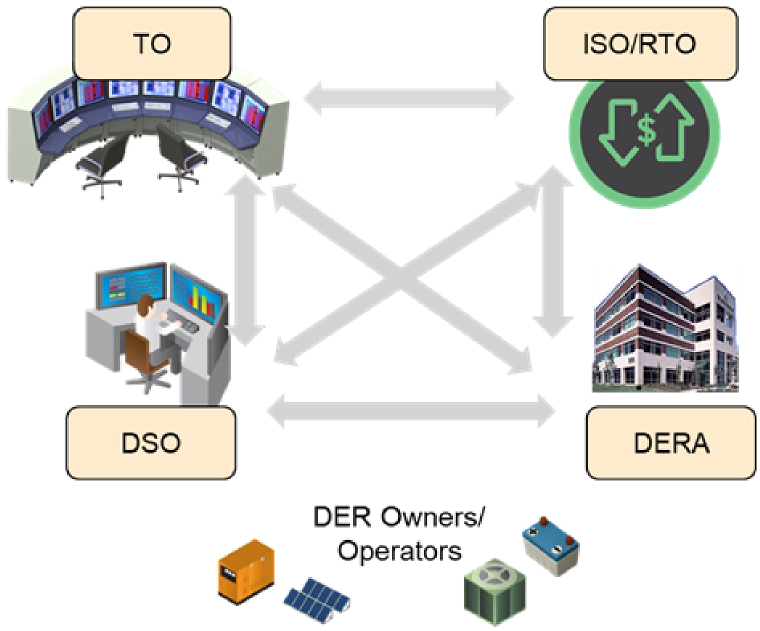
Operational Coordination

Coordination was not a well-recognized issue for electricity distribution until recently due to the rise of DER assets not owned by the utility itself. The advent of a mixed set of DERs owned and operated by entities other than utilities, such as aggregators, has shifted the engineering challenge from one of *control* to one of both *control and coordination* requiring disparate organizations to function in a highly organized manner to ensure effective and reliable grid operations. Coordination involves setting rules governing the respective roles and responsibilities, including data sharing expectations, of all the entities participating in the provision, operation, and oversight of DER services. It also necessitates the deployment of systems that can provide the requisite sensing, communication, control, computing, and data management capabilities needed to observe, dispatch, and orchestrate these distributed assets to achieve a wide variety of operational objectives, which may shift from moment to moment.

As FERC Order 2222 is moving the industry towards utilizing DERs to serve bulk-power system needs, the situation is requiring a greater level of coordination between transmission system operators (TSOs), distribution system operators (DSOs), DER aggregators (DERA), and the owners of DER assets, as shown in Figure 40. What is emerging is a requirement to develop coordination frameworks which formalize the set of actions, responsibilities, and data exchanges between two or more entities so they can function cooperatively depending upon the task and state of the grid. These frameworks will need to apply structural considerations based on grid architecture principles to:

- Identify and mitigate potential conflicts resulting from competing requests sent to one asset,
- Enable optimal performance of assets accounting for both local and system interests,
- Eliminate the bypassing of key participants in any action,
- Ensure that the system can scale to accommodate an expanding number of endpoints or participants without having to undertake major rework,
- Consider latency requirements of data and information exchange within communication pathways, and
- Minimize the number of communication interfaces to reduce the threat of cyber-intrusion.

FIGURE 40: THE SET OF RELATIONSHIPS CONSIDERED WITHIN A COORDINATION FRAMEWORK[115]



In addition, a formal set of coordination rules and codes of conduct that set the respective roles and responsibilities of each of these actors, including requirements for data/information exchange, are needed and are currently in development.[cc] For example, as shown in Figure 41: Distribution Grid Code Families and Elements, DOE is working with the industry to develop and institutionalize a set of distribution grid codes, which refer to the collection of institutional and business processes, as well as technical standards, needed to integrate and utilize DERs and DER aggregations within the electric system safely and effectively. Grid code families include requirements for grid engineering, information sharing and security, governance and oversight, and the integration and operational use of DERs, including microgrids, electric vehicles, and virtual power plants. The grid codes will advance needed standard practices to effectively enable the integration and utilization of DERs under a variety of ownership models.

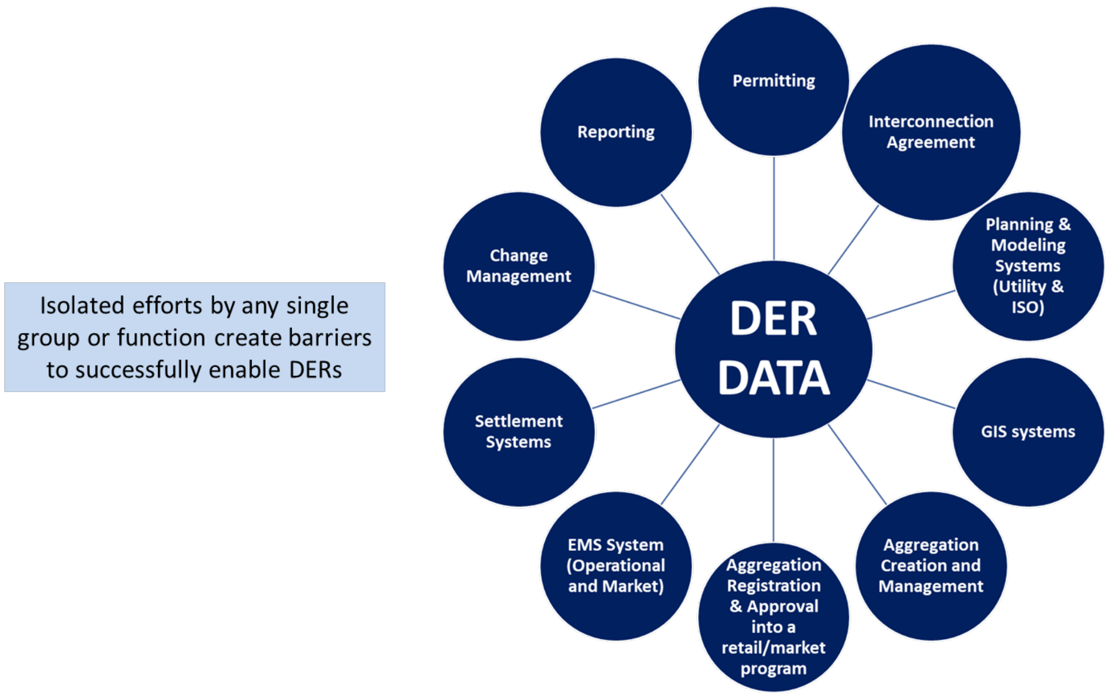
[cc] Materials on this subject, including documents relating to codes of conduct, grid codes, and a utility-DERA standard services agreement are available at: https://www.energy.gov/oe/operational-coordination.

FIGURE 41: DISTRIBUTION GRID CODE FAMILIES AND ELEMENTS

Code Families	Code Elements
Grid Engineering	Hosting Capacity Analysis Short and Long – Term DER Forecasting Locational Value Analysis Electrification
DER & Microgrid Integration	Inverter Based Resources Microgrids Monitoring and Control of DERs DER Interconnection Procedures Community Based Renewable Energy Microgrid Interconnection Procedures
Virtual Power Plants and Microgrid Services	Retail Energy and Distribution Grid Services Distribution Resilience Service DER Aggregation DER Aggregator Wholesale Market Services
DER & Microgrid Operations	Monitoring and Control of DERs Distributed Resource Management – Utility Distributed Resource Management – Aggregator Operating Agreements Common Information Sharing Model/ Framework/ Capability between System Operators, Utilities, Market Participants Utility Operational Technology (ADMS/ DERMS/ SCADA) Registration of DERs and DER Aggregations for Market Services Market Participation Rules Validation for DER Aggregations Net Load Baselining and Performance Analytics for DERs and DER Aggregations
Information Sharing and Security	Customer Data Access and Privacy Distribution System Data Information Sharing – Aggregators Cybersecurity
Governance and Oversight	Distribution Open Access DER Aggregator Oversight DER/ Microgrid Value Determination and Cost Allocation Governance and Oversight of Wholesale Market Participating DER (for e.g., through FERC Order 2222)

In addition, a significant effort is underway to establish a DER registry, or system of record, to ensure that all stakeholders have the required information to perform their respective roles to enable DERs to function in support of grid operations and associated markets. As shown in Figure 42: DER Data Uses, DER data has multiple uses. Standardizing processes for securely sharing data in a way that can effectively support these uses is needed in the industry.[116]

FIGURE 42: DER DATA USES[117]



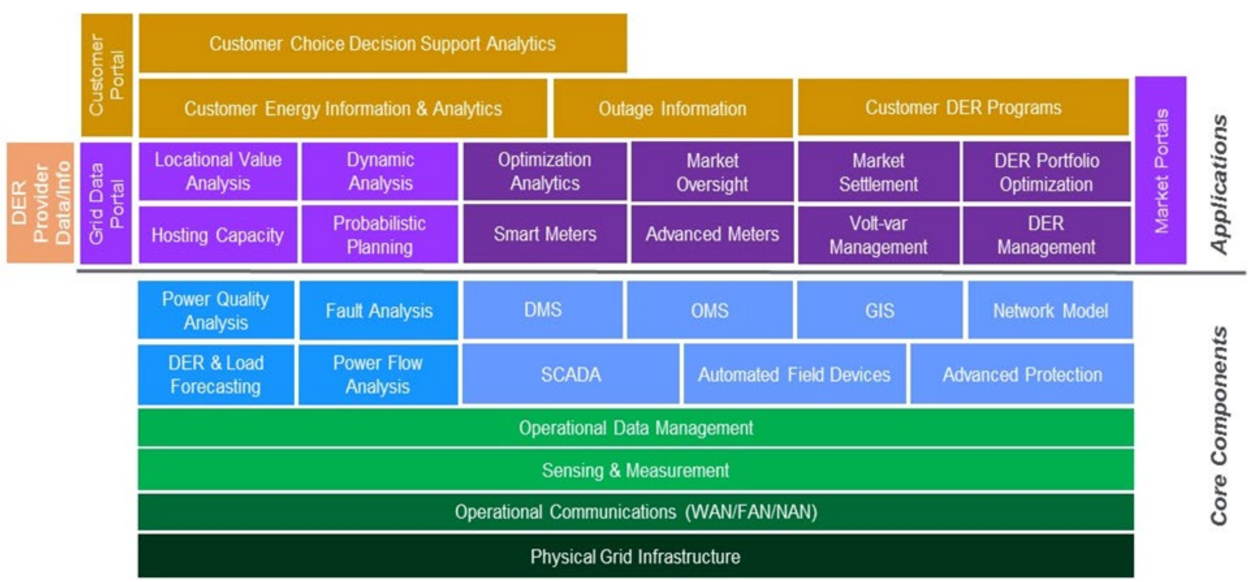
DER registration would facilitate the process of using individual DERs and DER aggregations in wholesale electricity markets and retail/distribution grid services. Such a registration would provide a master record serving as a state or regional database for the management and dissemination of DER data. Registration involves cataloging DER data in a standardized manner, such as DER technical specifications, location, interconnection and operational constraints, performance characteristics, operational status, and mapping to related retail and wholesale aggregation rules.

