Chapter IV

ENSURING ELECTRICITY SYSTEM RELIABILITY, SECURITY, AND RESILIENCE

This chapter addresses a range of possible risks to the electricity system and the broader economy, and it suggests options to mitigate and prepare for these risks. The first section explores the changing nature of reliability—the ability of the system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components—in the future electricity system. The next section examines existing and growing vulnerabilities for the electricity system and opportunities to address these vulnerabilities, including cybersecurity risks, interdependency of electricity with other critical infrastructures, and increased risk due to worsening global climate change. The final section focuses on enhancing the resilience of the system to minimize disruptions of service and return rapidly to normal operations following adverse events.

FINDINGS IN BRIEF:
Ensuring Electricity System Reliability, Security, and Resilience

- The reliability of the electric system underpins virtually every sector of the modern U.S. economy. Reliability of the grid is a growing and essential component of national security. Standard definitions of reliability have focused on the frequency, duration, and extent of power outages. With the advent of more two-way flows of information and electricity—communication across the entire system from generation to end use, controllable loads, more variable generation, and new technologies such as storage and advanced meters—reliability needs are changing, and reliability definitions and metrics must evolve accordingly.
- The time scales of power balancing have shifted from daily to hourly, minute, second-to-second, or millisecond-to-millisecond at the distribution end of the supply chain, with the potential to impact system frequency and inertia and/or transmission congestion. The demands of the modern electricity system have required, and will increasingly require, innovation in technologies (e.g., inverters), markets (e.g., capacity markets), and system operations (e.g., balancing authorities).
- Electricity outages disproportionately stem from disruptions on the distribution system (over 90 percent of electric power interruptions), both in terms of the duration and frequency of outages, which are largely due to weather-related events. Damage to the transmission system, while infrequent, can result in more widespread major power outages that affect large numbers of customers with significant economic consequences.
- As transmission and distribution system design and operations become more data intensive, complex, and interconnected, the demand for visibility across the continuum of electricity delivery has expanded across temporal variations, price signals, new technology costs and performance characteristics, social-economic impacts, and others. However, deployment and dissemination of innovative visibility technologies face multiple barriers that can differ by the technology and the role each plays in the electricity delivery system.
- Data analysis is an important aspect of today's grid management, but the granularity, speed, and sophistication of operator analytics will need to increase, and distribution- and transmission-level planning will need to be integrated.
- The leading cause of power outages in the United States is extreme weather, including heat waves, blizzards, thunderstorms, and hurricanes. Events with severe consequences are becoming more frequent and intense due to climate change, and these events have been the principal contributors to an observed increase in the frequency and duration of power outages in the United States.
- Grid owners and operators are required to manage risks from a broad and growing range of threats. These threats can impact almost any part of the grid (e.g., physical attacks), but some vary by geographic location and time of year. Near-term and long-term risk management is increasingly critical to the ongoing reliability of the electricity system.
- The current cybersecurity landscape is characterized by rapidly evolving threats and vulnerabilities, juxtaposed against the slower-moving deployment of defense measures. Mitigation and response to cyber threats are hampered by inadequate information-sharing processes between government and industry, the lack of security-specific technological and workforce resources, and challenges associated with multi-jurisdictional threats and consequences. System planning must evolve to meet the need for rapid response to system disturbances.
- Other risk factors stem from the increasing interdependency of electric and natural gas systems, as natural gas–fired generation provides an increasing share of electricity. However, coordinated long-term planning across natural gas and electricity can be challenging because the two industries are organized and regulated differently.
- As distributed energy resources become more prevalent and sophisticated—from rooftop solar installations, to applications for managing building electricity usage—planners, system operators, and regulators must adapt to the need for an order of magnitude increase in the quantity and frequency of data to ensure the continuous balance of generation and load.

FINDINGS IN BRIEF:
Ensuring Electricity System Reliability, Security, and Resilience (continued)

- Demand response and flexibility technologies—such as hydropower and storage—offer particularly flexible grid resources that can improve system reliability, reduce the need for capital investments to meet peak demand, reduce electricity market prices, and improve the integration of variable renewable energy resources. These resources can be used for load reduction, load shaping, and consumption management to help grid operators mitigate the impact of variable and distributed generation on the transmission and distribution systems.
- Information and communications technologies are increasingly utilized throughout the electric system and behind the meter. These technologies offer advantages in terms of efficient and resilient grid operations, as well as opportunities for consumers to interact with the electricity system in new ways. They also expand the grid's vulnerability to cyber attacks by offering new vectors for intrusions and attacks—making cybersecurity a system-wide concern.
- There are no commonly used metrics for measuring grid resilience. Several resilience metrics and measures have been proposed; however, there has been no coordinated industry or government initiative to develop a consensus on or implement standardized resilience metrics.
- Low-income and minority communities are disproportionately impacted by disaster-related damage to critical infrastructure. These communities with fewer resources may not have the means to mitigate or adapt to natural disasters, and they disproportionately rely on public services, including community shelters, during disasters.
- This chapter was developed in conjunction with the closely related and recently published "Joint United States-Canada Electric Grid Security and Resilience Strategy."

Reliability, Resilience, and Security: Grid Management and Transformation

Traditional electricity system operations are evolving in ways that could enable a more dynamic and integrated grid. The growing interconnectedness of the grid's energy, communications, and data flow creates enormous opportunities; at the same time, it creates the potential for a new set of risks and vulnerabilities. Also, the emerging threat environment—particularly with respect to cybersecurity and increases in the severity of extreme weather events—poses challenges for the reliability, security, and resilience of the electricity sector, as well as to its traditional governance and regulatory regimes.

The concepts of reliability, security, and resilience are interrelated and considered from different perspectives. Meeting consumer expectations of reliability is a fundamental delivery requirement for electric utilities, where reliability is formally defined through metrics describing power availability or outage duration, frequency, and extent. The utility industry typically manages system reliability through redundancy and risk-management strategies to prevent disruptions from reasonably expected hazards.

Grid Reliability, Security, and Resilience

- For purposes of this discussion, *reliability* is the ability of the system or its components to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components. *Resilience* is the ability of a system or its components to adapt to changing conditions and withstand and rapidly recover from disruptions. *Security* refers specifically to the ability of a system or its components to withstand attacks (including physical and cyber incidents) on its integrity and operations.

Delivery of electricity service has been consistently and highly reliable for most of the century-long development, expansion, and continuous operation of grids across all regions of the Nation. The traditional definition of reliability—based on the frequency, duration, and extent of power outages—may be insufficient to ensure system integrity and available electric power in the face of climate change, natural hazards, physical attacks, cyber threats, and other intentional or accidental damage; the security of the system, particularly cybersecurity, is a growing concern.

Resilience is the ability to prepare for and adapt to changing conditions, as well as the ability to withstand and recover rapidly from disruptions, whether deliberate, accidental, or naturally occurring.[1] While resilience is related to aspects of both reliability and security, it incorporates a dynamic response capability to reduce the magnitude and duration of energy service disruptions under stressful conditions.[2] Infrastructure planning and investment strategies that account for resilience typically broaden the range of risk-reduction options and improve national flexibility through activities both pre- and post-disruption, while also focusing on the electricity-delivery outcomes for the consumer.

U.S. policies, markets, and institutional arrangements must evolve to reflect new electricity system realities and trends—continuing to enable and enhance the reliability, security, and resilience of the electric grid. The Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), regional planning authorities, utilities, power system operators, states, and other organizations work together to ensure the reliability of the U.S. power system through the implementation of reliability standards, timely planning and investment, and effective system operations and coordination.

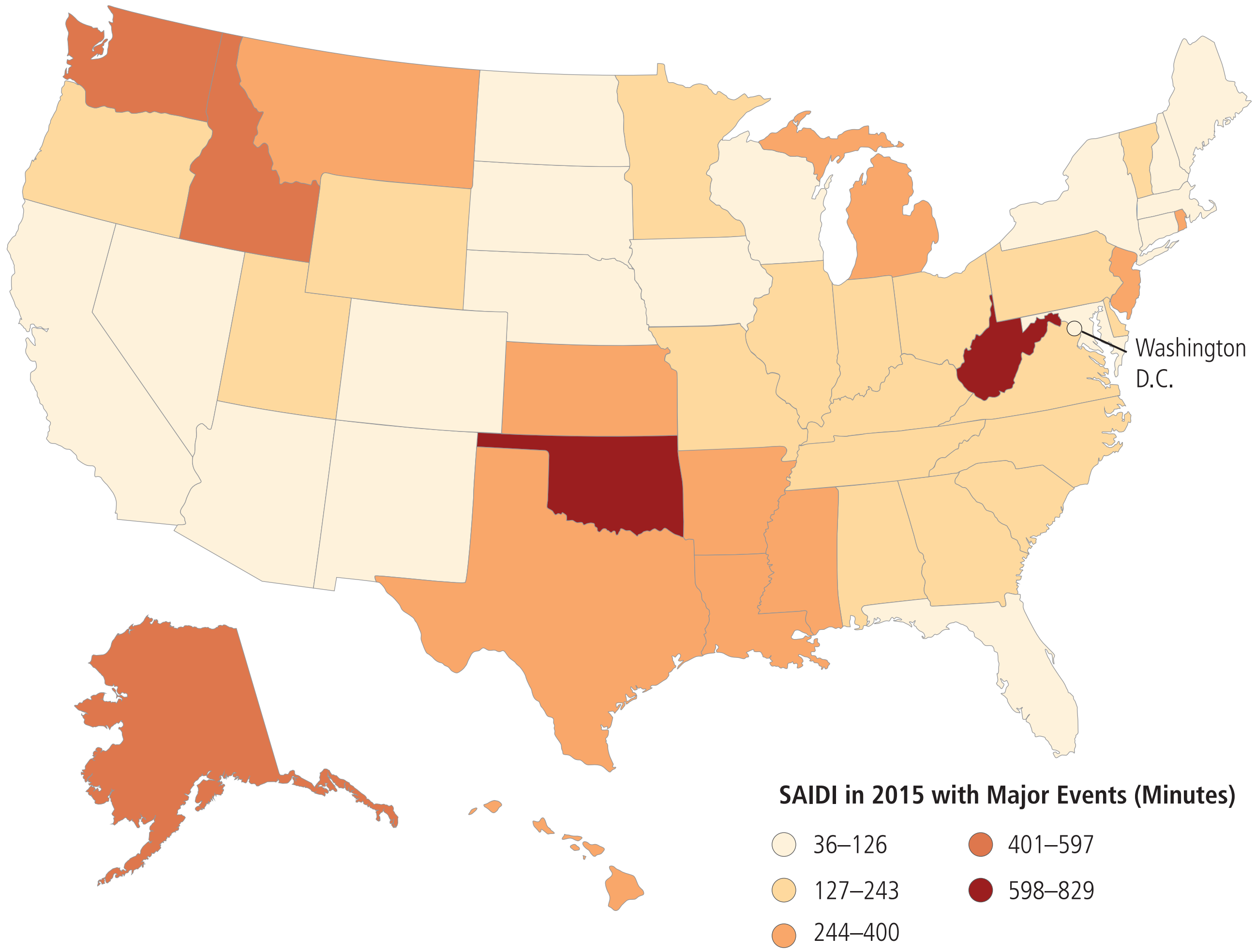
The Changing Nature of Reliability

Electricity customers have high expectations of electricity reliability from their utility providers. Virtually every sector of the modern U.S. economy depends on electricity—from food production, to banking, to health care. Critical infrastructures like oil, gas, transportation, and water all depend on electricity, and the electric system depends on them. This places a high premium on reliability.

