NCSL TASK FORCE ON ENERGY SUPPLY

Modernizing the Electric Grid

State Role and Policy Options

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Modernizing the Electric Grid: State Role and Policy Options

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Glossary

■ **Advanced Metering Infrastructure (AMI):** electric meters, known commonly as smart meters, which record electricity usage and communicate that data to utilities at five-minute to one-hour intervals. Meters can in some cases both send consumption information and receive information (like demand response signals).

■ **Beneficial Electrification:** replacing direct fossil fuel use (propane, heating oil, gasoline, natural gas) with electricity in a way that reduces overall emissions and energy costs.

■ **Combined Heat and Power (CHP):** provides electricity and useful thermal energy (heating and/or cooling) from a single source of energy, such as a natural gas turbine or fuel cell.

■ **Demand Response (DR):** a coordinated process of reducing electricity consumption to relieve stress on the grid during peak hours or power outages. Demand response provides utilities and demand response companies with the ability to adjust bill payers' heating, cooling or other energy services in exchange for monetary credits on their bill. DR is also useful for integrating variable generation sources, such as wind and solar.

■ **Distributed Energy Resources (DER):** energy resources that are located close to where electricity is used. May be owned by customers and located on the customer side of the electric meter. Examples of DER include distributed generation, energy storage, demand response and energy efficiency.

■ **Distributed Generation (DG):** power generation at the point of consumption on the distribution grid. Rooftop solar is an example of DG.

■ **Distribution Grid:** the portion of the electric grid that is located between the transmission grid substations and individual houses or businesses.

■ **Energy Efficiency Resource Standard (EERS):** requires utilities to achieve a specified amount of energy savings through energy efficiency programs within a specified timeframe.

■ **Federal Energy Regulatory Commission (FERC):** the federal entity responsible for monitoring interstate energy markets and regulating interstate transmission, wholesale electricity prices, natural gas pipelines and hydroelectric dams.

■ **Gigawatt (GW):** equal to 1,000,000 kilowatts (kW) of power, or 1,000 megawatts (MW).

■ **Integrated Resource Plan (IRP):** a plan designed by an electric utility that outlines how it plans to meet forecasted annual peak demand with supply- or demand-side resources.

■ **Internet of Things (IoT):** everyday appliances and devices that are Internet-connected in order to be controlled remotely.

■ **Kilowatt-hour (kWh):** one kWh of energy is 1,000 watts (1 kW) of power delivered for one hour. A microwave or toaster consumes in the range of 1,000 watts and would consume 1 kWh if run for an hour. The average U.S. residence consumed 867 kWh per month in 2017.

■ **Net Energy Metering (NEM):** a billing mechanism that allows distributed generation owners who export electricity to the grid to receive credits at the retail rate for use at a future time. Some states provide credits at a rate other than the retail rate.

■ **Non-Wires Alternatives:** solutions to grid reliability or capacity challenges that may defer, mitigate or eliminate the need for traditional transmission and distribution investments. Non-wires alternatives could include, but are not limited to, energy efficiency, energy storage and other solutions.

■ **Performance-Based Regulation (PBR):** an alternative regulatory framework that rewards utilities for achieving well-defined outcomes (performance metrics).

■ **PV:** solar photovoltaic technology, the fastest growing form of solar energy generation.

■ **Renewable Portfolio Standard (RPS):** also known as a Renewable Energy Standard (RES), requires utility companies and other electricity suppliers to source a certain amount of the energy they sell from designated renewable and clean energy sources.

■ **Stranded Costs**: created when a utility investment becomes unusable due to shifts in policy or technology. The stranded infrastructure investment still needs to be paid off, even it if is no longer competitive or useful.

■ **Time-of-Use Pricing (TOU):** an approach to electricity ratemaking where prices vary based on the time of day. Pricing is generally higher during peak times, lower during mid-peak, and lowest during off-peak times.

Introduction

Much of the nation's network of electricity generation, transmission and distribution resources is aging. Major upgrades will be needed to reliably incorporate new technologies and systems, changing market dynamics and shifting consumer preferences. Technological change is outpacing both infrastructure capabilities and policy development while states look for ways to sync policy with a rapidly changing energy market.

The explosion of new technologies—from smart water heaters and thermostats to electric vehicles, rooftop solar panels, energy storage and advanced metering infrastructure—promise a more efficient, reliable and resilient energy future. The degree to which states have moved toward a more advanced and distributed grid varies greatly, however. Several states are finding that that these technologies and practices are outpacing regulatory policy and that changes are needed to appropriately value their contributions, or costs, to the grid. While the changes are significant and rapid, most electricity is still provided by large central power plants and the ultimate balance of centralized and distributed energy resources is yet to be determined.

The challenge facing state policymakers is how to craft policies that promote cost-effective investment in the electric system while allowing innovative technologies and new energy management approaches to flourish and compete in a rapidly shifting environment. This effort will require states to adapt their policy regimes and infrastructure, which were designed for a centralized energy grid with one-way energy flows from large, centralized power plants to customers. Instead, they must craft policy that will function with a less centralized electric system that incorporates multi-directional energy flows between energy providers and customers (or between customers) and includes a far greater number of participants.

Significant infrastructure upgrades will be required to address the needs of an evolving energy network. This includes upgrading existing transmission lines to incorporate distributed energy resources and building new lines to improve wholesale market operations, increase resilience and bring energy from remote renewable resources to population centers. The distribution grid—which carries energy to individual homes and businesses at the local level—will need even more investment than the transmission system. Sixty percent of U.S. distribution lines have surpassed their 50-year life expectancy, according to Black and Veatch, while the Brattle Group estimates that $1.5 trillion to $2 trillion will be spent by 2030 to modernize the grid just to maintain reliability.[1]

As more customers deploy distributed energy resources, some communities are seeing a fundamental shift in energy management, with large, distant generation sources being replaced by smaller, modular and local sources. Creating a more flexible system—where customers can also be energy producers, energy managers and market participants—will require a much more adaptable and technologically advanced distribution grid. Developing a dynamic grid that can absorb and use the rapid expansion of distributed energy resources and other energy solutions will require advanced grid management technologies, digital controls and communications, new analytics and supportive regulatory approaches, such as time-of-use pricing.

While these upgrades promise increased reliability, resilience, efficiency and more choice for customers, a greater reliance on digital computing and connectivity increases the visibility of these systems. This new visibility makes them targets for those inside and outside the country that are intent on harming the nation's energy system.

With these many considerations in mind, energy stakeholders and policymakers across the country are working to determine the best options for states. Given the complexity and variety of grid modernization paths that can be taken, it is important to develop holistic planning approaches and decision-making frameworks. These can help determine which grid investments are worthwhile and minimize the potential for stranded investments. Since the issues related to grid modernization can be complex, nuanced and challenging, this report was designed to assist state lawmakers in their efforts to gain an understanding of the many components of grid modernization. It also seeks to provide a foundational knowledge of these issues and a platform of understanding upon which they can build.

Grid Transformation

Legislatures, public utility commissions and energy providers across the nation are discussing grid modernization, assessing needs, policies, costs and return on investment. While needs vary from state to state, the latest report from the American Society for Civil Engineers found that current grid investment trends will lead to funding gaps of $42 billion for transmission and $94 billion for distribution by 2025.[2] Regardless of the exact numbers, investment will be needed to incorporate a more diverse energy supply, increase resiliency and upgrade infrastructure. Although many of these upgrades may require significant investment, many can result in operational savings while providing resiliency and other benefits. Technologies that increase knowledge of grid operations, for instance, can allow utilities to better balance fluctuating supply and demand, respond to outages, optimize resource use and increase efficiency.

A confluence of factors is driving the need for modernization, including:

- State and federal incentives that are helping to increase the deployment of distributed resources, such as rooftop solar and energy storage.
- Newly discovered methods for accessing natural gas combined with falling technology costs, leading to a dramatically altered energy mix and larger amounts of renewables on the grid.
- Advances in telecommunications and control technologies along with falling costs for distributed generation technologies.
- The entrance of new market players, such as the electricity consumer as producer, which has been enabled by the factors cited above.

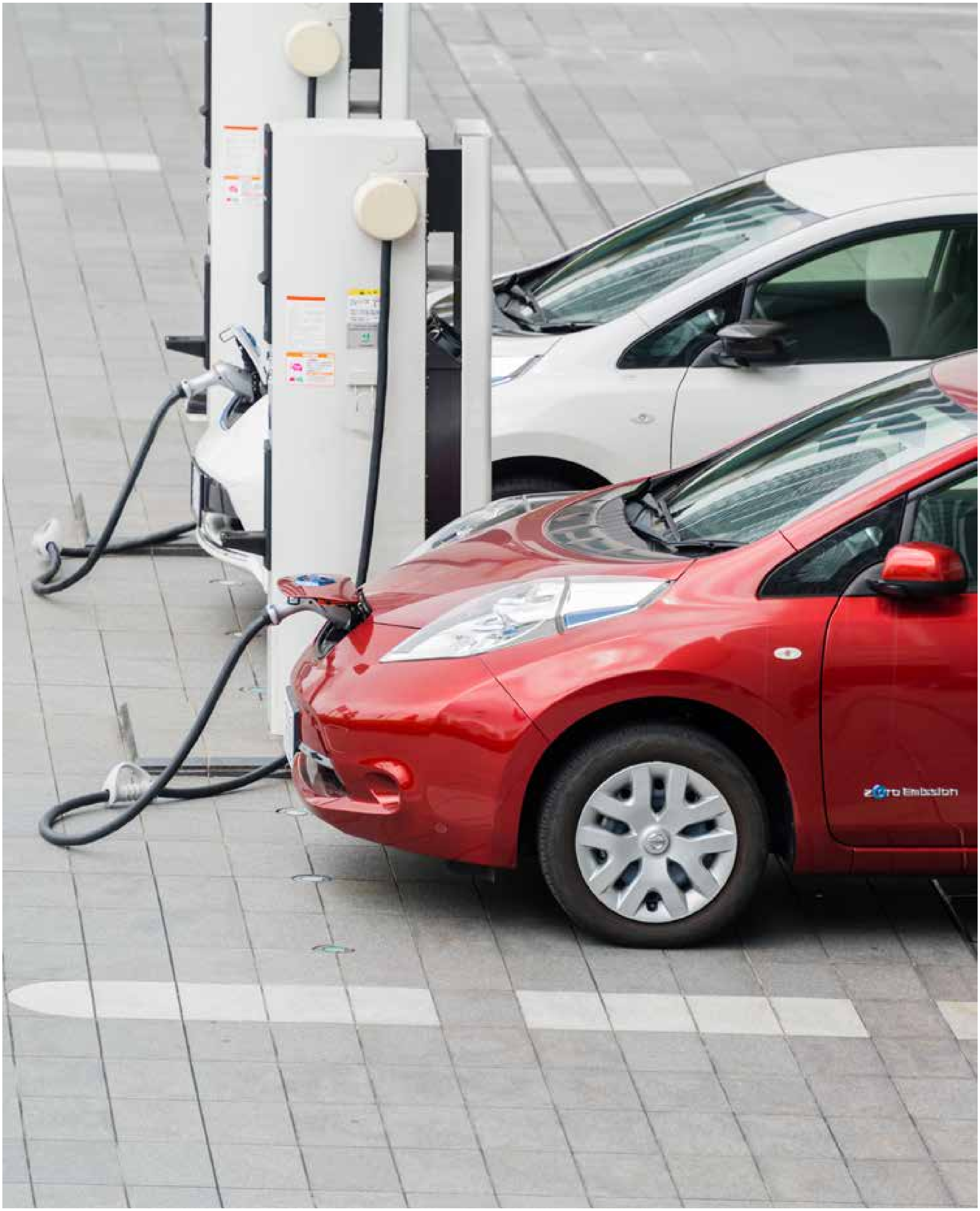
The rapid increase in variable renewable energy and natural gas generation is altering grid management needs and the reliance on baseload generation. Nearly 95% of net new electricity capacity added to the U.S. grid in 2017 was renewable, according to data from the U.S. Energy Information Administration.[3] This figure incorporates the retirement of fossil fuel generation, which dramatically lowered the amount of net fossil fuel generation added to the grid. With utilities finding renewable energy resources easier to site, finance and build than many traditional sources, the growth of these resources is likely to continue, increasing the need for a flexible and adaptable grid.[4]

Energy transmission, distribution and generation infrastructure is built to meet peak system needs, which may only occur for a few hours per year. This is a costly approach to meeting needs, since much of the system's capacity goes unused for most of the year. The advent of new grid management technologies and approaches, however, provides an opportunity to significantly decrease these peaks, reducing the infrastructure needed to reliably meet peak load.

New grid technologies, such as energy storage, also can improve resilience and reliability, while offering utilities a lower-cost alternative to traditional transmission and distribution solutions. Energy efficiency, energy storage, distributed generation, demand response, microgrids and new grid controls are starting to be used individually or in tandem to delay or eliminate the need for new transmission and distribution lines, substations, transformers and other equipment. While implementing these "non-wires" solutions can be complex, a carefully planned approach can provide cost savings, increased reliability and decreased emissions. There are many new technologies that enable non-wires solutions and their potential benefits continue to be explored.

Many of these new technologies enable modular solutions that, when considered and coordinated carefully, can reduce the potential for stranded costs and lower risk for customers and their energy providers. Big infrastructure projects, like transmission lines or power plants, inherently come with a larger risk of stranded costs, which are created when a utility investment becomes unusable due to shifts in policy. A utility will often seek to recover stranded costs—like those incurred from closing a coal plant early due to regulatory requirements or uncompetitive operating costs—from ratepayers. Technologies like distributed generation, demand response, energy efficiency and energy storage may provide lower-cost, lower-risk solutions that greatly reduce the risk of leaving consumers on the hook for stranded costs. While likely not the best approach for all situations, these technologies should be weighed equally against more conventional solutions to ensure ratepayer benefits and an efficient allocation of resources. Also, the operational lifetime of these technologies, and their ability to provide reliable power as needed in the future, need to be considered.

While the technologies that are part of the grid modernization effort promise several benefits, how do policymakers, utility commissions, energy companies and customers determine which investments will provide adequate benefits and which may be unnecessary? How can states create an environment where innovative solutions can compete and flourish on a level playing field? The first step for decision-makers is to understand the changing energy system and growing variety of options available to utilities, state governments and energy planners. This report explores these issues, illustrating case studies that can provide insight into benefits, costs and challenges.



Components of the Modern Grid

In recent years, new technologies and communication systems have been integrated into the grid, allowing for greater control and real-time operational awareness. These new technologies have challenged industry standards and touched every aspect of the electric industry—from how electricity is generated and managed to how it is delivered, consumed and stored.

