



NARUC

National Association of Regulatory Utility Commissioners

Advancing Electric System Resilience with Distributed Energy Resources: A Review of State Policies



Kiera Zitelman, NARUC
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About SEIN

The Solar Energy Innovation Network (SEIN) assembles diverse teams of stakeholders to research solutions to real-world challenges associated with solar energy adoption. This paper is written as input to a broader project by the National Association of Regulatory Utility Commissioners under SEIN. NARUC's SEIN project focuses on the value of resilience and its use in state policymaking. NARUC has previously explored the topic of resilience as it relates to electricity regulation (Keogh & Cody, 2013). NARUC has also explored opportunities for improved electric grid resilience in the face of "black sky" hazards that can cause long-duration power interruptions (Stockton, 2014). In parallel, NARUC has developed a manual for state utility regulators on rate design and compensation models for distributed energy resources (DERs) (NARUC, 2016). NARUC's SEIN research builds on these previous efforts by investigating whether and how current state DER policies support resilience objectives. Concurrently, Converge Strategies LLC, as a member of NARUC's SEIN team, published a report covering valuation methodologies for resilience. The overall goal of the NARUC SEIN project is to provide state regulators with guidance for taking resilience into account when evaluating investments in the distribution system.

Disclaimer

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Executive Summary

Severe weather, cyber attacks, geomagnetic disturbances, and other hazards and threats have caused or have the potential to cause substantial levels of damage to electricity infrastructure and the global economy. Growth in distributed energy resources (DERs) and increasing attention to the resilience of the electric grid – its ability to “anticipate, absorb, adapt to, and/or rapidly recover” from disruptions, according to the Federal Energy Regulatory Commission (FERC, 2018) – have created an opportunity for energy stakeholders to develop and deploy “resilient DERs,” resources in the distribution grid that improve the ability of a customer, critical facility, and/or the distribution system in general to anticipate, absorb, adapt to, and/or rapidly recover from disruptions. This paper explores how existing state regulations intersect with resilience and highlights opportunities where state regulators can employ DERs to advance resilience.

DERs are resources sited close to customers on the distribution grid and include such technologies as solar photovoltaic, wind, combined heat and power, energy storage, demand response, electric vehicles, microgrids, and energy efficiency (NARUC Staff Subcommittee on Rate Design, 2016). DERs can be configured to support resilience goals in a number of ways. First, by producing electricity within the distribution grid, where more than 90 percent of outages originate, DERs can decrease the frequency and duration of outages. Second, DERs have the technical capability to deliver both energy to specific loads to enable continued operation despite interruptions or losses on the bulk power system, as well as ancillary services¹ to the grid. DERs must be configured to provide these capabilities, however, and policies need to be explicitly designed to incentivize them. For example, while ancillary services contribute to resilience, compensation mechanisms for ancillary services have not been designed with resilience in mind. With these combined benefits and increasing customer adoption of DERs, state public utility or public service commissions (commissions) charged with the economic regulation of investor-owned utilities have an interest in advancing their knowledge of resilience and how DERs can support resilience goals.

Resilience is an important focus for state energy regulators, particularly as novel and more severe threats have emerged and caused substantial damage to the energy system and broader society in recent years. Traditional definitions and measures of reliability do not fully account for the array of system threats and impacts. As NARUC observed in 2013, “Resilience fits within the existing structure of reliability that public utility commissions already oversee, but is particularly valuable for dealing with severe and non-traditional hazards” (Keogh & Cody, 2013). This paper aims to provide an overview of the potential resilience benefits of DERs and how commissions can incorporate DERs into resilience planning. The conversation around defining and quantifying resilience is complex and decentralized among numerous stakeholders (Rickerson et al., 2019). Commissions, however, are well positioned to apply a resilience lens to DER deployment strategies given their role in deciding who pays for DERs, what revenue streams DERs can pursue, who owns DERs, and how DERs are treated in resource planning. This paper does not attempt to draw conclusions from that ongoing conversation but instead focuses on the following questions:

- How are state commissions approaching electricity system resilience? What is the commission’s role?
- What is the relationship of DERs to system resilience?
- How can states implement policies to expand DER deployment in a manner that improves resilience?

¹ Ancillary services include regulation and frequency response, spinning reserves, non-spinning reserves, and other services; see <https://www.nrel.gov/docs/fy19osti/71984.pdf> for a complete definition.

NARUC facilitated a series of workshops with state regulators to understand their attitudes towards resilience and DERs. In response to questions about how DERs can improve resilience, state regulators developed a set of traits that describe resilient DERs and expressed interest in learning from demonstrations of DER installations that exhibit these characteristics. Depending on the particular resilience threat and load characteristics, DERs may possess one or more of the following capabilities that enable improved system resilience:

1. Dispatchability: Resilient DERs can respond to a disruption at any time with little to no advance warning.
2. Islanding Capability: Resilient DERs have the ability to isolate from the grid and serve load during a broader outage.
3. Siting at Critical Loads/Locations: Resilient DERs reside at critical loads or at critical points on the grid (e.g., areas of high residential density).
4. Fuel Security: Resilient DERs do not rely on the availability of a limited physical fuel to provide power.
5. Quick Ramping: Resilient DERs are capable of changing output quickly to match rapidly changing load.
6. Grid Services: Resilient DERs can provide voltage support, frequency response, and other grid services that contribute to stabilization during disruptions.
7. Decentralization: Resilient DERs are sized and sited to support a load in the distribution system.
8. Flexibility: Resilient DERs can be deployed quickly and at relatively low cost, when compared to centralized generation, transmission, and/or distribution, at locations and times where resources are needed.

This paper is organized as follows:

- Section 1 introduces trends in resilience and DERs and summarizes the current landscape for both.
- Section 2 discusses how resilience fits within the context of existing regulator and policymaker roles and responsibilities.
- Section 3 provides examples of state policies intended to encourage DER deployment and assesses whether those policies are supporting the characteristics of resilient DERs.
- Section 4 explores remaining barriers to realizing the resilience benefits DERs can provide.

1. Introduction

The modern electricity generation and delivery system faces a number of hazards and threats. Utilities must understand, prepare for, and respond to a growing set of intensifying challenges, from natural disasters such as hurricanes, wildfires, earthquakes, sea level rise, geomagnetic disturbances, and flooding, to manmade events like physical assaults and cyberattacks. The National Oceanic and Atmospheric Administration (NOAA) counted 14 separate events in 2018 that each caused more than \$1 billion worth of broader economic damage, including restoration costs (NOAA NCEI, 2019). Traditional utility grid-hardening investments (e.g., vegetation management, moving wires underground) may fail to prepare the system for emerging threats, leaving ratepayers vulnerable to more frequent and sustained outages and subsequent costly repairs.

These conditions have led to increased interest in a particular term into the electricity policy conversation: resilience. Definitions of resilience often encompass recovery from a disruption, overlapping with reliability, a well defined term with associated metrics. Where resilience clearly differs from reliability is how the system behaves prior to a disruption, and subsequently how preparation may decrease the probability, duration, and/or scale of a disruption (Taft, 2018). As the National Renewable Energy Laboratory (NREL) defines it, resilience is “the ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions through adaptable and holistic planning and technical solutions” (NREL, 2019). Resilience also includes actions to keep power disruptions as brief and minimal as possible. Resilience encompasses responses to non-traditional hazards, large-scale catastrophic events, long-term outage potential, and cascading failures (Keogh & Cody, 2013).

Resilience is a new term for some state public utility or public service commissions (commissions). The National Association of Regulatory Utility Commissioners (NARUC) has helped guide commissions in electricity system resilience previously, most notably in a 2013 paper, *Resilience in Regulated Utilities*. That paper defined resilience as:

Robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event (Keogh & Cody, 2013).

NARUC’s definition is one of many proposals developed by electricity stakeholders.² Unlike reliability, resilience lacks a single, broadly accepted definition or value. Critically, most definitions of resilience accept that major events occur and will damage electricity infrastructure. Resilient systems plan for and minimize the effects of these events.