Standard Measures of Reliability

A brief review of how reliability is measured today will help define the playing field and the associated value at stake. From the utility industry perspective, reliability is formally defined through metrics describing power availability or outage duration, frequency, and extent. Reliability within the utility industry is managed to ensure the system operates within limits and avoids instabilities or the growth of disturbances. These practices are not static, and utilities continue to improve their reliability practices and implementation methods to reflect increased consumer expectations. Typical approaches to reliability include hardening, investment, and redundancy to prevent disruptions from reasonably expected hazards.

Figure 4-1. System Average Interruption Duration Index by State, 2015[3]



States experienced varying levels of reliability in 2015. A reliable bulk power system does not necessarily mean reliable end-user electricity service because outages often originate on local distribution systems, as reflected in the SAIDI measurements in the above map.

Most state and Federal regulators have significant experience addressing system reliability and currently consider the issues of resilience and security through the lens of existing reliability tools, approaches, and metrics. One metric applied with the goal of improving system performance with respect to reliability indicators is the System Average Interruption Duration Index (SAIDI). SAIDI measures the total duration of an interruption for the average customer given a defined time period. Typically, it is calculated on a monthly or yearly basis. Another metric, the Customer Average Interruption Duration Index (CAIDI), measures how long it takes to restore the system once an outage occurs. And, the System Average Interruption Frequency Index (SAIFI) measures the average number of times that a customer experiences an outage during the year. SAIFI is calculated by dividing SAIDI by CAIDI. As most outages occur on the distribution system rather than the bulk power system, these reliability indices are commonly used to measure distribution level reliability. NERC uses a number of bulk power system reliability indices.[4]

Based on these reliability measures, the average customer experiences 198 minutes of electric power unavailability per year,[a, 5] although there is significant variability among states and utility providers. The best-

[a] Analysis is based on 2016 Energy Information Administration (EIA) data. Information reported to EIA is estimated to cover approximately 90 percent of electricity customers.

performing state had a SAIDI level of 85 minutes a year. In contrast, as shown in Figure 4-1, one state had a SAIDI statistic in 2015 of nearly 14 hours of outage for the year, with an availability level of 99.84 percent. Even this state level of aggregation masks some outliers in the data. There were several utilities with a SAIDI index below 1 minute of outage for the year.

There are, however, caveats to these findings. First, the variability of reliability performance is a function of a myriad of factors, including regional differences, varying regulatory standards, costs, system configuration, customer density, hazard exposure, and other. Also, utilities have historically reported SAIDI, SAIFI, and CAIDI statistics in inconsistent ways; for example, some utilities include data associated with "major events" in their public reporting to public utilities commissions, while others do not.[6] Utilities also take inconsistent approaches to defining "major events."[7] The lack of uniform national data inhibits more sophisticated analysis of macro trends in distribution reliability—something that is important to remedy in an electricity sector that is increasingly data intensive.

Also, although the predecessor to today's NERC was first formed in 1968 to address system reliability, the Institute of Electrical and Electronics Engineers (IEEE) Standard 1366 only formally defined industry reliability metrics in 1998.[8] The Energy Information Administration (EIA) began collecting distribution-level reliability data, including SAIDI and SAIFI information, in 2013—marking increased attention and effort on the reliability front. Yet, even today, only 33 percent of utilities report these statistics, covering 91 percent of the electricity sales in the Nation, which indicates that there is room for improving reliability reporting practices.[9]

There are other reliability measures and associated government reporting requirements as well. NERC, for example, collects the additional data it needs to promulgate reliability and security standards, but it does not make all of these data available to government agencies. Beyond reliability, a number of resilience metrics and measures have been proposed; however, there has not been a coordinated industry or government initiative to develop consensus or implement standardized resilience metrics, though the Grid Modernization Laboratory Consortium is launching the Foundational Metrics Analysis project to develop some resilience metrics.[10]

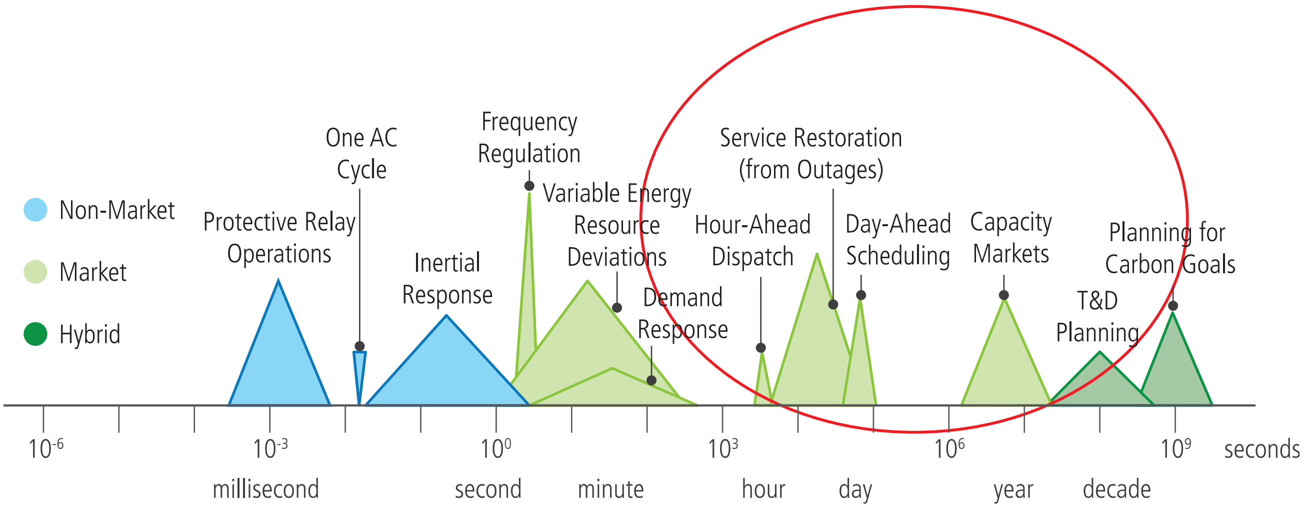
Time Scales and Grid Reliability

Throughout the 20th century, the design of power systems and early metrics (such as the loss of load expectation) focused on periods of maximum consumer electricity use. With more controllable loads, more variable generation, new technologies (such as storage), and the increasing importance of power system reliability, reliability is becoming a more complex concept, and reliability metrics and criteria must evolve accordingly.

Adequacy of generation resources is measured by a utility's reserve margin and has traditionally meant the extent to which utilities have adequate infrastructure to generate electricity to meet customers' needs. Generation reliability criteria is focused on installed generation to meet customer demand; the role of the customer as a system resource was not a consideration.

For vertically integrated systems, grid operators manage the entire electricity supply chain from end (generation) to end (delivery service). When new market structures were created across many U.S. regions in the form of independent system operators (ISOs) or regional transmission organizations (RTOs), end-to-end management was replaced with competing power generators. In these markets, variable generation may be the lowest cost generation; and, generation from certain power stations may not be accepted to run because they are not cost competitive for a specific day's operations. However, if a generator is deemed critical to system integrity, power stations can get "reliability must run" payments. These out-of-market payments, in turn, lower power market prices, which has been especially problematic for certain types of generation such as nuclear, which already faces challenges from low power prices due to the relatively low capital, operations, and fuel costs of natural gas–fired generators.

Figure 4-2. System Reliability Depends on Managing Multiple Event Speeds[11]



Markets are used for traditional grid operations, including hour-ahead, day-ahead, and capacity markets. Long-term planning reaches beyond typical market and financial signals. Acronyms: transmission and distribution (T&D), alternating current (AC).

Supply variability[b] is an important part of system operations, where ISOs/RTOs must ensure that risks of unexpected loss or variability of supplies are hedged by having some power plants immediately available (spinning reserves) and other plants able to supply power with short-term notifications of need (non-spinning reserves).

These adjustments to power flow management occur within the general framework of grid operations. This framework has historically been well understood by grid operators because the time dimensions of operations have not changed significantly, even when ISOs/RTOs were given responsibility for transmission system management. These dimensions, which operators have historically understood well, are seen in Figure 4-2 on the right side of the continuum, where the time scales of capacity markets, day-ahead, and hour-ahead products are depicted. For out-years beyond capacity contracts, traditional transmission and distribution system planning methods work to map and price investment requirements to ensure long-term grid reliability. Planning for decarbonization and climate resilience reaches beyond typical planning horizons for grid operators.