Access to registration information would be governed by specific privileges and rules established by FERC and/or relevant electric retail regulatory authorities (RERRA), as applicable. This ensures entities such as DER aggregators, TSOs, DSOs, regulators, and other authorized users can securely interact with the data. Transactions are logged, and data is archived to maintain a historical record. Also, it is necessary to ensure data consistency and accuracy by including embedded approval functions for data entry and changes to maintain the integrity of the information. Interoperability of devices and systems to seamlessly exchange data is foundational to allow for smooth interactions with DER aggregators, DSOs, and TSOs.[118]

System Technology Requirements

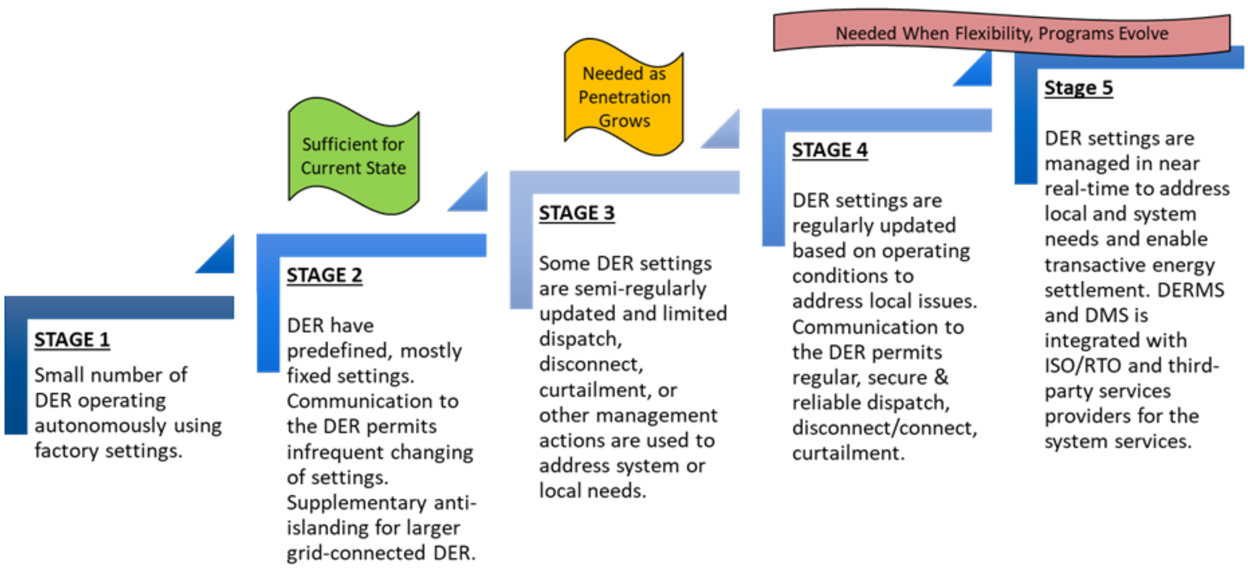
The various technologies comprising a distribution grid are shown in Figure 43. These include the core components consisting of the physical infrastructure, the communications network, devices used to sense and measure the state of the grid and its various assets (including DERs), data management and computational tools to manage real-time grid operations, and analytical tools to assess and address power flow requirements. Sitting on top of these core components and working with them are applications, which include the management of operational interfaces with customers and third parties, such as DERMs. The emergence of customer and third-party systems will necessitate their convergence with the utility distribution grid. A great deal of system engineering is required to design and build-out core components and applications, that also consider the convergence with non-utility systems, to address increasingly complex operations, which involve advancements in the functional capabilities and structure of the electric grid.

FIGURE 43: DISTRIBUTION GRID TECHNOLOGIES[119]



The advent of DERs introduces the need to address increases in the speed and scale of operations due to requirements to orchestrate many more grid-edge devices (potentially millions of DERs for large utilities) that are also spatially dispersed and subject to power flow adjustments due to quick changes in grid topology, e.g., via islanding or automated feeder-switching operations. For example, a real-time, load management capability that utilizes services from DERs will need to operate on very fast time cycles requiring autonomous operation.[dd] Figure 44: Staged Approach for Implementing DER Settings illustrates how settings for DERs will need to change as grid conditions become more dynamic.

FIGURE 44: STAGED APPROACH FOR IMPLEMENTING DER SETTINGS[120]



As a result, several key challenges emerge for sustaining the reliability of the electric grid given this complex and dynamic operational environment. The operational challenges associated with managing high levels of DERs and technological approaches for addressing them are discussed here.

ORCHESTRATION OF DER OPERATIONS AND DYNAMIC MODELING

The orchestration[ee] of DERs is necessary for supplying the energy they provide where and when needed, as well as for ensuring that electricity is managed within the capacity constraints[ff] of the grid, particularly for distribution feeders, which are highly constrained with respect to power flow. DER orchestration will require advanced dynamic modeling capabilities, which would incorporate DERs in power flow simulations and other analytical methods to address system capacity constraints and to optimize their use within operational timeframes. The orchestration of DERs, e.g., via flexible load management techniques, would impart benefits, such as providing an ability to host additional DER assets on a given distribution feeder, in addition to enhancing its flexibility and resilience characteristics. To address bulk-power concerns, NERC recently issued a guideline for both bulk and transmission owners that provides

[dd] Autonomous operation involves the ability to sense grid conditions and perform actions automatically without the need for human or external intervention.
[ee] DER orchestration is the coordination and management of multiple independent and aggregations of DERs providing one or more grid services to maintain reliable and safe operations in response to dynamic conditions.
[ff] Capacity constraints are due to limitations in the capacity of grid devices for managing current, voltage, and frequency.

a dynamic modeling framework for entities to consider when modeling DERs in transient stability analyses and power flow simulations.[121]

OBSERVABILITY AND SITUATIONAL AWARENESS

To operate DERs at scale, grid operators and DER aggregators will need to observe and be aware of the state of DER assets[gg] and how they might impact grid operations. Observability and situational awareness are obtained via the direct sensing of devices and providing information on their state through telemetry in combination with the application of system models. Having situational awareness of DER assets is critical to operators of both distribution and bulk-level systems.[hh] FERC recently directed NERC to develop new or modified reliability standards so that transmission planners and operators have sufficient information to predict the behavior of inverter-based resources, such as DERs, under all operating conditions (see reference to the new NERC Inverter Based Resource Reliability Standards in Appendix D)

ENHANCED COMPUTATIONAL AND DATA-PROCESSING CAPABILITIES

Enhanced computational and data-processing capabilities are necessary at the distribution system level to handle the increasing speed and scale of operations with greater levels of DERs, and to enable distributed intelligence at the grid edge. As an example, as shown in Figure 45, Portland General Electric (PGE) with cost-shared funding from the Department of Energy's Grid Resilience and Innovation Partnerships (GRIP) grant program[ii] is piloting the NVIDIA-Utilidata smart-chip-platform[jj] working alongside smart meters and other field devices to manage local DER interactions with the grid.

[gg] The state of DER assets refers to the energy they could provide (or consume), e.g., the state of available charge of energy storage devices, and/or whether they are dispatchable within a timeframe of interest.

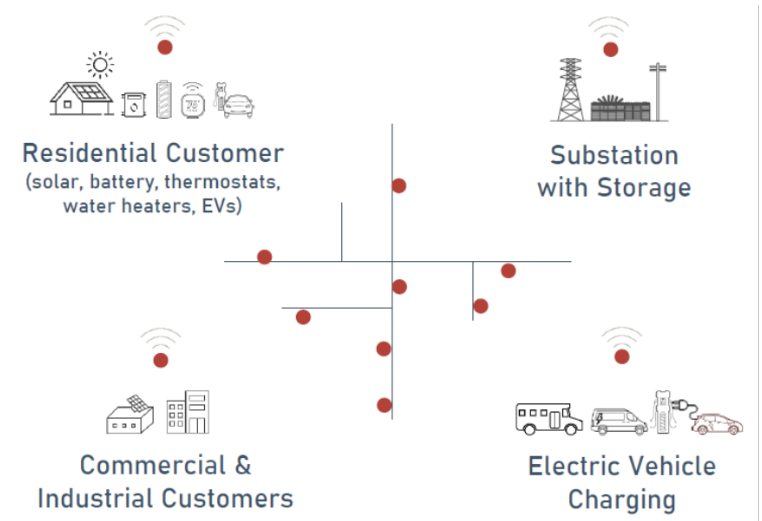
[hh] For example, the CAISO has stated that behind-the-meter solar has been the most impactful DER for their operations; see TN243408_20220602T143126_Presentation - DER in the CAISO Market and Operational Awareness.pdf.

[ii] More information on the DOE-PGE project is available at: DOE-GRIP-Portland-General-Electric-Company.pdf (energy.gov)

[jj] Utilidata's smart chip is integrated into the NVIDIA system-on-module platform; more information is available at: https://utilidata.com/press-release/utilidata-announces-development-of-a-custom-module-for-ai-at-the-edge-of-the-grid.

FIGURE 45: ACCELERATING AND DEPLOYING GRID-EDGE COMPUTING BY PORTLAND GENERAL ELECTRIC*

Advanced computational devices (SGCs) with on-chip processing deployed at key locations to enable visibility, automation, and DER optimization



Portland General Electric will deploy smart grid chips (SGCs) capable of enabling grid-edge computing combined with a suite of software platforms to enable:

- DER plug-and-play integration and deployment optimization
- Local decision-making and real-time automation to adjust DER operations given system conditions
- Local software applications for waveform processing (sub-second timeframe) to assess and correct for grid disturbances
- Coordination with centralized grid management systems (5-minute to 60-minute timeframe)

SGCs embedded in meters, gateways, and other distribution grid devices provide advanced computational capabilities (on-chip processing) deployed at key locations and at the point of service

* Adapted from graphical materials provided by PGE; PGE intends to deploy 90,000 SGCs by the end of 2025 with cost-sharing provided by the U.S. Department of Energy's Grid Resilience and Innovation Partnerships (GRIP) Program

The platform is specifically designed to rapidly process measurements like waveform data from the grid and continuously generate artificial intelligence (AI) models for uses such as granular demand forecasting, identifying pre-outage conditions, and interconnecting new DERs to the grid. The small-sized module is easier to add directly into grid-edge devices, such as EV chargers, solar inverters, and meters. In addition, the open hardware and software architecture empowers third-party developers to integrate proprietary software and build new grid-edge applications, using standard metrology, data processing, and DER interaction tools.

SECURE COMMUNICATIONS NETWORKS THAT SUPPORT DISTRIBUTED OPERATIONS

Grid systems will need communications networks that are secure and can handle data flow within required timeframes. The key to ensuring a secure communications infrastructure is building in security, resilience, and redundancy from the start. The basic architectural feature of the infrastructure is the communications pathway, which must support all applications/protocols and systems requiring communications via a network. A secure communications system protects the end-to-end physical pathway that transports data from origin to destination. That pathway may incorporate different transmission methods, such as optical fiber, copper wire, and microwave; transport diverse data including grid-state information and control messaging, as well as use a variety of analog and digital formats. Securing this end-to-end communications pathway, which is essential for reliable grid operations, involves preventing unauthorized access and monitoring traffic to identify anomalous activity without compromising the confidentiality, integrity, or availability of the data. Communications security methods complement cybersecurity approaches used to protect data at origin and destination.[122]

The sophistication of customer premises equipment (CPE)[kk] continues to grow, both for commercial/industrial (CI) and residential customers. CI and residential CPE and associated software holds a wealth of information, such as energy production, consumption, and system health. Such information provides utilities with useful knowledge for improving the efficiency of their operations and the effectiveness of their delivery of services to their customers, including improving response during emergency situations. Coupling key information contained in customer systems with utility systems requires a secure end-to-end communications network that is robust, interoperable, and resilient.

GRID COMPONENTS THAT ENABLE FLEXIBLE OPERATIONS

The dynamic conditions anticipated with high levels of DERs interconnected to the distribution system will require components that can manage and optimize the flow of electrical power within very short timeframes. Solid-state, power electronics devices (which utilize semiconductor materials) provide finer levels of control of physical parameters, such as voltage,

[kk] Customer premises equipment (CPE) is telecommunications and information technology equipment kept at the customer's physical location rather than on a service provider's premises.