Resilience and the Distribution System

The distribution system is prone to multiple hazards. Thunderstorms, high winds, or other weather events can disrupt distribution by directly or indirectly (e.g., high winds causing trees to fall) knocking down poles or wires. Animals, mainly squirrels, are capable of damaging distribution infrastructure (Hoffman, 2017). Equipment that enables the distribution system itself (e.g., substations) may fail, leading to local outages. Extreme weather events cause the majority of long-term outages today, with damage from animals, mostly squirrels, causing most short-term outages (Hoffman, 2017).

Utilities invest in preventative measures (to decrease the likelihood of outages) as well as restoration measures (to decrease the duration of outages). System redundancies, emergency preparedness, and preventative measures

² The Federal Energy Regulatory Commission (FERC) defines resilience as “[t]he ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.” The North American Electric Reliability Council (NERC) and the National Infrastructure Advisory Council (NIAC) adopted FERC’s definition. Although FERC, NERC, and NAIC are more attentive to the bulk power system than the distribution system, the notion of “anticipate, absorb, adapt to, and/or rapidly recover” is equally relevant for distribution.

deliver dependable power the vast majority of the time to nearly 150 million retail customers via 6.4 million miles of transmission and 700,000 miles of distribution lines (U.S. DOE, 2017a). An established set of reliability metrics (e.g., System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), and Customer Average Interruption Duration Index (CAIDI))³ enables customers and regulators to compare utility performance in minimizing minutes of outages and to take steps to improve reliability in at-risk locations. Independent system operators adhere to a “one day in 10 years” reliability standard to dictate resource procurement and market structures (Melvin, 2018).

U.S. customers experienced average power interruptions (SAIDI) of 4 hours excluding major events, and 7.8 hours including major events in 2017 (U.S. EIA, 2018c). Hurricanes and winter storms are more difficult to counter. Equipment may be flooded or frozen, extending restoration time. Customers in Florida, for example, experienced nearly 40 hours of power interruption including major events in 2017, largely due to Hurricane Irma (U.S. EIA, 2018c). The scale of damage from extreme weather is high and increasing as climate change leads to more frequent and intense storms. A June 2018 study found that as climate change alters atmospheric circulation, wind patterns slow down, causing tropical cyclones (hurricanes and typhoons) to move more slowly and magnify the scale of damages. Combined with observed increased rainfall, slower storms have the potential to result in more inland flooding, causing even more damage to utility equipment (Kossin, 2018). In addition, climate change-driven drought threatens virtually all components of energy generation and delivery via the increased risk of wildfires, changing precipitation patterns, and limited availability of water for cooling power plants (U.S. DOE, 2016).

Whereas vegetation management may reduce the likelihood of a tree falling on a distribution line, there is no action utilities can take to eliminate weather. In 2017, the 16 biggest weather events caused a collective \$350 billion worth of damage and led to large-scale, multi-day outages (Silverstein et al., 2018). Traditional reliability investments failed to prepare the system to “anticipate, absorb, adapt to, and/or rapidly recover” from these types of threats.

But with 700,000 miles of distribution lines and hundreds of thousands of pieces of distribution equipment, utilities cannot harden the entire system while keeping rates affordable. The costs of undergrounding distribution lines can reach up to \$2,000 per foot in dense urban areas like San Francisco (Broomhead & Carr, 2016). The consequences of inaction, however, have brought previously unpalatable options up for review. Devastating wildfires in 2017 and 2018—including the Camp Fire, attributed by the California Department of Forestry and Fire Protection to Pacific Gas & Electric’s transmission lines—resulted in lost lives, billions of dollars in liability costs, and PG&E’s eventual bankruptcy filing in January 2019 (Walton, 2019). In May 2019, the California Public Utilities Commission approved the use of proactive power shutoffs in utility wildfire mitigation plans. While specified as a “measure of last resort” (CPUC 2019b), PG&E has already instituted a public safety power shutoff that affected 1,600 customers for several hours on a Saturday in June 2019 and additional proactive shutoff events are anticipated (PG&E, 2019).

Commissions are responsible for directing ratepayer funds in the most cost-effective manner. With more threats to the distribution grid, strategically placing generation resources or energy storage on the distribution system may be the most cost-efficient option in some cases; particularly in remote locations where transmission and distribution lines are difficult to build or maintain. In a 2016 manual on rate design for DERs, NARUC presented several definitions of DERs from various stakeholders, ultimately adopting the following description:

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

3 Common reliability indices are elaborated upon by IEEE here:
http://www.ewh.ieee.org/r6/san_francisco/pes/pes_pdf/Reliability_and_Artificial_Intelligence/Common_T&D_Reliability_Indices.pdf

DERs have exhibited substantial declines in costs and significant market growth (Trabish, 2018). Solar photovoltaic (PV) and battery storage systems have seen substantial advancements in technology that have driven improved efficiency and lower costs (LBNL, 2018). The cost of solar panels has fallen 60 percent since 2010, with installed distributed solar PV capacity nearly quadrupling from 5.6 GW in 2014 to 20.1 GW in 2019 (U.S. EIA, 2018b).

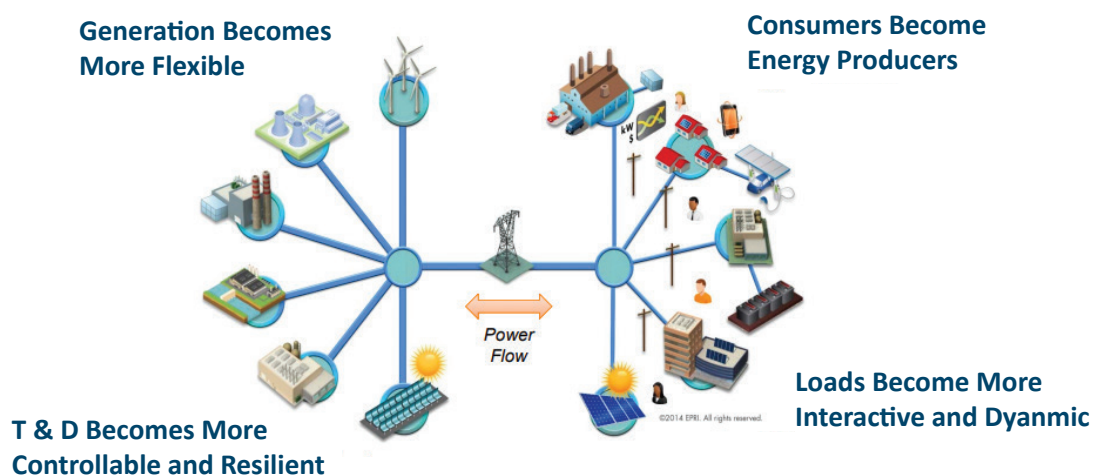
DERs can be configured to support resiliency of the electric grid. DERs capable of islanding—continuing to supply power while electricity from the distribution utility is no longer present—may be able to counter generation issues, including fuel shortages. Some DERs, particularly when aggregated, are also capable of providing similar capacity and ancillary services that traditional, centralized generators do, including demand response, voltage regulation, and other grid services (Cook et al., 2018a).

2. Approaches to Resilience

2.1. State Commissions and Resilience

The majority of electricity customers receive power from investor-owned utilities (IOUs) (U.S. DOE, 2017a). State commissions regulate retail sales of electricity by IOUs—and in some infrequent cases, electric cooperatives—to end users. State commissions are typically charged with ensuring the provision of safe, reliable, and affordable electricity service to all ratepayers. Commissions are one of several regulatory entities with authority over electricity generation and delivery. FERC regulates, among other areas, transmission and wholesale sales of electricity in interstate commerce, including by regional transmission operators (RTOs) or independent system operators (ISOs). Each RTO/ISO operates energy (FERC, 2015), capacity (GAO, 2017), and/or ancillary services (Zhou et al., 2016) markets with distinct differences. FERC delegated reliability regulation to a separate entity, the North American Electric Reliability Corporation (NERC), in July 2006. NERC is responsible for the resilience of the bulk power system adequacy and security. Responsibility for the resilience of the distribution system is shared among multiple entities, with no single organization holding ultimate accountability (Keogh & Cody, 2013). All of these regulatory entities and market operators play a role in assuring reliable electricity delivery. Each of their roles in defining and ensuring resilience, however, has yet to be decided and will likely evolve.