Changing Time Dimensions, Grid Topology, and Emerging Grid Management Challenges

Variable energy resources (VER) provide a range of benefits to utilities and their customers, including avoided fuel costs, greenhouse gas emissions, and costs associated with environmental compliance.[12, 13] In some cases, distributed VER are also credited with providing electric reliability and resilience benefits, particularly in the context of microgrids.[14]

However, the widespread integration of VER at both utility scale and distributed across all consumer segments significantly expands the time dimensions in which grid operators must function, and it complicates operations. It underscores the need "to coordinate time and space within the electric grid at greater resolution or with a higher degree of refinement than in the past."[15] A recent White House report noted, "The distinctive characteristics of [VER] will likely require a reimagining of electricity grid management."[16]

Impacts on transmission and distribution systems and integration options vary by scale. For instance, utility-scale solar power flowing onto high-voltage transmission lines can be smoothed and firmed up at the point of production by using smart inverters and storage. When onshore wind plants are integrated at a

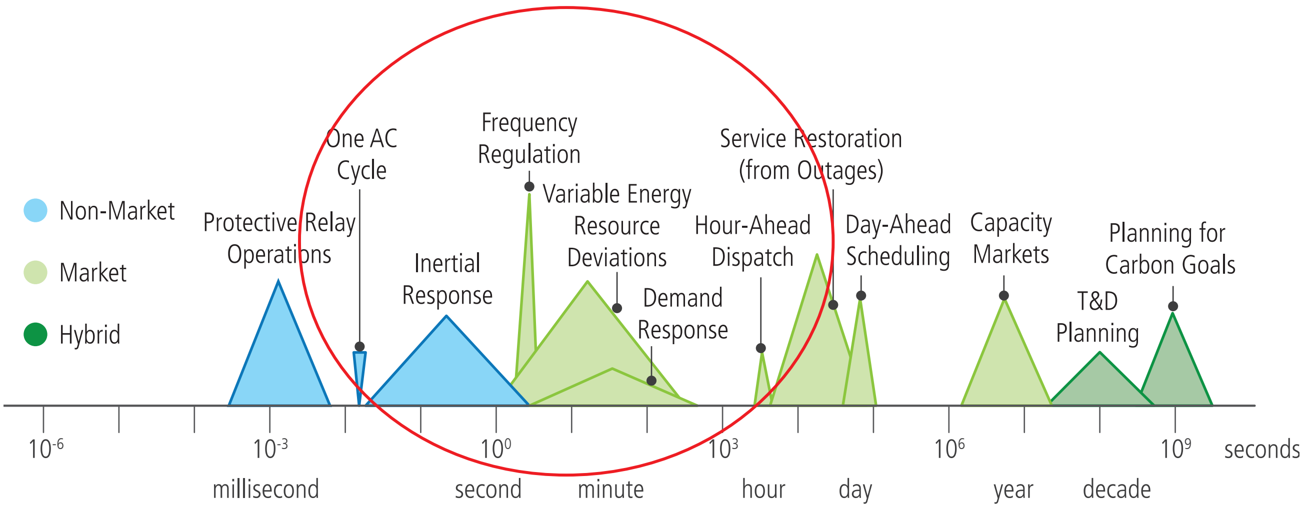
[b] As used here, variability refers to the difference between the expected and actual load or generation.

large geographic scale, lower correlation factors can smooth out variability. Assuming these aggregations are visible to grid operators to adequately assess both their costs and benefits, many aggregated distributed solar installations can smooth out the random variations from individual installations.

The time dimensions in which grid operators must function to accommodate the unique characteristics of VER and distributed energy resources (DER) are identified in the hourly, to minute, to second intervals (Figure 4-3). While grid operations are successfully managed today in some markets with relatively high levels of VER penetration,[17] this can complicate grid management. Consider a generic example of utility-scale generation portfolio management in a high VER supply system. Power supplied from solar stations has two types of variability to manage: minute-to-minute fluctuations and the dramatic drop in power supplied from solar as the sun goes down. This drop can be precipitous and occur within an hour or less.

Figure 4-3. System Reliability Depends on Managing Multiple Event Speeds[18]

Markets are used for grid operations in the order of seconds to minutes, such as frequency regulation and demand response (DR). Some essential



reliability capabilities, such as inertial response, occur faster than typical market signals. Acronyms: transmission and distribution (T&D), alternating current (AC).

Grid dispatch (actions that operators take to engage power suppliers to provide power to the grid) occurs around load changes, traditionally referred to as load-following activities. In grids with ISO/RTO wholesale markets, economic dispatch occurs based on which generators win daily auctions and produce power for the grid. ISOs/RTOs also load follow for grid management, and in regions with high VER production, load following and load shaping may provide linked challenges.

By calling or not calling on generators to produce electricity, grid dispatch determines the value that power producers obtain from their assets. Grid dispatch ensures system reliability through management of operating generators, as well as those waiting to be called if needed. In a world of subsecond decision making, dispatch effectiveness will require the integration of automated grid management, with continuing human oversight. The pace of change may dictate faster adaptation times for grid operators, but grid reliability may dictate a more methodical consideration of operating protocol changes, which are driven by changes in the types, scale, scope, and location of power supplies. Continuous engagement of grid dispatchers in planning for the 21st-century grid is essential.

VER fluctuations on the bulk power side of the equation can be mitigated by regulating power flows onto the grid—both up and down and from minute to minute. Mitigating power flows can occur with resources and services such as regulation that respond in one to several seconds; through process-flow techniques involving ramping up and throttling down generation plants; via transmission system blending with flexible resources such as hydro; and through demand response (DR) (including advanced water infrastructure),[19] which can be used to align demand with supply variations for grid services, including frequency regulation.

Variability is managed through geographic diversity and aggregation. FERC (through NERC) requires balancing authorities to constantly match supply and demand within their respective balancing areas.[c, 20] Larger balancing areas could help manage variability by sharing generation resources to smooth out supply. A recent National Renewable Energy Laboratory analysis concluded that, "consolidated operations of two or more balancing authorities fully captures the benefits of geographic diversity and provides more accurate response."[21] For example, the integration of PacifiCorp into the California ISO Energy Imbalance Market reduced the amount of required flexibility reserves by about 280 megawatts (MW), or 36 percent.[22]

While there is ramping associated with all generation technologies, because of their variability, baseload generators must ramp more frequently to accommodate VER. Ramping to match supply and demand can reduce the efficiency of baseload generators, possibly decrease their ability to recover capital costs, and increase fossil unit emission rates. Innovation to improve baseload generators' ramping capability is an important need that will become more important at high levels of VER. Recent analysis suggests that "…High renewable energy penetrations could significantly change dispatch requirements and use of conventional generators."[23] Also, price suppression is occurring in RTO/ISO wholesale markets, with noticeable amounts of wind and solar generation (and low-cost gas generation). While passing on savings to consumers is desirable, in some regions, these low prices have put pressure on baseload units, particularly zero-carbon emissions nuclear generation.

Better forecasting has also reduced VER integration costs. Most North American power markets dispatch wind plants along with conventional power plants based on current grid conditions and economics.[24] Setting wind generator schedules as close as possible to the dispatch time minimizes forecast errors, and using wind forecasting can greatly facilitate wind integration and reduce costs from carrying reserve capacity.[25]

Another complication, as noted earlier, is that system operators dispatch the least-cost mix of generation needed to meet load; these least-cost sources are often VER sources, which are fueled by the sun or the wind and therefore have low or zero marginal cost of production. In New England, as additional variable resources have come online, there has been "more frequent localized [transmission] congestion."[26] In the past, congestion was reduced by the system operator "through manual curtailment instructions that [were] not reflected in Real-Time Prices," causing a "mismatch" of signals, when generators who would normally respond to high prices by increasing output were instead told to decrease output in order to maintain reliability.[27] The system operator has undertaken several steps to address these challenges, and in April 2016, wind and hydro resources were designated as automated dispatch.[28] Going forward, the system operator will require a series of actions to further integrate VER sources.[29] Specifically, on October 12, 2016, ISO New England filed proposed revisions to its Transmission, Markets, and Services Tariff with FERC, which in part were made to "more directly incorporate non-dispatchable, intermittent power resources into [market pricing]", and on December 12, 2016, FERC issued an order accepting the proposal.[30, 31]

Another example of the changes to grid management made in response to increasing penetrations of VER is seen in the California market. Under existing operations, the California ISO found that "the fleet of resources committed…to provide energy often does not provide sufficient flexible ramping capability…to meet the

[c] A balancing authority "integrates resource plans ahead of time, maintains demand and resource balance within a Balancing Authority Area, and supports interconnection frequency in real time." The Balancing Authority Area (shortened here to Balancing Area) is the "collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority." From North American Electric Reliability Corporation (NERC), "Glossary of Terms Used in NERC Reliability Standards," NERC, last modified November 28, 2016, http://www.nerc.com/files/glossary_of_terms.pdf.

actual changes in net load."[32] As a result, the operator must "dispatch units out of economic sequence, or dispatch units that are not in the market," imposing "additional costs on the system" and creating "prices [that] do not reflect such marginal costs."[33] In California, the ISO addressed this issue by amending its tariff to "enhance the CAISO [California ISO] ability to manage the ramping capacity necessary to meet changes in net load—both forecasted and unexpected."[34]

Real-time wind penetration in the Southwest Power Pool (SPP) has, at times, approached 40 percent of generation.[35] Between March 2016 and May 2016, wind accounted for 21.5 percent of all energy generated in SPP.[36] In examining scenarios with significantly more VER, SPP found that new procedures "would enable the SPP transmission system to reliably handle up to…60% wind penetration"[37] while lowering overall costs and reducing price volatility.[38] These new procedures include increasing the dispatchability of renewable resources, adding additional transmission capacity, enhancing ancillary services, and adding new tools to manage inter-hour ramps.[39]

In the Pacific Northwest, an increase in wind generation has meant that the operator must "dispatch units out of economic sequence, or dispatch units that are not in the market," imposing "additional costs on the system" and creating "prices [that] do not reflect such marginal costs."[40] Additionally, an increase in wind generation has meant that "utilities must hold more resources in reserve to help balance demand minute-to-minute," increasing "the need for system flexibility."[41] The Northwest Power and Conservation Council anticipates, however, "that the region will have sufficient generation and demand side capability on its existing system to meet balancing and flexibility reserve requirements over the next six years if [the region's] energy efficiency and demand response development goals are achieved."[42]

Hydropower provides a variety of essential reliability services that are beneficial to the electricity system. One example is regulation and frequency response (including inertia), in which hydropower generators can quickly respond to sudden changes in system frequency, making hydro a very suitable complement to wind generation. Other essential reliability services include spinning and supplemental reserves enabled by high ramping capability, reactive power and voltage support, and black start capability.