While these technologies come with the promise of a cleaner, more efficient and more resilient electric system, they represent a new frontier. Policymakers find themselves on the cutting edge of reshaping a system, the structure of which has remained largely unchanged for many years. This creates a dynamic that makes grid modernization a difficult policy area to navigate, given that there is no clearly defined and universally accepted vision of what constitutes a modernized grid. Simply adding modern components does not necessarily enhance grid operations. Thoughtful planning to ensure these new components complement one another and the rest of the electric network is also needed.

This section describes many of these new grid components, along with associated benefits and challenges they may create. One challenge is determining the cost-benefit and long-term effects of encouraging or requiring use of specific technologies on the grid.

To address the many challenges in modernizing the grid, policymakers, energy companies, regulators and grid operators are trying to develop:

- Comprehensive and coordinated planning to ensure the fundamental components of the grid are able to scale for a greater penetration of distributed and clean energy assets.
- Requirements for operational coordination and communication across the various sub-sections of the grid—from bulk power grid operators to the distribution system, third-party operators and individual customers.
- Methodologies for evaluating the various attributes that new technologies bring to the grid—including resiliency, security, dispatchability and flexibility—and how to equitably apply that value through tariffs and other pricing structures.
- Approaches for accommodating and incentivizing new business models that encourage utility system innovation, alternative rate structures and consumer engagement.

One approach uses Grid Architecture concepts to develop the design strategies needed to manage a complex structure of distributed energy resources, allowing planners to work through complex issues in a logical way. Grid modernization strategies that apply these principles can help guide technology selection as grid modernization is implemented. The Hawaii Public Utilities Commission and commissions in other states have applied grid architecture ideas in developing their grid modernization plans.

Many of these issues, along with associated policies, will be discussed later in this document.

Distributed Generation

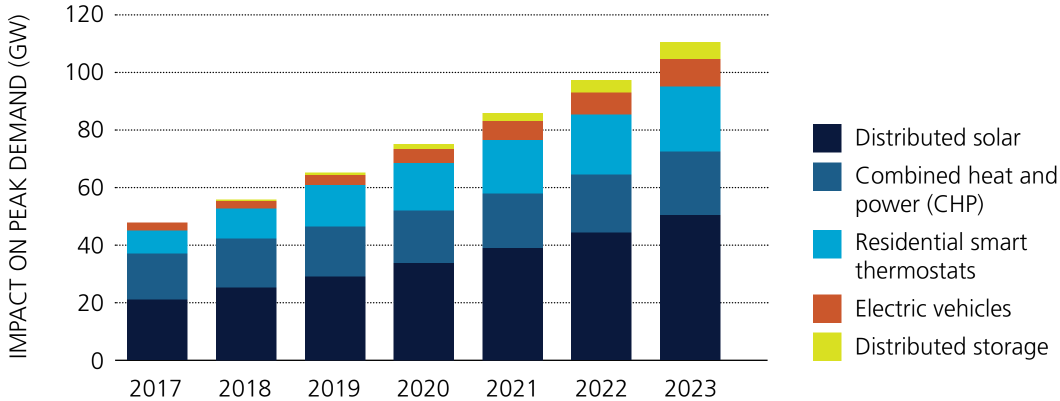
One of the most discussed aspects of the modern grid, distributed generation has grown rapidly over the past decade. Distributed generation refers to resources that generate electricity near the location where it will be consumed. In most cases these resources are connected to the distribution system, which can help reduce the energy losses that occur when electricity is carried over long distances. Some are connected on the customer's side of the utility meter, which is why they are sometimes referred to as "behind the meter."

They can provide many services, offering supplemental and backup power to homes and businesses, reducing grid congestion and anchoring a microgrid for increased resilience. They pose a challenge for utilities, grid operators and regulators since they can offset or eliminate a customer's electricity demands, as well as require additional infrastructure requirements that create costs for customers. The issue of who is creating costs for the grid and who should pay for infrastructure upgrades is a continuing concern for regulators.

Some of the more common distributed energy resources include solar photovoltaics (PV), small wind turbines, natural gas microturbines, fuel cells, and combined heat and power (CHP) systems. Energy storage is another distributed energy resource, though its ability to store and dispatch energy makes it unique. Due to this, energy storage will be discussed in greater depth in a later section. Because some are behind the meter, the number of installed distributed resources can be difficult to accurately count. Estimates suggest that in 2017, distributed resources contributed 46.4 gigawatts (GW), or around 6%, of the nation's summer peak.[5] This number is expected to more than double to 104 GW by 2023.

Distributed Energy Resources' Growth and Impact on Peak Demand

In gigawatts (GW)



Source: GTM Research

Solar has accounted for around 30% or more of all new electric generating capacity additions for all fuel types in each of the past four years.[6] That growth is expected to continue and possibly increase in the coming decade. In early 2019, the solar industry surpassed 2 million installations, and market analysts expect the industry to double the number of installations by 2023.[7] Solar growth is highly concentrated in certain areas, affecting some states much more than others. It has particularly affected states that have enacted policies to promote distributed solar, such as net metering or distributed solar carve-outs, in state renewable portfolio standards.

These resources have the potential to support and enhance the grid in several ways, but when they are behind the meter, they can be invisible to the distribution system, hampering a utility's planning and operations. While they have the potential to offset large capital projects under certain conditions, thereby reducing the need for costly infrastructure investments, many of those benefits are only possible when the local utility can incorporate them into its system planning.

Distributed generation changes the way utilities' grid operators manage, plan and invest in the grid. Many of the country's distribution utilities are increasing infrastructure investments as a result. These investments include traditional infrastructure to keep the grid running as well as the modernization needed to monitor the distribution grid, where much of the technological change is taking place.[8] Investments in traditional infrastructure are still critical to the grid's operation and reliability and will be for some time.

Under certain conditions, distributed generation—along with other distributed energy resources (DERs), like energy efficiency, demand response and energy storage—can play a role in reducing system costs by avoiding or delaying the construction of large power plants, substations or transmission lines. Incentivizing certain customers on a constrained portion of the grid to invest in storage or rooftop solar, for instance, could avert the need to build new costly infrastructure. This approach can be more effective if locational value of resources, hosting capacity and the need for distribution upgrades have been determined.

One growing energy sector—shared or community renewable energy—provides flexibility in siting and allows medium-sized renewable energy projects to be developed in optimal locations on the grid. Community or shared renewable energy programs offer an alternative to on-site systems, such as rooftop solar, by allowing multiple customers to invest in a renewable energy facility, which can be located on- or off-site, and directly benefit from the energy produced. Community energy facilities can be owned by a utility, energy provider, third party or by the customers themselves. As they are not limited to rooftops or by property lines, shared renewables projects can be placed in optimal locations, close to load centers or in areas unsuitable for larger utility-scale renewable energy projects. At least 20 states and Washington, D.C., have enacted legislation authorizing shared renewables.[9]

With more customers adding distributed generation, utilities are in need of ways to integrate this data for grid planning, and to be incentivized for doing so.

Advanced Controls and Communications

The continued growth of distributed generation is changing the way electricity moves on the electric grid, which means grid operators are having to adjust the way they manage the flow of energy. Traditionally, electricity has moved in one direction—from power plants, through wires, to customers. But as more distributed generation is connected to the distribution system, the grid will be able to accommodate a shift toward a less centralized power network, where power can flow both to and from the customer.[10] In addition, this shift is increasing the amount of variable demand that utilities need to meet. As distributed resources, like rooftop solar, fluctuate in output, the grid operator must fill the void with on-demand resources such as natural gas or hydropower when a storm passes overhead, and rebalance output from those resources when sunny skies return. The issue can be compounded in areas with high rates of rooftop solar adoption.

This shift will require many changes, including new approaches to distributed generation interconnection policies as well as advances in communication, system monitoring, and coordination between distribution networks and the bulk power system. In some areas, the high penetration of distributed generation is creating opportunities for utilities to reconsider how they plan for and operate a more fluid and decentralized network. The stakes are high, since utilities are tasked with both meeting customer demand for this new technology and ensuring that increased penetration of distributed resources will not result in grid reliability problems.[11]

As distributed resource integration continues, advanced controls and communications systems are helping to bridge the gap between technology and regulations. Smart meters and advanced metering infrastructure, for example, enhance utility awareness of the distribution grid, increasing reliability and improving coordination between the distribution and transmission networks.[12] Advanced automation technologies and grid modeling software and algorithms, while still evolving, are other essential components for dynamic grid operations.

Some utilities are working to integrate advanced planning and real-time management services that can process incoming data and integrate larger amounts of distributed resources. These distributed resource management systems are still in the early stages of development but are likely to play an important role for aggregation, planning and forecasting—including the use of advanced weather forecasts to predict output from solar and wind generation.

New controls and metering can greatly assist in managing generation and consumption by providing price signals that better reflect system costs.[13] Leveraging the market in this way, however, requires regulatory reforms, along with dynamic communications technology and the widespread use of advanced metering.

Advanced Metering and Smart Devices

The reversible flows of electricity mean that electricity meters must track flow both to and from the consumer. These devices are considered essential to developing a modern grid because they act as the utility's eyes and ears—in some cases, offering close to real-time information on grid conditions.

The use of smart meters—part of advanced metering infrastructure—is growing rapidly, in part due to state and local policies. As of 2017, more than 78 million smart meters have been installed, covering more than 60% of U.S. homes.[14] Smart meter deployment remains the most common type of grid modernization policy—often viewed as a first step in grid modernization work.[15] Estimates suggest that number could reach 90 million smart meter installations by 2020.

By enabling two-way communication between the utility and consumer, smart meters provide measurements of grid activity, and their data can improve grid operations, prevent outages and provide customers with energy-management services. These devices, combined with other sensors that are being deployed, can better connect the electric system's disparate components, allowing for real-time systemwide operational awareness. Phasor measurement units are one such technology that can enhance reliability by measuring synchrophasors—time-synchronized numbers that offer precise readings of grid conditions—which offer grid operators real-time awareness of grid stability or stress.

Smart meters can assist customers by providing time-based pricing, control over electricity consumption, high usage alerts and other money-saving services to help manage energy use. Combined with smart devices—like smart thermostats, home energy monitors and smart home sensors—advanced metering greatly increases customer control over energy consumption, as well as energy production if they own distributed generation and energy storage. However, as more customer data comes in, there are privacy concerns that policymakers are having to address.

Some states, like Pennsylvania and Illinois, have passed laws that require universal smart meter deployment. In the case of Pennsylvania HB 2200, passed in 2008, the deployment of smart meters was one part of a larger push to get electric utilities to reduce customer consumption and demand.[16] In other cases, deployment initiatives are managed through regulatory proceedings.

However, not all customers are comfortable with utilities installing these devices and a vocal minority have called for the removal of smart meters. At the heart of their concerns are perceived health effects, though data and personal privacy are also points of contention. Customer health concerns have been largely debunked. For example, the Maine Supreme Court upheld a finding by the Maine Public Utilities Commission that smart meter deployment posed no credible health and safety threat. The court pointed to an extensive technical record supporting the commission's decision, including more than 100 peer-reviewed scientific studies that determined smart meters were not a health risk.

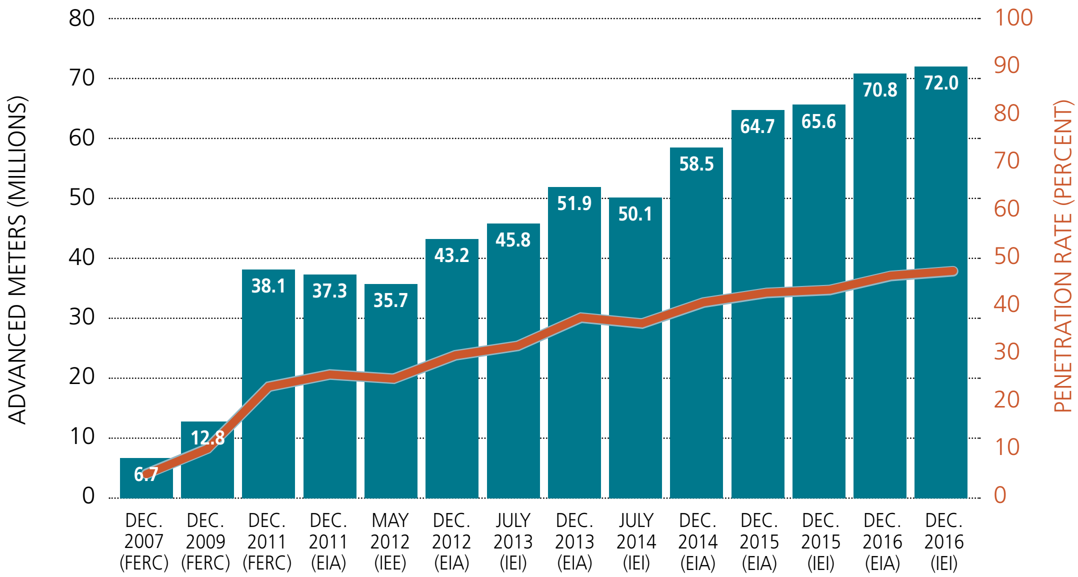
To facilitate deployment, some states are increasingly considering whether to allow opt-out programs, which allow customers to pay an additional fee in order to have a basic meter. At least nine states have statewide policies allowing customers to opt out, while another 16 states have permitted utilities to implement opt-out programs. At least 14 states have considered opt-out legislation in the past several years. Only New Hampshire has an opt-in policy, which requires utilities to obtain written consent from customers prior to installing smart meters.

Energy Storage

While energy storage as a power system resource has been around for decades in the form of pumped hydropower, recently there have been significant developments in advanced energy storage technologies—such as batteries, super capacitators and flywheels. These technologies can perform a variety of grid services, with some capable of responding to rapid power and voltage fluctuations while others are better suited to long-duration discharge. They continue to play a key role in improving grid reliability, meeting peak energy demand, and smoothing out the grid effects of variable output of resources like wind and solar and allowing them to be used most effectively.

Advanced Meter Growth

2007-2016



Source: FERC, 2018 Assessment of Demand Response and Advanced Metering

Lithium-ion batteries are the leading technology, accounting for more than 90% of new storage capacity in 2017. The rapid expansion of hand-held electronics and electric vehicles has catapulted the technology to the forefront, though other battery technologies, such as flow batteries, are growing in use and may be better suited to grid operations. However, the scaled production of lithium-ion batteries has been responsible for much of the cost-reductions witnessed over the past several years, and these batteries continue to win out as highly cost-effective.