Figure 2.2.1: The Power System Looking Forward (Electric Power Research Institute, 2015)



http://smartgrid.epri.com/doc/20150821/2_EPRI%20Integrated%20Grid%20Overview%20Opportunities%20and%20Challenges_Wakefield_Final.pdf.

Through oversight of the costs of delivering electricity through the grid, commissions have a key role to play in ensuring that utility investments are prudent and cost effective while meeting reliability and other goals. As the transmission and distribution (T&D) system begins to support two-way power flows resulting from wider DER deployment, the array of technologies and behaviors that impact system resilience grows (**see Figure 2.2.1**), along with the array of decisions about investments that utilities could make. Commissions must stay knowledgeable about these changes to exercise their oversight responsibilities. The potential for leveraging ongoing activities, like customer-driven DER installation, to provide resilience benefits for the entire grid is a promising prospect for cost efficiency and grid hardening, particularly as customers choose to adopt DERs at increasing levels.

2.2. Regional and Federal Stakeholder Viewpoints

The actions of other stakeholders at the state, regional, and federal levels influence the level of authority and the range of options available to commissions towards the goal of improving resilience. As economic regulators, commissions are primarily responsible for the economic regulation of electric service through direct oversight over retail electricity rates, electricity distribution, reliability, and infrastructure siting (M.J. Bradley & Associates LLC, 2011). However, commissions are constrained by the actions of state legislatures and federal laws and cannot act without a clear mandate from policymakers. Additionally, the scope of commission authority is limited to retail sales while federal agencies, mainly FERC, have jurisdiction over wholesale power markets. FERC action may be required to enable resilient DERs to participate in wholesale markets. FERC has begun this process by issuing Order 841, instructing ISOs to write rules enabling the full participation of energy storage, one component of resilient DER deployment.

At the federal level, the U.S. Department of Energy (DOE) has asserted that on-site fuel supply is a critical determinant of resilience (Heidorn, 2018) (Perry, 2017). However, independent analysis has demonstrated that less than 0.1 percent of outages during the last five years resulted from generation shortfalls or fuel supply interruptions, whereas the vast majority of outages occurred in the distribution system (Sliverstein et al., 2018). The national conversation on the meaning of resilience and what policymakers and different stakeholders should do to assure it is ongoing.

ISOs have differing viewpoints on the importance of fuel security to grid resilience, although all have asserted that an impending emergency driven by generators running out of fuel does not exist. Most are engaged in stakeholder discussions of what resilience means and how it should be incorporated into each market. ISO New England (ISO-NE) President and CEO Gordon van Welie noted that the optimal solution would be to price resilience and incorporate the value into the ISO-NE market (Melvin, 2018). The California Independent System Operator (CAISO), ISO-NE, Midcontinent Independent System Operator (MISO), and Southwest Power Pool (SPP) called on FERC to “allow individual RTOs/ISOs to pursue the resilience-related issues and initiatives they have identified in their region through collaborative efforts with their stakeholders” (CAISO et al., 2018). PJM Interconnection, the wholesale electricity market operator for the Mid-Atlantic region, affirmed the importance of fuel security as an element of resilience but sees it as one of many factors affecting grid resilience (PJM, 2018a).

The Department of Defense (DOD) is an important stakeholder in the resilience conversation. The need for reliable electric service at domestic military installations to accomplish national defense objectives has led DOD to pursue energy resilience more aggressively than most states and municipalities. DOD has successfully partnered with states, communities, regulators, and utilities in resilient energy projects and looks to continue expanding these partnerships to build resilience to emerging threats (Rickerson et al., 2018). Cooperation between commissions and DOD is important to advance resilience going forward, particularly to advance partnerships with state and local governments in developing resilience solutions with community benefits. Naval Submarine Base New London in Groton, Connecticut, demonstrates the benefits of state support for resilient microgrids to achieve broader public benefits and meet the base’s needs (Rickerson et al., 2018). The state awarded a \$3 million grant from the Department of Energy and Environmental Protection’s (DEEP’s) microgrid grant and loan pilot program to advance

the project. The program has provided funding to multiple projects across the state, with resilience objectives as the main driver (Gaunt, 2016).

DOE, ISOs, and DOD all have an interest in monitoring and learning from distribution-level resilience solutions. What works for individual critical infrastructure facilities and communities can be scaled up to improve bulk system resilience. Commissions are better situated to consider the effectiveness and efficiency of distribution system strategies. In the following sections, this paper elaborates on state approaches to resilience and how DERs can contribute.

3. Resilience Capabilities of DERs

Resilience is a new term for some commissions, and regulators in many states are considering how resilience planning fits into commissions' existing regulatory frameworks. Commissions' roles as public venues for decision-making are especially important to gather input from a broad array of stakeholders. In the face of new challenges and opportunities, electricity stakeholders are debating the definition of resilience and what to do about it.

Given changing technologies, emerging threats, and evolving customer demands, the question for regulators is how DERs can advance system resilience alongside the benefits they already provide to ratepayers, utilities, and the grid. As NARUC wrote in 2013: "Far better [than system-wide hardening for generation, transmission, and distribution assets] are investments that deliver lower-cost service and improve system performance" (Keogh & Cody, 2013).

In a series of facilitated workshops with stakeholders from commissions, RTOs, and federal government (NARUC, 2017), regulators developed a set of eight characteristics of resilient DERs to elaborate on how DERs can counter threats and enhance resilience. These traits include:

1. Dispatchability: Resilient DERs can respond to a disruption at any time with little to no advance warning.
2. Islanding Capability: Resilient DERs have the ability to island from the distribution grid and serve load during a broader outage.
3. Siting at Critical Loads/Locations: Resilient DERs reside at critical loads or at critical points on the grid (e.g., areas of high residential density).
4. Fuel Security: Resilient DERs do not rely on the availability of a limited physical fuel to provide power.
5. Quick Ramping: Resilient DERs are capable of changing output quickly to match rapidly changing load.
6. Grid Services: Resilient DERs can provide voltage support, frequency response, and other grid services.
7. Decentralization: Resilient DERs are sized and sited to support a load in the distribution system.
8. Flexibility: Resilient DERs can be deployed quickly and cheaply (when compared to centralized generation, transmission, and/or distribution) at locations and times where resources are needed.

Resilient DERs offer distinct advantages from "non-resilient" DERs – those not designed with resilience as an explicit objective. All DERs, resilient or not, are decentralized and offer benefits distinct from large centralized generators. Single or aggregated DERs can both offer resilience benefits, although aggregated DERs have increased ability to provide grid services. Islanding capability is a unique trait of resilient DERs that requires intent during project design to configure the resource to island from the distribution grid. Several traits are enabled by energy storage paired with a generating DER: dispatchability, quick ramping, and flexibility. Renewable DERs remove the need to rely on a physical fuel supply, but they do exhibit intermittency driven by limited availability of sun or wind.

Pairing these resources with battery energy storage enables access to electricity for longer or different time periods than when it is generated, although durations are limited by what the battery can provide. (Typical commercially available batteries provide up to four hours of storage, although many installed batteries have shorter durations (U.S. EIA, 2018d)).

The optimal combination of traits depends on the specific resilience needs of project customers. For example, a resilient microgrid might be able to rely partially or fully on diesel or natural gas generation, removing or reducing the need for battery storage paired with renewable generation. Physical fuel storage is difficult in urban or flood-prone areas, but regions that face different resilience threats may not experience issues siting and maintaining fuel storage. Project developers, customers, state regulators, and other stakeholders will need to assess their own needs and decide which traits are important in their context.