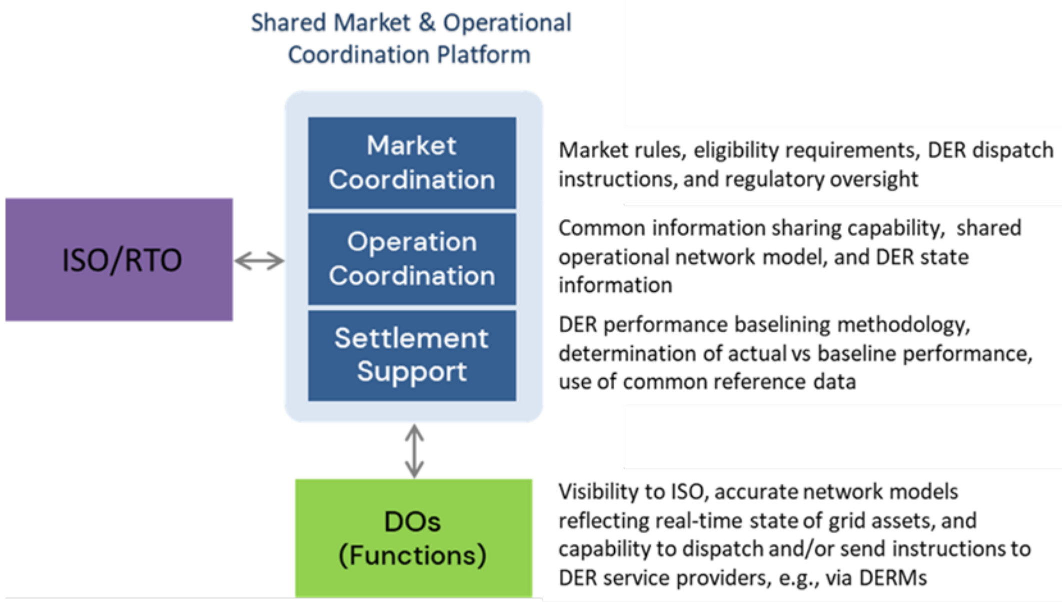
frequency, and current, which is essential for managing power flow. Such devices are useful for multiple power flow applications with modular and standardized designs. Ultimately, envisioned as a system consisting of modular, scalable, flexible, and adaptable power blocks that can be used for multiple applications, power electronics devices will serve as power routers or hubs that have the capability to electrically adapt to quickly changing grid conditions and provide bidirectional alternating current (AC) or direct current (DC) power flow control from one or more sources to one or more loads, regardless of voltage or frequency.

Design and development of flexible, standardized power electronics that can be applied across the full range of grid applications and configurations can enable the economy of scale needed to help accelerate cost reductions and improve reliability. Modularization of traditional grid components provides multiple benefits to the future grid by allowing for greater control, as well as natural standardization that improves both manufacturing and the supply chain challenges, we face today.

PLATFORMS FOR COORDINATED OPERATIONS

As we scale the grid to manage and utilize increasing levels of DERs and the services they can provide, underlying IT/OT systems having the above capabilities are required to enable coordinated operations. Figure 46 provides a concept for a coordination platform showing the various functional requirements necessary to enable the robust participation of DERs in markets supporting grid operations that integrate the operations of bulk-power system market operators (ISO/RTO), distribution system operators (DO), and DER service providers (e.g., DER aggregators). The electric utility industry is currently working towards developing this type of capability, as a result of the FERC 2222 Order; DOE is working with the industry to develop a reference design for such a platform.

FIGURE 46: SHARED MARKET & OPERATIONAL COORDINATION PLATFORM



Interoperability and Cybersecurity

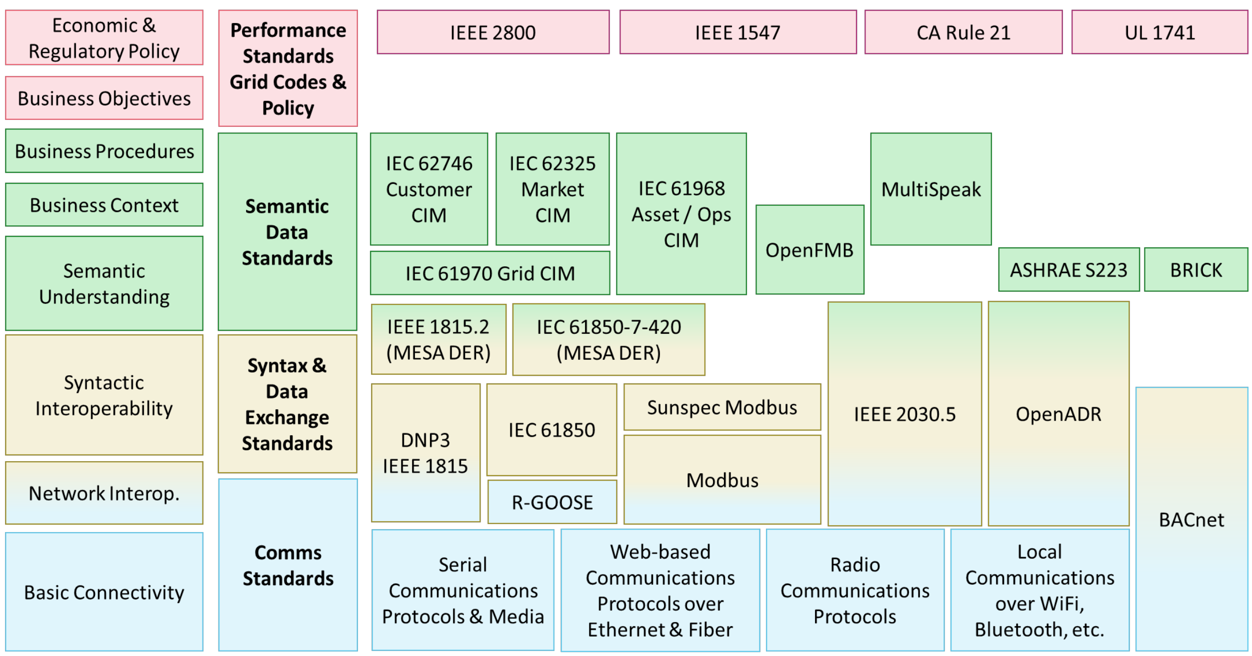
INTEROPERABILITY [123]

Decarbonization efforts are rapidly increasing the number of devices at the grid-edge, which are driving exponential growth in the amount of data that needs to be exchanged and integrated. This growth is driving an urgent need to improve interoperability between devices, software, and utility systems. Interoperability describes the ability of two entities to connect and exchange information without custom reconfiguration or manual intervention to resolve resource conflicts. Two of the best examples of “plug and play” interoperability are the universal serial bus (USB) and Bluetooth standards in the consumer electronics realm, where any USB device can be plugged into a USB port and operate seamlessly. Unfortunately, such a level of interoperability does not exist yet within the electric grid.

Within the bulk electric grid, the data exchange problem was initially solved with the introduction of Inter-control Center Communications Protocol (ICCP) in the 1990’s. ICCP allowed utilities to exchange data between proprietary vendor systems, but still required manual mapping of datapoints to the correct equipment in each utility’s local representation of the grid. The introduction of thousands to millions of grid-edge devices is now making manual mapping of data impossible. The challenge of exchanging data at the grid edge is complicated further by the number of competing strategies and communications protocols. Many different communication protocols exist, and the vendors of devices and systems apply them at their discretion.

The existing protocols and standards for data exchange in the electric grid can be categorized into four layers, as shown in Figure 47. At the highest layer are performance standards, grid codes, and regulatory policies, such as IEEE 1547 for grid-edge inverters, IEEE 2800 for large-scale inverter-based resources, UL-1741 for inverter electrical safety, and CA Rule 21 for smart inverters within the state of California. These standards dictate only what behavior is expected for devices during normal and abnormal conditions; they do not prescribe how functionalities should be implemented and offer multiple competing alternatives for lower-level data and communications protocols that are compliant with each standard. For example, IEEE 1547 allows device manufacturers to pick any one of three different communications protocols and still be compliant with the standard.

FIGURE 47: LAYERS OF STANDARDS COVERING POLICIES, SEMANTICS, SYNTAX, AND COMMUNICATIONS FOR GRID-EDGE DEVICES [124]



> **Semantics Standards**
>
> It will not be possible to achieve interoperability unless all devices use the same vocabulary.
>
> CIM is the only standard semantic dictionary for describing and naming grid data from the bulk transmission system to the grid edge.
>
> Universal adoption of the CIM and other standards is critical to achieving plug-and-play interoperability (like USB and Bluetooth).

At the second level are semantic standards, which are the technical equivalent of a Webster's English dictionary of spelling and usage for electrical equipment. The Common Information Model (CIM)[125] and MultiSpeak are the primary standards for grid equipment and business processes. MESA-DER describes what parameters exist for inverter controls and schedules. ASHRAE s223 and BRICK are increasingly used for buildings systems that need to interface with the grid. These standards only specify what are the agreed-upon names for various devices and their physical characteristics (e.g., the CIM specifies that length of a wire should be written as "Conductor.length"). Semantic standards do not dictate *how* the data should be communicated. Nonetheless, it is critical for both parties to understand *what* is being sent and whether the data received has any meaning in the given context (e.g., the attribute of "length" makes no sense in describing market revenue paid to a DER).

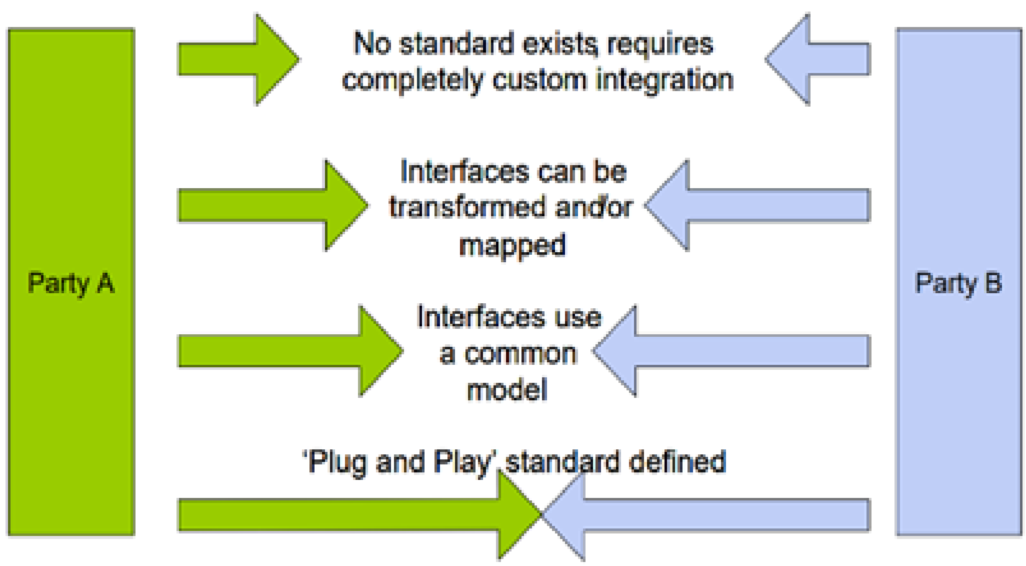
At the third level are data exchange / syntax standards, which describe how a data message should be constructed and what needs to be communicated. Key examples of these protocols include IEEE 2030.5, DNP3, and Sunspec Modbus for inverter controls; ICCP for communication between utilities; and DNP3 or IEC 61850 with Routable GOOSE for substation equipment. These standards are the technical equivalent of English grammar: in the same way that grammar defines that a sentence must have a subject, verb, and object, these standards define the correct structure for data sent between entities.

At the lowest level are communications protocols, which specify *how* a message is sent from one system to another. There exist a vast range of options at this layer that allow a device to determine where the message is going to be sent and how it should be encrypted, converted to a digital signal (ones and zeros), and then sent over a specific network (fiber, radio, ethernet, 5G, etc.). In addition, cybersecurity standards exist to ensure that data is delivered in a secure manner.