Despite hydropower's technical ability to provide essential reliability services, these services are not always explicitly compensated by existing market structures. For example, hydropower is one of the main providers of inertia and primary frequency response in the Western Electricity Coordinating Council, but it is not explicitly compensated for either service.[43] Some recent market advances have been made that allow greater ancillary service participation. For example, FERC now requires ISOs to better compensate generators for frequency regulation services based on their response speed and flexibility to respond to a range of situations.[44] In addition, in June 2016, FERC issued Order No. 825, requiring all RTOs and ISOs to implement subhourly settlements, allowing more accurate alignment of the services provided with the prices paid for them. Market rules governing participation of flexible resources, such as hydropower and pumped storage, could be reviewed to determine if additional changes could allow these resources to participate more effectively and ensure just and reasonable compensation.

Part of the challenge facing hydropower lies in the difficulty of optimizing the limited generating ability of hydro resources due to non-market environmental and competing use constraints. Determining the best use of hydro resources through manual dispatch or market-based bidding process can be difficult because the value of essential reliability services can change quickly due to a number of factors, including location, day, time, regulatory constraints, and interaction with other generators. Moreover, in the long term, the best use of hydro resources may evolve as the generation mix changes.[45] Essential reliability services are, however, undervalued in some existing market structures.

On the consumer side of the utility meter, consistent growth in DER (of which distributed VER are a subset) has also changed how grid operators sustain high system reliability at both the distribution and transmission levels of electricity delivery. DER represent a broad range of technologies that can significantly impact how much, and when, electricity is demanded from the grid, and they include distributed generation (DG) and storage technologies, as well as DR.[46] Consumers with rooftop solar may influence their demand frequently and in diverse ways. This can impact total load (tending to reduce it) but may not be directly controlled by grid operators. Other DER, such as truly dispatchable DR, can be directly managed and called by grid operators when needed.

Deployment of distributed VER places additional design and operational requirements on distribution grid operators. Currently, distribution systems are predominantly radial networks (feeders) delivering grid-supplied power to customer premises. With significant penetration of distributed generation, some distribution utilities are facing new demands to interconnect multiple feeders together to accept customer-generated power and to be able to balance generation and demand. The new structure and roles of distribution systems will require development of advanced distribution circuits and substations to enable significant two-way power flows, new protection schemes,[d] and new control paradigms.

Grid Frequency Support from Distributed Inverter-Based Resources in Hawaii

Hawaii leads the United States in the portion of its electricity that is produced from variable renewable sources, and as an island state, it cannot rely on neighbors to help balance generation and load. Hence, the Hawaiian Electric Companies are currently experiencing the bulk system frequency stability impacts that mainland U.S. power systems will experience in the coming years and decades.[e] The Grid Modernization Laboratory Consortium will develop, simulate, validate, and deploy practical solutions that enable distributed energy resources (DER) to help mitigate bulk system frequency contingency events on the fastest time scale (milliseconds to seconds).[f] The project will examine the ability to leverage the fast response capability of power electronics to enable photovoltaic inverters and storage inverters to support grid frequency starting a few fractions of a second after the appearance of a frequency event. The capabilities of currently available products to provide rapid frequency response will be characterized, and new capabilities will be developed with a goal of maximizing DER's ability to support grid frequency stability.

[e] William Parks, Kevin Lynn, Carl Imhoff, Bryan Hannegan, Charles Goldman, Jeffery Dagle, John Grosh, et al., *Grid Modernization Multi-Year Program Plan* (Washington, DC: Department of Energy, November 2015), 2, https://energy.gov/sites/prod/files/2016/01/f28/Grid%20Modernization%20Multi-Year%20Program%20Plan.pdf.

[f] "Pioneer Regional Partnerships," Grid Modernization Laboratory Consortium, https://gridmod.labworks.org/pioneer-regional-partnerships.

California's recent experience with its requirements for 20,000 MW of small renewable generation (under 20 MW) by 2020 is instructive for both valuation and grid management. To make these volumes both visible to the ISO and valuable to consumers, aggregators, and grid operators, market designers at the California ISO allowed bids of at least 0.5 MW into day-ahead, energy, and ancillary markets. Similar efforts are underway in Texas and New York.[47]

The electricity system is also experiencing an increasing array of "subsecond" events that require response times that are far too short for humans to react. One of the driving forces making smart grids necessary is the proliferation of smart devices; each one is capable of microscopic frequency disruptions, which cumulatively

[d] Protection schemes identify coordinated corrective actions to detect and address abnormal system conditions (e.g., faults).

present an unprecedented new challenge for system operators. Many consumer electronic devices (such as mobile phones, Wi-Fi-based home automation solutions, and smart entertainment devices) represent "endpoints" that can impact system operations. In addition, Internet of things (IoT) devices function at microsecond "clock speeds." In the aggregate, these devices represent a new source of variability at speeds far faster than what grids have traditionally managed. The solution must take the form of protective relays and synchrophasors operating more-or-less autonomously in real time. The upside implications going forward include the need for integrating machine learning into grid operations (i.e., as positive solutions for mitigating unprecedented grid disruptive forces); on the downside, digitizing grid operations deep into subsecond operations raises new cyber vulnerabilities.

The kinds of anomalies affecting wholesale markets and grid operators noted above suggest the need for frequent adjustments to market designs to accommodate new technologies, changing consumer preferences, and security needs. The Nation's ISOs/RTOs, FERC, and NERC are continuously engaged in analysis, evaluation, and design modification processes—working to ensure that the present scoping and pace of regulatory change is aligned with the scale and speed of change occurring as a result of continued VER deployment. In September 2016, FERC approved new requirements for the quality of real-time monitoring and analysis capabilities for system operators,[48] and NERC has made a number of improvements that have significantly reduced the time it takes to develop a standard. This is an ongoing process; both state and Federal regulators face complicated and evolving challenges that grid operators must address in a timely fashion while simultaneously operating under existing performance standards and system requirements.

Grid Operation Impacts of the Internet of Things

Grid control systems now handle, sense, and control endpoints numbered in the thousands. Widespread DER/DR penetration implies that future grid control systems may have to coordinate millions of endpoint control devices to support grid functions. These devices vary in type, from digital sensors and smart boards built into transformers, to mobile devices used by field operators and grid control managers.

Current grid control systems are not structured for large-scale optimization of millions of devices, and they are not equipped to handle increasingly large volumes and types of data. End-users (consumers, as well as aggregators controlling multiple demand profiles) may wish to perform optimal local controls to meet their desired requirements that may be in conflict with optimal *system-wide* control.

Grid control systems must evolve from being centralized to a hybrid of central and distributed control platforms. The need for flexible grid operations is challenging basic assumptions about grid control, which will require changes in standards and operating protocols. Bulk power systems operations are the purview of both FERC and NERC, but grid security and reliability assurance concerns mean that Federal authorities must be included in designing 21st-century grid control systems.

Overview of Department of Homeland Security Strategic Principles for Security of the Internet of Things (IoT)

The Department of Homeland Security developed strategic principles, published on November 15, 2016,[g] to mitigate vulnerabilities introduced by the IoT through recognized security best practices. These principles are intended to offer guidance to stakeholders as they seek to manage IoT security challenges.

Strategic Principles for Securing the IoT:

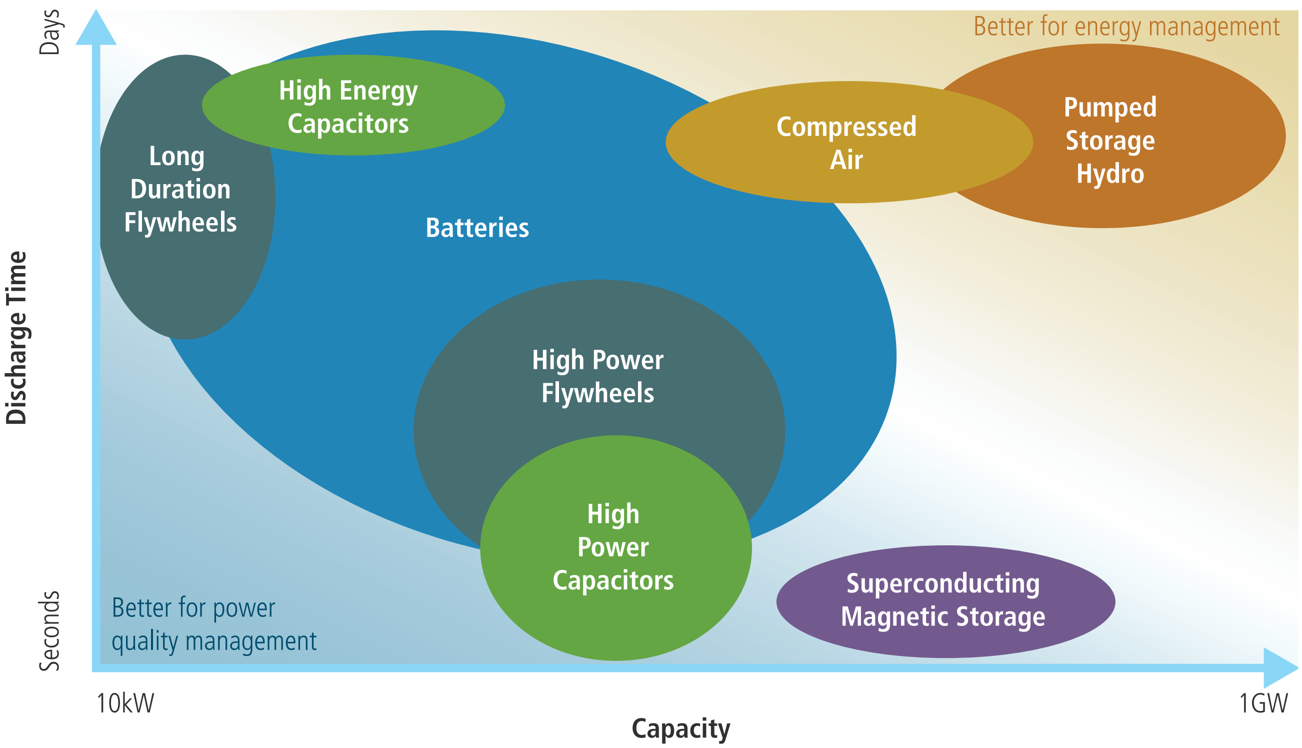
1. Incorporate security at the design phase—building in security at the design phase reduces potential disruptions and avoids the much more difficult and expensive endeavor of attempting to add security to products after they have been developed and deployed.
2. Advance security updates and vulnerability management—vulnerabilities may be discovered in products after they have been deployed. These flaws can be mitigated through patching, security updates, and vulnerability management strategies.
3. Build on proven security practices—many tested practices used in traditional information technology and network security can be applied to the IoT, helping to identify vulnerabilities, detect irregularities, respond to potential incidents, and recover from damage or disruption to IoT devices.
4. Prioritize security measures according to potential impact—risk models differ substantially across the IoT ecosystem, and the consequences of a security failure across different customers will also vary significantly. Focusing on the potential consequences of disruption, breach, or malicious activity across the consumer spectrum is therefore critical in determining where particular security efforts should be directed and who is best able to mitigate significant consequences.
5. Promote transparency across the IoT—increased awareness could help manufacturers and industrial consumers identify where and how to apply security measures, build in redundancies, and be better equipped to appropriately mitigate threats and vulnerabilities as expeditiously as possible.
6. Connect carefully and deliberately—IoT consumers can also help contain the potential threats posed by network connectivity, connecting carefully and deliberately, and by weighing the risks of a potential breach or failure of an IoT device against the costs of limiting connectivity to the Internet.