To maximize the resilience value of DERs, regulators can learn about existing DER projects that exhibit some or all of the identified DER characteristics, and prioritize the deployment of resilient DERs in their own states. The Borrego Springs microgrid in California provides a case study of the benefits of solar plus storage to serve an isolated area with transmission constraints. San Diego Gas & Electric (SDG&E) selected the microgrid as an alternative to costlier transmission upgrades. Project capabilities include peak load reduction and demand response (Berkeley Lab, 2019). A single project containing all eight of the DER resilience characteristics may not yet exist, nor may it be needed to demonstrate the resilience value of DERs (Cook et al., 2018a), but DERs have demonstrated each characteristic independently, and there is no technical reason that a resilient DER project could not demonstrate numerous of these traits. While the range of use cases for each trait is still a topic of conversation, the following section explores how state-level DER policies interact with resilient DER characteristics.

4. States and DERs

Commissions are an important piece of the DER policy landscape. As economic regulators, commissions are resource-neutral when making decisions on distribution-level investments and consider the costs and benefits of any potential solution, whether a capital expenditure, policy, or other strategy to delivery affordable, reliable, and efficient electricity. Commissioners balance affordability with reliability, efficiency, and in some instances, public policy goals as directed through governing statutes. Commissions are also charged with implementing regulations to carry out the will of ratepayers via policies from the state legislature or governor. Both of these aspects put commissions in an ideal position to support applying resilience to DER deployment—they decide who pays for DERs, what revenue streams DERs can pursue, who owns DERs, and how DERs are treated relative to other resources in planning.

This section focuses on broadly replicated actions states have taken to encourage DER deployment and evaluates whether and to what extent those actions have supported or discouraged the traits of resilient DERs. **Table 4.1** summarizes the eight resilience traits of DERs and whether various types of regulatory processes and policies could encourage those resilience capabilities. No single existing policy encourages all eight characteristics, but incremental improvements can support additional traits by incentivizing specific performance capabilities or unlocking compensation streams. The subsections below include discussions of each policy type and its connection to resilience characteristics. In each subsection, a table summarizes which resilience characteristics could be encouraged with this type of action.

Table 4.1 Key Resilient DER Characteristics that Can Be Encouraged by Types of Regulatory Processes and Policies

Key Resilient DER Traits	REGULATORY PROCESSES AND POLICIES					
	Integrated Resource Planning	Hosting Capacity Analysis	Clean Peak Standards	Advanced Rate Design	Public Purpose Microgrids	State and Local Resilience Roadmapping
Dispatchability	•		•	•		
Islanding Capability					•	•
Siting at Critical Loads / Locations		•			•	•
Fuel Security				•	•	•
Quick Ramping	•				•	
Grid Services	•				•	
Decentralization	•	•		•	•	•
Flexibility	•	•	•	•	•	•

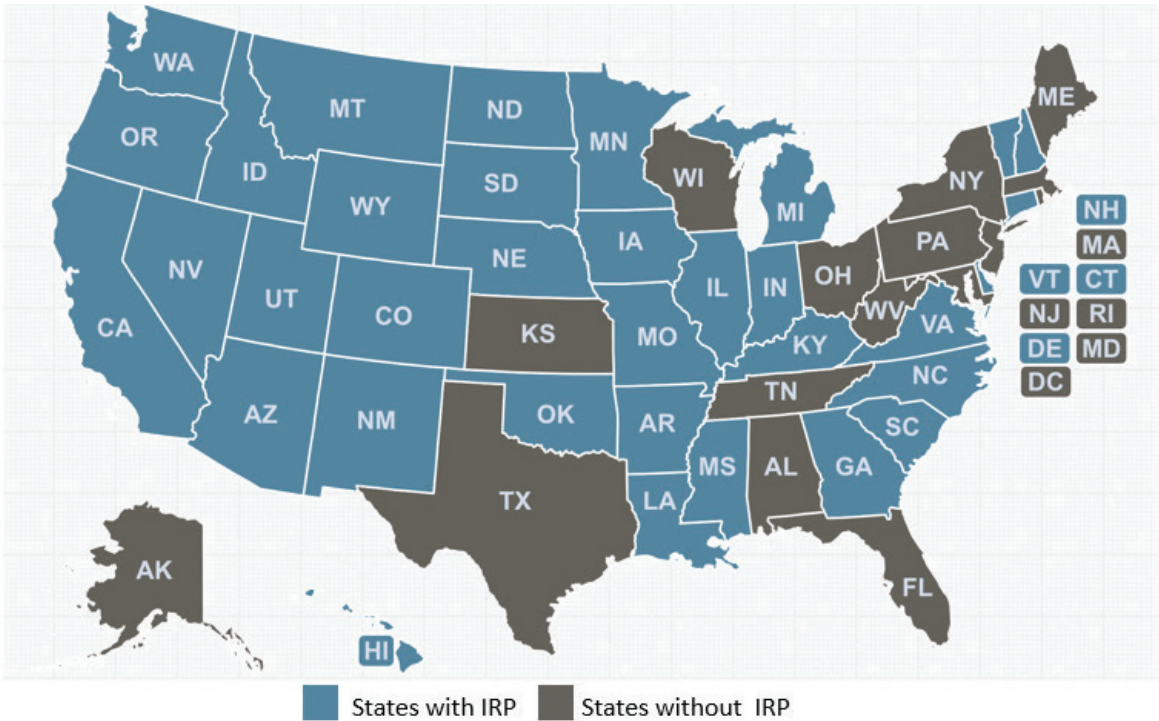
4.1. Planning Processes

Integrated Resource Plans

Regulated utilities and commissions invest considerable effort into preparing, submitting, evaluating, and implementing integrated resource plans (IRPs). IRPs are long-term plans (typically 10 years, with exceptions in both directions) for how utilities intend to meet demand. An IRP sets out which demand-side and supply-side

Figure 4.1: State IRP Policies

States with Integrated Resource Plan (IRP) Requirements



resources the utility plans to use in the future (Wilson & Biewald, 2013). In states that require IRPs, there is usually an extensive stakeholder process enabling consumer advocates, project developers, generators, interest groups, and ratepayers to express their views on which resources the utility should pursue. Thirty-four states have statutes or rules requiring utilities to submit periodic IRPs, subject to a varying degree of commission review (Figure 4.1) (Wilson & Biewald, 2013) (Frick, 2018).

IRPs can lead a utility to make decisions with long-term costs and benefits in mind by considering the full suite of available options on the supply and demand side to reliably serve customers (Wilson & Biewald, 2013). IRPs serve the critical function of providing transparent information about the choices a regulated utility faces. By calling for utilities to consider all appropriate information about the costs and benefits of various choices, including relatively newer options like demand-side management and distributed energy resources, commissions can achieve better value for ratepayers. IRPs could support the resilience characteristics of dispatchability, quick ramping, grid services, decentralization, and flexibility, particularly when commissions require the consideration of specific technologies or ownership structures that utilities may not have incorporated absent a commissioner order (Table 4.2).

Table 4.2: Key Resilient DER Characteristics that Can Be Encouraged by Integrated Resource Plans (IRP)	
Dispatchability	
Quick ramping	
Grid services	
Decentralization	
Flexibility	

Some commissions have taken specific actions to require that utilities consider particular technologies or accounting methods in their IRPs. The Washington Utility and Transportation Commission (UTC), for example, required regulated utilities to include energy storage in their biannual IRPs in an October 2017 policy statement. The change was non-prescriptive, establishing “an expectation that utilities will demonstrate reasonable consideration...of energy storage options in their IRPs” (Washington UTC, 2017a). The Washington UTC’s policy statement admitted that the state’s utilities lacked access to an organized market to provide storage price data and opportunities for monetization, but noted that a critical first step was to encourage utilities to make efforts to quantify the benefits of storage and begin gathering cost data (Washington UTC, 2017b). Although this approach does not explicitly encourage resilient DERs, mandating the consideration of all the benefits of storage, such as the ability to provide electricity when generating assets are not producing, can bolster the range of use cases for DERs and may eventually lead to more investment in resilient DERs.