The need for these standards can be understood by examining the distance to "plug and play" interoperability[126] and seamless data analytics for increasing levels of standardization, as shown in Figure 48. Currently, there exist multiple standards and communications protocols for sending data between various entities at the grid edge. However, most devices and software still use their own proprietary data formats even if they support common protocols, such as IEEE 2030.5 or DNP3. In addition, even if two systems both communicate using the same standard, they typically refer to the same device by different names. As a result, large amounts of mapping and transformation are required (as shown in the second level of Figure 48). Adoption of semantic standards is necessary to provide a shared dictionary of terminology and equipment definitions so that custom data transformations are no longer necessary (as shown in the third level of Figure 48). Finally, grid codes and performance standards will need to be extended to dictate the types of standardized interactions and behaviors that should occur so that all devices, software, and systems within a given environment can exchange data without custom adapters and translators.

Although much work remains to achieve plug-and-play interoperability, there are significant benefits to be gained by industry, utilities, vendors, and customers. These benefits would particularly benefit small utilities, e.g., rural cooperatives and small municipals, as they do not have the resources in terms of staff and funds, as do large IOUs, to build custom integration adapters between non-standard interfaces.

FIGURE 48: INTEGRATION COMPLEXITY CAN BE REDUCED THROUGH COMMON INTERFACES AND COMMON DATA MODELS [127]



Achieving greater levels of interoperability, which would include establishing better capabilities for observing and controlling assets, is a high priority for the U.S. National-level efforts to drive the adoption of CIM and other standards through the development of grid codes, the provision of training and education to state regulators, and applying incentive mechanisms, such as funding to small utilities, would be useful.

CYBERSECURITY

The high deployment rate of DERs poses cybersecurity challenges for the electric grid. The main concern stems from the fact that utilities will rely on coordinated operations with DERs, which they will not own or operate, a situation that introduces the convergence of customer and 3rd-party systems with utility systems and challenges the traditional perimeter security model characterized by distribution control systems that are isolated within dedicated, purpose-built environments. As a result, the security of the electric grid is becoming threatened due to an increase in the number of pathways by which malicious parties can attack utility systems via digital, cyber networks. Addressing such cybersecurity challenges will require both technological and institutional solutions as operations within distribution systems become increasingly distributed and shared with non-utility participants.

To date, considerable effort has been undertaken to secure the bulk electric system via implementation of the NERC Critical Infrastructure Protection (CIP) standards, which cover the regulation, enforcement, management, and monitoring of this system with respect to ensuring cybersecurity. However, the distribution system does not have the same sort of wide-scale protections in place and, instead, regulation of distribution systems is generally performed by individual states with varying levels of cybersecurity measures, expertise, and resources.

However, there are significant ongoing activities to help address cybersecurity challenges at the distribution system level. A noteworthy effort, undertaken by DOE's Office of Cybersecurity, Energy Security, and Emergency Response (CESER) in partnership with the National Association of Regulatory Utility Commissioners (NARUC), is an initiative to set common practices for the industry.[128] This includes the development of baseline requirements, which provide a set of recommended cybersecurity practices for utilities, DER owners and service providers (including aggregators), and vendors supplying distribution utilities with hardware and software, which includes describing their respective roles and responsibilities. The initiative will also include the formulation of implementation and adoption strategies for the recommended practices.

DER Valuation and Compensation

Methods for determining the value of DER services and for providing compensation to entities providing them are evolving but are crucial for establishing a robust third-party DER service industry. Currently, DERs are sourced by utilities via three mechanisms:

- **Pricing** – Pricing refers to the application of tariffs offered by a bulk-power system operator (e.g., an ISO or RTO) or a distribution system operator (e.g., a utility), which are meant to elicit a response from a DER owner or aggregator. Examples include time-varying retail rates to shift the demand for electricity and market price signals for providing energy from solar plus storage systems. While regional grid operators and utilities can request regulatory approval to modify tariff structure and price signals to incentivize specific DER operations, they typically have minimal control over the type, quantity, and location of DER deployments.
- **Programs** – DER programs are operated by utilities, and third parties with funding provided by utility customers through retail rates. State agencies also operate DER programs. DER programs often incorporate an upfront incentive or rebate for installation of a specific technology (e.g., an energy-efficient appliance, smart thermostat, or solar plus storage system) or revenue opportunities for DER operations,

as specified in the tariff and program rules.[ll] In addition to program participants, all utility customers can benefit from programs that alleviate grid infrastructure investment needs. Through DER programs, utilities typically have control over the type, quantify, and, potentially, operations of DER technologies deployed within approved programs. However, DER owners and aggregators participate in programs if they provide the highest value for their resource, but typically can leave a program at any time.

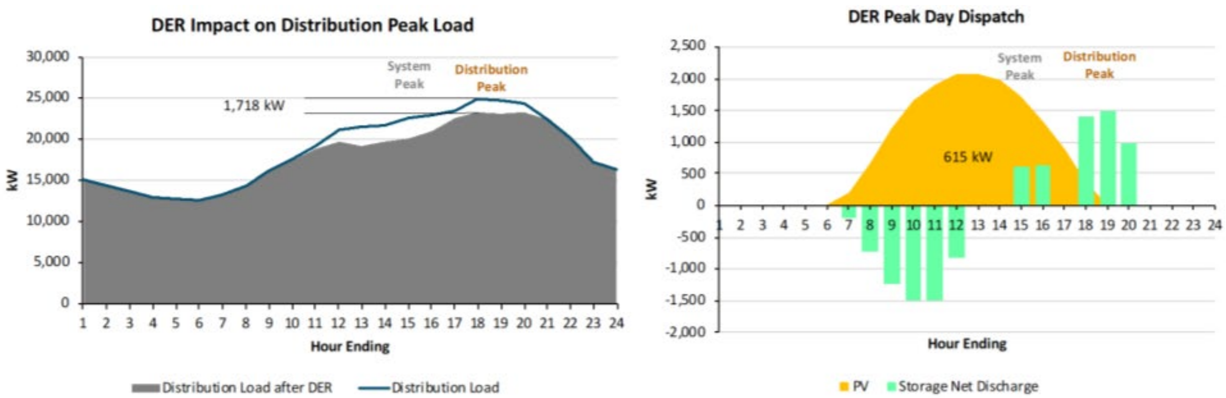
- **Procurements** – DER services can be sourced through competitive solicitations, such as a request for proposal (RFP) or auction mechanism. Services obtained from NWAs are typically accomplished via procurement mechanisms. Under this approach, utilities have control over the type, quantity, and operations of DER technologies deployed as outlined in the procurement contract. Such procurements are typically one-offs and can be repeated over time as utility needs change. Once a contract is signed, DER service providers have an obligation to perform during the duration of the contract.

Traditional compensation mechanisms do not always fully account for the value of DERs. For example, net-energy metering (NEM) programs allow utility customers who generate energy from qualifying systems, such as distributed photovoltaic (PV), to receive a financial credit on their electric bills for surplus energy supplied to the utility grid, up to the amount they consume in a given period (typically over the course of a year). But not all NEM programs take into account when surplus energy is sent to the grid — for example, using time-varying rates — or consider benefits to the utility system when locally generated energy reduces constraints on the grid during peak demand periods. Storage paired with solar, in combination with appropriate compensation mechanisms, can provide important resilience value for utility systems.[129]

Compensation for DERs should reflect the value they provide to the power system. That requires mechanisms that reflect the range of spatial and temporal variance in the value of DER energy exports or load shifting potential.[130] For example, Figure 49 illustrates potential benefits from the operational coupling of solar and storage technologies at specific points on a utility distribution system. Charging batteries during the day from the power produced by PV resources enables discharging those batteries during early evening hours to help meet peak load requirements. Enhancing the ability of the local grid to meet energy needs reduces energy needed from generating plants in the bulk-power system. In addition, real-time optimization of DER can help to alleviate system constraints (e.g., hosting capacity), as well as provide power when needed to serve local conditions. As illustrated in Figure 49, a greater emphasis on quantifying the locational value of DERs, within a framework for valuing all potential system solutions, is becoming increasingly important for designing reliable, least-cost electricity systems.[131]

[ll] In some states, regulated utilities can receive performance incentives for these programs to address the financial disincentive due to resulting reductions in retail revenues.

FIGURE 49: PEAK LOAD REDUCTIONS FROM PV + STORAGE[132]

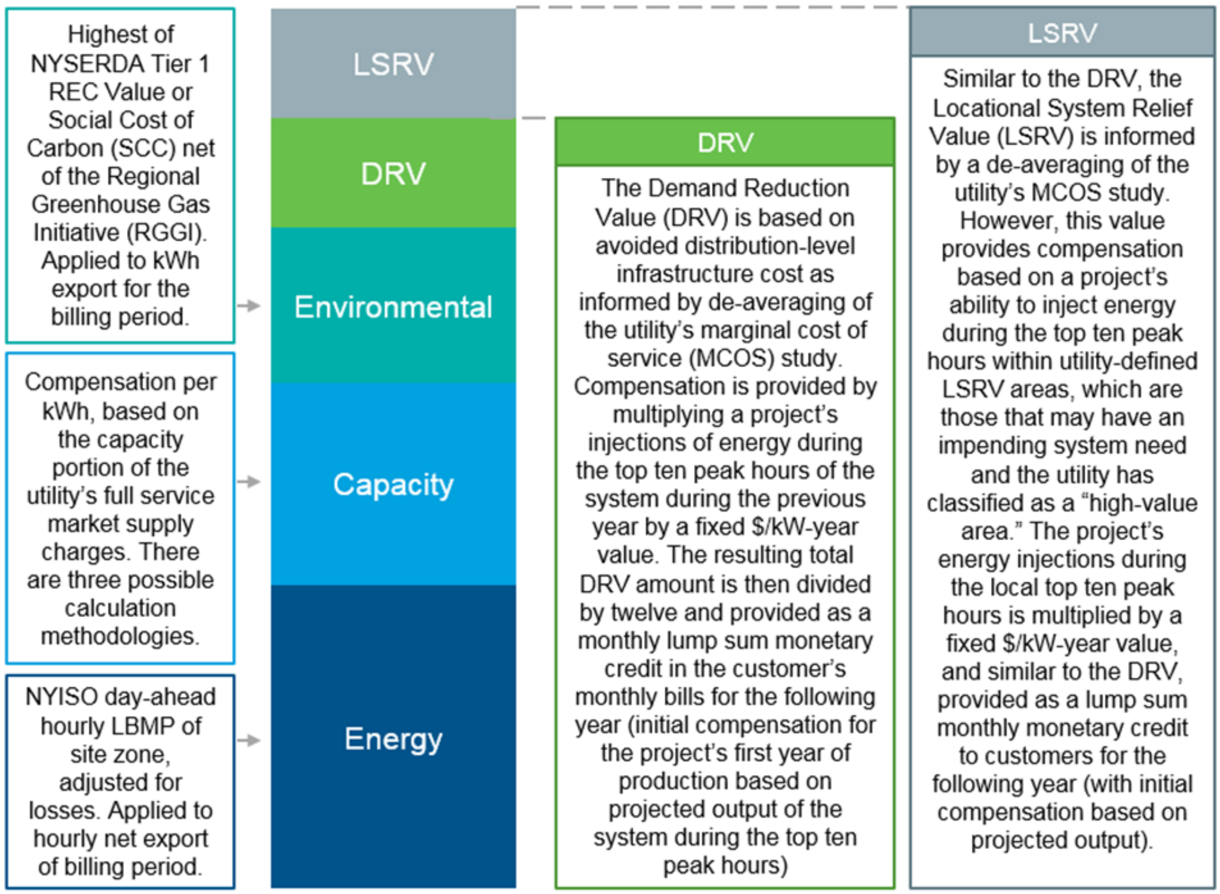


Along these lines, several states are working towards a unified approach for valuation and compensation of DERs. For example, the New York State Public Service Commission established the Value of Distributed Energy Resources (VDER), or the Value Stack, depicted in Figure 50, to compensate energy produced by DERs. Formulating and instituting such a practice requires coordination between bulk-power, distribution, and behind-the-meter service providers. The NY Value Stack compensates DERs based on when and where they provide electricity to the grid, with compensation in the form of bill credits.[133] The degree of compensation is determined according to the project's contribution[mm] to the following value stack components:

- **Energy Value** – based on NYISO's day-ahead price of energy at a specific location within its transmission system, the location-based marginal price.
- **Capacity Value** – based on the contribution to NYISO's Installed Capacity Market (ICAP), which serves to maintain reliability of the bulk power system by procuring sufficient resource capability to meet expected maximum energy needs.
- **Environmental Value** – based on the contribution to carbon reduction programs.
- **Demand Reduction Value** – based on the avoided distribution-level infrastructure cost.
- **Locational System Relief Value** – based on the ability to inject energy during the top ten peak hours within high-valued areas.