While around 20% of energy storage capacity is behind the meter, utility-scale projects are popping up across the country and are likely to see robust growth in the coming decade. Estimates suggest that energy storage could grow from 6 GW of capacity in 2017 to over 40 GW by 2022.[17]

This increase will be due, in part, to state legislation aimed at promoting energy storage. The number of bills on this subject has exploded in recent years, from around a dozen measures in 2015 to more than 80 measures out of 17 states in 2018. In fact, the 2018 legislative session saw at least 17 bills aimed at supporting energy storage pass in nine states—including two bills to establish energy storage targets.

There are now five states—California, Massachusetts, New Jersey, New York and Oregon—with energy storage targets, while the Nevada Legislature has asked state regulators to establish one. In every case, the target resulted from state legislation. Most recently, New Jersey and New York set targets of 2 GW and 3 GW, respectively, by 2030. Meanwhile, the Arizona Corporation Commission has proposed a 3 GW target for 2030, though the commission has not yet approved the initiative.

States are also considering other energy storage policies. Hawaii and Maryland enacted tax credits for storage systems. Colorado established rules to incorporate storage into the integrated resource planning process for electric utilities and provided utility customers with the right to connect batteries to the grid.

In many areas, renewable generation is being paired with energy storage to enhance grid reliability and resiliency. Green Mountain Power, the utility that serves three-fourths of Vermont, has launched a solar-plus-storage pilot program to help build resiliency into the system. The utility has signed up more than 500 customers for solar-plus-storage systems to help make homes more resilient to outages, especially in the winter months, by offering monthly bill credits and one-time credits on the value of the battery.

At the utility scale, renewables-plus-storage projects are becoming competitive with traditional generation solutions in some regions and have continued to set pricing records in several states, including Arizona, Colorado and Hawaii. Six out of seven recent grid-scale contracts totaling 1 GWh of energy storage from Hawaiian Electric came in at record-low pricing for solar-plus-storage projects in the state.[18]

In September 2019, the Los Angeles Department of Water and Power approved a power purchase agreement for 400 MW of solar generation and a 300 MW/1,200 MWh battery, at an average cost of less than 2 cents/kWh.[19]

Electric Vehicles

The use of electric vehicles is set to increase dramatically. At the beginning of 2019, there were just over 1 million electric vehicles (EVs) on U.S. roads. It took around eight years to reach that point, and analysts project it will take under three years to add another 1 million EVs. By 2030, the number is expected to reach 18.7 million—representing around 7% of all cars and light trucks, and at which point EVs are projected to account for 20% of all new vehicle sales.[20]

Harnessing the collective capacity of the batteries in these electric vehicles could represent significant storage potential and, depending on owners' charging patterns, either a challenge or a benefit to the grid. Many of these considerations also depend on localized penetration—how densely EVs are packed onto a specific section of the electric system. While overall penetration might be manageable, if it is all focused in one neighborhood, the increased load could require the utility to make upgrades.

When those vehicles are charged is another consideration for utilities. If EV owners decide to charge during peak hours, the collective demand could require upgrades to the distribution system, new transmission to relieve congestion, and increased peak capacity.[21] The likelihood of this happening appears to be relatively low, however, as utilities and regulators have many tools at their disposal to help shape EV owners' charging behavior.

Through incentives and pricing schedules, such as time-of-use rates, utilities in some areas of the country have already been able to shift EV charging to off-peak hours.[22] Utility or grid operator-controlled charging could help stabilize the grid by extending demand response efforts and allowing EV batteries to store energy when excess renewable energy is being generated or when prices are low. Under utility or grid operator-controlled charging, an EV owner would receive a monthly rebate for allowing the utility to control vehicle charging—though the utility's control would be limited by certain parameters. Especially as they relate to utility-controlled charging, these programs are largely still conceptual.

Utilities are also exploring the role that electric vehicles could play in supporting the grid with "vehicle-to-grid" programs, in which owners are compensated for allowing utilities to have some control over both charging and discharging of an aggregated population of electric vehicles. This coordinated control—especially with respect to fleet vehicles and public transportation—could provide a variety of grid services. They include regulating frequency and voltage, and supplying power during critical peak demand periods or grid failures.

Several states, including California, Connecticut and Minnesota, have considered measures to explore vehicle-to-grid programs. However, the technology and policy surrounding these programs are still in their infancy and require continued refinement and stakeholder input.

Microgrids

Microgrids are micro versions of the larger electric grid, which can operate independently of the larger grid. Microgrids include interconnected loads (houses, buildings, lights, machinery), distributed energy resources and advanced controls that coordinate energy production and use, allowing the microgrid to disconnect from the larger grid during outages. Since microgrids are anchored by on-site generation, they can operate even when the larger grid is down due to extreme weather or other disturbances. This is referred to as a microgrid running in "island mode."

A number of college and medical campuses, along with military installations, have built microgrids to provide an added layer of resiliency to their electrical system. In Chicago's Bronzeville neighborhood, ComEd used grants from the U.S. Department of Energy (DOE) to build the nation's first interconnected microgrid cluster.[23] The neighborhood is home to critical facilities, like the city's police headquarters, several fire departments and hospitals, and a university. In addition to supporting these critical facilities, the microgrids will serve over 1,000 residential, commercial and small industrial customers by providing them with resilient power. ComEd will use the project to study how microgrids can help the utility manage load and integrate renewables into its distribution network.[24] In a number of these larger-scale microgrids, combined-heat-and-power (CHP) generators that run on natural gas are used to anchor the system, which also uses solar, wind and energy storage.

On the smaller end of the spectrum, a single-home microgrid could use a variety of technologies, such as rooftop solar, fuel cells, natural gas microturbines and battery storage to operate independently from the large electric grid if needed.

In areas of the country that have been affected by extreme weather events, microgrids have been a primary focus of policymakers and utilities. The first large uptick in state legislation to help develop microgrids came in the wake of Superstorm Sandy in 2012 as states affected by the storm tried to harden their electric infrastructure. The past two years have seen renewed interest in states affected by other major storms, including Hurricanes Irma and Maria in 2017 and Hurricanes Florence and Michael in 2018.

At least eight states considered over two dozen bills in 2018. California and Hawaii each passed measures (SB 1339 and HB 2110, respectively), which directed state regulators to establish standardized microgrid tariffs to facilitate and encourage development of microgrids. The Puerto Rico Energy Commission delivered a set of rules to that effect in May 2018.

State green banks and infrastructure banks have also been used to facilitate financing. New Jersey established an Energy Resilience Bank aimed at ensuring critical facilities—specifically, hospitals, wastewater treatment plants and universities—remain operational even when the grid is down.

Connecticut has been a leader in passing microgrid policies. Following Superstorm Sandy, the state has implemented four primary microgrid policies. It established a pilot program to fund projects at critical facilities. Next, it included microgrids under its definition of "energy improvements" that the state's green bank could help finance. The Legislature also included microgrids under projects that local governments can develop under "energy improvement districts." And in 2017, the Legislature included microgrids in its Property Assessed Clean Energy (PACE) financing program.

Demand Management and Energy Efficiency

Distributed energy resources can also include demand side management, like energy efficiency and demand response, because each has a role to play in reducing load and helping to manage a more flexible and cleaner grid.

Energy efficiency describes the technologies, materials and practices that reduce energy consumption and offer multiple reliability, economic and environmental benefits. In addition to lowering energy bills, efficiency decreases emissions and reduces energy demand, alleviating stress on the electric grid and reducing the need to build new infrastructure. Efficiency programs and technologies have major benefits for the grid and are responsible for a significant portion of power sector carbon emissions reductions, which have declined by 28% since 2005. Around half of that reduction can be attributed to reduced energy consumption.[25]

Demand response programs are already in use in many parts of the country to cost-effectively reduce demand and peak loads, improve resilience and balance the variations in distributed generation output. Additionally, deploying demand response resources can avoid costly transmission infrastructure upgrades and free up electricity during power plant or transmission outages.

Demand response provides utilities and demand response companies with the ability to adjust a customer's heating, cooling or other energy services, or release energy from customer-sited energy storage, in exchange for monetary credits on their bill. If a utility abruptly needs more energy due to a spike in demand or drop in production, the utility can send a signal that discreetly reduces the energy consumption of program participants. Demand response programs are tailored to be nearly unnoticeable by their commercial, industrial and residential participants, while producing substantial benefits, including reduced system costs, lower emissions and increased system resilience.

Demand response participation in wholesale markets rose to 27,541 MW in 2017, meeting 5.6% of peak demand, representing year-over-year growth of 3%. Total potential savings from these programs nationwide rose around 9% the previous year.[26]

New grid technologies increase the potential for demand management and efficiency to help manage the grid, increasing reliability and lowering costs while reducing the need for additional generation, transmission and distribution infrastructure.

Demand management practices help utilities offset the need for new generation and other infrastructure, lowering system costs and customer bills. Traditional regulatory models that compensate utilities based on electricity sales and capital investments, however, make these choices less appealing to utilities than building new power plants and infrastructure. Policy approaches—such as decoupling, lost revenue adjustment mechanisms, performance incentives, performance-based regulation and alternative ratemaking structures—are among the many steps states are considering or have implemented to address utility disincentives for energy efficiency and demand response.

Securing a Modern Grid

Data Access and Privacy

A modern, interconnected grid will depend on data analytics to create a more robust, efficient and resilient electric system. Data will come in from every corner of the grid—including homes and generators, weather forecasts, system monitoring devices and markets. A modern grid will constantly absorb data from many sources and react accordingly. Used correctly, this data has the potential to improve situational awareness for grid operators, and to bring enhanced customer services and savings. For example, Florida Power & Light uses grid data to monitor grid operations and the utility says its use of smart meter data contributed to $30 million in operational savings in 2014.[27]

But hurdles remain as utilities and regulators consider standards, requirements and privacy concerns. Not only will data be analyzed by utilities and grid operators to build system planning algorithms, it may also be analyzed by third parties eager to offer new services to electric customers. As with all discussions surrounding consumer data, there are many outstanding questions regarding data ownership, privacy and security concerns, and how that data can and will be used. It's generally understood that utilities will use the data to optimize planning and operations of their electric systems, and that customers should be granted access to their data for their own purposes. Unresolved questions include how much, and in what format, data should be made available to third parties who could use it to tailor marketing campaigns.

There are currently no universal standards for which data is collected, how it's sent to the entities that are collecting it, or how it's organized and formatted. Similarly, there are no hardware or security standards. Due to this, the data can be messy, inconsistent or incomplete.[28]

However, there has been some progress in this realm. The Green Button initiative is an industry-led effort to provide customers with access to user-friendly information on their energy usage. The initiative has led to some standardization in how this information is presented, with over 50 utilities and electric suppliers, serving over 60 million homes and businesses, having signed on since it began in 2012.[29]

Additionally, a legal framework needs to be established to determine how data can be used.[30] Several states—California, Illinois, New Hampshire, Texas and Vermont—have already acted to establish clear rules on access, ownership and sharing of utility customer data.

California passed SB 1476 in 2011 to clearly prohibit several actions regarding electrical customer data.[31] The law restricts utilities from sharing data with a third party without approval from the customer and prohibits the sale of data or personally identifiable information. It enables customers to see their data without being required to share it with other parties. It also requires that customers be informed of all secondary commercial purposes for which their data is used.

While the law clearly emphasizes customer consent and transparency regarding how data is used, it exempts aggregated, non-identifiable data that is used for analysis or program management. It also allows aggregated data to be released to third parties for system and operational needs.

Illinois passed a law in 2011 requiring utilities to provide state regulators with Advanced Metering Infrastructure Deployment Plans that "secure the privacy of personal information and establish the right for consumers to consent to the disclosure of personal energy information to third parties."[32]

In Texas, the state's administrative code establishes that all data belongs to the customer and prohibits the sale, sharing or disclosure of information generated by smart meters for any purpose other than providing utility service or other customer-approved services.[33]

Concerns remain over how data can be used to identify and monitor behavior patterns based on unique load signatures generated by different types of appliances.[34] A consumer group sued the city of Naperville, Ill., over its use of smart meters, claiming the automatic reporting was tantamount to unlawful searches and a violation of the Fourth Amendment. The U.S. Court of Appeals for the Seventh Circuit agreed that smart meter communications were equivalent to a search, but it ruled that those searches were reasonable in scope and therefore legal.[35]

To promote the creation of voluntary standards, DOE created a voluntary code of conduct, the DataGuard Energy Data Privacy Program, in 2015. It promotes a clear and transparent customer consent process and the right to revoke consent for sharing data at any time.[36]

Cybersecurity

In addition to creating new legal questions, new technologies may create new security challenges. The nation's energy infrastructure faces a range of cyberthreats as millions of smart technologies and internet-enabled devices are connected to the grid. In many ways, grid modernization efforts are bridging the gap between two very different generations of technology, with modern computing working in tandem with legacy equipment that was developed at a time when cybersecurity wasn't even a consideration.

These new technologies are often information-oriented—collecting and transmitting data on system and network performance. By incorporating these computer systems with older, equipment-oriented technologies, the industry is bringing information and operations systems together, which raises concerns about the security of the grid. While operators have taken steps to minimize the associated risks and established network barriers, the world has already seen that what happens in cyberspace can have ramifications in the physical world. Russian hackers have shut down and disrupted power system operations in Ukraine, and malware has sabotaged and damaged Iranian centrifuges. For these reasons, cybersecurity has become one of the most important new frontiers in securing U.S. critical infrastructure. All of this comes as policymakers consider a variety of physical threats to the grid—both man-made and natural.

The U.S. electric grid is considered the most crucial of all critical infrastructure systems due largely to the fact that electricity is used to power many other systems. Because of this, the bulk power grid is the only sector with mandatory and enforceable security standards. However, this still leaves large segments of the distribution grid under state jurisdiction.

With all of this as a backdrop, states have quickly found themselves in the position of regulating cybersecurity for local distribution utilities. In some cases, state regulators have stepped in to establish robust protocols, often following the lead of national regulatory agencies. Several utilities have taken steps internally, or relied on industry resources and guidance, to protect against threats. Nonetheless, there are quite a few states that have yet to establish sufficient cybersecurity standards for their regulated utilities, leaving large swathes of the grid less protected.

CYBER AND PHYSICAL CHALLENGES

In the six years that the U.S. Department of Homeland Security (DHS) published reports tracking cyberthreats, the energy sector was the most targeted subsector of all U.S. critical infrastructure. According to DHS, more than half of all reported incidents in recent years have been classified as advanced persistent threats coming from sophisticated actors.[37]

While initial attacks focused on traditional targets—whether power plants, transmission systems or grid operations—recent years have seen a shift in approach as cyberattackers focused more energy on probing the defenses of industrial control system vendors.[38] A successful attack on a vendor could theoretically compromise vendor devices and provide backdoor access to power sector industrial control systems that regulate power management.