Florida’s planning approach offers an example of instituting a new planning process specific to resilience threats. In 2006, following intense hurricanes in 2004 and 2005, the Florida Public Service Commission ordered the state’s utilities to file three-year storm hardening plans. The PSC’s evaluation of system performance during the 2016 and 2017 storm seasons has shown this proactive planning approach to be effective in improving resilience (Florida PSC, 2018). The PSC used outage duration as a metric for resilience in its 2018 report, although the commission did not explicitly define resilience as distinct from reliability, nor did it assess the cost-effectiveness of specific hardening investments.

Hosting Capacity Analyses

“Integrated distribution planning” is a holistic planning process requiring the consideration of distribution investments alongside transmission or generation expenditures in a standardized framework for long-term utility resource planning (ICF, 2016). Hosting capacity analysis (HCA) is a component of integrated distribution planning that offers potential for incorporating resilient DER deployment into long-term strategy. HCA is a relatively new tool that synthesizes distribution system location details, load curves, feeder designs, and other attributes to improve the integration of DERs into system planning given system characteristics (i.e. thermal, power quality, and frequency controls) (IREC, 2017). The Electric Power Research Institute defines hosting capacity as “the amount of DER that can be accommodated on the existing system without adversely impacting power quality or reliability” (Punt, 2017). HCA can streamline DER interconnection processes, help in distribution system planning, and offer input into the locational value of DERs (Baldwin, 2018).

HCAs can aid in resilient DER deployment by prioritizing projects in high-value locations on the grid. While system resilience is not an explicit component of nascent HCA, utilities may see value in comparing HCA maps with locations prone to resilience threats, thereby enabling customers, developers, and utilities to identify where DERs could offer high resilience benefits. HCA maps can also reveal areas in need of increased hosting capacity, whereby DERs (e.g., energy efficiency, storage) can be designed and deployed to increase feeders' hosting capacity (IREC, 2017). HCA could support the resilience characteristics of critical load siting, grid services, decentralization, and flexibility (**Table 4.3**) by pinpointing high-value locations for resilient DER installations.

Table 4.3: Key Resilient DER Characteristics that Can Be Encouraged by Hosting Capacity Analyses (HCA)

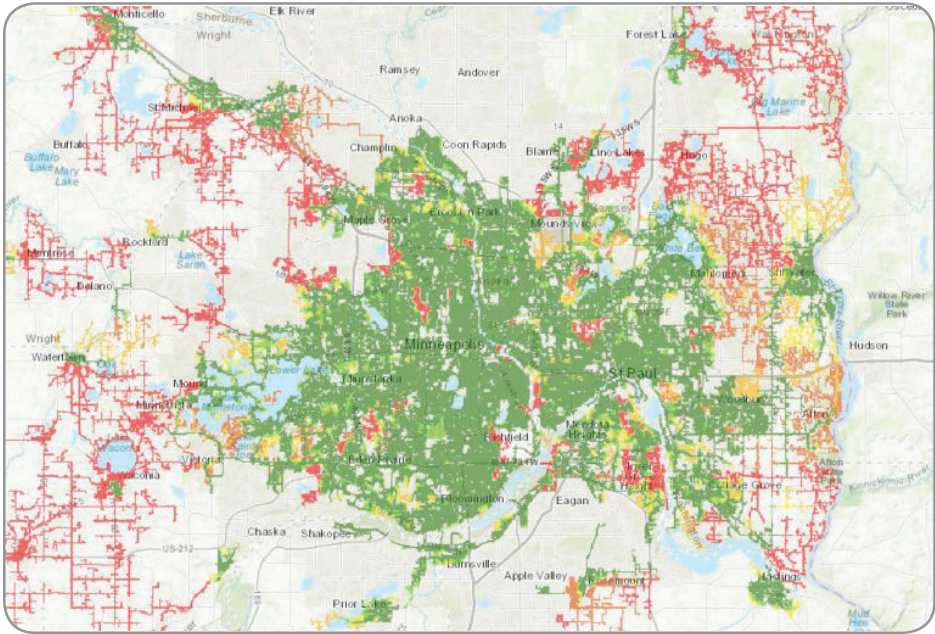
Siting at critical loads/locations
Decentralization
Flexibility

However, HCA is a labor-intensive process requiring high quality data. The level of effort depends on the selected method. The Interstate Renewable Energy Council (IREC) cites four available methods of conducting HCA, each with tradeoffs between effort required and relevance of results (IREC, 2017). Integrating resilience into the HCA process will need to strike the right balance between effort and usefulness. For example, lengthy lag time between new projects on the system and addition of data to HCA maps reduces usefulness, but quick updates require investments and may raise costs.

The Minnesota Public Utilities Commission (PUC) ordered the state's largest utility, Xcel Energy, to complete a HCA in 2016.⁴ In the company's second HCA iteration (2017), Xcel produced a publicly available map of the distribution system throughout the company's service territory with easily understandable red/yellow/green ratings of each individual feeder according to favorability for additional DER interconnection (**Figure 4.2**). Xcel released an update in November 2018 that is under consideration before the commission (Hannah, 2017).

By combining existing HCA data with detailed local resilience vulnerability assessments and historical outage data, the Commission could prioritize high-impact locations for resilient DER installations. As a form of data collection and visualization, HCA can only highlight areas on the grid and does not currently factor into rates or compensation mechanisms for resilient DERs. In the future, commissions could incorporate HCA into rate design and resource planning to enhance resilience.

Figure 4.2 Xcel hosting capacity map, November 2017



⁴ Per Minn. Stat. 216B.2425. Docket No. E002/M-15-962 (Xcel's first HCA); Docket No. E002/M-17-777 (Xcel's second HCA); Docket No. E002/M-18-684 (Xcel's third proposed HCA)

4.2. Portfolio and Clean Peak Standards

Renewable portfolio standards (RPS) require a percentage of a utility’s total load or a set amount of energy (MWh) to be generated from renewable resources. An RPS and the definitions of the renewable resources eligible for compliance are generally dictated by state law (NCSL, 2019). While they generally do not set targets, commissions are responsible for ensuring that regulated utilities achieve RPS targets. As of October 2018, 29 states and the District of Columbia have a set RPS, nine of which include carve-outs for solar or customer-sited renewable generation. RPS targets vary considerably, with Hawaii, Oregon, California, New York, New Jersey, the District of Columbia, and Vermont setting goals of 50 to 100 percent (DSIRE, 2018).

Since they were initially designed in the 1990s, RPS targets have had a significant impact on renewable energy growth in the United States. A 2017 Lawrence Berkeley National Laboratory analysis shows that RPS requirements have accounted for approximately half of all growth in renewable energy since 2000 (Barbose, 2017). States have generally met their interim RPS goals, and program costs have averaged 1.6 percent of retail electricity bills, according to the same study. RPS programs have driven utility-scale and distributed generation, the latter mainly through carve-outs requiring procurement from a set amount of DERs under a given capacity (Synapse, 2017). As RPS programs continue to be largely effective in achieving renewable generation deployment and controlling costs, policymakers and regulators can turn their attention to aligning goals with resilience planning through a number of emerging strategies.

Motivations for RPS targets are generally focused on reducing greenhouse gas emissions and improving air quality, not improving reliability. However, attention to particular resilient technologies can enhance the ability of RPS programs to deliver resilience. Several states have adopted capacity targets for specific technologies, such as distributed PV or energy storage. In 2013, the California Public Utilities Commission (CPUC) established an energy storage target of 1,325 MW for the state’s three IOUs to achieve by 2020 (CPUC, 2013). The storage target is in addition to a broader RPS of 100 percent carbon-free electricity by 2045, as per a 2018 state law (CPUC, 2019a). Massachusetts has an energy storage target of 200 MWh by 2020 (MA DOER, 2019).

Massachusetts is the only state that has passed a “Clean Peak Standard” (CPS) into law. Arizona, California, and North Carolina have considered implementing a CPS (DeFelice, 2020). A CPS could support the resilience characteristics of dispatchability and flexibility (**Table 4.4**) by incentivizing the procurement of renewable generation paired with storage, making it dispatchable when needed.