[mm] A project usually consists of a contractor/developer, which may develop and interconnect DERs owned by utility customers who receive compensation and who also provide a service fee to the DER contractor/developer.

FIGURE 50: NEW YORK STATE VALUE OF DER TARIFF PHASE ONE VALUE STACK PROPOSAL[134]



CHALLENGES TO THE DER AGGREGATOR MODEL[135]

DER aggregation for the provision of grid services faces several challenges, many of which are due to lack of standard practices across the industry combined with technical and financial risks. The industry is beginning to address these challenges through the development of standard practices, e.g., grid codes, codes of conduct, DER registration, and standard service contracts, however, coordinated efforts across the industry are needed to scale the DER aggregator model. Key challenges are discussed here.

CUSTOMER ACQUISITION AND SUSTAINED PARTICIPATION

DER aggregators need to acquire customers who are willing to participate in programs for the duration of a DER aggregation (DERA) services contract. Recruiting customers is challenging and expensive, requiring efforts to engage and educate them about the benefits of providing grid services. It may become increasingly difficult to recruit customers if their resources are called upon frequently to provide a service, e.g., where they may function as an operational asset, especially if such participation competes with a customer's preferred use of the resource.

To alleviate these concerns, DER aggregators are pursuing partnership arrangements with utilities and exploring programmatic approaches to address risk-sharing and align capabilities and costs to achieve better outcomes. Customer churn caused by dissatisfaction can create significant costs and service performance risks for DER aggregators; DERA contracts may have to overcompensate by recruiting a larger set of customers to achieve utility or regional grid operator performance requirements.

TECHNOLOGY

DER aggregators need to manage a diverse range of DERs, including smart thermostats, grid-interactive water heaters, EV charging, battery storage systems, and distributed generation and storage. Doing so requires sophisticated monitoring and control software and hardware systems to address the complexity. In addition, DER aggregators need to collect and manage large amounts of data from DERs requiring robust data management systems that can ensure data security and privacy. Compounding the technology issues is a lack of interoperability among the various DER technologies and aggregation platforms. Managing these diverse technologies, each with its own standards and interfaces, is a significant problem for aggregators. Standardization of information protocols, hardware and software interfaces, and communications is essential to achieve cost efficient scalability.

FINANCIAL VIABILITY

Several factors create revenue uncertainty for DER aggregators.

Revenue Uncertainty

DER aggregators face competition among themselves and from other market players such as utilities, as well as from retail electric suppliers in restructured markets. This competition can reduce the market share potential for an individual DER aggregator and price paid for services. In addition, the compensation methods vary for each type of service. For example, many wholesale electricity services are based on real-time dynamic prices that can vary significantly. Furthermore, the amount of flexible DER dispatched by the utility or regional grid operator varies depending on the service and grid need, impacting the amount of revenue. As a result, the absolute dollar value of any individual service provided can be rather modest, driving the DER aggregator to pursue the provision of several distinct services to maximize the economic value (“value stacking”) of the aggregated DERs.

Performance Risk

To address the risk of non-performance, DER program and market rules, utility and wholesale market tariffs, and grid services contracts typically include performance assurance and/or liquidated damages provisions. While these provisions may be prudent from a market/grid operator perspective, they add costs and other financial issues for DER aggregators.

In addition, DER aggregators may not be able to fully recognize revenue in the same period as performance. Settlement is often at a later date, and there may be liquidated damages for any non-performance.

Cost Structure

A DER aggregator needs a cost-efficient business structure to create a viable business model. In addition to upfront and ongoing costs to recruit and maintain participating customers, technology costs required for visibility, control, and management of DERs (which may include many thousands of devices, or more), and settlement systems, are substantial. DER aggregators may face challenges in securing financing and attracting investment.

Partnering is often a strategy to reach cost efficiency sooner. Teaming with other firms that have comparative advantage on certain business functions can help fill capability gaps, reduce costs, and mitigate execution risks. However, sharing revenue with partners or outsourcing services to others dilutes profit margins.

REGULATORY COMPLEXITY

The rules governing the use of DERs for grid services vary significantly across wholesale markets, states, and utilities. As a result, DER aggregators must navigate complex regulatory landscapes, which involve compliance with differing wholesale market rules; retail regulations, programs and tariffs; and utility procurement processes.

In addition, regulations are evolving at wholesale and retail levels. For example, FERC Order 2222 implementation will become established through efforts occurring across the six ISO/RTOs through 2029. In addition, state regulations continue to uniquely evolve regarding the use of pricing, programs, and procurements of distribution grid services. This makes it difficult for DER aggregators to plan their business strategies and operations.

As mentioned above, addressing all of these challenges will require coordinated efforts to develop and institute standard practices combined with advancing institutional processes that permit technological innovation, regulatory collaboration, and strategic planning to create a sustainable and efficient DER aggregation business model.

VI. Conclusion

Distributed energy resources are emerging as critical assets that provide valuable services for both utilities and their customers resulting in improved operational and energy efficiencies, enhanced reliability and resilience, and reduced emissions of greenhouse gases. These services include providing energy, additional generating capacity to meet peak demand requirements, and enhanced capabilities for managing system parameters, such as voltage and frequency. These services are useful for supporting both bulk-level and distribution system operations, and they provide value to utility customers who may apply them to serve their particular interests. The emergence of DERs and the ability to apply them optimally, especially as they scale in type and magnitude, fundamentally changes the way we will plan, design, and operate the electric grid.

The advent of a mixed set of DERs owned and operated by entities other than utilities, such as DER aggregators, has shifted the engineering challenge from one of control to one of both control and coordination requiring disparate organizations to function in a highly organized manner to ensure effective, secure, and reliable grid operations. Coordination frameworks, which define the respective roles and responsibilities, as well as data/information sharing requirements, of all participants engaged in the delivery and oversight of services from DERs are nascent and evolving. Standardization of the various aspects of such coordination frameworks would reduce barriers to a more robust and efficient utilization of DERs.

Incorporating DERs as core resources in utility operations will require advancements and more widespread application of integrated planning processes. These planning processes include integrated distribution system planning, as well as more comprehensive regional planning practices, in which the utilization of DERs for providing grid services can be incorporated into holistic grid investment strategies. Currently, integrated distribution system planning is not practiced universally across the country and consideration of DERs in regional planning processes is at an early stage.

In addition, advancements in analytical methods that support these planning processes are needed. For example, techniques for forecasting the adoption rates of DERs and electrification that are sufficiently granular and forward-looking while accounting for uncertainty are evolving and not consistently applied. These planning processes also require system engineering approaches that assess alternatives in grid structures and technology choices, and that enable the formulation of staged, least-regrets, grid investment strategies. These investment strategies will need to incorporate and dictate the demand for technological advancements that will provide the sensing, communications, control, data management, and computational capabilities needed for a more dynamic operating environment.

Finally, it will be important to institute practices that provide greater levels of certainty in the performance of DERs to ensure the reliable delivery of electricity and associated services. The ability of DERs to provide grid services is evolving. New methods for DER valuation and compensation are necessary to capitalize on this ability and enhance the role of DERs. A reasonable expectation of adequate compensation for both utilities and DER service providers is a necessary predicate for the capture of the benefits of DERs and the success of developing DERs as a reliable resource. A fundamental question is whether DERs will be provided under either a market-based or regulated regime. Either regime will necessarily build on an understanding of the intrinsic value that DER brings to distribution and bulk electric system operations. Additional effort is needed to advance DER valuation and compensation methods to enable reliable and cost-effective approaches for utilizing DERs.

In summary, the introduction of DERs for the provision of services for both utilities and their customers has introduced a set of challenges that are both technological and institutional in nature. Addressing these challenges will require coordinated efforts across governmental jurisdictions and among stakeholders to advance practices for grid planning, operations, and the design and implementation of markets.

VII. Appendices

Appendix A –Drivers and Enablers of DER Adoption

TABLE 6: DRIVERS AND ENABLERS OF DER ADOPTION

Entity Type	Category	Details
Federal	Investment and production tax credits and incentives are driving DER growth.	The Biden Administration set goals such as reducing emissions by 50% from 2005 levels,[136] achieving a Federal light-duty vehicle fleet that is zero emissions by 2027,[137] and procuring 100% carbon-free electricity for Federal agencies by 2030. Funding for clean energy and power under the under the Infrastructure Investment and Jobs Act (IIJA) of 2021, also known as the Bipartisan Infrastructure Law (BIL),[138] includes building clean power ($21.3 billion), clean energy demonstrations ($21.5 billion), energy efficiency and weatherization retrofits for homes, buildings, and communities ($6.5 billion).[139] The Inflation Reduction Act of 2022[140] provides for over $250.6 billion for tax incentives, grants, and financing and loans toward funding clean energy technologies, with particular focus on clean electricity, clean transportation, and electric vehicles. Federal and state money, including the extension of Investment Tax Credits (ITC) for solar and storage, and direct pay provisions of laws and executive orders are estimated to spur a $24B market for DERs.[141]
Federal	Federal actions aim to accelerate investment to address climate change, support domestic supply chain, and grow a domestic clean energy workforce to support DER development and deployment.	The Inflation Reduction Act authorized the Environmental Protection Agency (EPA) to implement the Greenhouse Gas Reduction Fund, a $27 billion investment to mobilize financing and private capital to address climate change. This includes financing support through the $14 billion National Clean Investment Fund and the $6 billion Clean Communities Investment Accelerator.[142] Clean energy and climate financing available from the Bipartisan Infrastructure Law and Inflation Reduction act established funds and tax treatments for eligible technologies. State utility regulatory authorities will work with utilities, members of the public and other relevant government agencies to identify funding opportunities and communities to host clean and zero-carbon electricity generation. 2021 Bipartisan Infrastructure Law allots more than $62 billion for U.S. Department of Energy investments in 60 new programs focused on preventing outages and increasing resilience, upgrading electric grids, facilitating transmission, deploying technologies to enhance grid flexibility, modeling and assessing energy infrastructure risks, assuring nuclear operations, and hydroelectric production and efficiency improvements.[143] Bipartisan infrastructure law will make $23 billion available to DER and EV infrastructure. Residential resources will account for 70% of capital expenditures over 2022–2026.[144]