[g] Department of Homeland Security (DHS), *Strategic Principles for Securing the Internet of Things (IoT) Version 1.0* (Washington, DC: DHS, November 15, 2016), https://www.dhs.gov/sites/default/files/publications/Strategic_Principles_for_Securing_the_Internet_of_Things-2016-1115-FINAL....pdf.

Utility-Scale and Distributed Storage

Electricity remains unique among commodities in its limited capability available for storage. There are few viable ways to store electrical energy (e.g., batteries, or pumped storage solutions), and there are other more exotic possibilities like superconducting magnet rings. Inventory options tend to narrow the amount and duration of ready access electricity. The graphic depiction in Figure 4-4 summarizes the power and duration capabilities of various storage technologies.

Figure 4-4. The Storage Technology Development Map[49]



Most electricity storage is water that fuels turbines that produce electricity. Currently, the largest storage capacity is pumped hydro. Electrochemical batteries have been the fastest growing new storage technology. Batteries in the form of fuel cells can be used for continuous power production and the scaling capabilities of fuel cells make them attractive for fitting load shapes to specifically sized power supplies. Other technologies for energy storage include compressed air, flywheels, and capacitors.

Utility-scale battery storage and distributed battery storage vary by scale and duration, but perform consistently at any scale from a grid management perspective. When distributed storage is aggregated, it can offer local grid operators greater flexibility for managing system reliability and power quality than utility-scale resources. Aggregation can be scaled to fit specific local needs in distribution systems.

An example of grid reliability applications of energy storage is seen in California, where the building of about 60 MW in new battery storage capacity is underway.[h, 50, 51, 52] These installations are being built to resolve reliability issues caused by the Aliso Canyon leak[53] (for more information on Aliso Canyon, see "Underground Storage Leak in California Driving Natural Gas Storage Safety and Reliability Improvements" text box on page 4-33) and the San Onofre Nuclear Generating Station outage,[54] and they will help level out electricity supply in California by moving energy from the afternoon production of solar to the evening peak.[55] While region-specific critical reliability requirements can drive storage deployment, additional incentives can help accelerate these benefits ahead of a major disruption.

[h] Upon commissioning, the 20-MW/80-megawatt-hour (MWh) SCE Mira Loma project will be the largest battery in operation. The 37.5-MW/120-MWh San Diego Gas & Electric Escondido project will then overtake Mira Loma as the largest battery when it is commissioned. In addition to their titles as largest yet in operation, both projects were built quickly—about six months from contract award to commissioning. These projects show how new technologies, many of which benefitted from early publicly supported demonstrations, can provide rapid solutions for reliability, resilience, and security.

Public investment and policy have been key to electricity storage technology development; the American Recovery and Reinvestment Act of 2009 (ARRA) is the most commonly identified funding source for storage projects.[56] By 2015, through a combination of regulatory reforms, innovation, and cost reductions, lithium-ion batteries emerged as a dominant battery design for frequency regulation and renewables integration; lithium-ion batteries made up 95 percent of deployed capacity in 2015, with 80 percent of this capacity located in the PJM Interconnection territory, attracted by its pay-for-performance frequency regulation market.

The evolution of storage technology is likely to take the electricity sector into new realms. "Hybridizing" storage solutions with solar and wind power sources may redefine what is meant by "power plant," and alter how the grid is understood and used. If hybrids can "self-power" even a portion of a significant load, then tomorrow's future electricity sector will be able to achieve national objectives for clean, secure, and affordable electricity supplies in a system that is imminently flexible and considerably resilient.

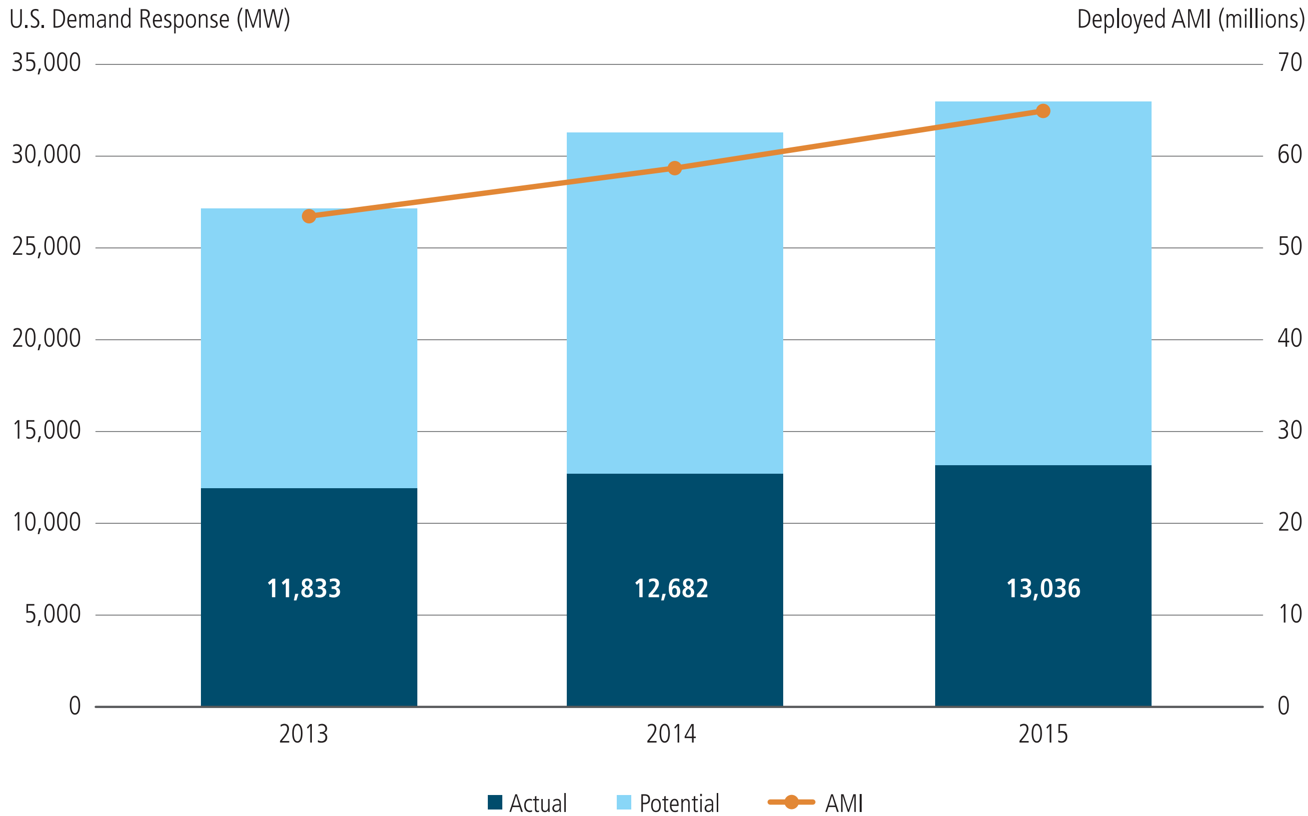
Demand Response Can Aid Grid Management

DR empowers consumers to change their normal electricity consumption patterns; it is a particularly flexible grid resource, capable of improving system reliability, reducing the need for capital investments to meet peak demand, as well as electricity market prices. DR can also be used for load reduction and load shaping, as well as to help grids mitigate generation variability, including from VER. A variety of DR programs exist, some of which are offered directly by utilities, while other programs are offered by the grid system operators, retail competitors, and aggregators. DR challenges the view that a utility's generation adequacy, measured by its reserve margin, is "steel in the ground." DR can offset "installed capacity" and currently provides nearly 30 gigawatts (GW) of peak reduction capability nationwide;[57] this accounted for 3.9 percent of U.S. peak demand in 2016[58] and exceeded 10 percent in some regions.[i, 59, 60] Future DR growth—FERC scenarios show 82 GW to 188 GW in possible DR capacity by 2019[61]—along with other DER could significantly shift customer demand from peak to off-peak periods.

A key driver of today's DR programs has been the growth of advanced metering infrastructure (AMI), now deployed for nearly 65 million customers in the United States (Figure 4-5).[62] AMI typically includes two-way communications networks that utilities can leverage to improve electric system operations, enable new technological platforms and devices, and facilitate consumer engagement. More than half of deployed AMI are in five states, with California, Florida, and Texas accounting for over 40 percent of the total.[63] AMI investments have been largely driven by state legislative and regulatory requirements, as well as ARRA funding.[64]

[i] For example, in PJM Interconnection, demand resources account for over 10 GW out of the 167 GW from all capacity resources in the 2019/2020 delivery year. See references for more information.

Figure 4-5. Advanced Metering Infrastructure Growth Has Contributed to Expanded Role of DR Programs[65]



A key driver of today's DR programs has been the growth of advanced metering infrastructure (in orange). In 2015, approximately 65 million customers in the United States had advanced metering infrastructure installations.

State Regulatory Actions That Have Impacted Demand Response[j]

- The California Public Utilities Commission will require default time-of-use (TOU) rates for residential customers in 2019, and it is working with California Independent System Operator and the California Energy Commission to create a market for demand response (DR) and energy efficiency resources.[k]
- In 2014, Massachusetts ordered its electricity distribution companies to file TOU rates with critical peak pricing as the default rate design for residential customers once utility grid modernization investments are in place.[l]
- In 2015, the Michigan Public Service Commission directed DTE Electric to make TOU and dynamic peak pricing available on an opt-in basis to all customers with advanced metering infrastructure by January 1, 2016. Similarly, Consumers Energy must make TOU available on an opt-in basis by January 1, 2017.