Table 4.4: Key Resilient DER Characteristics that Can Be Encouraged by Clean Peak Standards (CPS)

Dispatchability
Flexibility

States considering CPSs can draw lessons from successful applications of energy efficiency programs reducing peak demand. Peak demand reductions save customers money in the short term by eliminating the need for expensive peak generation and in the long term by potentially removing the need to invest in new generation, transmission, and distribution. The American Council for an Energy-Efficient Economy counted four utilities that had reduced peak demand by 2 percent or more from annual peak and seven that reduced by between 1 percent and 2 percent in 2017, demonstrating that targeted peak demand reductions can be highly effective (Relf et al., 2017). Because 40 percent of energy costs are driven by the highest 10 percent of hours (Spector, 2013), shaving peak load can deliver substantial savings to ratepayers. The resources that can be deployed to achieve CPS compliance are the same resources that enhance resilience by delivering dispatchable, flexible power quickly. To take resilient CPS targets to the next level, CPS-compliant projects could coordinate with hosting capacity analysis and resilient DER mapping efforts (see Sections 4.1 and 4.5) to pair storage with renewable generation in optimal locations.

Arizona has proposed modifications to its RPS with resilience specifically in mind as a program goal. Commissioner Andy Tobin of the Arizona Corporation Commission (ACC) proposed the Energy Modernization Plan (EMP) in

January 2018 (Tobin, n.d.). The EMP includes resilience as a guiding principle alongside affordability and reliability, innovation, economic development, and resource diversity. The proposal seeks to broaden Arizona’s existing RPS to include clean energy, energy efficiency, and storage. The plan also includes a goal of 80 percent generation from clean energy sources. The EMP proposes a specific target of 3,000 MW of deployed energy storage by 2030. Most notably, the EMP would require regulated utilities to set and achieve a Clean Peak Target measuring clean generation during peak demand hours, increasing by 1.5 percentage points annually through 2030 (Tobin, n.d.). The ACC is still actively considering whether to adopt the proposed EMP in a docket opened in August 2018 (ACC, 2019).

While RPS policies have been successful in increasing renewable generation, several states are moving to larger targets or more targeted policies to ensure renewable generators serve specific grid needs. Compared to smaller penetration targets, specific storage targets or clean peak goals more directly address resilience by incentivizing flexible, dispatchable, and distributed renewable generation that can produce power at critical times and in the right places. Islandable DER systems that provide power during clean peak periods can also produce power during outages.

4.3. Rate Design Trends

Rate design influences project economics; services provided; project location, size, and configuration; and the impact a DER installation has on a customer’s electricity bill, with important implications for whether customers decide to install DERs and what benefits and services—resilience or otherwise—the resources provide to the grid. As the regulatory authority responsible for approving rates, commissions have pursued a number of different compensation and rate structures for DERs including net metering, net billing, fixed charges, and time-of-use rates. While some structures have been implemented as a response to higher levels of DER penetration, some of these strategies were enacted at the onset of DER growth, and not every rate structure has been compatible with growing DER penetration. This section will discuss select rate structures and how they encourage and/or discourage resilient DER deployment, as well as how commissions are changing or considering changes to rates to reflect higher DER penetration levels.

As of November 2017, 38 states plus the District of Columbia, U.S. Virgin Islands, and Puerto Rico offered net energy metering (NEM) rates to DER owners (DSIRE, 2017), providing a standard credit per kilowatt-hour (kWh) of electricity generated by a DER to offset a customer’s electricity bill. Net metering policies can differ significantly across several characteristics—including compensation, individual system size, aggregate capacity limit, and other attributes—but are designed on the same foundation. By enabling “customer-generators” to deliver power back to the distribution system in excess of on-site consumption (IREC, 2009), net metering policies are easier for customers to understand relative to more complex time-varying rates, simple for utilities to implement, straightforward for commissions to regulate, and effective in improving the attractiveness of installing DERs, mainly rooftop solar PV. Opponents of net metering argue that it subsidizes DER owners at the expense of non-DER customers by allowing customer-generators to use the delivery system at no charge (Edison Electric Institute, 2016). Commissions face the task of deciding how rates can accurately reflect the value of DER.

As rooftop solar penetration levels hit statutory targets or opposition to potential cost-shifting grows, some states are shifting away from net metering and toward more nuanced compensation mechanisms for distributed solar, namely net billing measures that pay for exported solar at rates other than retail to account for the true value of distributed solar to the grid. Arizona, Louisiana, and Utah are shifting to net billing, which credits customers at a below-retail avoided cost rate for exported energy. While net billing reduces the attractiveness of installing DERs for end users, it still provides an assured, long-term revenue stream for exported energy and enables resilient DERs to generate income during blue sky conditions. New Hampshire and Michigan are also considering a transition away from net metering.

Net metering and net billing policies generally do not differentiate compensation based on where DERs are located and when they are producing power. As E3 stated in an evaluation of New York’s net metering policy, “while NEM offers a simple and understandable tool for consumers, it is an imprecise instrument with no differentiation in pricing for either higher or lower locational values or higher or lower value technology performance” (Energy + Environmental Economics, 2015). As a result, traditional net metering or net billing encourage DERs but without motivating system resilience benefits of DERs. If rates were structured to reflect the locational value of DERs for system resilience, net metering and net billing could be more supportive of resilient DERs. Such an approach would require additional data, a stakeholder process, and commission decision-making to establish transparent, certain, and equitable rates.

Smart Rate Options

Several commissions have been promoting grid modernization and associated changes in rate structures to achieve state policy goals related to renewable generation, emissions reduction, electrification, and/or resilience. Grid modernization can be initiated and led by the commission, resulting in a final commission report, or ordered by the commission, with regulated utilities submitting grid modernization plans for commission approval. Resilience may be an explicit goal of grid modernization or rate structures, or it may be an indirect benefit of policies to incentivize “smarter” DER adoption.

Some states are looking broadly at retail rates as a way to modernize the grid, integrate DERs, and achieve other state policy objectives simultaneously. Vermont’s 2016 Comprehensive Energy Plan (CEP) emphasizes broader DER adoption to pursue two goals: increased resilience and reduced infrastructure costs (Vermont DPS, 2016a). The plan cites resilience risks from increased flooding and climate disruption and discusses how the state can manage both its energy use and natural resources to mitigate the effects of both threats. The plan calls for regulated utilities to create “smart rate transition plans” for customers with advanced metering infrastructure (AMI, defined as meters with two-way communication capability, sending data to both the user and service provider [NETL, 2008]), laying out a process to shift all ratepayers to smart rates by 2021 (maintaining a flat rate option for customers wishing to opt out). The plan defines “smart rates” broadly as hourly, time-of-use, variable or critical peak rate, peak-day rebate, fixed time-of-use, seasonal flat pricing, electric vehicle-specific rates for vehicle charging, net metering, or rates reflective of third-party control of appliances or equipment (Vermont DPS, 2016b). Rates encouraging the colocation of storage with generating DERs—a consequence of several of Vermont’s proposed smart rate structures—can enable DERs to contribute to system resilience.

Advanced Rate Design

As a more mature example of smart rates that send price signals for energy efficiency, self-generation, and conservation goals, the Hawaii PUC revised its net metering successor tariffs to create a smart export option encouraging solar plus storage. This tariff approach could support the resilience characteristics of dispatchability, fuel security, decentralization, and flexibility (Table 4.5).

Hawaii’s Smart Export tariff is designed to encourage beneficial DER deployment by shifting electricity exports from periods of low demand during the middle of the day to evening and morning peaks. The tariff was ordered by the PUC in November 2017 to replace tariffs created in a 2015 decision to end NEM rates of \$0.27/kWh. The original NEM rates had led to high penetration of solar PV nearing 20 percent on some circuits and causing reliability threats (Trabish, 2016).