Entity Type	Category	Details
Federal	Increased opportunities for revenue and rate designs that compensate DER for valuable capabilities for system stability and supply. Today, DERs participate in markets almost exclusively as emergency capacity. Market constructs are in transition to enable economic participation to fully utilize DER capabilities.	FERC Order No. 2222 promotes competition in electric markets by removing the barriers to DERs from competing in the organized capacity, energy and ancillary services markets administered by regional grid operators.[145] Challenges to fully opening RTO/ISO markets to DER participation include metering, telemetry, and data requirements; modeling and operational tools to manage distributed systems and participation; and operational coordination with multiple levels of system operators.[146]
States	State laws and policies requiring 100% clean and/or renewable energy, mostly through public utility supply, by 2035-2050. Policies cover 54% of U.S. population. States are increasingly taking measures to accelerate the adoption distributed energy resources such as electric vehicles (EVs) Energy equity and energy justice policies consider the role of energy systems, including use of DER, in achieving objectives.	Twenty-nine states and the District of Columbia currently have renewable and clean energy standards, and six states have a clean energy standard. Seven states have renewable portfolio goals, six have clean energy goals.[147] State renewable portfolio standards (RPS) often include specified amounts of technologies to be used in contribution toward goals. Twenty-two states and the District of Columbia has an RPS with solar or distributed generation provisions.[148] Since 2020, 13 states have enacted bills that require 100% of either clean energy, carbon-free electricity, renewable energy supply, net-zero greenhouse gas emissions, or GHG reductions. In total, 23 states, Puerto Rico, and the District of Columbia have all passed these goals by legislation or executive action. The timelines of goals vary, with most laws or orders ensuring goals are met by 2050. These create drivers for DER adoption as part of the portfolio of resources available to meet these state goals. Almost half of U.S. states are taking actions to address energy equity issues. States focus on distributive and procedural tenets. State policies increasingly require consideration of equity and environmental justice in utility regulation, including system planning. Metrics for equity improvements are nascent, though focus is on economic issues, such as energy burden.[149] Energy justice tools support state policy to identify, illustrate, and evaluate energy questions, policies, regulations, and practices with respect to energy and environmental justice.[150] Forty-five states and the District of Columbia provide an incentive for certain EVs and/or plug-in electric hybrid vehicles (PHEVs), either through a specific utility operating in the state or through state legislation. The incentives range from tax credits or rebates to fleet acquisition goals, exemptions from emissions testing or utility time-of-use rate reductions.[151]
States	In 2022, 49 states and the District of Columbia took policy and regulatory actions related to grid modernization, rate, and business model reforms,	Notable trends included actions related to resilience, grid management and flexibility, performance incentive mechanisms, wholesale market participation, distribution system planning, battery storage DR, resiliency, interconnection, critical peak pricing, battery decommission and recycling systems thinking and planning. Policies increasingly require electricity delivery systems both enable/attract and manage/accommodate services available from DER.

Entity Type	Category	Details
	microgrids, energy storage, and demand response.[152] State green banks function like loan or investment funds to support investment	Green Banks are mission-driven institutions that use innovative financing to accelerate the transition to clean energy. They function like loan or investment funds, using a wide array of financial tools to support investment in clean energy infrastructure. Currently there are 23 green banks in the United States, driving $4.64 billion in total investment in 2022.[153]
States	State-level requirements for electric power system planning and distribution system planning address a broader range of needs related to evolving objectives, including those tied to equity, resilience, cybersecurity, decarbonization, and electrification.[154] Regulators increasingly wish to ensure comparable evaluation between utility-owned and non-utility owned resources. State policies that seek to value electricity delivery systems ability to both enable/attract and manage/accommodate deployment of and services available from DER.	Electricity system planning will increasingly integrate assumptions – including IDSPs (21 states),[155] grid modernization plans (6 states), and IRPs (35 states). Ten states require hosting capacity analysis/maps illustrating locations where DER may be accommodated on distribution systems. Twelve states require locational value/non-wires analysis.[156] New electric distribution planning requirements include variable energy resource integration, system inertia, resilience, energy storage, dynamic voltage support and cybersecurity. Emerging planning requirements include climate change adaptation, decarbonization, environmental justice, and electrification. Planning capabilities, methods, tools, and approaches will evolve, and improvements in utility methods prioritize those with the greatest impact in achieving policy objectives.[157] A more holistic approach to solution identification and solution evaluation in electricity systems planning implies new planning capabilities and analysis requirements. The visibility of the planning process must directly or iteratively extend to all relevant subsystems of the system in order to capture the impact DERs have in each process. Second, planning tools must capture the dimensions of resource value relevant to policy objectives. Finally, modeling must accurately capture the quantities and costs of resource supply. DER forecasting methodologies are nascent within state regulatory proceedings.[158] While increasing numbers of states require utilities to file distribution system plans with DER forecasts, tools and accepted methodologies are not standardized across industry. Based on a survey of IDSPs in the US:[159] • 10 states identify customer choice and engagement in energy services as an objective or goal (CA, CT, HI, IL, MA, MN, NH, NY, RI, VT). • Two states identify objectives related to compensating customers for the value of DERs (WA, RI). DC and NH require access to data. • Five states have a goal or objective to accelerate the deployment of new technologies and services to optimize grid performance and minimize electricity system costs (CA, CT, IL, MI, MN). • Nine jurisdictions have goals or objectives that support DER integration and utilization of grid services (CA, CO, DC, HI, IL, MA, MN, OR, VA). A recent study on states' engagement on electric distribution planning to meet state policy highlights a few notable examples:[160]

Entity Type	Category	Details
		• 2021 Washington State Energy Strategy – Included in its recommendations are several that address the need to establish a smart and flexible grid, specifically developing a better understanding of the value of DERs and the capacity of distribution systems to host them. • 2019 North Carolina Clean Energy Plan – Several recommendations address grid modernization in support of clean energy resource adoption and grid resiliency and flexibility, among other outcomes. • 2019 New Jersey Energy Master Plan – Among the plan's recommendations are requiring IDSPs to identify the need for distribution system upgrades that enable the state to prepare for the growth of DERs and EVs. Interconnecting solar energy, wind energy, and energy storage resources to the grid requires navigating complex regulatory structures and technical impact assessments, which vary by jurisdictional authorities of the distribution or transmission grid systems. Interconnection rules and policies govern critical processes and impact interconnection costs for DER. Interconnection challenges include, but are not limited to, timeline and process delays; high grid upgrade costs; lack of grid transparency; and incomplete or outdated technical standards.[161] Allocation of system upgrade costs for DER interconnection impacts DER deployment. Since 2017 in New York, costs have double from projects relative to costs 2006–2016.[162]
States/Utilities	Market frameworks and mechanisms, tariffs, utilities programs and contracts, which enable market growth for DER by providing compensation.	Utilities and regulators seek to effectively address the growth of DER and its impacts withing regulatory frameworks. Designing and implementing tariffs, rate designs, and compensation mechanisms that best utilize DER-enabling investments, while also ensuring recovery of the prudent costs is a critical institutional role of regulators.[163] DER deployment is facilitated by a range of monetization schemes for grid services. Those schemes are a function of several characteristics of U.S. energy markets and regional variations. DERs are economically viable today in states and regions where DERs, including potential aggregations of DERs, can sell to utilities or participate in wholesale markets and earn market prices.[164] Rate designs attempt to communicate differences in locational and temporal value of DER generation to the grid. Utility programs increasingly seek to compensate DER for necessary grid services and/or to supply services to wholesale markets in the interest of ratepayers.
Cities	City commitments and represented load and/or carbon contribution. As of 2022, over 100 cities and towns committed to 100 % clean energy.[165] Cities and energy utilities must coordinate to realize benefits	City climate plans will require significant infrastructure investments to ensure low-carbon supply resources and to drive efficiency in critical electricity use including buildings and transit. Coincident planning across critical systems will require multi-sector modeling, including water and wastewater, transportation, and other critical public services. Climate plans from 50 cities indicate less than 1/3 have detailed benchmarking and reporting; 28% include sector-specific strategies for electricity, buildings, and transportation decarbonization.[166] Spatial and sociodemographic factors indicate equitable use of infrastructure in climate action plans, driving potential benefits from DER deployment.

Entity Type	Category	Details
	across public service sectors and populations.	Many cities have long-term energy decarbonization goals but lack detailed benchmarks and reporting. Plans often do not include sector specific electricity, buildings, or transportation decarbonization strategies.[167]
Cities	A mix of financing tools are available through cities that will increasingly drive DER and related investments.	Tools include property assessed clean energy financing, local financing authorities, funding partnerships, and Federal funds.[168]
Corporate and Commercial Actions	Commercial and residential demand for low carbon resources and resilience are stimulating DER investment.	In commercial sectors, 66% of the five hundred largest companies in the world by revenue have significant climate commitments, 39% have a net zero target, 35% a carbon neutral target, and 15% have a 100% renewable energy target.[169] More than 100 U.S.-based companies have committed to 100% renewable energy as part of the RE100, with target achievement dates ranging from 2025-2050.[170] 56 new companies joined the RE100 in 2022.[171] Commercial and industrial sectors increasingly use power purchase agreements to ensure low carbon energy supplies, primarily through purchase agreements with bulk sources. Coalitions of large U.S. energy buyers support energy policies that accelerate decarbonization of supply and supply chains.[172] In 2022, corporations signed contracts to purchase a record 19.9 GW of zero-carbon power. Virtual power-purchase agreements reached 17 GW in 2022.[nn] Increased spending for purchase agreements is expected in the technology sector to keep pace with rising electricity demand, such as for data center operations. The U.S. Department of State and the Clean Energy Buyers Alliance announce the formation of a Secretariat for the Clean Energy Demand Initiative to accelerate corporate and government collaboration in global renewable energy markets.[173]

[nn] In virtual purchase agreements the project sells power into organized markets (wholesale) and capture the spot price at the time. The buyer in turn gets ownership of the certificates from the project and pays a fixed price.

Appendix B - Grid Modernization Technology Subcategories[174]

Physical infrastructure

- Capacity expansion
- Enhanced physical security
- Infrastructure hardening
- Infrastructure inspection
- Infrastructure replacement
- Undergrounding

Distribution automation

- Automated feeder reconfiguration
- Capacitor bank
- DER-driven advanced protection
- Enterprise distribution automation program
- Fault indicator
- Fault protection
- FLISR
- Load tap changer
- Remote monitoring and control
- Substation automation
- VVO

Enterprise operating software

- ADMS
- Advanced modeling tool
- Advanced planning tool
- Automated load interconnection tool
- CIS
- CRM
- DMS
- Enterprise program
- GIS
- Historian
- Historian
- OMS
- SCADA
- Systems integration

Asset management

- Advanced asset inspection tools
- Asset management enterprise program
- Field work management
- Proactive asset maintenance
- Resilience-focused vegetation management

AMI

- AMI system integration
- Billing system
- Distributed intelligence
- MAMS
- MDMS
- Smart meters
- Turnkey AMI

DER deployment

- Energy storage
- Microgrid
- Microgrid make-ready
- NWA deployment
- Remote grid

DER management

- Automated DER interconnection tool
- DER integration strategy
- DER market participation enablement
- DERMS
- DRMS
- Flexible interconnection
- Hosting capacity portal
- NWA enablement
- Vehicle-grid integration

Communication infrastructure

- Cybersecurity
- Enterprise Communication infrastructure
- Enterprise service bus
- FAN
- Integrated network operations center
- Network Operations Center
- Operation network monitoring tool
- Optical network
- Other
- Private LTE
- Radio network
- Telcom operations management
- WAN
- Wireless network

Enterprise data analytics

- AMI data analytics
- Asset data analytics
- Center of excellence
- Data analytics platform
- Data access
- Data sharing
- Grid data analytics

Others

- Advanced personnel safety
- Advanced safety training
- Budget contingencies
- Control room modernization
- Emerging technology evaluation
- Incubator
- Intra-organizations coordinated planning
- Land acquisition
- M&V
- Other
- PMO
- Project management
- Testing facility

Appendix C – Examples of Grid-Edge Interactions

EXAMPLE OF GRID-EDGE INTERACTION AT BG&E

Exelon Corporation and its utilities in Maryland, Delaware, and the District of Columbia, specifically the Potomac Electric Power Company (Pepco), the Baltimore Gas and Electric Company (BGE), and Delmarva Power, have embarked on a managed charging pilot and research study to better understand the impact of electric vehicle (EV) charging on the utilities' distribution systems. The multi-phase pilot study included an assessment of anticipatory infrastructure investment costs with the rise in EV adoption and the impact of time-based charging costs for customers.