As discussed, malware and other cyberthreats can result in physical damage to equipment and even service disruptions. Of concern are supervisory control and data acquisition (SCADA) systems, which have been in use since the 1970s to allow remotely controlling complex systems over a wide territory. These systems were not designed with the internet or cybersecurity in mind, and they have been compromised through malware attacks.

In other cases, internet-enabled devices—everything from smart coffee makers to smart thermostats, often referred to as the "internet of things" (IoT)—have been hacked to jam server bandwidth. In these distributed denial-of-service (DDoS) attacks, thousands or millions of unsecured devices are hacked and directed to flood the bandwidth of targeted systems with traffic, overwhelming them in the process.

Moving forward, experts have emphasized that new systems must be designed with cybersecurity as a primary concern, as it will take decades for all the legacy equipment to be fully phased out.

Meanwhile, physical threats to the electric grid and other critical infrastructure continue to exist. Several assaults from high-powered rifles on electrical substations have garnered national attention. A 2016 attack on a substation in Utah damaged a transformer and knocked out power for 13,000 customers, while a similar attack on a substation near San Jose, Calif., prompted the Federal Energy Regulatory Commission (FERC) to call for new physical security protections for critical parts of the high-voltage electric network.[39]

UTILITY ACTIONS, FEDERAL AND STATE POLICY SOLUTIONS

The National Cybersecurity and Communications Integration Center (NCCIC), housed under DHS, is responsible for reducing the risks associated with cybersecurity. NCCIC is the central hub for cyber monitoring and communications information, technical expertise and operational integration, while also operating around-the-clock situational awareness and emergency response capabilities.[40]

In 2017, NCCIC absorbed two separate cyber response teams—the Industrial Control Systems Cyber Emergency Response Team (ICS-CERT) and the U.S. Computer Emergency Response Team (US-CERT)—along with their associated missions to further integrate cyber defense functions.

The North American Electric Reliability Corporation (NERC), which FERC chose as the nation's Electric Reliability Organization, is also tackling this broad and emerging threat along with several federal agencies, including the National Security Agency, FERC and DOE. DOE has recently created a new office called the Office of Cybersecurity, Energy Security and Emergency Response (CESER), which works closely with industry and other stakeholders to mitigate the risk of energy disruptions from cyber incidents and other emerging threats. These agencies are dedicating resources to this complex issue, focused on enhancing system defenses to cyber intrusions and to ensuring that any operational impacts from successful attacks are minimal. In a show of intent, NERC handed down a record $10 million fine to an electric utility in early 2019 for repeated cybersecurity lapses over three years.[41]

The Energy Policy Act of 2005 granted authority to oversee the reliability of the bulk power grid to FERC. To this end, FERC has tasked NERC with developing cybersecurity guidelines and standards for critical infrastructure protection (CIP). In recent years, FERC has approved and updated the cybersecurity standards developed by NERC—including standards intended to identify weaknesses in the supply chain—which aim to enhance the electric grid's defenses. NERC has also been directed to improve mandatory reporting requirements for cyber incidents.[42]

While the federal government has taken the lead in developing a response to cyber intrusions, it is very much a collaborative effort between the electric power industry, federal agencies, and state and local governments. And while FERC is responsible for the bulk power grid, the nation's electric distribution networks and the distribution utilities that manage and operate those networks are overseen by state regulators or policy-setting boards of directors. By some estimates, NERC's CIP standards only apply to 10% to 20% of the grid's assets.[43]

FERC does not have jurisdiction over the distribution system. These systems—owned and operated by investor-owned utilities, municipalities and electric cooperatives—have been identified as potential weak links in the grid's cyber defenses. There are thousands of utilities that operate distribution networks across the U.S., and the robustness of their cybersecurity practices varies significantly. Each state maintains its own standards and regulations. Given that these standards vary substantially from state to state and establish minimum requirements, even utilities that are in full compliance with state regulatory requirements may be vulnerable.[44]

Many of these utilities are working to bolster cybersecurity measures, often through interactions with national associations like the Edison Electric Institute, the American Public Power Association or the National Rural Electric Cooperative Association, in addition to collaborating with state fusion centers and regional associations. In some cases, state-level agencies monitor security planning and implementation.

Research conducted by the DOE's National Renewable Energy Laboratory (NREL) found that all the distribution utilities it investigated had a cybersecurity team. However, the resources available to allocate to cybersecurity varied greatly, with many smaller energy providers struggling to adequately fund cybersecurity through their base rate. This issue was particularly prevalent among electric cooperatives, while most municipal and investor-owned utilities used base rates to fund their cyber mission. In addition, the report found broad use of nationally and internationally recognized cybersecurity standards and guidelines, though this also suggests a lack of a cohesive cybersecurity approach at the distribution level.[45]

In recent years, states have increased their legislative activity on cybersecurity of critical infrastructure and the electric grid. At least 10 states considered around 30 bills related to the topic during the 2018 legislative sessions.

Many of the bills sought to establish state-level task forces or committees dedicated to study the issue and provide recommendations to policymakers. Since 2017, at least eight states—California, Delaware, Maryland, Nevada, New Jersey, New York, Texas and Washington—considered this type of measure, with Delaware and Maryland enacting legislation. The Missouri legislature created a broader Committee on Disaster Preparedness and Awareness, which included cybersecurity threats along with other types of natural and man-made disasters.

Other measures, like California's SB 532, enacted in 2018, would add cyberterrorism to the list of conditions that could constitute a state or local emergency declaration. By passing AB 2813 in 2018, California also established a state Cybersecurity Integration Center within the Office of Emergency Services, which is essentially a state-level version of NCCIC, along with its own cyber incident response team.

Another common theme has been to restrict public disclosure through the Freedom of Information Act (FOIA) of certain information that could reveal cyber vulnerabilities to critical infrastructure. In 2018, Iowa and Virginia each passed multiple FOIA exemption bills. Virginia's bills—HB 817 and HB 1539, and SB 645—focus on protecting vulnerabilities to critical infrastructure, information related to response plans and information that would hinder antiterrorism efforts.

These FOIA-related bills are complementary to the Federal Power Act's restrictions, which establish that critical electric infrastructure information, as designated by FERC or DOE, is exempt from federal, state and tribal public disclosure laws.[46]

The electric industry has also taken its own initiative, including a Cyber Mutual Assistance Program, which builds on the long-standing practice of providing voluntary mutual assistance by sharing critical personnel and equipment when responding to an emergency.[47] The program coordinates with relevant government partners to enhance the nation's preparedness.

Policy and Regulatory Approaches for a Modern Energy System

State legislatures and utility commissions play an important role in modernizing the grid. Their policies and the regulatory framework they create can promote or discourage investment in innovative technologies and energy management approaches. Legislatures have a number of options. They can create policies to encourage adopting and deploying new and emerging technologies, such as energy storage and demand response. They can work with public utility commissions to reshape the traditional regulatory framework in a way the better aligns customer and utility goals.

State legislatures have significant power to steer the course of policy through statutory and regulatory requirements. In most states, public utility commissions are limited by statute, with the legislature providing the foundation upon which commissions build their regulations. Those regulations, informed by the underlying statutes, play a significant role in directing investment and encouraging innovation in the energy sector. Public utility commissions can also direct studies to explore grid modernization and establish pilot programs.

Vertical Integration and Competitive Markets

While every state is a little different and hybrid systems do exist, there are two primary models for utility regulation in the U.S.—vertical integration and competitive markets. Whether a state falls into one category or the other determines some aspects of how its electric utilities pursue grid modernization efforts. However, even under these divergent regulatory models, most local distribution utilities are still under the jurisdiction of state utility regulatory commissions, which oversee how those utilities pursue grid modernization initiatives.

Vertically integrated utilities are natural monopolies. They own everything from generation to transmission and distribution networks and are responsible for delivering electricity to captive customers within a specific geographic region. While independent power producers and transmission companies do operate in a number of these markets, these utilities have traditionally owned, operated and maintained most of their own infrastructure. Customers are considered captive because they have no other options for electric service. State public utility commissions exert regulatory oversight, reviewing rates and capital projects, such as infrastructure investments. Municipal utilities and electric cooperatives are generally not subject to state PUCs and are governed by a board, operated as a city department or report to city councils.

In states that have chosen to rely on competitive markets, the investor-owned utilities have been restructured so that generation, transmission and distribution are functionally separated. In restructured states, merchant power plants sell power into wholesale markets run by grid operators—commonly referred to as independent system operators (ISOs) or regional transmission organizations (RTOs)—which, in turn, sell that power to local distribution utilities. Those distribution utilities deliver electricity to end-use customers and are still regulated by state PUCs, though customers may have the opportunity to purchase power through alternative retail service providers.

Grid modernization initiatives—such as smart meter deployment—are often submitted to PUCs through rate cases, which attempt to justify the need for infrastructure investments and their impact on consumer rates. PUCs review those proposals and approve or deny them. While a number of states require utilities to submit integrated resource plans (IRPs) for approval by state regulators, there is a growing movement to expand this concept to integrated distribution system planning. In most cases, IRPs deal with bulk power issues of forecasting future load and detailing how the utility plans to meet that load through demand-side or supply-side resources.

Integrated distribution system planning assesses physical and operational challenges in the local distribution system and prepares it for anticipated future changes in the use of distributed energy resources and other grid technologies. The goal is to establish a process and an integration protocol that will allow the system to adopt new technologies as seamlessly as possible. These efforts require utilities to look at the challenges facing specific sections of their systems caused by load growth, increased penetration of DERs and aging infrastructure. Like the IRP process, integrated distribution system planning is intended to be transparent to policymakers and the public.

To promote this process, DOE has supported a joint effort between the National Association of Regulatory Utility Commissioners (NARUC) and the National Association of State Energy Officials (NASEO) to create a forum for states to develop new approaches for utility system and resource planning. The NARUC-NASEO Comprehensive Electricity Planning Task Force, announced in February 2019, will give officials from 15 states and Puerto Rico the opportunity to learn more about the integrated distribution system planning process and how to incorporate it into state planning efforts.[48]

As states move closer to innovative distribution system models, there can be effects on the wholesale transmission end of the system. Historically, grid operators control power flows moving in one direction—toward the end users in distribution networks. They take power from a limited pool of generators and send it through the grid to distribution networks, which deliver the power to customers.

The process of managing the grid and the work of grid operators could become substantially more complicated if power is coming from a much greater number of generators located at many different points on the grid, and potentially flowing from the distribution grid onto the transmission grid. On the technology side, the coordination and operational controls necessary to do this are currently being developed. However, work will also need to be done on the policy side, as unresolved questions over state and federal jurisdiction, compensation and power flow management will need to be addressed.

In some cases, RTO and ISO rules can limit the services and programs that distribution utilities are able to offer. One example is the confined access to markets that energy storage and demand response providers have faced in recent years. These programs cannot exist unless the market is constructed to value and allow them.

FERC has taken up both issues in the past decade to facilitate adopting new technologies. In 2011, FERC approved Order 745, which required wholesale markets to compensate demand response programs at the same rate received by generators. For example, if a demand response program lowered customer demand by 2 MW, it would be compensated as if it had generated 2 MW of electricity. To accommodate new storage technologies, FERC issued Order 841 in 2018, which required wholesale markets to develop rules that enable energy storage systems to participate more fully in electricity markets, allowing owners to be compensated for their full range of services. This concept is now under consideration before FERC in relation to DER aggregation, to determine whether distribution-level aggregated DER capacity can participate in transmission-level markets, raising some early questions over jurisdictional issues.

Public Power and Cooperative Utilities

Publicly owned utilities and electric cooperatives, while working to deliver the same services as investor-owned utilities (IOUs), have some distinct differences in their approach. IOUs must follow the regulatory structure laid out in statute and satisfy the requirements of the public utility commission in their states, while working to get a return on investments for shareholders. Municipal utilities are run by cities and must answer to the city council while electric cooperatives are nonprofit entities owned by their customer-members. Co-ops are governed by an elected board of directors.

Although cooperatives and municipal utilities do not have a profit motive and answer to city council or a board of directors instead of investors, they may still have a bias toward selling more electricity. This is because debt holders and debt raters may apply pressure to sell more in order to assure repayment. The Los Angeles Department of Water and Power, a municipal utility, adopted decoupling to promote energy efficiency and reduce the pressure to sell more electricity. This has allowed city managers and planners to change their focus from revenue recovery and increasing sales to goals such as lowering energy production and delivery costs through efficiency programs.

Since cooperatives often serve rural areas with lower population density, the remoteness of facilities and greater distance between structures can result in higher costs for adding services and technology. However, co-ops have found that modernizing infrastructure, by installing smart meters, for example, can have great benefits in low-population areas. Smart meters decrease costs by eliminating in-person meter-reading, while offering improved service, reduced outages and quicker recovery times.

State Policies for Grid Modernization

States are driving grid modernization through a variety of approaches, including establishing study commissions, developing broad grid modernization legislation, and providing grants for researching and developing smart grid technologies. In recent years, several states, such as California, Minnesota, Missouri, New Hampshire and Washington, have enacted legislation supporting broad grid modernization efforts.

States are also creating policies that encourage greater deployment of new and emerging technologies, including those that promote distributed energy generation, demand response, energy efficiency, smart grid technologies, distribution system planning and energy storage targets. Distributed energy resource deployment is also being driven by economic factors. As these technologies become increasingly competitive with traditional generation sources, such as coal and natural gas, DER adoption rates have steadily risen. The growth of DERs, resulting from policy efforts and increasing economic viability, is driving the need for a more complex energy grid. Ultimately, policymakers are responding to constituents, energy companies and industry innovators as they work to create a more reliable, efficient and flexible system that offers tailored customer solutions at an affordable price.