Table 4.5: Key Resilient DER Characteristics that Can Be Encouraged by Advanced Rate Design
Dispatchability
Fuel Security
Decentralization
Flexibility

Smart Export rates are available between 4:00 p.m. and 9:00 a.m. on O’ahu, Hawai’i Island, Maui, Moloka’i, and Lana’i. The rates are below-retail (\$0.11/kWh to \$0.2079/kWh, depending on location) and fixed for five years.

Smart Export lets storage owners choose how much electricity to store when the export rate is set to zero between 9:00 a.m. and 4:00 p.m.

Another Hawaii tariff, Customer Grid-Supply Plus (CGS+) is available to solar or solar + storage users and compensates exported power at below-retail rates around the clock. The PUC allowed HECO limited curtailment of CGS+ suppliers and required ratepayers receiving either rate to install smart inverters with utility or third-party controllability (Hawaii PUC, n.d.).

In addition, the PUC's Market Track (Hawaii PUC, 2014) is undertaking a long-term project to fully compensate DER for a range of services. The PUC's October 2017 order adopting Smart Export and CGS+ set forth the PUC's priority to move "toward more sophisticated DER systems that can help support, and ideally enhance, grid reliability... through programs that accurately value the provision of energy and grid services and compensate customers based on the relative value these DER systems provide to the electrical grid at the time of delivery" (Hawaii PUC, 2017). The Hawaii PUC envisions these tariffs as a next step in an overarching effort to increase customers' electricity choices.

4.4. Public Purpose Microgrids

When utilities propose to allocate ratepayer revenue to DER projects, commissions must carefully consider whether front-of-meter projects provide system-wide benefits beyond those the individual customers interconnected to the project will receive. Utilities have the burden of demonstrating these broad benefits and convincing the commission that a DER solution such as a microgrid is preferable to other generation, transmission, or distribution technologies. In general, the costs of existing microgrids are borne by the connected loads. However, utilities have recently made requests to include microgrid costs in the general rate base, spreading costs among all ratepayers. Such proposals present interesting questions for the commissions, which have ultimate decision-making authority over costs passed on to ratepayers. If the commission is not convinced, utilities will need to cover these costs elsewhere or abandon the project.

Utility proposals for microgrids offer an example of the potential resilience value of DERs. The DOE defines a microgrid as "a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid," with the ability to operate in grid-connected or islanded mode (Berkeley Lab, n.d.). Microgrids are especially valuable during long-term outages, where outage costs may increase dramatically with added duration. Microgrids could support the resilience characteristics of islanding, critical load siting, fuel security, decentralization, and flexibility (see **Table 4.6**). A resilient microgrid can be comprised of multiple DERs such as solar PV, storage, and small fossil generation.

The lack of an established valuation methodology for resilience makes it difficult for commissions to compare the costs and benefits of microgrids (Rickerson et al., 2019). In addition, state retail choice laws, ownership issues, cost allocation, interconnection, and other factors can inhibit microgrid development.

Case 9361 before the Maryland Public Service Commission (PSC) asked regulators to decide when a microgrid project provides sufficient benefits for its costs to be spread among all ratepayers. Pepco proposed to recover \$63.4 million in microgrid construction costs for two projects that it claimed would delay a costlier substation upgrade, improve resilience, and integrate more DERs into its territory (Wood, 2018). Pepco attempted to apply Lawrence Berkeley National Laboratory's Interruption Cost Estimate (ICE) calculator to quantify some of the project's resilience benefits. However, because the ICE calculator can only model the costs of outages up to 16 hours, Pepco noted that it did not capture the full resilience value of the proposal. Pepco did not attempt to quantify a full value encapsulating how the project would benefit the community during long-term outages. In September 2018, the commission denied Pepco's request without prejudice, leaving the door open for the utility to reapply after addressing PSC concerns about unquantified benefits to community resilience (Rickerson et al., 2019). In

short, these concerns were (1) project costs should not be recovered from Pepco’s entire Maryland rate base and (2) Pepco did not propose a pilot study with a definitive sunset date (Maryland PSC, 2018).

In Illinois, Commonwealth Edison’s proposed Bronzeville microgrid addressed some of these shortcomings by soliciting third-party bids for components, relying on renewable generation and storage, and documenting lessons learned. The proposal received Illinois Commerce Commission (ICC) approval in February 2018. The ICC’s decision included a process to design a microgrid services tariff to stimulate greater third-party microgrid development (ICC, 2018).

Table 4.6: Key Resilient DER Characteristics that Can Be Encouraged by Public Microgrids

Islanding Capability
Siting at Critical Loads / Locations
Fuel Security
Quick Ramping
Grid Services
Decentralization
Flexibility

4.5. State and Local Resilience Initiatives

States can engage in resilience planning through collaborative roadmapping initiatives. State efforts often focus on providing resources to understand local threats and vulnerabilities and convening stakeholders to specify and evaluate a range of actionable responses, as seen in Colorado’s Resilience Roadmap. After wildfires in 2012 and 2013, the state partnered with NREL to convene multi-jurisdictional stakeholders (see **Figure 4.3**) in proactive, long-term resilience planning focused on pilot programs in three counties directly impacted by the wildfires. State leadership can be crucial in building collaboration between local governments with awareness of local threats and vulnerabilities, utilities with knowledge of the electricity generation and delivery system, commissions with decision-making authority over the distribution system, and other stakeholders with diverse interests in and control over all aspects of infrastructure.

Local governments can also play an important role in supporting resilient DERs and should be engaged in any state initiatives. Municipal efforts to map favorable locations for resilient DER or assist customers in assessing suitability, siting, and optimal characteristics for their own resilient DER are important first steps while commissions consider how to factor resilience into decision-making more broadly. Through providing support for particular projects, outlining specific resilience threats, analyzing gaps in reliability investments, and prioritizing optimal

Figure 4.3 Intergovernmental resilience planning



<https://www.nrel.gov/docs/fy19osti/73509.pdf>

locations for resilient DERs, municipalities can further action on resilience in the absence of broader federal or state policy. In particular, municipal resilience roadmapping, an exercise that typically consists of defining and characterizing the benefits of resilient DERs over traditional reliability investments, understanding barriers to resilient DER deployment, and identifying critical facilities that could benefit from resilient DER installations. Roadmapping supports the resilience characteristics of islanding capability, siting at critical loads/locations, fuel security, decentralization, and flexibility (Table 4.7).

<i>Table 4.7: Key Resilient DER Characteristics that Can Be Encouraged by State and Local Resilience Roadmapping</i>
Islanding Capability
Siting at Critical Loads / Locations
Fuel security
Decentralization
Flexibility

Missouri, San Francisco, and New York City, in particular, have engaged in roadmapping exercises that could serve as models for other municipalities or states. The Missouri Department of Economic Development, Division of Energy received a \$285,000 grant from DOE’s State Energy Program in 2017 to develop resilience roadmaps for three cities: Rolla, Stockton, and St. James. Missouri has experienced substantial damages and outages from extreme weather, mainly tornados, such as the 2011 tornado that killed 161 people around Joplin, MO and knocked out power to 20,000 customers by destroying a substation, 100 miles of power lines, and 4,000 distribution poles. The state planned to utilize energy efficiency, DERs, and combined heat and power to improve the resilience and reliability of local energy infrastructure (U.S. DOE, 2017b). The Division of Energy has also sought to expand CHP for critical facilities by conducting outreach to trade associations in critical sectors like healthcare and education, working with utilities to conduct feasibility screenings for CHP, participating in Public Service Commission proceedings, and developing an incentive framework for CHP at critical infrastructure (U.S. DOE, 2019).

San Francisco looked at the likelihood of a major earthquake causing a multi-week extended power outage. Current reliability measures include diesel generators, which would be inadequate during an earthquake-induced outage because no more than three days of fuel is kept on-hand. Adding more fuel storage is not an option because tanks would be prone to spilling during an earthquake and are difficult to locate and permit in an urban area. Diesel generators also require maintenance and monthly testing to ensure performance during an outage. The city documented solar plus storage as having three key benefits over diesel generators: reducing the need for maintenance and testing, improving air quality, and providing daily benefits in bill reduction and peak load management.