The pilot targeted three user groups: residential customers, commercial businesses with electric fleets, and Exelon's public charging network. For the residential portion of the pilot, Exelon partnered with Weave Grid, Inc. (WeaveGrid), a vehicle telematics company with strong expertise in managed charging and relationships with major EV original equipment manufacturers (OEMs).

In the first phase, residential customers' home charging would be managed based solely on their electric rate schedule and would prioritize off-peak charging. In the second phase, the pilot applied hourly wholesale price signals to schedule participants' charging during the least expensive times of the day. The third phase is focused on distribution asset protection, including mitigating overloads of utility assets (e.g., transformers) by staggering participants' charging based on the state of charge and EV departure schedule. In this latter phase, program participants were grouped into virtual distribution assets of various sizes based on their home zip code, and their charging was managed based on the status of other participants in the surrounding area. For example, up to 10 customers were assigned to a virtual transformer, up to 300 customers assigned to a virtual circuit, and up to 900 customers on a virtual feeder.

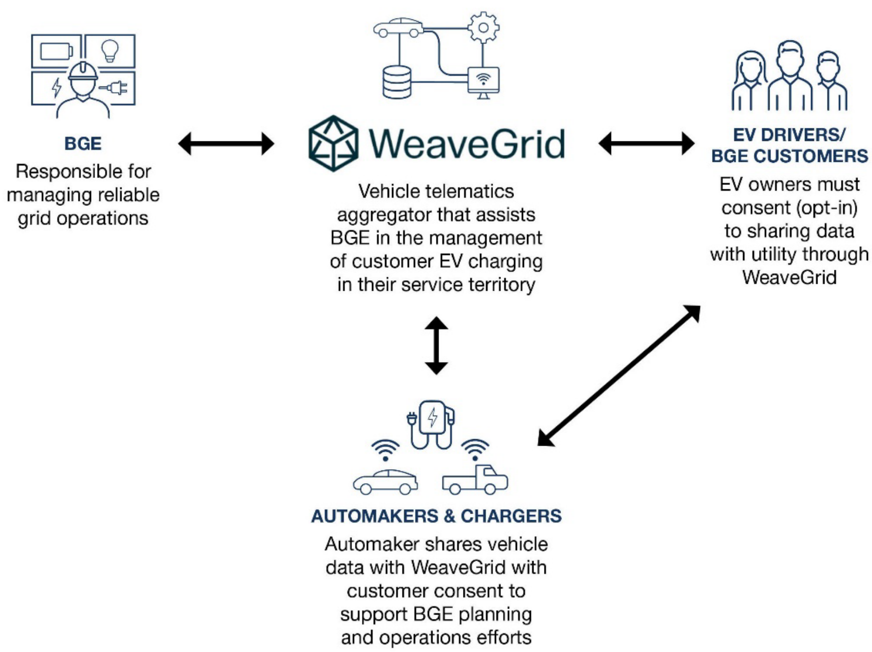
Participation in Exelon's residential pilot currently includes 2,700 BGE customers, 900 Pepco customers, and 85 Delmarva Power customers. To participate, customers must sign up for WeaveGrid's evPulse platform and consent to share their vehicle telematics data with BGE. Electric vehicle telematics can include current battery levels and discharge rates as well as additional driver metrics from the vehicle's software.[175] By doing so, participants allow and enable WeaveGrid to manage their vehicle's home charging in exchange for a financial incentive of $10 a month. Participants are allowed 4 opt-outs per month to maintain their incentive.

In the first and second phases of the study, WeaveGrid acted as an aggregator for the utility, administering the program and managing the data flow and data collection. To enable secure data transfer between parties, WeaveGrid had a daily batch file transfer to the utility's customer care and billing system. Charging and participant data was then shared with different teams within the utility organization including those focused on load forecasting and capacity planning, clean energy solutions, strategy, utility of the future, and customer operations.

As the third phase begins, WeaveGrid now acts as a virtual power plant, with BGE looking to further integrate the third-party system into the utility's enterprise information management (EIM) system directly to share data more expeditiously. This will enable the pilot study to test "real-time" signals for various charging scenarios. Thus far, BGE has been able to reduce participating EV load during peak times by 30–50% on weekdays and 20% on weekends.

In addition, Exelon has commissioned Argonne National Laboratory to conduct a grid impact analysis and economic impact study to help its utilities evaluate electrical infrastructure upgrades. Specifically, Exelon is looking to better understand how much money will be needed to invest in upgrades to prepare for Maryland's 2035 EV goals, as well as how these costs can be reduced through managed charging. The utility is also evaluating the impact of scenarios where managed charging doesn't materialize. Cost studies will also be conducted with different numbers of managed charging participants forecasted by 2035 to better understand how utilities can manage risk and cost.

FIGURE 51: BGE MANAGED CHARGING PILOT FRAMEWORK



CALFLEXHUB – PARTNERSHIP BETWEEN THE CALIFORNIA ENERGY COMMISSION AND LAWRENCE BERKELEY NATIONAL LABORATORY

The California Load Flexibility Research and Deployment Hub (CalFlexHub) is a $16 million research, development, demonstration, and deployment program funded by the California Energy Commission's (CEC) Electric Program Investment Charge program.[oo] The program is led by Lawrence Berkeley National Laboratory and was launched in Fall 2021. The program will run through 2025. The goal of the program is to advance the capability of buildings and electric vehicles (EVs) to provide flexible loads to the power grid in California. Flexible loads can enable more cost-effective use of renewable energy on the electric grid, reduce peak demand, accommodate electrification loads, and support use of clean, reliable, and affordable electricity. Over 40 participants representing building owners, utilities, and industry partners are involved in the program.[176]

The vision for CalFlexHub is to use dynamic pricing and greenhouse has (GHG) signals to motivate demand flexibility (e.g., load shifting and load shedding) from customer loads to decarbonize and improve reliability of the California grid and provide customer electricity bill saving opportunities. The program created fictitious hourly dynamic price and GHG profiles for testing and uploaded them to the CEC's Market Informed Demand Automation System (MIDAS)[177] for use by the participants.

The CalFlexHub program is demonstrating automated price response capabilities to existing commercial and pre-commercial flexible load control technologies while promoting equity. Currently, there are nearly 20 such technology demonstration projects in the CalFlexHub program, which cover a number of different applications including single family, multi-family, small-to-medium commercial, and large commercial buildings, as well as campus environments.

One of the key objectives of the program is to understand the load impact of the price and GHG signals on different technology applications through measurement and verification efforts. The project team also tracks different communication and control pathways used to convey test prices and GHG signals to DERs such as smart thermostats, heat pump water heaters, air conditioners, heat pumps, EVs, behind-the-meter batteries, and thermal energy storage systems.

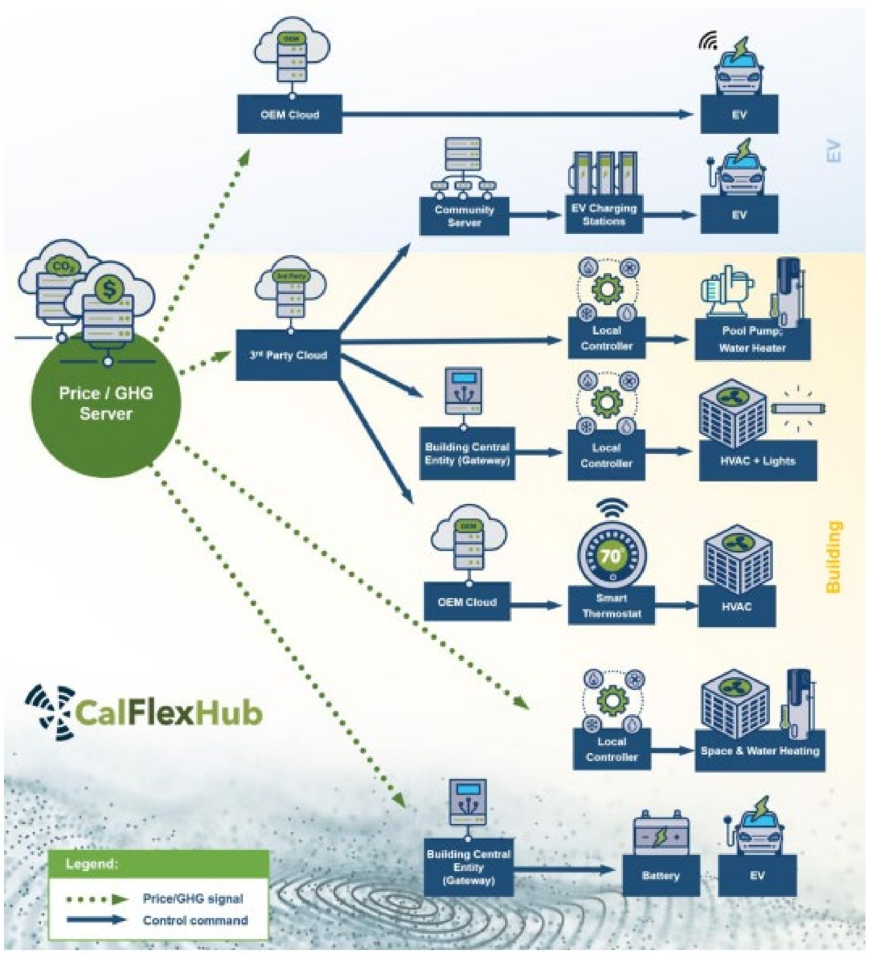
Figure 52 shows four types of communication and control architectures (i.e., pathways) currently demonstrated in the CalFlexHub program. A variety of pathways exist, for example:

1. The OEM of the grid-edge device uses a vendor cloud where price or GHG signals are received to create device control commands for a load flexibility response.

[oo] With cost share from the U.S. DOE's Building Technologies Office and Southern California Edison.

2. The signal can be received by a third-party cloud. These third parties are often referred to as aggregators or Automated Service Providers (ASP).[pp] Their clouds interact with customer devices through an OEM application programming interface (API), or through the other methods described in paths 3 and 4 below.
3. A local controller in the building can receive the signal directly through broadband and have the capability to provide control commands to system components. The example in the figure is an integrated heat pump for space and water heating.
4. A building central entity or gateway can be capable of receiving signals and orchestrating several connected devices to adjust electricity consumption. These systems are used in commercial buildings and are emerging in some home energy management systems and smart electric panels.

FIGURE 52: COMMUNICATION AND CONTROL PATHWAYS OF DYNAMIC PRICE/GHG SIGNALS TO GRID-EDGE DEVICES IN CALFLEXHUB DEMONSTRATION PROJECTS[178]



[pp] The ASP can be a traditional demand response aggregator although they do not need to be. A key distinction is that the ASP's service focuses on demand flexibility optimization of grid edge assets. They can provide a financial settlement function in addition to the optimization. The data flow is one-way in the "prices to devices" paradigm.

The CalFlexHub program is exploring the advantages and disadvantages of these communication and control architectures, as well as the business models and long-term market implications associated with each. Research is also underway to evaluate how to improve interoperability of control and communication technologies to enable lower-cost technology integration and market innovation. The research includes an evaluation of customer perspectives, ease of use, equity for disadvantaged communities, cost effectiveness, utility bill impacts, and the value to utility and grid operations from these technologies.

SOUTHERN CALIFORNIA EDISON (WITH STEM) VPP

In 2014, Southern California Edison (SCE) contracted Stem, Inc. (Stem) to build and operate a virtual power plant (VPP) to offer local energy capacity through 2027. Stem delivered its first seven systems in December 2015 and expanded over the next several years to reach 20 MW/80 MWH in 2018, across 200 systems. These systems use energy storage systems to provide capacity and energy. In 2020, Stem also became the operator of a similar, but larger and separate VPP portfolio delivering 50 MW, 340 MWh.