[j] Federal Energy Regulatory Commission (FERC), *Assessment of Demand Response & Advanced Metering, Staff Report* (FERC, December 2015), https://www.ferc.gov/legal/staff-reports/2015/demand-response.pdf.

[k] California Public Service Commission (CPUC), *California's Distributed Energy Resources Action Plan: Aligning Vision and Action, Discussion Draft: September 29, 2016* (CPUC, 2016), http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Commissioners/Michael_J._Picker/2016-09-26%20DER%20Action%20Plan%20FINAL3.pdf, accessed December 13, 2016.

[l] L. Evers, "Massachusetts DPU Says Time of Use Pricing Will Be the Default for All Customers," Smart Grid Legal News, June 26, 2014, http://www.smartgridlegalnews.com/regulatory-concerns-1/massachusetts-dpu-says-time-of-use-pricing-will-be-the-default-for-all-customers/.

State Regulatory Actions That Have Impacted Demand Response (continued)

- Also in 2015, the New York Public Service Commission released a regulatory framework and implementation plan ("Reforming the Energy Vision") to align electric utility practices and the state's regulatory framework with technologies in information management, power generation, and distribution. A related measure in 2014 approved a $200 million Brooklyn-Queens demand management program, which includes 41 megawatts (MW) of customer-side measures, including DR, distributed generation, distributed energy storage, and energy efficiency, to cost effectively defer approximately $1 billion in transmission and distribution investment.
- In June 2015, the Pennsylvania Public Utility Commission set a total peak demand reduction of 425 MW for electric distribution companies by 2021, against a 2010 baseline.
- In Rhode Island, DR is continuing to be tested in pilot programs by National Grid and will be incorporated in analysis for "non-wires alternatives" to traditional utility infrastructure planning.[m]

[m] "System Reliability Program," State of Rhode Island, Office of Energy Resources, accessed December 13, 2016, http://www.energy.ri.gov/reliability/.

The legal and regulatory environment for DR is highly dynamic and evolving at both the national and state levels. On January 25, 2016, the U.S. Supreme Court upheld FERC's authority to regulate DR programs in wholesale electricity markets (FERC Order No. 745).[66] While this decision provides final policy clarity, it was made almost 2 years after the Appeals Court issued the opposite decision; in the intervening time, the markets were operating under the lower court's interpretation that FERC's DR order was encroaching on each state's exclusive right to regulate its utility markets. As affirmed by the Supreme Court, the FERC order ensures that DR providers are compensated at the same rates as generation owners. This ruling is also expected to provide a more favorable environment for DR market growth by facilitating the participation of third parties in the aggregation of DR resources.

Total DR capacity varies widely by region, reflecting the diversity in utility, state, and regional policies toward DR and other forms of demand-side management. Regions where DR is installed directly in multiple electricity markets (e.g., capacity and essential reliability services) generally have greater total DR capacities and can reduce a larger proportion of their peak demand by using DR.[67]

It is important to note that the potential peak reduction in Table 4-1 may not all be reduction in "real capacity." There are significant challenges to making DR resources reliable, predictable, and sustainable so that they may function as "proxy generators." Also, the terms related to non-delivery or partial delivery of DR that is called into service by grid operators tend to have highly variable penalty clauses from region to region, and from utility to utility, grid operators generally favor more reliable and predictable resources over DR. Until there are consistent standards across regions that ensure data accuracy and validity, data on DR capacity will tend to be discounted by grid operators—an estimated 100-MW DR resource that *can* be called does not mean that 100 MW will show up *when* called. Real-time visibility of these resources is important to grid operators and essential for maximizing the value of DR.[68]

Table 4-1. Potential Peak Reduction from Retail DR Programs, by Region and Customer Class[69]

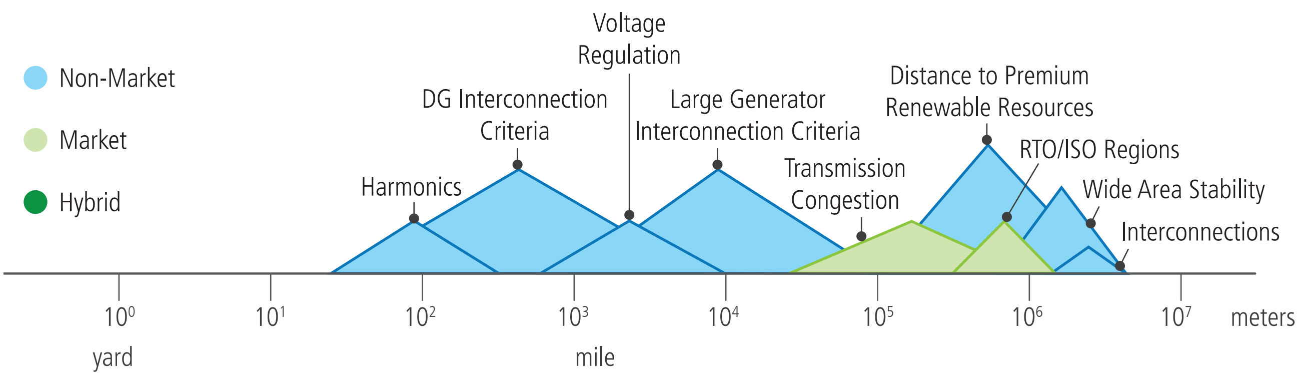
NERC Region	Total DR Capacity (megawatts)	Residential	Commercial	Industrial	Transportation
Alaska	27	19%	48%	33%	0%
Florida Reliability Coordinating Council	1,924	42%	39%	19%	0%
Hawaii	35	57%	43%	0%	0%
Midwest Reliability Organization	4,264	44%	19%	37%	0%
Northeast Power Coordinating Council	467	8%	55%	34%	3%
ReliabilityFirst Corporation	5,362	29%	13%	58%	0%
SERC Reliability Corporation	8,254	16%	10%	74%	0%
Southwest Power Pool	1,594	13%	20%	66%	0%
Texas Reliability Entity	459	19%	74%	7%	0%
Western Electricity Coordinating Council	4,681	22%	24%	50%	3%
Unspecified	28	100%	0%	0%	0%
Totals	27,095	25.8%	18.9%	54.6%	0.6%

DR resources tend to be drawn principally from industrial and commercial customers of utilities, although three regions—Florida Reliability Coordinating Council, Hawaii, and Midwest Reliability Organization—exhibit high-residential DR capacity. Variability among segments within and between regions is a function of DR program characteristics and requirements: whether penalties for non- or under-performance apply, the frequency with which DR resources are called, and the purpose for which DR is used, such as peak mitigation or frequency regulation. Capacity estimates must be adjusted for value and reliability of delivery based on operational outcomes, as well. DR, when called, may not sustain for a complete event period; only a portion of what is called may show up; resource availability may vary over an event period; and sometimes the "snap back" at the end of an event can create "echo effects" of peak mitigation problems, as well.

Topography and Geography are also Important to Grid Operators

Topography and geography are additional and important aspects of core grid management challenges (Figure 4-6). Geography is the physical area covered by the grid; topography is the type of geography (e.g., flat, hilly, mountainous, etc.). Figure 4-6 illustrates how physical distances can influence system structure and operational challenges.

Figure 4-6. Network Geography and Topography Impact Real-Time Operations Management and Influence How System Planning Is Done for Grid Operations and Related Markets.[70]



A variety of grid services are managed across different distance scales and markets, and they can be used to integrate some necessary services.

An example of why these features are important is that information and communications technology (ICT) infrastructure and reliability for smart meters and smart grid assets are less effective when mountainous terrain and urban infrastructure disrupt reliable wireless signal strength. Smart grid designers must and do build in redundancy to deal with certain topographic asymmetries by using multiple ICT channels.

As another example, the concentration of distributed VER in a specific urban geography can lead to stresses on local infrastructure, including transformers and substations. This can present more disruptive problems for local grid operators than non-clustered dispersion of VER. System operators must watch for grid impacts in more granular ways, and grid design changes to mitigate clustering effects will become important new paths for adapting to consumer-side influences on grid operations. Because consumer behavior can change quickly, new grid design processes must be made to function faster, from core architecture to actual deployment. In turn, regulators must become nimble in considering incremental system costs that are compelled by grid operators anticipating problems and acting to mitigate them before they lead to grid interruptions.

The Growing Role of the Consumer in Grid Reliability

Reliability is increasingly a two-way proposition between grid operators and consumers, and grid reliability, while remaining true to its longstanding commitment to ensure high system "uptime," now abuts an emerging "consumer reliability." Reliability has typically been synonymous with "grid reliability" or "system reliability." Consumer reliability derives from a series of initiatives over several decades; the continuous improvement in energy efficiency; the value of DR to both the grid and consumer; emerging new consumer value creation from the IoT development; and the shifting priority of consumers (especially the commercial segment) for uninterruptible power services. The growing interdependence between grid operators and consumers—the two-way flow of information and power—means that grid reliability can be made more efficient and more robust if consumer integration into grid operations occurs.

Customer Engagement in Demand-Side Management

Today, many customer categories and segments are interacting with the grid. Customers now have the tools to alter their consumption patterns in response to price signals or requests from grid operators. This significant change—from a customer that is a passive load to one that is more actively engaged in demand management—may trend toward greater customer participation in the future. Within 10 to 15 years, many of the new devices likely to become part of our electricity system—from power plants to rooftop solar systems, from batteries to street lights, from transformers to electric vehicles—will also be digitally communicating with the grid.[71, 72] Most of these new devices will be able to "see" others on the grid, as well.

This kind of connectivity with customers may lead to more fully integrated customer participation in grid operations on either an active level—where customers respond to time-of-use or real-time price signals—or a passive level—with devices encoded to reflect customer preferences that are responsive to system prices and operating signals. Visibility of this connectivity is, however, key to grid operations and management and essential for both customer and system reliability.