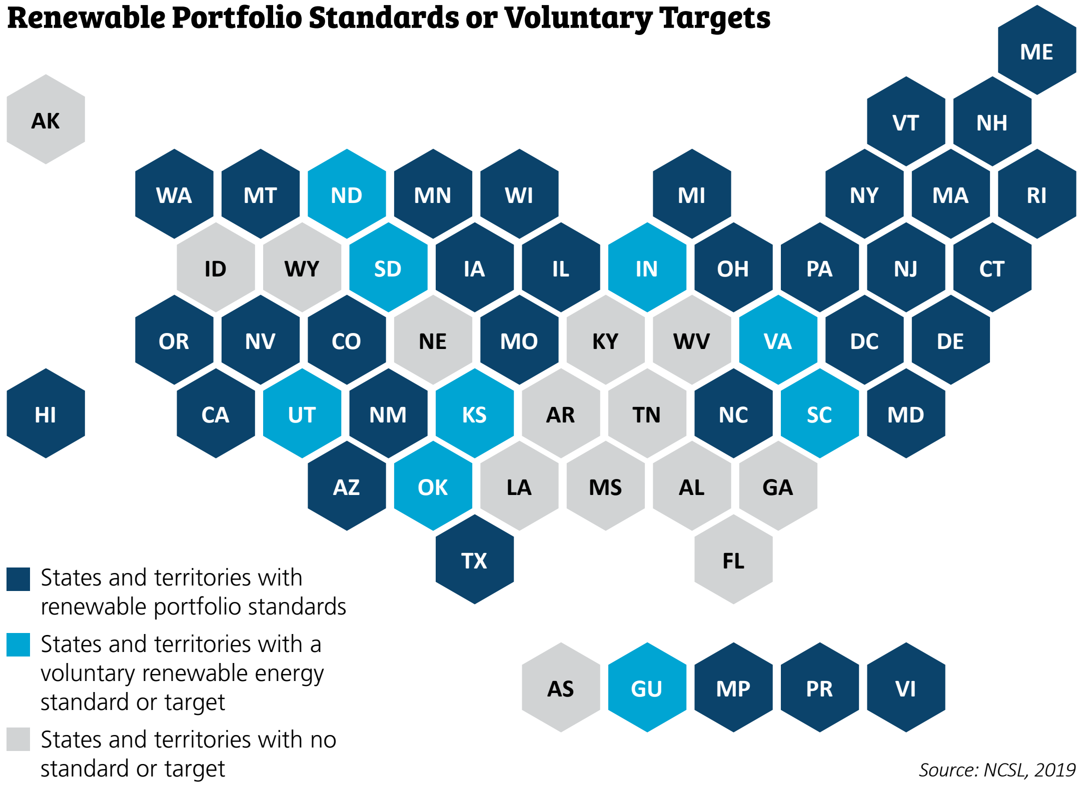
One step taken by several states is adopting the Next Generation Distribution System Platform (DSPx), which uses DOE grid architecture principles to develop holistic plans that can guide grid modernization efforts. The goal is to help plan and facilitate grid modernization decision processes so they better align the expectations of regulators, utilities and technology developers. These efforts have been initiated by state public utility commissions in a number of states, including California, Hawaii, Minnesota, New York and Ohio.

RENEWABLE PORTFOLIO STANDARDS

Renewable portfolio standards (RPS) require utilities to ensure that a percentage, or a specified amount, of the electricity they sell comes from renewable or clean energy sources. Roughly half of the growth in U.S. renewable energy generation since 2000 can be attributed to state renewable energy requirements.[49] These standards are helping drive the growth of distributed generation. Much of the growth is taking place on the distribution grid and pushing along other technologies, such as smart meters and energy storage that can help manage the increase in customer-generated power.

Renewable energy policies help drive the nation's $64 billion market for wind, solar and other renewable energy sources.[50] These policies can play an integral role in state efforts to diversify their energy mix, promote economic development and reduce emissions. Twenty-nine states, Washington, D.C., and three territories have adopted an RPS, while eight states and one territory have set renewable energy goals. State RPS policies have established a variety of percentage requirements for renewable energy and clean energy, though many states with RPS policies require between 10% and 45% renewable energy. During the 2018 and 2019 legislative sessions, a significant number of states enacted legislation to increase their RPS policies, with many states establishing ambitious renewable and clean energy targets. At least six states—California, Hawaii, Maine, New Mexico, New York and Washington—Washington, D.C., and Puerto Rico have enacted legislation establishing time-based requirements for 100% clean or carbon-free energy.

Renewable Portfolio Standards or Voluntary Targets



Source: NCSL, 2019

Recent Notable Renewable Portfolio Standard Increases

State, Bill No.	Standard
California SB 100 (2018)	100% clean energy by 2045, 60% renewable by 2030
Hawaii HB 623 (2015)	100% renewable energy by 2045
Maine Senate Paper 457 (2019)	100% renewable by 2050, 80% by 2030
Nevada SB 358 (2019)	50% renewable by 2030, non-binding 100% carbon free by 2050
New Mexico SB 489 (2019)	100% carbon-free by 2045
New York SB 6599 (2019)	100% carbon-free electricity requirement by 2040
Washington SB 5116 (2019)	100% carbon-free by 2045
Washington, D.C., Bill 904 (2018)	100% carbon-free by 2045
Puerto Rico SB 1121 (2019)	100% carbon free by 2050

Many states have established provisions, including carve-outs and credit multipliers, in their RPS policies to encourage greater deployment of distributed generation, such as rooftop solar. Carve-outs require a certain percentage of the overall renewable energy requirement to be met with a specific technology, while credit multipliers award additional renewable energy credits for electricity produced by certain technologies. At least 21 states and Washington, D.C., include distributed generation in their targets.[51] For example, Colorado has a 3% carve-out for distributed generation, while Illinois has a 1% annual requirement for distributed generation. Delaware has a 3.5% solar PV requirement by 2025 and Missouri has a 2% carve-out for solar. Nevada, Oregon and Washington have established solar and distributed generation credit multipliers under their RPS policies. Nevada has a credit multiplier for photovoltaics and on-peak energy savings. Oregon has a credit multiplier for solar PV installed before 2016, while Washington has a credit multiplier for distributed generation.

Although RPS policies have historically been significant drivers of growth in renewable energy generation and capacity, their role has diminished with the rapid decline in solar and wind costs. According to the Lawrence Berkeley National Laboratory, RPS policies were responsible for just 34% of all U.S. renewable capacity additions in 2017.[52] Renewable energy has become increasingly competitive with conventional energy generation costs, which is driving greater deployment.

ENERGY EFFICIENCY RESOURCE STANDARDS

One policy that states have implemented to encourage greater energy efficiency and deployment of efficient technologies is energy efficiency resource standards (EERS). EERS requires utilities to achieve a specified amount of energy savings through energy efficiency programs within a specified timeframe. State EERS can apply to electric or natural gas utilities, or both, depending on the state. Like RPS policies, EERS establishes long-term goals, which send a clear signal to market actors about the importance of energy efficiency in utility program planning and creates a level of certainty that encourages large-scale investment in cost-effective efficiency.

EERS plays an important role in driving sustained investment in energy efficiency and is one of the most effective state policies to guarantee long-term energy savings. According to the American Council for an Energy-Efficient Economy, states with an EERS policy in place have shown average energy efficiency spending and savings levels more than three times higher than those in states without an EERS policy.[53] States see these policies as necessary to overcome the bias created by the regulatory framework, which induce utilities to prefer power plant and infrastructure projects over efficiency measures that result in less electricity sales. These policies are helping drive the implementation of new grid technologies—connected heating and cooling systems, appliances and other devices—which are providing many more opportunities for energy savings.

At least 27 states have established an EERS either through legislation or the state public utilities commission. Of these states, 10 have an EERS for electric utilities only and 17 have an EERS for both electric and natural gas utilities.

EERS policies require a minimum amount of savings and allow utilities to choose how to achieve the required savings—such as rebate programs for energy efficient appliances and smart thermostats, home weatherization and lighting replacement programs, behavior-based programs, supply-side efficiency improvements, and combined heat and power or waste heat recovery applications.

In addition to providing utility flexibility, an EERS can have several other potential benefits. These policies provide defined targets that utilities can incorporate into their strategic planning and that regulators can use to evaluate and reward performance. Unlike minimum spending mandates for energy efficiency programs that have been implemented in several states, EERS encourage utilities to make cost-effective investments in energy efficiency. Finally, the minimum level of savings required by an EERS policy can also contribute to states' achievements of environmental, health and economic development goals.

There are, however, challenges and costs associated with the implementation and operation of an EERS. Administering an EERS requires organization and communication between public utility commissions, utilities, efficiency program administrators and program evaluators. The traditional regulatory model, which compensates utilities based on capital investments and electricity sales, both of which may be reduced by energy efficiency policies, can also be a barrier. Decoupling, discussed in the Utility Business Models section, addresses this barrier and can be a useful energy efficiency companion policy. Additionally, measuring and verifying the energy savings resulting from efficiency programs can pose a challenge.

In addition to EERS, states can increase investment in energy efficiency by requiring utilities to include energy efficiency resources in their IRPs or by requiring utilities to spend a specified percentage or amount of their annual revenue on energy efficiency programs.

DEMAND RESPONSE

Electricity providers and grid operators consider demand response programs to be increasingly valuable resource options whose capabilities and potential impacts are greatly expanded by modern grid technologies. Demand response is the ability to adjust customers' heating, cooling or other energy services in exchange for monetary credits on their bill. It is helpful for reducing stress on the grid during peak consumption times or power outages, integrating renewable energy resources and providing other grid services. It provides customers with the ability to shape their electricity consumption throughout the day, resulting in lower electric bills.

As states continue their efforts to modernize the electrical grid and deploy larger amounts of renewable energy, they are increasingly exploring policies to encourage deployment of demand response resources to better manage electricity demand and integrate intermittent energy resources. California enacted SB 1414 in 2014, which accelerates adopting demand response by requiring utilities and regulators to include it in IRPs. The bill also requires regulators to ensure appropriate valuation of demand response resources. In 2017, California enacted SB 801 that, among other provisions, requires the Los Angeles Department of Water and Power to maximize the use of demand response, renewable energy and energy efficiency in the area affected by the Aliso Canyon natural gas leak in 2016.

Washington enacted HB 1826 in 2013 to promote technologies and practices that lower integration costs. The law requires integrated resource plans, which utilities submit regularly to state regulators. They outline how utilities plan to meet forecasted annual peak demand and identify methods and commercially available technologies, including energy storage and demand response, for integrating renewable and distributed resources. In 2018, the Washington Utilities and Transportation Commission approved a request for proposals filed by Puget Sound Energy to procure demand response programs for 2019 through 2023 to meet a 351 MW capacity need the utility will have by 2023.

Vermont enacted HB 40 in 2015, raising its renewable standard to 75% by 2032. As part of this mandate, 12% of the standard can be met with energy transformation projects, which could include energy efficiency, energy storage or demand response.

In 2018, Massachusetts enacted HB 4857 establishing the first clean peak standard in the country. The bill directs the state's Department of Energy Resources (DOER) to establish a clean peak standard that would require utilities to provide a minimum percentage of KwH sales to customers in the state from clean peak resources, including certain renewable resources, energy storage systems and demand response resources. DOER must determine the percentage of sales during seasonal peak load hours that electric utilities must meet beginning in 2019. DOER will determine the initial standard and each year thereafter the standard will increase by 0.25% of sales. The department will also establish a minimum percentage of the clean peak standard that must come from demand response resources.

Montana and South Carolina enacted legislation in 2019 to require utilities to include demand response and demand-side management programs in their IRPs. Montana HB 597 requires utilities to submit long-range IRPs every three years and for these plans to include demand-side management programs. The bill also allows the state's Public Service Commission to authorize utilities to recover the cost of demand-side management programs in their rates. Similarly, South Carolina HB 3659 requires utilities to submit IRPs, which must include an evaluation of potential demand response resources, in addition to other technologies.

ENERGY STORAGE TARGETS AND MANDATES

Energy storage technologies, including batteries, pumped hydro, super capacitators and flywheels, store excess electricity generation and can quickly dispatch power to the grid as needed. These technologies offer a variety of benefits, including decreasing the need for costly grid upgrades, improving the electric grid's stability and reliability, and enhancing power quality and reliability. Energy storage also facilitates greater use of renewable energy resources by smoothing out variable generation from renewable technologies, such as wind and solar. When paired with microgrids, energy storage can ensure power reliability and enhance grid resiliency.

States have shown increasing interest in energy storage technologies as the cost of lithium-ion batteries has declined, establishing a number of energy storage mandates to encourage deployment of this emerging technology.[54] In 2017, at least 31 states took legislative and regulatory action related to energy storage.[55] These actions included conducting studies, amending resource planning and interconnection rules, considering incentives for storage systems, adopting procurement targets and deploying storage facilities.

Several states have enacted energy storage targets, including California, Massachusetts and Oregon, while Connecticut, Nevada, New Jersey and New York have directed state regulators to establish targets.

In 2013, the California Public Utilities Commission established an energy storage target of 1.3 GW by 2020, making California the first state to adopt an energy storage mandate.[56] In 2017, Massachusetts enacted HB 4857, increasing its previous energy storage target to 1 GWh by 2025. New York enacted legislation in 2017 to create a statewide energy storage target. Shortly after signing the bill, Governor Andrew Cuomo established a target of 1.5 GW of energy storage by 2025 through a series of clean energy proposals.[57] In late 2018, the New York Public Service Commission increased the state's commitment, raising the energy storage target to 3 GW by 2030. In 2018, New Jersey became the fifth state to adopt an energy storage target by enacting AB 3723, which directed the Board of Public Utilities to study and establish a process for reaching 600 MW of energy storage by 2021 and 2 GW by 2030. Nevada enacted energy storage-related legislation in 2017 that requires the PUC to investigate and establish energy storage targets.

Other states have advanced a variety of different policies, including energy storage tax credits in Hawaii, Maryland and New York. In addition, states have commissioned studies and sought state agency recommendations, provided funding for storage pilot projects and required storage to be considered in the utility planning process.

NET METERING

Net metering has been instrumental to the growth of distributed resources in many states since it allows distributed generation customers to sell excess electricity to the utility and receive a retail rate credit on their utility bill. The credit offsets the customer's electricity consumption during other times of the day, reducing the amount of electricity the customer needs to purchase. Minnesota was the first state to adopt net metering compensation at the retail rate in 1983 and at the policy's height, 44 states, Washington, D.C., and several territories had net metering policies.[58] Some states compensate net exports at less than the full retail rate, a practice referred to as net billing. Some call this approach net metering as well.

Forty states, Washington, D.C., and five territories provide net metering as of July 2019. Utilities in two additional states—Idaho and Texas—have voluntarily adopted net metering programs.[59] At least five states—Arizona, Georgia, Hawaii, Mississippi and Utah—have statewide distributed generation compensation rules other than net metering. As of July 2019, at least six additional states—Connecticut, Illinois, Indiana, Kentucky, Michigan and New York—have passed legislation or issued public utility commission decisions to phase out retail rate net metering after a certain date. Maine enacted legislation (House Paper 77) in May 2019 ending gross net metering and reinstating retail-rate net metering. The 2019 bill largely reversed a 2017 public utilities commission decision to replace net metering with a buy-all, sell-all compensation program.[60]

Although net metering policies have helped expand access to distributed renewable energy, they have also generated questions of equity and cost-shifting.

Originally designed to spur a nascent technology, net metering's success has led to debates on the policy's sustainability in virtually every state legislature or utility commission. While a net metering customer provides generation and other benefits to the grid, some feel the customer is not adequately paying for the operation and maintenance of the electricity transmission and distribution system. If customers are paid retail rate, some contend, they may be shifting grid operation costs to their neighbors. Others claim that the reliability, demand reduction and peak savings benefits may make distributed solar valuable enough to receive retail rate.