San Francisco’s Department of Emergency Management identified critical locations as police stations, fire stations, medical facilities, disaster relief coordination centers, shelters, kitchens, and public assembly buildings. The city identified close to 50 critical sites and grouped nearby locations together, noting which buildings could support solar and/or storage. Next, San Francisco gathered detailed load estimates and sized solar plus storage systems for each group of locations, pinpointing the precise location for each system. The city developed a best practices guide for other municipalities considering resilience solutions (SFEnvironment, 2017a) and released a public calculator tool to estimate the required rating and size of grid-connected solar plus storage to provide backup power during an extended outage (SFEnvironment, 2017b).

In its municipal resilience roadmap, New York City cited four benefits of resilient solar, defined as solar PV paired with battery storage, auxiliary generation, and/or an advanced inverter: backup power, bill savings, grid support, and fossil fuel reduction (NY Solar Smart DG Hub, 2017). New York City also specified four barriers to large-scale deployment of resilient solar: lack of compensation for grid services, lack of value for resilience services, policy risk and market uncertainty, and education and outreach (NY Solar Smart DG Hub, 2017).

Similar to San Francisco’s process, New York City’s Smart DG Hub project team tried to overcome these barriers by identifying critical infrastructure with potential for resilient solar installations, selecting buildings with adequate roof space, no existing backup power, and appropriately sized load that serve vulnerable populations located in

areas of congestion (NY Solar Smart DG Hub, 2017). The New York Solar Map, a site identification tool, is available to the public to enable individual property owners to see if their buildings are optimal for resilient solar installations (Sustainable CUNY, 2015).

Public utility commissions have the authority to address several barriers identified by state and local governments in resilience planning processes. Commissions can take lessons from multi-jurisdictional approaches to resilience and identify areas where regulatory processes may inhibit or could better facilitate local solutions. However, independent commission action alone is not sufficient to overcome these roadblocks. Commissions will need to work with other state regulatory and policy entities, federal counterparts, industry, municipalities, and other stakeholders to implement meaningful solutions to increase the deployment of resilient solar resources and other DERs (see Section 2.1).

5. Challenges in Defining and Quantifying Resilience

State-level DER policies already incentivize some traits of resilient DERs. As discussed in Section 4, incremental adjustments to account for other traits can constitute early components of state resilience policies. This section discusses difficulties in defining resilience and how, given these challenges, commissions may take first steps toward developing comprehensive resilience policy, through which DERs can contribute alongside other investments.

A common hindrance to investing in grid resilience is the lack of a commonly accepted definition and associated metrics with which to track performance. As with all types of utility investments, state regulators require accurate and complete information about the costs and benefits of reliability and resilience investments, as NARUC recognized in 2013: “To determine if a reliability investment is prudent, Commissions use formulas that weigh the costs of outages to utilities against the costs of investments that avoid or minimize outages” (Keogh & Cody, 2013).

Stakeholders generally agree that resilience should encompass the ability to quickly recover from a disturbance, but there is substantial disagreement over the best way to express that attribute, which other attributes should be valued, and how to translate those attributes into technical features that could become quantifiable (Keogh & Cody, 2013).

Regulators can develop a common valuation framework for resilience. Because threats vary by region, states may need to develop specific locational goals and strategies to achieve resilience. A particular investment may improve resilience in one area but actually worsen resilience in another—for example, greater DER aggregation and associated DER management systems may provide more avenues for potential cyberattacks (Beasley & Greenwald, 2018). Regardless, a single cost-benefit framework applied with regionally accurate information could improve decision-making. New York’s approach, discussed in Section 4.5, offers a good example.

Conducting an adequate cost-benefit analysis of resilience measures requires accurate assessments of the cost-benefit equation of avoiding and/or shortening an outage. Both of these are difficult to pinpoint with accuracy, particularly the benefits of avoiding an outage (Rickerson et al., 2019).

Outage Costs

The costs of outages are often expressed as lost productivity and/or the costs of restoring the system to its pre-outage state. Such measures understate the true cost of lost electricity by failing to account for the societal costs experienced by the public at large. Outages also place costs on society that are shared by the public, particularly when outages harm the ability of first responders to provide critical services.

The value of lost load is expressed as lost kWhs times the retail rate per kWh; SAIDI and CAIDI metrics use a static value of electricity. Traditional outage cost estimators do not differentiate lost kWhs over time. This approach fails

to account for temporal differences in the value of electricity. Losing power for a few minutes is inconvenient and may impose some costs, (particularly for commercial or industrial customers), but losing power for several days is a severe disruption to any customer and can result in exponentially higher damages (Cook et al., 2018a). In addition, outage cost estimation should strive to account for differing values of lost load among different customer classes or types of customers within the same class (i.e., elderly residential customers vs. young adult residential customers). While the level of data necessary for quantifying this variation may make it cost-prohibitive to arrive at accurate estimates, an intermediate approach accounting for some portion of temporal and customer class differentiation, as the ICE calculator attempts (DOE, Berkeley Lab, Nexant, nd), as well as longer-duration outages, may be feasible and would be an improvement over present approaches.

Critical Load Planning

Regulators may wish to take a more active role in assessing what qualifies as critical load and how the utility will differentiate those customers during an adverse event. Fire stations, hospitals, first responders, and 911 call centers generally count as critical load, but research facilities, schools, and public buildings are capable of providing shelter for residents to access emergency personnel, recharge phones, and receive supplies. Some critical loads have chosen to install their own resilient DER or microgrid solutions without sharing costs among all ratepayers or the surrounding community. Commissions generally do not have a direct role in approving or rejecting such projects but can take lessons from their financing, operation, and performance.

Resilience investments around critical loads are capable of reducing outage costs for the critical customer and may deliver system-wide benefits (Keogh & Cody, 2013). While commissions already coordinate with utilities, critical defense facilities, and municipal/state/federal government customers, the level of coordination varies from state to state. All stakeholders can improve the availability of data on critical loads and infrastructure, enabling utilities and commissions to compare the costs and benefits of resilience investments across different locations.

Future High-Impact, Low-Probability Events

Current thinking around reliability investments should evolve to consider the wider resilience universe – while reliability encompasses familiar issues with long track records, resilience involves actors, threats, motives, and impacts that may be largely unknown or difficult to model. Regulators and utilities are beginning to think beyond the reliability mindset of single points of failure in the system. Deterministic $n - 1$ or $n - 2$ models account for only one or two pieces of equipment failing. More complex, large-scale threats can take far more equipment out of service in a short period of time. Utilities must prepare for the possibility of a long-term, widespread outage affecting multiple pieces of critical equipment. Shifting to probabilistic risk assessment models that can account for both multiple points of failure and interdependencies between equipment will give regulators a more complete understanding of the system, leading to better investment decisions and improved resilience.

6. Conclusion

Resilience will be an increasingly important focus for energy regulators at all levels of government. While in the process of developing definitions, metrics, and valuation methodologies for resilience, commissions can take intermediate steps toward a more proactive approach to resilience planning that delivers immediate benefits to consumers while improving system resilience. In embarking on efforts to define, measure, and improve system resilience and understand the potential and advantages of how DERs contribute to resilience, commissions and other stakeholders need to observe demonstrations of the resilience capabilities of DERs to feed into a track record enabling future cost-benefit analyses. This paper has attempted to draw attention to a handful of existing projects and policies that can be used to encourage the use of DERs for grid resiliency, but it will be critical to draw operational data and lessons learned from other installations and policy approaches to provide a more thorough evaluation of the resilience potential of DERs.

It is in ratepayers' best interest for commissions to improve their understanding of grid resilience and the capabilities of DERs to support resilience, particularly for attributes not already supported by existing state policies affecting DERs. As more regions confront new and increasing threats to electricity infrastructure, DERs can be one of several options for commissions, utilities, and other stakeholders to improve resilience.

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