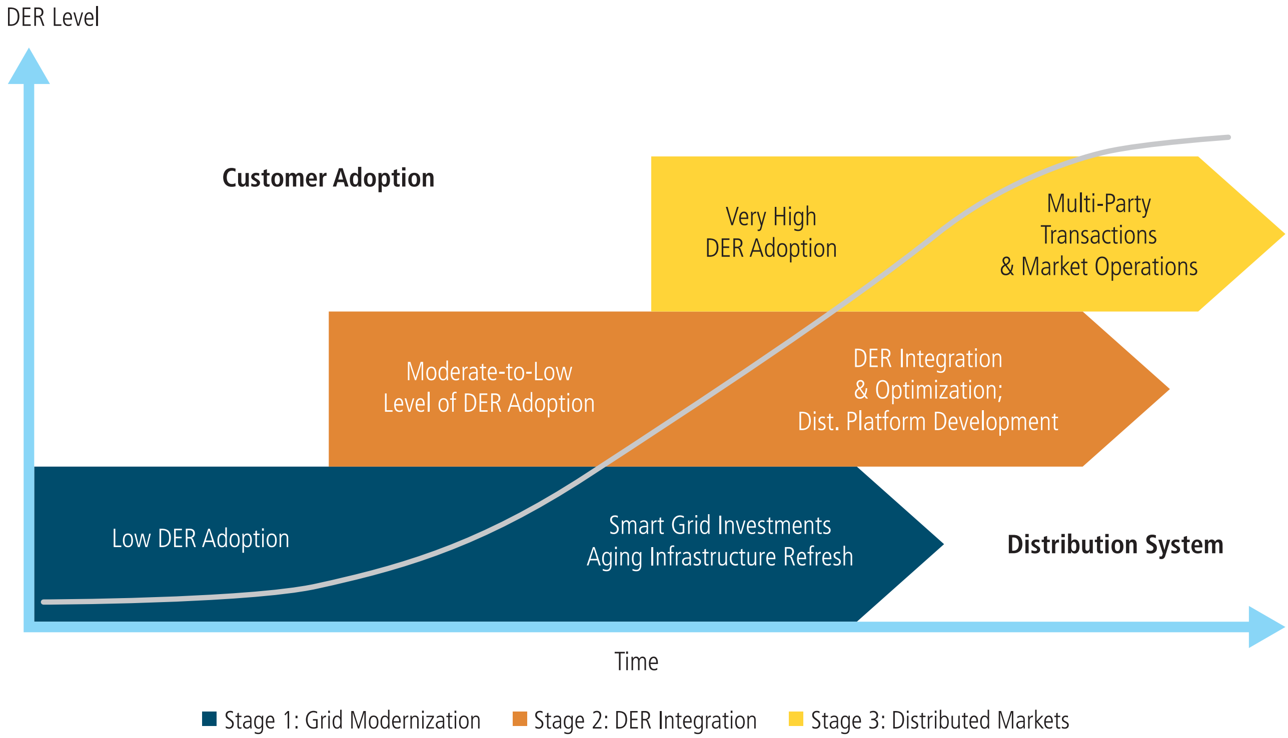
Consumption response to system signals can be more precise, timely, and predictable thanks to improved ICT enablers and better grid-side analytics focused on managing overall system reliability, not just peak mitigation. DOE, through its laboratories, for example, has developed a platform that "enables mobile and stationary software agents to perform information gathering, processing, and control actions and independently manage a wide range of applications, such as HVAC [heating, ventilation, and air conditioning] systems, electric vehicles, distributed energy or entire building loads, leading to improved operational efficiency." This platform provides the capabilities for real-time, scalable distributed control and diagnostics that we need for security and reliability and "…the integration of today's new energy system."[73]

Customer Engagement in Generation and System Reliability

In addition to the potential for increased customer participation in demand side management, there have been dramatic increases in distributed generation, such as rooftop solar, which enable customers to produce power that is sold back to the grid by the customer or aggregators acting on behalf of the customer. The result is that both electricity and information can now flow in two directions across the distribution grid, enabled by smart meters and/or Internet platforms. This two-way engagement has become more complex as distributed generation continues to penetrate industrial, commercial, and residential delivery service segments.

Most utilities are in the low distributed generation adoption phase, with some states approaching moderate levels.[74] Regulatory characteristics within each state will drive growth (e.g., through rate design and utility regulation as set by a public utilities commission). Figure 4-7 shows the conceptual growth of DG/DER in three phases, from low to high adoption. Such conceptual forecasts are helpful in posing policy issues and assisting investors in seeing new opportunities. However, structural and systems outcomes depend as much on actual results of markets, regulators, and various jurisdictions co-evolving into the future.

Figure 4-7. Major Technology, Policy, and Infrastructure Enablers of DER Adoption[75]



This figure shows a three-stage evolutionary framework based on an assumption that the distribution system will evolve in response to both top-down policy and bottom-up customer drivers. Each level includes additional functionality to support greater amounts of distributed generation/distributed energy resources (DG/DER) adoption and complexity building upon the earlier level. Most of the U.S. distribution system is at stage 1; the speed and nature of DG/DER adoption will vary by region based on top-down and bottom-up drivers.

Currently, around 4 percent of U.S. generation is from DG, although this varies widely by region.[76] Low levels of DG penetration generally require modest, though critical, levels of planning and operational considerations. Under high DG adoption rates, grid operations and market structures will most likely require significant modification. In a future grid where DG comprises a larger portion of the resource base, disruptions of system dispatch and control signals that could result from higher levels of DG penetration will increase the risk of disturbing grid stability and reliability. In its "2015 Long-Term Reliability Assessment," NERC noted the complications DG/DER create for grid operations and how these issues might be resolved:

> "Operators and planners face uncertainty with increased levels of distributed energy resources and new technologies. Distributed energy resources (DERs) are contributing to changing characteristics and control strategies in grid operations. DERs are not directly interconnected to the BPS [bulk power system], but to sub-transmission and distribution systems generally located behind customer metering facilities. Visibility, controllability, and new forecasting methods of these resources are of paramount importance to plan and operate the BPS—particularly because the majority of DER are intermittent in nature and outside the control of the System Operator. As more DER are integrated, the supply of control to System Operators can decrease. However, distribution-centric operations can reliably support the BPS with adequate planning, operating and forecasting analyses, coordination, and policies that are oriented to reliably interface with the BPS. Coordinated and reliable integration of DERs into the BPS can also present opportunities to create a more robust and resilient system."[77]

At high penetration levels, distribution system changes to enhance DG/DER value to grid reliability will require developing advanced distribution circuits and substations that allow for two-way power flows, new protection schemes, and new control paradigms. There are digital solid-state technologies combined with ICT, such as smart inverters, power electronics, and smart energy storage that can provide grid operators the flexibility needed to manage a mixed set of DER and deal with inbound impacts from utility-scale VER upstream as well. The introduction of new grid control and optimization algorithms taking advantage of distributed generation and load flexibility in the United States could also contribute to grid reliability and related benefits, such as reduction of renewables curtailment, peak load mitigation, and transmission and distribution (T&D) congestion management. Development of new technologies could enable DG to provide voltage or reactive[n] control resources.

Currently, customer reliability investments and interests are not necessarily contributing to supporting and enhancing overall grid system reliability. The electricity sector has a range of choices to adapt to these challenges and demands, many of them coming from new generators and consumers. The path that is chosen will shape future sector value-creation potential and the long-term relevance of utilities to electricity service delivery. Technology innovation, along with market forces, are redefining "grid reality," the management space where high system reliability is sustained under the aegis of critical national goals for a clean, secure, and competitive electricity sector.

Increased penetration of DGs and increased interconnectivity also bring increased vulnerabilities to malicious attacks on customer assets and on the grid. Public networks carry with them risks of being conduits through which cyber attacks can be executed—where impacts can spread through grids as well as through customer assets that are part of the IoT. There are policy gaps at the interface of electricity and information that require new policies that both promote value creation through connectivity and protect critical infrastructure against cyber attacks.

Valuation of DER: System Benefits and Costs

The growth of DER, where significant, will require additional valuation efforts in both planning and market design to capture the value of these new systems and services, as well as to avoid uneconomic or unintended issues. Valuation can be developed based on different cost perspectives, such as private costs that affect the ratepayers' cost of service or social costs that include the private cost of service and externalities. Valuation efforts need to be performed for a system as a whole, as well as for planning and compensation structures (e.g., rate design).

It is important to consider both the system cost and benefits when valuing DER. Factors that influence DER value include constraint reduction, loss reduction, voltage control, investment deferral, environmental benefits, and reliability. These factors can vary significantly based on the size and location of the DER. Accurate valuations will depend on evaluations at a finer level or resolution than has been considered historically.

Flexibility and Management of DER, VER, and Two-Way or Multi-Directional Flows

Resilience and flexibility might be considered complementary factors of grid modernization. Grid modernization planning should take flexibility of resources, as well as grid operations techniques, into account; architecting a flexible grid may require distinctive configurations of ICT and physical assets on the grid side, as well as the customer side, of the utility meter. Flexibility is not only a generation matter; it bears directly on the core reliability challenges of maintaining balance between generation and load.

[n] NERC requires transmission operators to ensure that resources capable of providing "reactive power" or "voltage control" in addition to electricity are online or can be scheduled because these reactive power or voltage control services regulate voltage levels that maintain grid stability.

Solar and wind (which are not synchronously connected to the grid) contribute to a net decrease in system inertia (loss of frequency control). System frequency[o] must be managed tightly around 60 Hertz; it measures how well the supply and demand of electricity are in balance, which has significant implications for how resources are deployed literally minute-to-minute. Conventional generation, such as nuclear facilities or coal-fired power stations, serve as baseload resources and as spinning reserves. These resources are synchronously connected to the grid and provide system inertia.[p] Deviations in frequency are corrected by the spinning mass and governor controls of conventional generators, which automatically adjust electricity output within seconds to correct out-of-balance conditions.