As penetration of distributed energy resources increases, numerous state legislatures and public utility commissions are discussing the best way to balance customer demand for distributed generation with the effects new technologies have on the electric grid. This includes exploring ways to appropriately assess the actual costs and benefits to the energy grid and all customers.

States such as Arizona, California, Hawaii and New York have explored next-generation compensation approaches that attempt to comprehensively value DER, not only solar energy. In 2013, California passed AB

327, requiring the California Public Utilities Commission (CPUC) to create a successor tariff for net metering, termed NEM 2.0. The CPUC decided in January 2016 to preserve the retail rate credit through 2019 and guarantee net metering credits for existing customers for 20 years after they are connected.[61] The decision also requires all new net metering customers to be subject to provisions under a new successor tariff, which includes interconnection fees, non-bypassable charges for all electricity consumed from the grid and participation in time-of-use rates.

In 2015, the Hawaii Public Utilities Commission issued a ruling that ended conventional net metering.[62] The PUC designed two interim tariff options to replace net metering—a grid-supply option and a self-supply option. The interim tariffs were replaced in 2017 by two new tariffs—a customer grid supply plus option and a smart export option.[63]

As part of its Reforming the Energy Vision proceeding, New York has addressed the transition from traditional net metering to a new tariff to appropriately value and compensate DERs. The New York Public Service Commission (PSC) established the Value of Distributed Energy Resource (VDER) tariff, or the Value Stack, to replace net metering. The VDER is designed to compensate DER projects based on when and where they provide electricity to the grid. In March 2017, the PSC approved an order adopting Phase 1 rates for the VDER tariff.[64] The Value Stack order was expanded in September 2018, and recently updated in April 2019.[65]

In September 2018, the Arizona Corporation Commission approved a replacement for net metering called the Resource Comparison Proxy. The slightly lower rate applies to new distributed solar owners and, combined with new higher monthly meter fees, is designed to address potential cost-shifting issues associated with net-metering. The commission also approved a special rate for new solar customers with home storage systems.

NON-WIRES ALTERNATIVES

Non-wires alternatives (NWAs) leverage microgrids, distributed solar, energy storage, energy efficiency, demand response and other energy solutions to delay or avoid construction of costly transmission, power plants or other infrastructure. Traditionally, when infrastructure needed to be replaced or upgraded to meet growing demand, utilities procured and installed the equipment and were able to earn a rate of return on those capital expenditures via the regulatory framework. The host of new technologies integral to the modern grid offer more creative ways to address infrastructure needs while improving benefits for customers and the environment. Since this approach is relatively new and may involve harmonizing the use of many newer energy technologies, utility planning procedures do not systematically emphasize consideration of these solutions.

Several states are now requiring that utilities consider non-wires solutions in their plans to meet energy needs. In New York, which also requires utilities to consider non-wires solutions, Con Edison implemented one of the largest NWAs to date with the Brooklyn-Queens Demand Management program, which deferred a $1 billion substation upgrade with a $200 million investment in demand response and other measures. Bonneville Power also found substantial savings through non-wires alternatives. The utility canceled a $1 billion transmission line and is instead using demand response to manage line congestion, rather than overbuilding for a few peak hours of demand each year.[66] Rhode Island passed a law in 2006 requiring utilities to consider cost-effective energy efficiency and other demand-side measure before building costly supply-side solutions. Maine, Vermont and California also have been working to encourage or require consideration of non-wires alternatives.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Utility Regulatory Options

Policymakers can select from a range of approaches to modernize the regulatory approach. These can range from specific actions related to ratemaking or completely reworking the regulatory framework.

Utility Business Models

The traditional cost-of-service regulatory model was designed at a time when the grid was far simpler than it is today. While the requirements for utilities—to provide affordable, reliable electricity while meeting basic federal and state environmental regulations—have not changed, the energy landscape has changed dramatically. Utilities are now required to consider demand-side solutions, new management technologies, distributed generation, clean energy mandates, distribution planning, two-way energy flows, and many other issues as they work to meet reliability and affordability requirements.

New technologies, innovative third-party energy companies and changing consumer demands are challenging the traditional regulatory model. The cost-of-service model worked well in a time when electricity demand was growing rapidly, new power plants and infrastructure were continually needed to meet demand, and electricity generation was centralized. However, in recent years, demand growth has slowed, challenging a traditional regulatory model that compensates utilities based on capital expenditures and electricity sales. With the introduction of many new technologies and the grid increasingly moving toward a more distributed model, utilities have an even greater need to invest in grid modernization. This dynamic is coupled with a shift in consumer behavior as efficiency, flexibility and clean energy have grown in popularity. The rapid spread of rooftop solar and smart thermostats is a prime example.

To address these challenges, states across the country are working to reshape the traditional regulatory framework in a way that better aligns customer and utility goals and state policies. The traditional regulatory model, also called the called the cost-of-service model, has numerous structural concerns that state policymakers are attempting to address, including:

- **Bias Toward Capital Investments.** Utilities earn a return on building new power plants and infrastructure and none when they are meeting needs with energy efficiency or demand side solutions.
- **Throughput Incentive.** Since a utility's profits are often directly tied to the quantity of electricity it sells, it may see losses from approaches that lower sales, including energy efficiency, distributed generation and demand response.
- **Risk Shifting.** The cost-of-service model may shift risk from the utility and shareholders onto rate payers in some cases, as has happened with large cost overruns for power plants, such as Diablo Canyon, discussed later in this report.
- **Restrictions on Innovation.** The traditional model limits opportunities for utilities to be innovative in their approach to revenue and profit, since it often doesn't incentivize innovative new services, infrastructure alternatives or innovation in general.
- **Limits to Competition.** With new technologies and energy management approaches looking to compete, and the tendency for utilities to be risk-averse, there is concern that utilities may use their monopoly advantages—including system access and customer relationships—to exclude competitors, or technologies, that may offer significant benefits to customers.

Policymakers are looking to modernize regulating the new 21st century grid with new and innovative approaches that reward utilities for performance and service rather than sales and capital expenditures.

Goals of these adjustments include:

- Creating an incentive for utilities to make objective decisions on technology implementation and resource planning, whether they are utility or third-party solutions. This may include changing competitive market rules and wholesale energy market design to properly value variable generation, storage technologies and demand-side resources. Valuation processes are still evolving and often consider efficiency, cost, resilience and other factors.

- Providing opportunities for third-party energy providers to add value for customers and the grid.
- Allowing utilities to be a partner in meeting social and policy goals, such as resiliency, energy efficiency and emissions reduction.
- Creating a regulatory structure that rewards innovation, low-cost solutions and improvements in customer satisfaction.
- Providing opportunities to transition to a lower financial risk energy portfolio, which helps both customers and investors. This could include using savings gained from new opportunities to pay for stranded asset depreciation or investments in new technologies and clean energy resources.

To achieve these goals, states are taking a range of approaches, from tweaking the traditional regulatory approach to a wholesale reimagining of the utility regulatory model.

One of the steps that some states have taken to address the throughput incentive is to break the link between a utility's sales and its earnings through revenue decoupling. By removing the threat of utility losses due to energy efficiency, demand response and distributed generation, decoupling eliminates the bias toward selling more electricity, allowing utilities to more easily select energy solutions that are best for the customer, even if they reduce electricity sales. For utilities, decoupling reinforces the concept that service, not throughput, is paramount. Nineteen states allow electric utilities to implement revenue decoupling and 16 states have at least one utility that has implemented it.[67] A few states, like California, require investor-owned utilities to use revenue decoupling.

While decoupling removes the throughput incentive, it does not necessarily motivate utilities to choose low-cost efficiency or other demand side solutions if they can earn a higher return by meeting demand with investments in new power plants and power lines. To address the potential bias toward capital expenditures, many states enable utility shareholders to earn a return on their non-capital investments, just like they would for power plant investments. These "shared savings" policies allow the utility, when it meets certain demand response or efficiency goals, to receive a percentage of the savings that result from reduced energy purchases. Thirteen states have instituted shared savings incentives.

Colorado's investor-owned utilities receive energy efficiency and demand side management performance incentives for customer benefits attributable to the utility's energy efficiency and demand response achievements. The savings amount to 19% of incremental net benefits for energy efficiency and 15% of benefits from demand response.[68]

Policymakers also have implemented performance incentive mechanisms, which provide monetary rewards for successfully achieving desired utility functions, reaching state energy policy goals and serving customer interests. These mechanisms also penalize underperformance. This approach can encourage utilities to meet state energy efficiency savings requirements and has been implemented in at least 26 states.[69]

New York has used performance incentives to make non-wires alternatives more attractive to utilities. Con Ed has been allowed to spend up to $200 million on non-wires alternatives to avoid building a $1 billion substation. The utility also receives bonus incentives based on the energy savings it achieves, the diversity of distributed energy resources deployed and other factors. State regulators have allowed Con Ed to spend one-fourth of the money on utility-side grid investments while the remainder goes toward customer-side projects, including battery storage, lighting upgrades and other demand-reduction programs.

Performance-Based Regulation

Some states are finding that the capital expenditure bias and other outdated features of cost-of-service regulation cannot be addressed without dramatic changes to the regulatory regime. A major issue policymakers are looking to address is that traditional regulation creates a disincentive for utilities to accommodate distributed energy or other demand-side resources, even if these resources meet customer needs at a lower cost.[70] While policies to promote least-cost alternatives, including IRPs and mandates to consider demand response or energy efficiency, can be effective, without the proper incentives, utilities may be less supportive of existing policies and may not effectively promote cost-effective DERs.[71]

To address these challenges a number of states are now investigating performance-based regulation (PBR), which aligns utility, customer and public policy goals while allowing utilities to become innovative partners in reaching these goals. Instead of creating a mandate that requires utilities to pursue actions that may hurt their bottom line, PBR rewards utilities for achieving desired outcomes that benefit consumers. It does so by disconnecting electricity sales and capital expenditures from profit, tying profit instead to performance metrics. While traditional cost-of-service regulation encourages capital-intensive projects, PBR rewards utilities for achieving a desired outcome, such as increasing energy efficiency and demand response, improving resiliency and reliability, or heightening customer satisfaction. The approach is collaborative, not prescriptive; goals and targets can be determined by the utility. This model allows utilities to test different approaches and, if successful, receive a share of the savings generated.

An early example of PBR was implemented during the construction of the Diablo Canyon nuclear plant in California. Due to cost overruns and delays that caused great consumer consternation, the state PUC rejected the standard rate-based cost recovery mechanism in favor of a performance-based approach. This made the revenue recovery for the utility, Pacific Gas and Electric, dependent on whether the plant could generate power when needed, shifting some of the risk away from ratepayers and creating greater accountability for the utility. Since its opening, the plant has experienced a high availability rate and operated at high capacity, which could be attributed to PBR.[72]

New York was the first state to investigate statewide PBR with its Reforming the Energy Vision initiative, which serves as a comprehensive roadmap for building a clean, resilient and affordable energy system. The approach aims to construct a regulatory system that rewards distribution utilities for high levels of customer satisfaction, facilitates power sector transformation to cleaner and more distributed resources, and increasingly focuses on outcomes. It also focuses on performance-based incentives and more accurate pricing schemes for distributed generation.

Hawaii is also looking to implement a new regulatory model. SB 2939, enacted in 2018, directs the Hawaii Public Utilities Commission to implement PBR by 2020, making Hawaii the first state to pass a legislative mandate that breaks the link between utility revenues and capital expenditures. The legislation requires the commission to evaluate existing ratemaking structures and to design incentives and penalties around several outcomes, including customer affordability and electric reliability, as well as the rapid interconnection of renewable energy systems and distributed resources. The effort is designed to assist Hawaiian Electric in complying with Hawaii's RPS and to reduce grid defection by ensuring the utility has a sustainable business model that can weather the disruptive changes in the future. The commission is also acting on performance-based rates for the state's regulated utilities.[73] Through a docket proceeding, the PUC will create regulatory mechanisms that focus on increasing levels of renewable energy, lowering costs and improving customer service. Hawaiian Electric, the state's only investor-owned utility, approved a demand response program in early 2018 that also includes performance-based metrics.

Pennsylvania enacted HB 1782 last year to reform its utility business model as well. The bill allows utilities to propose, and the PUC to approve, alternative ratemaking approaches based on decoupling mechanisms, performance-based rates, formula rates and/or multiyear rate plans. Many other states, including Ohio, Minnesota, Rhode Island and Illinois, are investigating or moving toward a more PBR model. Utilities tend to be supportive of these moves and see them as a way to ensure they remain profitable and competitive in the future.

Utility Actions and Case Studies

Public utility commissions and utilities in several states have undertaken initiatives related to grid modernization. Some are taking a comprehensive approach, considering technology, policy, rate design and utility business model reforms simultaneously. Others are tackling portions of the grid modernization puzzle by commissioning studies and exploring pilot projects. This section highlights actions by commissions and utilities in several areas of grid modernization.

Illinois

Illinois has embarked on a broad effort to simultaneously address several different elements of grid modernization. The state enacted the Future Energy Jobs Act (SB 2814) in 2016, which spurs investment in wind, solar and energy efficiency. The act provides incentives for utilities to fairly evaluate demand reduction actions with a performance incentive mechanism that rewards utilities for achieving progress toward efficiency goals. It also provides a full rate of return for meeting a specified goal or a portion of a goal, with penalties or bonuses for every 1% shortfall or achievement relative to that goal.

The utilities also have the option to expense, rather than rate base, efficiency spending if preferred. Following this bill, the Illinois Commerce Commission (ICC) opened a "NextGrid proceeding" to explore ways to build on this and other energy legislation from the past decade.[74] The ICC formed a working group for each of the seven topic areas targeted by the NextGrid initiative: new technology and grid integration; electricity markets; customer and community participation; regulatory, environmental and policy issues; metering, communications and data; reliability, resiliency and cyber security; and ratemaking.

In December 2018, the ICC released a draft of the final report that provides a broad overview of policy options for modernizing the grid.[75,76] Although the report does not make specific recommendations or discuss costs and benefits, it does describe how the electric grid functions and presents options for how Illinois' system could be transformed as technology and consumer demands change.