Stem maintains contracts with a variety of commercial and industrial customers that range from retail locations to larger campuses and industrial customers. Batteries at these premises range in storage capacity from 36kW/60 kWh to up to 5MW/32 MWh. Customers choose to sign up for the service to receive financial incentives and contribute to sustainability objectives.

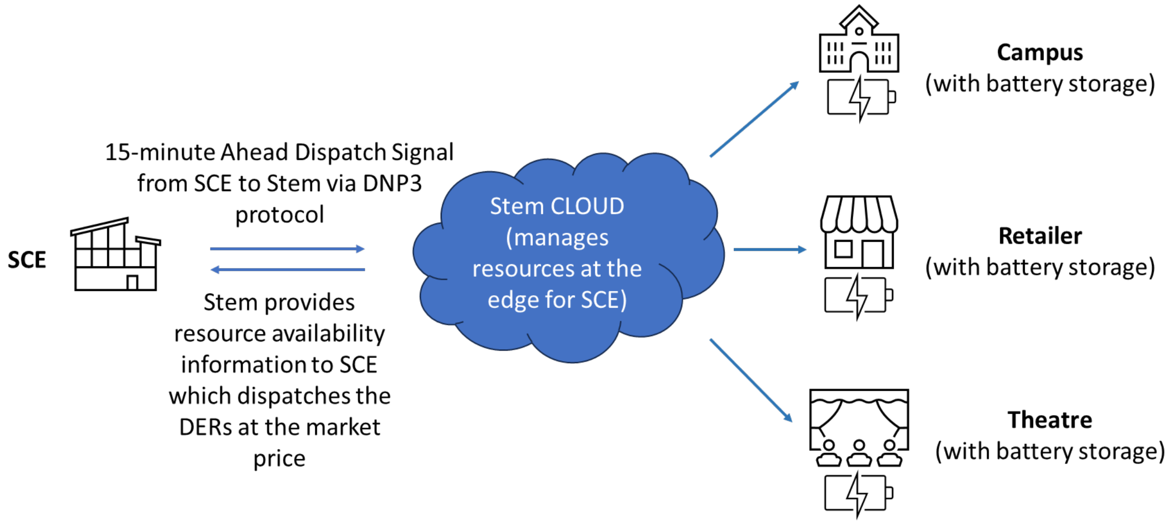
The Stem VPP resources are also available to support the supply and demand balancing requirements of the CAISO by participating in the Proxy Demand Resource (PDR) program. For example, when CAISO wants to reduce demand on the system, it can notify SCE, which can then draw upon the Stem VPP resources via a dispatch signal, as shown in Figure 53. Stem does not communicate with CAISO, but rather receives a dispatch signal directly with the utility and operates at the utility's instruction.

Stem leverages their cloud infrastructure to manage the input information, including telemetry to monitor the health and status of the battery systems. Stem also manages compliance with the interconnection requirements, including reliability and protection. They capture detailed information on the state of the energy storage systems and site load data on a one-second basis and store that data in its cloud. Stem shares a DNP3 connection with SCE's energy management system, and the utility provides a 15-minute dispatch notice in the cloud before the event, including sending a signal to stop dispatching when the event is concluded. Events may range from 1–4 hours.

The key benefit of the VPP service is that it is an "on-call" resource for capacity for SCE, improving customer satisfaction by reducing their utility bills while contributing power to the grid and meeting local capacity needs offsetting distribution upgrades in constrained regions.

FIGURE 53: COORDINATION

STRUCTURE FOR THE SCE-STEM VPP[179]



Appendix D – FERC Orders Affecting the Application of DERs

FERC Order No. 719
Dockets RM07-19-000 and AD07-7-000
https://www.ferc.gov/media/order-no-719

In October 2008, FERC amended regulations to improve the operation of wholesale markets with respect to demand response and market pricing for periods of shortages, long-term power contracting, market-monitoring, and responsiveness of RTO/ISOs to their stakeholders and customers. These reforms sought to ensure that demand response is treated comparably to other resources.

FERC Order No 745
Docket # RM10-17-000
https://www.ferc.gov/sites/default/files/2020-06/Order-745.pdf

FERC issued Order 745 in March 2011, which resulted in rules and regulations regarding demand response compensation in regulated wholesale energy markets. These rules improved the functioning and competitiveness of those markets. In that order, the Commission required each RTO and ISO to pay a demand response resource the market price for energy (locational marginal price or LMP) when the demand response resource can balance supply and demand as an alternative to a generation resource and dispatch of the demand response resource is cost-effective.

FERC Order No 755
Dockets Nos. RM11-7-000 and AS10-11-000
https://www.ferc.gov/sites/default/files/2020-06/OrderNo.755.pdf

FERC Order 755, issued in October 2011, revised regulations to provide compensation for frequency regulation service provided in wholesale markets. This includes separate payments for capacity and for actual performance. Frequency regulation services help system operators balance supply and demand over small timescales through a variety of resources. The removal of unduly discriminatory practices permitted more efficient dispatch of services and more appropriate compensation mechanisms.

FERC Order No. 2222
Docket No. RM18-9-000
https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf

FERC issued Order No. 2222 in 2020 with updates in 2021, requiring each ISO and RTO to develop a wholesale market participation model that allows DER and DER aggregations to provide and be compensated for wholesale market services. Each ISO/RTO must develop a compliance plan that outlines how it will comply with Order 2222 across a broad array of requirements, including DER interconnection, aggregation composition and size, information and data sharing, and coordination among the ISO/RTO, distribution utility, DER aggregator, and state and local regulatory authorities.

ISO/RTO FERC Order 2222 Compliance Plans

CAISO
https://www.ferc.gov/media/e-16-er21-2455-003

On May 18, 2023, FERC approved CAISO's second filing to implement Order 2222 compliance requirements by 2025.

ISO-NE
https://www.iso-ne.com/static-assets/documents/100005/er22-983-004.pdf

On November 2, 2023, FERC accepted ISO-NE's third compliance filing to implement Order 2222 compliance requirements for energy and ancillary services market changes by the fourth quarter of 2026.

MISO
https://cdn.misoenergy.org/2024-05-31%20Docket%20No.%20ER22-1640-003%20Order%20No.%202222%20Supplemental%20Filing633128.pdf

On May 30, 2024, MISO submitted its Order No. 2222 compliance filing, as directed in the October 10, 2023, Order from FERC, which ruled in that order that MISO must submit a revised date and address compliance deficiencies for their proposed Order 2222 implementation. FERC had noted insufficient explanation for the late 2029 date.

NYISO
https://nyisoviewer.etariff.biz/ViewerDocLibrary//Filing/Filing5049/Attachments/Filing_5049.zip

On April 20, 2023, FERC issued a second order partially accepting NYISO's Order 2222 compliance filing that proposes a Q4 2026 complete date. FERC directed NYISO to address additional inconsistencies in a subsequent filing, which was submitted on May 22, 2023.

PJM
https://www.pjm.com/directory/etariff/FercOrders/7033/20231113-er22-962-004.pdf

On November 13, 2023, the Commission issued an order partially accepting PJM's third compliance filing for implementation by Q1 2026. FERC directed PJM to address remaining compliance deficiencies in a subsequent filing.

SPP
https://www.spp.org/documents/71531/20240429_informational%20filing%20-%20order%20no.%202222%20compliance%20filing_er22-1697.pdf

On April 28, 2022, Southwest Power Pool (SPP) filed their FERC Order 2222 compliance filing that proposed an implementation date of Q3 2025. FERC provided a deficiency letter to SPP in August 2022 and SPP responded with clarifications on October 12, 2022. On March 1, 2024, FERC accepted SPP's Filing, finding that it partially complies with Order No. 2222, and requiring an additional compliance filing. On April 29, 2024, SPP submitted an informational filing to provide an update on implementation timeline milestones towards SPP's compliance with Order No. 2222.

FERC Order No. 901 – NERC New Inverter Based Resource Reliability Standards
Docket No. RM22-12-00
https://www.govinfo.gov/content/pkg/FR-2023-10-30/pdf/2023-23581.pdf

In October 2023, the FERC directed the NERC, the Commission-certified Electric Reliability Organization, to develop new or modified Reliability Standards that address Bulk-Power system reliability gaps related to inverter-based resources (IBR), including IBR-DER, in the following areas: data sharing; system model validation; Bulk-Power system planning and operational studies; and performance requirements.

VIII. Acronyms

ACEEE	American Council for an Energy-Efficient Economy
ADMS	Advanced distribution management system
AI	Advanced intelligence
AMI	Advanced metering infrastructure
API	Application programming interface
ASHRAE	American Society of Heating, Refrigerating and Air-Conditioning Engineers
ASP	Automated service providers
BG&E	Baltimore Gas and Electric
BIL	Bipartisan Infrastructure Law
BQDR	Brooklyn-Queens Demand Response program
BQMD	Brooklyn-Queens Management District
BTM	Behind the meter
C/I	Commercial/industrial customers
CAD	Computer-aided design
CAGR	Compound annual growth rate
CAISO	California Independent System Operators
CEC	California Energy Commission
CESER	Cybersecurity, Energy Security, and Emergency Response
CHP	Combined heat and power
CIM	Common Information Model
CIP	Critical Infrastructure Protection
CIS	Customer information systems
CPE	Customer premises equipment
CPP	Critical peak pricing
CPUC	California Public Utilities Commission
DA	Distribution automation
DER	Distributed energy resource
DERA	Distributed energy resource aggregation
DERMS	Distributed energy resource management system
DG	Distributed generation
DMS	Distribution management systems
DO	Distribution operators
DOE	Department of Energy
DR	Demand response
DSM	Demand side management
DSO	Distribution system operators
EE	Energy efficiency

EIA	Energy Information Administration
EISA	Energy Infrastructure and Security Act
EMS	Energy management system
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ESIG	Energy Systems Integration Group
ESS	Energy storage systems
EV	Electric vehicles
FERC	Federal Energy Regulatory Commission
FLISR	Fault location, isolation, and system restoration
FTM	Front of the meter
GEB	Grid-interactive efficient buildings
GHG	Greenhouse gas
GIS	Geographic information systems
GOOSE	Generic Object Oriented Substation Event
GW	Gigawatt
HVAC	Heating, ventilating, and air conditioning
IBR	Inverter-based resources
ICAP	NYISO's Installed Capacity Market
ICCP	Inter-control Center Communications Protocol
IDSP	Integrated distribution system plans
IEEE	Institute of Electrical and Electronics Engineers
IOU	Investor-owned utility
IRP	Integrated resource plans
ISO	Independent system operators
ISO-NE	New England Independent System Operator
IT	Information technology
ITC	Investment tax credits
LBNL	Lawrence Berkeley National Laboratory
MDM	Meter data management
MESA	Modular Energy System Architecture
MIDAS	Market Informed Demand Automation System
MISO	Midcontinent Independent System Operator
MW	Megawatt
MWh	Megawatt hour
NARUC	National Association of Regulatory Utility Commissioners
NEM	Net energy metering
NERC	North American Electric Reliability Corporation
NWA	Non-wire alternatives

NYISO	New York Independent System Operator
OEM	Original equipment manufacturer
OMS	Outage management systems
OPEC	Organization of Petroleum Exporting Countries
ORNL	Oak Ridge National Laboratory
OT	Operations technology
PCT	Programmable controllable thermostats
PDR	Proxy Demand Resource program
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PV	Solar photovoltaic
RFP	Request for proposal
RPS	Renewable portfolio standards
RTO	Regional transmission organizations
SCADA	Supervisory control and data acquisition
SCE	Southern California Edison
SPP	Southwest Power Pool
T&D	Transmission and distribution
TOU	Time-of-use
TSO	Transmission system operators
USB	Universal serial bus
VDER	Value of Distributed Energy Resources
VPP	Virtual power plant
VPP	Variable peak pricing

IX. References

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