The ICC has also investigated energy storage, holding several panel sessions in 2018 to discuss the economics of energy storage and related legal, policy and regulatory frameworks.[77]

The policy actions in Illinois generated several utility actions. Ameren, one of the state's large investor-owned utilities, filed a proposed tariff in March 2018 for rebate programs for distributed generation projects that incorporate smart inverters.[78]

Michigan

As part of its grid modernization efforts, the Michigan Public Service Commission has undertaken several studies and published reports that address various aspects of grid modernization. They include demand response, alternative utility business models and PBR, and solar-plus-storage compensation.[79]

In September 2018, the PSC staff filed a report providing a framework for future distribution plans, which contained several recommendations. They include:

- Requiring a dynamic approach to load forecasting.
- Requiring utilities to make hosting capacity information publicly available.
- Requiring utilities to use specific advanced metering infrastructure standards to provide customers access to usage data.
- Providing criteria for and information on non-wires alternatives projects in future plans.
- Developing a common cost-benefit methodology for use in future distribution plans.[80]

Two of Michigan's utilities—Consumers Energy and DTE Electric—have also taken action on grid modernization. Both utilities filed draft grid modernization investment proposals in 2017, as well as their final five-year distribution investment and maintenance plans, which included plans for system modernization in 2018.[81] In 2018, the PSC ordered DTE to move to default time-of-use rates for residential customers.[82]

Minnesota

Minnesota's PUC and investor-owned utilities have undertaken several initiatives related to grid modernization. The PUC opened a docket in May 2015 to consider developing policies to modernize the grid.[83] The effort engaged a broad swath of stakeholders and incorporated several workshops. In concert with this docket, the PUC also solicited comments from its large investor-owned utilities—Xcel Energy, Minnesota Power and Otter Tail Power—on various topics around distribution system planning. In April 2018, the PUC staff released a briefing paper that included a proposed procedure and schedule for developing utility-specific integrated distribution plans. As part of its grid modernization efforts, the PUC has also updated the state's interconnection standards, which are now based on FERC's Small Generator Interconnection Procedures and include provisions to allow energy storage.[84]

Xcel Energy, Minnesota's largest investor-owned utility, filed a proposal for a pilot time-of-use (TOU) tariff in November 2017, in conjunction with its grid modernization plan, which was approved by the PUC in June 2018.[85] Xcel's TOU pilot rate will launch in 2020 and will be initially open to 10,000 customers.

■ Ohio

Ohio's PowerForward grid modernization investigation is a broad proceeding initiated in March 2017.[86] The investigation, spearheaded by the Ohio Public Utilities Commission (PUCO), will chart a path forward for future grid modernization projects and innovative regulations. The PowerForward initiative was rolled out in three phases, and the third and final installment concluded in March 2018. Following the completion of the final phase, the PUCO published the PowerForward Roadmap in August 2018.[87] The roadmap details stakeholder discussions that were held during the investigation, includes recommendations on the technical and policy aspects of grid modernization, and establishes foundational tenants for grid modernization decisions. The publication addresses next generation grid architecture, distribution system planning, electric vehicles, energy storage, distribution system markets, ratemaking and rate design, data analytics and cybersecurity.

Ohio's investor-owned utilities have taken actions in conjunction with the PowerForward initiative. In 2016, the PUCO ordered FirstEnergy to file a Distribution Modernization Rider, allowing the utility to collect $600 million over three years to fund grid modernization efforts.[88] The rider was approved in December 2016, and PUCO ordered its staff to work with a consultant to review how FirstEnergy uses the money collected under the rider. Additionally, in December 2017, FirstEnergy filed a separate plan that outlined a three-year $450 million investment in modernizing its distribution network.[89] The utility's plan included circuit ties, reconductoring, reclosers and data acquisition systems.

■ Rhode Island

Rhode Island has been one of the most active states around grid modernization efforts in recent years. In 2017, the state created its Power Sector Transformation initiative, a comprehensive grid modernization proceeding.[90] The Power Sector Transformation has three objectives: to control long-term costs of the system; provide more energy choices for customers; and build a flexible grid to integrate more clean energy generation. The initiative addresses several topics, such as data access, distribution system planning, utility business models and transportation electrification. Rhode Island is also considering non-wires alternatives and investigating solar-plus-storage compensation.

As part of the Power Sector Transformation initiative, several working groups met in 2017 to discuss topics including utility business models, grid connectivity and functionality, distribution system planning and beneficial electrification. The groups published four documents that were compiled in the Phase One Report that was presented to Governor Gina Raimondo in November 2017 and will serve as a guiding document for the state's future energy transformation.[91] The report identifies several goals, including using pay-for-performance utility models; investing in intelligence and connectivity; identifying new sources of utility revenue; leveraging information; and increasing reliability and resilience. It also presents recommendations to achieve the goals.

In 2018, Rhode Island established a Power Sector Transformation advisory group to review progress on the components of the initiative's three-year rate plan. They include grid modernization, advanced metering functionality, time-varying rates, electric transportation, electric heat, energy storage and performance incentive mechanisms.

State regulators have also investigated distributed generation and net metering provisions. The PUC opened a docket in 2016 to identify and measure the costs and benefits of net metering and distributed energy resources.[92] Through the docket, regulators developed a detailed Benefit-Cost Framework to use to evaluate distributed generation programs, alternative rate designs and grid modernization projects.[93] The process yielded several recommendations that were accepted by the PUC to be used in future rate cases.[94] In December 2017, regulators determined that solar-plus-storage facilities that meet certain qualifications are eligible for net metering.[95]

The state's investor-owned utility, National Grid, has also been active in Rhode Island's grid modernization efforts. In November 2017, the utility proposed an investment plan following the publication of the Phase One Report.[96] The plan implements certain goals of the initiative and proposes steps to shift toward performance-based regulation. Regulators approved a settlement agreement on the proposal in August 2018.[97] Additionally, National Grid filed its system reliability procurement plan at the end of 2017, which builds on a previously established non-wires alternative evaluation framework.[98]

Determining the Economic Benefits of Grid Improvements

As PUCs and utilities undertake their grid modernization efforts, many are confronting the question of cost-effectiveness. Utilities must make the business case for grid improvements and regulators are carefully considering the costs and benefits of new grid technologies, such as advanced metering infrastructure. They aim to ensure that the benefits of these improvements and new technologies outweigh the costs and lower the risk of creating stranded costs. Additionally, PUCs must grapple with the uncertainty of whether the proposed benefits of these new grid technologies will be realized. This discussion has played out in PUCs across the country on smart meter investments and larger grid modernization investment proposals.

While smart meters are the most common type of electricity meter deployed in the U.S., the rate of deployments has been slowing in recent years. Regulators in some states are questioning whether the savings that smart meters generate justify their costs. In 2018, regulators in Kentucky[99] and Massachusetts[100] rejected proposals for smart meters, citing concerns that utilities did not sufficiently justify the costs.

Regulators in Virginia rejected Dominion Energy's smart meter deployment proposal, as well as large portions of the utility's grid transformation proposal, in January 2019.[101] The proposal would have cost approximately $6 billion over a 10-year period and included reliability and resilience measures, cyber and physical security upgrades, telecommunications infrastructure and other upgrades. While regulators approved the physical and cyber security portions, the remainder of the plan was rejected due to concerns about its cost-effectiveness.

However, regulators in some states have approved grid modernization investments.[102] The Rhode Island PUC approved a settlement that allows National Grid to increase residential customer rates by 3.5% for investments in a range of modernization and grid transformation initiatives. The approval allows National Grid to launch electric vehicle and energy storage programs, create a performance incentive mechanism to encourage energy efficiency, and establish a stakeholder process around smart meters.

Rate Design for a Modern Grid

The way rates are set can be critical to grid modernization efforts. They can guide consumer and utility investment in the grid, affecting reliability, operating costs and consumer bills in both the short and long term. They also influence competitive service providers' decisions to support the electric grid. Rates send signals to consumers that influence how much electricity they consume, when they consume it and to what degree they choose to implement efficiency or distributed energy measures. They also influence how utilities make capital investments and the type of investments they choose.

Through the rate design process, public utility commissions approve electric rates that allow utilities to collect the revenues necessary to recover their capital and operating expenses through charges on customer bills. While setting rates, commissions seek to balance the divergent goals and priorities of utilities, customers and industry interests. Although public utility commissions approve rates for investor-owned utilities and determine what expenses they can recover, state legislatures set the framework and guiding policies within which commissions operate. Rate design is often influenced by legislative initiatives and can be used to meet policy objectives, such as increasing energy efficiency, lowering peak energy demand or deploying distributed energy resources. Legislatures can also request that commissions explore specific rate designs, complete studies and report their findings.

CHALLENGES TO TRADITIONAL RATE DESIGN

Traditional rate design assumes that utilities meet all customer electricity demand with large, centralized generation facilities and that nearly all electricity flows in only one direction—from the utility to customers. Under this model, both fixed costs (a new power plant or utility infrastructure) and variable costs (fuel and operating costs) are recouped through a fixed charge and a variable energy charge based on electricity consumption.

Increasing adoption of customer-sited generation, smart metering, demand response and other distribution-level technologies has challenged this method. The increasing deployment of distributed generation means power no longer flows just from the utility to the consumer, but also from the consumer to the utility, and on to another consumer. With customers as energy producers, new rate designs have been implemented with the aim of fairly compensating ratepayers that generate electricity and send it back to the grid.

Smart grid technologies and distributed energy resources have the potential to create benefits for utilities and consumers, including reliability, efficiency, flexibility and resilience. They may also add to grid management costs and require more investment in complex grid infrastructure to support a more decentralized grid. Designing rates that appropriately weigh benefits and costs is a critical task, sometimes complicated by the fact that the location of distributed resources and other variables beyond the control of the utility could negatively affect the benefits.

Many states are investigating ways in which rate design can assist in grid modernization. When paired with market-based rate designs, technologies such as smart thermostats and smart water heaters can reduce peak load and improve reliability while lowering consumer and utility costs. Advanced metering infrastructure enables the development and implementation of dynamic, time-variable rate designs, which allow utilities to more accurately match consumer costs to the costs incurred by the grid.

This approach could lower costs and help the grid integrate the rising number of electric vehicles, which are likely to increase electricity demand and grid infrastructure needs in the future. If charging is done during peak demand times—which may often happen with fixed electric rates—a great deal more generation and grid infrastructure will be needed than if charging is done during periods of low demand. Time-based electric rates use the market to guide charging and reduce system costs, signaling electric vehicle owners to charge when electricity demand is low and electricity is cheap. They also discourage owners from charging during peak demand periods when electricity is most expensive.

POLICY CONSIDERATIONS

Government and industry leaders are considering alternatives to traditional regulatory approaches to address a host of factors, including the rapid growth of distributed generation, flat or declining electricity sales, infrastructure replacement needs and the desire to increase energy efficiency. To further grid modernization efforts and increase deployment of advanced grid technologies, policymakers in many states are evaluating rate designs to create an energy system that allows for fair valuation of new technologies. When considering new approaches, policymakers and regulators must balance the needs of customers and utilities. They must ensure that customers, including low- and fixed-income customers, contribute equitably to energy infrastructure, and that utilities have a reasonable opportunity to recover and earn on their investments.

In addition to the alternative rate design approaches explored in the following pages, states have enacted several other policies to address emerging utility compensation challenges. They include decoupling sales from revenue, lost revenue adjustments, formula ratemaking and more frequent rate cases.

FIXED CHARGES AND MINIMUM BILLS

Utility bills include variable and fixed portions, although the largest portion of most consumer bills are variable charges based on consumption. Some utilities are seeking rate design changes that increase the fixed portion of the bill, which provides utilities with a more stable source of revenue in the face of slackening demand growth and increasing customer-sited electricity generation. Transmissions and distribution operations, maintenance, billing and accounting could be considered fixed costs, while fuel and electricity purchases are considered variable. Investor-owned utilities prefer that a larger portion of fixed costs be captured in fixed charges, which would create a more stable revenue stream, removing the uncertainty of predicting changes in electricity sales. Some contend that this approach will shift risk from shareholders to ratepayers, however. The time period one uses to define a fixed cost is also in question—economists find that most "fixed" costs are variable in the long term.[103]

These discussions have ramped up recently, with PUCs in at least 36 states receiving utility requests to increase fixed charges or minimum bills in 2018, while 35 states considered requests in 2017.[104] Utility rationale is that most of their costs are fixed, not variable, and contend that billing should better reflect this cost distribution. This approach has been spurred by the increase of distributed generation customers, who are currently offsetting most of their variable consumption charges through net metering. Higher fixed costs can be one way to ensure these customers continue to pay a share of the infrastructure and delivery costs. These discussions have explored increasing fixed charges for all residential customers as well as increases just on those with grid-connected distributed energy systems.

From a consumer viewpoint, however, higher fixed and lower variable charges weaken price signals, providing less motivation for customers to engage in energy efficiency or conservation efforts, which could lead to increased consumption. Ultimately, increased consumption in the long-term would necessitate more generation and transmission infrastructure, leading to higher system costs, which would be passed on to the consumer. A shift to higher fixed costs increases the energy burden on low-income households or others who may use less electricity than the average residential consumer. Higher fixed charges may also reduce the financial incentive for adopting distributed generation technologies, such as rooftop solar, or energy storage.

While economists believe all costs are variable in the long term, utilities have definite fixed costs in the short term. The debate is whether high fixed charges are the most appropriate mechanism for revenue recovery. Gasoline for instance, is sold on a purely volumetric basis despite there being fixed infrastructure costs in the short term for extraction, refining and delivery.

The increase in fixed charge discussions is highlighted in research by the North Carolina Clean Energy Technology Center (NC CETC). A recent study found that state activity on fixed charges has steadily increased in recent years, with 61 requests to increase charges pending or decided in 2015, 71 in 2016, and 84 in 2017.[105] In 2018, the number of actions dropped to 78, marking the first year that this number has decreased since 2015.[106] In analyzing these requests, NC CETC found that regulators approved only a portion of utilities' requested increases in 57% of these cases. In addition, only six utilities were granted their full requested increases, indicating that utility commissions did not always agree with an increase or the degree of an increase.[107]

While a minimum bill is separate from a fixed charge, many principles are similar to the policy discussed above. Minimum bills ensure that customers still contribute monthly, even if their energy use is near zero. A minimum bill requirement would not affect most customers since their fixed and variable energy charges would be above the minimum. The customers that may have bills low enough to trigger these charges would be distributed generation and net metering customers, customers with strong seasonal electricity use, those with very efficient homes and low electricity use, or those with vacant or vacation properties. According to the Lawrence Berkeley National Laboratory, minimum bills are not in widespread use and while they do not disincentivize efficiency as much as fixed charges, they also recoup less revenue.[108]

TIME-BASED RATES

Time-based rates are another type of rate design that includes time-of-use rates, critical peak pricing, peak time rebates and real time pricing. These approaches more accurately represent actual system costs, and signal customers to shift or reduce their energy use during periods of peak demand when the cost of providing electricity is highest. Time-based rates can decrease peak demand, allow flexibility in meeting demand and better reflect the time-variable cost of providing electricity. Ultimately, improved market signaling to consumers can reduce system operating costs in the short term and infrastructure costs in the longer term.

Time-based rates typically require two-way smart meters to communicate pricing information between a consumer and the utility. While dynamic pricing has been used in the U.S. since the 1970s, the increase in smart metering has helped the concept gain popularity as a modern rate design solution.

■ **Time-of-use rates (TOU)**. Utilities generally divide the day into set periods of "on-peak" and "off-peak" hours to help customers know ahead of time which periods of the day will be most costly, giving customers the option to lower their bills by shifting usage to low-cost periods. Some utilities have multiple pricing periods in their TOU rates. Xcel Energy Minnesota's pilot TOU rates include "super-off peak" hours and rates, and Xcel Energy Colorado's TOU rate features a "shoulder period" on either side of on-peak hours that is priced at a discounted rate.[109]

The method used to determine peak periods can play an important role in the success of this approach—if too many hours are designated as on-peak, customers may find it difficult to avoid consumption during peak hours. While it is a more economically transparent market-based approach, time-based rates may create higher bills for some and lower bills for others based on their consumption patterns. TOU rates are generally viewed as a more equitable rate design option and are typically more easily understood by customers than other rate designs, such as demand charges. This approach has also been shown to reduce peak load and total energy consumption.[110]

TXU Energy's Free Nights & Solar Days offer a 100% renewable time-of-use program.[111] To offset customers' usage, the utility purchases solar power and renewable energy credits. Enrolled customers have access to free wind electricity all night from 9 p.m. to 6 a.m. and pay for solar electricity all day from 6 a.m. to 9 p.m. TXU Energy encourages customers to shift their use of large appliances to the free nighttime hours and adjust programmable thermostat settings to take full advantage of the program.

■ **Critical peak pricing (CPP) and peak-time rebate.** These variations of the TOU concept incentivize customers to reduce usage on critical peak times of the year. Under CPP, utilities set much higher prices for critical periods—during expected shortages or anticipated high-use, for example—and customers agree to pay the increased price for usage during that time. Utilities are limited on the number of days that can be designated as "critical," typically between three and 12 days per year. Utilities may concentrate those days into a single on-peak season—for example, summer or winter, depending on when the overall system peak occurs. Customers are given one-day advanced notice of when critical peak periods will occur. Although these rates are generally opt-in, they have been largely successful in reducing critical peaks. In contrast to CPP, peak-time rebates use a carrot rather than a stick, providing a credit on the bills of customers who reduce usage during a peak-time event.

Utilities in most states offer time-of-use rates, however, they are generally optional programs. A handful of states are transitioning or are considering transitioning to default TOU rates for residential customers. For example, California enacted AB 327 in 2013 that gave the PUC the authority to direct investor-owned utilities to adopt TOU rates beginning Jan. 1, 2018. In 2015, the CPUC ordered the state's three largest investor-owned utilities—SDG&E, PG&E and SCE—to transition from voluntary to default TOU rates by 2019.[112] Some analysts have raised concerns that this transition could lower compensation for net-metered solar owners. Research by Greentech Media estimates the value of net-metered solar could be reduced by 15% to 20% for residential systems in SDG&E's service territory and by 20% to 40% for certain entities in PG&E's territory.[113]

■ **Real-time pricing.** Under this model, customers are charged the actual prices for energy being set in wholesale markets or short-run marginal generation costs, with prices varying hour by hour. With increased adoption of smart technologies, customers can set devices to monitor energy prices and automatically respond to price changes and realize the benefits. If prices are high, for example, these devices can delay water heating or allow the temperatures to rise a bit in the building before turning on the cooling system. However, while real-time pricing further refines price signals, these programs may pose financial risks to customers who are unable to shift their use outside of high-price hours. Real-time pricing also requires more sophisticated energy management, making it a more viable option for organizations that have or hire energy managers or customers with end uses, such as many electric vehicle charging systems, which can automatically respond to real-time prices.[114] Utilities in a small number of states, including Georgia, Illinois, Maryland and Texas, offer real-time pricing tariffs.

Georgia's large investor-owned utilities, Georgia Power, has offered real-time pricing tariffs to industrial customers for more than 10 years, and this pricing structure has been the standard tariff for large-use customers since 2011.[115] Under this tariff, customers only experience real-time prices when they consume more, or less, than the expected usage for a customer of their size. Customers are also given notice of day-ahead prices. Customers "subscribe" to power at a regulated rate, and then are charged a real-time price for greater or lesser amounts of electricity that they consume.

DEMAND CHARGES

Demand charges are based on the highest usage of a customer in a specific time frame during a billing period. A common approach would be to set a charge based on a single hour during the month when a ratepayer uses the most electricity. Since power infrastructure is designed to meet the largest peaks in energy demand, which may only happen for a short time on a few days a year, demand charges are meant to capture infrastructure costs caused by the user. If the rate is based on a "non-coincident peak," which is typical, customers are charged for their peak consumption, regardless of when it occurred. Under non-coincident peak demand charges, it does not matter when the customer's highest usage occurred or whether the customer's peak is actually driving system costs. "Coincident peak" demand charges, which are based on each customer's highest demand during the period of greatest total demand for the utility, are far less common, though they more accurately reflect whether a user is creating additional infrastructure costs. Demand charges may also include a "ratchet," where the customer's demand charge in any given billing period cannot be less than some specified fraction of their highest demand in the previous year. Demand charges have been widely used for large commercial and industrial customers that have a more significant incremental impact on infrastructure, rather than individual residential customers.[116]

Only recently have utilities proposed demand charges for residential customers, again with the aim of addressing potential cost-shifting associated with the growing amount of distributed generation owners and the need for infrastructure investment. If a residential customer's demand charge peak is coincident with the utility's peak, a customer's usage may be adding to the infrastructure sizing needs and increasing overall costs. In this case, demand charges create an incentive for a customer to reduce or shift their usage, which can lower peak demand and utility costs. According to NC CETC, many existing or proposed residential demand charges are based on non-coincident peak demand (such as a resident whose peak usage is on the weekend) which may not align charges based on the highest costs to the system, penalizing consumers who are not causing additional costs to the system.

In recent years, there has been growing utility interest in using demand charges to reduce the cost shifting concerns related to distributed generation or net metering customers. Some contend that demand charges may not be the most effective or economically sound approach to capturing the costs of distributed energy resources to the grid. While demand charges work well for large customers that have the resources and staff dedicated to managing energy use, there are questions about whether residential customers have the time and sophistication to monitor and respond to demand charges. If residential customers don't understand demand charges, they may be less able to change usage to decrease their electricity bills. A recent survey of utility customers found that around half of the customers understood the terms kW and kWh, while just 17% felt they had a good understanding of their bill. [117] This indicates that many customers may not have the capacity and time to understand and manage demand charges. There is also concern that demand charges may shift costs to certain customer groups who contribute minimally to system peaks—such as low-use and low- and moderate-income customers, and to customers living in multifamily dwellings that have less control over their peak demand usage.[118]

Utilities in more than a dozen states offer demand charge rates to residential customers. For example, two utilities in Arizona—Salt River Project (SRP) and Arizona Public Service (APS)—currently offer demand charges. SRP (a public power utility) introduced a tiered demand charge rate in 2015 that increases with a customer's peak consumption. Demand charges are mandatory for all SRP customers with distributed generation. APS first introduced demand charges in 1981 and now offers demand charges on an opt-in basis.[119] This APS rate has the highest enrollment of any residential demand charge rate in the U.S.

Currently, only two investor-owned utilities have a mandatory residential demand charge in place. In September 2018, Kansas regulators approved mandatory residential demand charge for distributed generation customers for Kansas City Power & Light and Westar Energy, citing concerns about cross-subsidization of Westar solar customers by its non-solar customers.[120] The approved charge is applicable to demand during system peak hours and varies seasonally.

In recent years, utilities in several states pushed for demand charges. According to NC CETC, three utilities proposed mandatory demand charges in 2017, five proposed these charges in 2016 and 10 utilities proposed them in 2015.[121] In 2017, demand charges were taken on in other arenas, including the legislature. Legislation was approved in several states specifically authorizing additional fees, including demand charges.[122] In 2018, although investor-owned utilities' requests to adopt mandatory demand charges for residential customers were generally denied, regulators approved three utilities' proposals—Kansas City Power & Light and Westar Energy in Kansas, and Eversource in Massachusetts.[123] While the Kansas utilities' demand charges are still in place, the Massachusetts General Court enacted legislation that effectively repealed Eversource's demand charge.[124]

If demand charges are carefully implemented and fully understood by customers, they may help to reduce peak demand and produce cost savings to all customers. However, very little data exists on the effects of demand charges on residential customers and their ability to decrease peak demand.[125]

LOCATION-BASED VALUATION

As distributed energy resources and new grid technology proliferate, states are exploring alternative valuation methods that incorporate the benefits that these technologies, such as distributed solar power or energy storage, provide to the grid. One such method, location-based valuation, places a value on the benefits that a technology provides to the local distribution system. The value of an energy resource depends on its location as well as its ability to contribute the needed characteristics of availability, dependability and durability to the grid. Locational valuation provides incentives to resources that are sited in locations that reduce grid congestion and the need to make cost grid infrastructure upgrades, allow for easy integration, and are close to consumption centers.

Several states are exploring location-based valuation for distributed generation, particularly those with high penetration of distributed energy resources, including California, Hawaii, Nevada and New York. A small number of states are studying ways to value DERs based on their location and to deploy DERs at optimal locations and in ideal quantities to maximize their benefits to the grid and reduce utility customer costs.

New York is addressing locational valuation as part of the state's Reforming the Energy Vision initiative.[126] One of the primary purposes of REV is to design accurate pricing for DERs that reflects their actual value. In April 2017, the New York PSC issued the Value of Distributed Energy Resources order as part of the REV initiative. The Value of DER Order (or VDER) establishes a new pricing methodology, which is based on the avoided costs combined with additional metrics that place values on qualities such as location, the location-based marginal wholesale price and environmental benefits.[127] The order required utilities to file schedules and work plans within 45 days to develop new pricing values, and in July 2018, the New York PSC filed two white papers suggesting improvements to the VDER tariff.[128] However, in one of the white papers, PSC staff recommended phasing out the locational value component of the VDER tariff , in favor of distribution system implementation plan, non-wires alternative and demand response programs that are more effective in addressing location-specific compensation.[129] The PSC's updated Value Stack Order, released in April 2019, includes provisions to improve the predictability, transparency and accuracy of the locational value component of the VDER Tariff.[130]

The Nevada PUC approved a distributed resource planning framework for Nevada Energy in September 2018.[131] Among other provisions, the PUC's ruling requires NV Energy to evaluate the locational benefits and costs of distributed energy resources and coordinate existing programs to maximize locational benefits.

Federal Action on Grid Modernization

While much of the work on grid modernization is taking place in states, the federal government is also working to promote and encourage the creation of a modern grid. In some cases, federal regulators have directed grid operators to establish more welcoming policies for new technologies. In others, the DOE has provided states with technical assistance and its national laboratories have worked on research fundamental to developing and integrating these new technologies and energy management systems.

Regulations

While FERC does not directly oversee most electric distribution utilities, its orders and rulemakings have a broad impact across the electric sector, even affecting jurisdictions outside its purview. Beyond its cybersecurity work, which was discussed earlier in this report, FERC oversees the bulk electric grid and the grid operators that manage that system, including the nation's wholesale electric markets. In the last decade, FERC has issued two rulings that have greatly facilitated the integration and participation of new technologies.

These orders established certain conditions within wholesale markets to facilitate the deployment of demand response and energy storage. FERC Order 745 requires wholesale markets to compensate demand response at the same rate that generators receive—essentially establishing the idea that a megawatt of demand avoided was of equal value to a megawatt generated. The rule could be cited as helping to enable the growth of demand response capacity in the nation's wholesale markets.

More recently, FERC Order 841 aims to force markets to develop rules that are more welcoming to the new range of services offered by energy storage systems. The current concept of something being either generation or load—never both—is incapable of valuing the services that energy storage can offer. While grid operators only filed their initial proposals with FERC in December 2018, many observers believe that FERC's order will be a catalyst for rapid growth and deployment of energy storage over the next decade.

Support for States

DOE established a Grid Modernization Initiative in 2015 to work across the electric industry to develop the concepts, tools and technologies needed to manage an increasingly complex electric grid. The initiative is primarily focused on the development of new grid architecture and concepts, along with the tools and technologies needed to analyze, predict, protect and manage the grid. Supporting this initiative is the Laboratory Consortium, which was established to enhance coordination and collaboration between experts from DOE's national labs and local and regional industry stakeholders.

DOE has written several reports, assessments and guiding documents geared for state policymakers. The department has also supported states—often through direct partnerships with state utility commissions—assisting them in designing a new grid architecture and in understanding the technical capabilities of various new technologies.

In addition, DOE is supporting the NARUC-NASEO Comprehensive Electricity Planning Task Force. The two-year collaborative initiative will bring together officials from 15 states and Puerto Rico to develop new system and resource planning processes to better align the bulk power and distribution grids. In addition to Puerto Rico, the states involved in this initiative are Arizona, Arkansas, California, Colorado, Hawaii, Indiana, Maine, Maryland, Michigan, Minnesota, North Carolina, Ohio, Rhode Island, Utah and Virginia.

Conclusion

As the electric grid enters a new frontier, it will be critical that states, policymakers, and utilities adequately consider the many different solutions that will be needed to create a more reliable, affordable, efficient and resilient grid. To do so, it will be necessary to provide a regulatory environment that better aligns customer needs with utility goals while allowing innovative technologies and new market players to compete and thrive.

Since state legislators create the legal framework within which regulatory commissions act, their decisions will influence how successful states are in navigating the transition to a modern grid. Policy design is instrumental to creating equitable cost allocation for consumers, encouraging competition, reducing the risk of stranded costs, and promoting innovative and cost-effective solutions. The challenge for legislators will be to craft policies—whether focused on rate design, distributed energy, energy efficiency, demand response or resiliency—that are flexible enough to adapt to an increasingly complex grid and the sudden market transitions, changing consumer preferences and unforeseen developments that are likely to occur.

Since a multitude of important decisions will need to be made, many of which may have long-lasting consequences, it will be important for states to ensure that grid modernization efforts are coordinated, beneficial and economically sound. To do so, policymakers in some states, as noted in this report, are working on a raft of policies, from rate design to broad regulatory reforms. Putting in place planning processes to convene knowledgeable stakeholders and creating a comprehensive grid modernization road map can be an important step. It establishes goals that guide and align the many policy and regulatory decisions that will have far-reaching effects on resiliency, competition, reliability, efficiency and cost.

As lawmakers deal with a new set of challenges presented by a changing electric sector, they have an opportunity to help their states set the guiding principles for creating a modern, dynamic energy system that better addresses the needs of electricity consumers, business and industry, and society at large.

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