In contrast, conventional solar photovoltaic (PV) generators, storage devices, and non-frequency responsive loads do not have inertial value for grid operators. As wind and solar power (and other non-synchronous DER) replace conventional synchronous generation, total system inertia is reduced along with the number of units available to provide frequency response services. In other words, system flexibility could be compromised in the absence of intentional mitigating actions that preserve or boost frequency response capabilities. Power electronics and advanced inverters that simulate inertia are available to add to wind and solar generators, providing a version of frequency response; but, development and deployment of these technologies may be hindered without additional policies prioritizing or enabling frequency response service.[q, 78]

Steep ramping resources will become more important as more VER come online and increase their share of power supply. Ramping is used to follow load patterns to ensure that resources match the loads on the system. VER expand the role of ramping from being primarily load focused to more of a role in matching increasing supply variability. For example, in California in 2015, grid operators were required to bring on approximately 10,000 MW within a 3-hour period at the end of each workday to compensate for the reduction in PV output as the sun was setting. Over time, more ramping will be needed as variable resources continue to grow.[79] There is not yet an established method for calculating the type of flexibility required to ensure reliability, especially in circumstances with high penetration of variable or DG.

Distribution systems were designed to deliver power to customers rather than receive power from them. When the same grid assets are tasked with handling power delivered to the grid, as well as power delivered to customers, the settings on many field devices (such as capacitors, feeder switches, and relays) need to be adjusted to handle multi-directional power flows. Where deployment of PV on distribution feeders may significantly exceed real-time demand, distribution system upgrades will be required. However, upgrades cannot be determined simply by evaluating grid requirements but must be configured to deal with existing and potential increases in PV deployments. Thus, the concept of "hosting capacity," much in the same way that Internet services calculate capacity requirements to serve Internet loads, will become a key decision criterion for future grid upgrades. Regulators will need to learn how hosting capacity is a relevant measure for grid planning and how cost justifications for rate purposes should be framed.

As noted, consumers are adopting renewable technologies and devices that enable them to manage their electricity use (e.g., through smart meters and energy management systems). Proactive consumers reduce demand pattern predictability, particularly when remote control of loads is involved. This complicates very near-term system planning, which, in turn, increases the need for redundancy to hedge the unexpected drops

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[o] Frequency is the number of times per second that the electric charge reverses direction. "Electric Systems Respond Quickly to the Sudden Loss of Supply or Demand," *Today in Energy*, Energy Information Administration, November 21, 2011, http://www.eia.gov/todayinenergy/detail.php?id=3990.

[p] NERC defines inertia as "the ability of a machine with rotating mass inertia to arrest frequency decline and stabilize the system." See http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF_Draft_Concept_Paper_Sep_2014_Final.pdf.

[q] FERC issued a Notice of Inquiry on February 18, 2016, seeking comment on whether it should require all generators, including wind and solar, to provide frequency response service. See https://ferc.gov/whats-new/comm-meet/2016/021816/E-2.pdf.

and surges in consumption that can happen. Discussion of these circumstances and policy implications can be found in Chapter II (*Maximizing Economic Value and Consumer Equity*).

Visibility Is Key to Addressing the Changing Nature of Reliability

Flexibility in grid operations requires visibility into connected resources. Visibility—knowledge of "which resources are interconnected, as well as their locations and current capabilities"[80]—is a key attribute for managing the electricity system. Visibility is a necessary condition for managing rapidly changing and complex grid conditions and for providing awareness of incursions, as well as foresight for planning.

Advanced communication and information technologies facilitate visibility. Visualization requires data collection; analysis (e.g., modeling, business cases, etc.); transparency (i.e., sharing data and results); modeling (with both existing and new models); and deploying various sensing technologies, such as synchrophasors and smart meters. Creating foresight for transformation requires increasing visibility across many dimensions:

- *Temporal*—real time to planning
- *Geographic*—such as seams between balancing areas in the bulk electric system
- *Analytical*—identification and specification of computer models needed to evaluate the path to the future grid (such as finance tools, transmission planning tools, etc.)
- *Price*—the single most important mechanism for conveying information to customers and suppliers
- *Societal impacts*—associated risks taken on by the consumer may not be accounted for in price
- *Business*—business models and business-use cases for incumbent service providers and new technology providers
- *Technological*—including characteristics of new technologies and grid elements
- *Regulatory*—between different layers of jurisdiction and many different types of entities that must be synchronized to make the future grid work
- *Vertical industry boundaries*—between distribution and bulk system operations.

Integration of DER resources with ICT and other enabling technologies that provide visibility in the distribution system can give system operators the ability to react and respond to critical events with a level of efficiency and accuracy that is currently unavailable. Policies that comprehensively assess and manage DER could help reduce associated reliability challenges. At some level of DER penetration, these policies may merit extending to encompass the interstate bulk power system. Data requirements and visibility of assets (possibly including tracking production) are important policy issues for state regulators.

The deployment of innovative visibility technologies face multiple barriers that can differ by technology and the role each technology plays in T&D systems. For example, synchrophasors are an important new technology that increase T&D operator visibility, but technology dissemination is limited by utility concerns about vulnerabilities associated with sharing data and the fact that current regulations do not necessarily encourage investments in new technical solutions. This suggests that there is a role for the Federal Government in working with stakeholders and state regulators to identify, analyze, and develop recommendations for removing barriers to the deployment of value enhancing advanced technologies.

Growing Vulnerabilities for the Electric Grid

The electricity system requires management of risks from a wide variety of threats, each with different characteristics, not all of which are considered in a comprehensive way by decision makers. Threats and hazards to the electricity system represent anything that can cause disruption and outages, while vulnerabilities are points of weakness within a system that increase susceptibility to such threats. The physical vulnerabilities and specific risks to the electric power system vary among infrastructure components and by geographic location.

Significant Cost of System Outages

A National Research Council study of the 2003 blackout in the Midwest, Northeast, and Canada concluded that "the economic cost of the 2003 blackout came to approximately $5 per forgone kilowatt-hour, a figure that is roughly 50 times greater than the average retail cost of a kilowatt-hour in the United States."[r] Data suggest that electricity system outages attributable to weather-related events are increasing, costing the U.S. economy an estimated $20 billion to $55 billion annually.[s]

[r] National Research Council, *Terrorism and the Electric Power Delivery System* (Washington, DC: The National Academies Press, 2012), http://www.nap.edu/openbook.php?record_id=12050.

[s] Richard Campbell, *Weather-Related Power Outages and Electric System Resilience* (Congressional Research Service, August 28, 2012), R42696, http://www.fas.org/sgp/crs/misc/R42696.pdf.

Grid Reliability Risk

Reliability risk is a complex mix of natural and human threats. Risk mitigation includes developing future grid designs that maximize flexibility, as well as making investments in structural, process, and technology solutions, which increase grid resilience to reduce outage events. Some strategies can help reduce risks with respect to a variety of threats, while other strategies are more threat specific. Specific measures fall into a few broad categories—such as hardening (e.g., protection from wind and flooding), modernization (e.g., investment in sensors, automated controls, databases, and tools), general readiness (e.g., equipment maintenance, vegetation management, stockpiling of critical equipment), and analytics and security upgrades.[81, 82, 83]

Grid owners and operators are tasked with managing risks from a broad range of threats, defined as anything that can disrupt or impact a system—natural, environmental, human, or other. Many threats to critical electricity infrastructure are universal (e.g., physical attacks), while others vary by geographic location and time of year (e.g., natural disasters). Threats also range in frequency of occurrence, from highly likely (e.g., weather-related events) to less likely (e.g., electromagnetic pulse). Electric utilities have long prepared for specific hazards. However, hazards that evolve over time, or combinations of hazards that occur simultaneously, require enhanced or new measures for prevention or mitigation.[84]

Cyber attacks are emerging and rapidly evolving threats that may increase the vulnerability of utilities' system operations. Understanding the various established and emerging risks to the electricity system, including characterization of historical trends and future projections, as well as the predictability of different threats, has important implications for threat mitigation and resilience.[85] Figure 4-8 depicts the scope and severity of risks where probabilities of occurrence of each threat can change significantly "without notice." This figure illustrates the status of risk management with respect to current threats, some of which are expected to worsen in the future, suggesting a need for new risk management strategies. Current risk management practices are well suited to address common threats for most system components; however, the picture is mixed, particularly with respect to emerging threats, where there is limited data and experience. Figure 4-8 includes the current risks of system disruption (color coding) for electricity system segments (columns across) to various threats (by rows). The threats are further broken out by incidents of low and high intensity (rows). While the sector has well-established risk management practices for many current threats (indicated with filled circles), practices for other types of threats are nascent (open circles).

Figure 4-8. Integrated Assessment of Risks to Electricity Sector Resilience from Current Threats[86]

Threat	Intensity	System Components / Assessment of Risk & Resilience: Electricity Transmission	Electricity Generation	Electricity Substations	Electricity Distribution (above)	Electricity Distribution (below)	Storage
Natural/Environmental Threats							
Hurricane	Low (<Category 3)	● Moderate	● Low	● Moderate	● High	● Low	◑ Moderate
Hurricane	High (>Category 3)	◑ High	● Moderate	● Moderate	◑ High	● Moderate	◑ Moderate
Drought	Low (PDSI>-3)	● Low	● Low	● Low	● Low	● Low	● Low
Drought	High (PDSI<-3)	● Low	◑ Moderate	● Low	● Low	● Low	◑ Moderate
Winter Storms/Ice/Snow	High (PDSI<-3)	● Moderate	● Low	● Low	● Moderate	● Low	● Low
Winter Storms/Ice/Snow	Low (Minor icing/snow)	● High	● Low	● Moderate	● High	● Low	● Low
Extreme Heat/Heat Wave		● Low	◑ Moderate	● Moderate	● Low	● Low	● Low
Flood	Low (<1:10 year ARI)	● Low	● Low	● Low	● Low	● Moderate	● Low
Flood	High (>1:100 year ARI)	● Moderate	◑ Moderate	◑ Moderate	◑ Moderate	● Moderate	● Moderate
Wildfire	Low (>Type III IMT)	● Low	● Moderate	● Low	● Low	● Low	● Low
Wildfire	High (Type I IMT)	● Moderate	● Low	● Moderate	● Moderate	● Low	● Moderate
Sea-Level Rise		● Low	● Moderate	● Low	● Low	● Low	● Low
Earthquake	Low (<5.0)	● Low	● Moderate	● Moderate	● Moderate	● Moderate	● Moderate
Earthquake	High (>7.0)	● Moderate	● High	● High	● Moderate	● High	● High
Geo-magnetic	Low (G1-G2)	● Low	● Low	● Low	● Low	● Low	● Low
Geo-magnetic	High (G5)	○ Low	◑ Moderate	○ High	◑ Low	○ Low	◑ Moderate
Wildlife/Vegetation		● Low	● Low	● Low	● Low	● Low	● Low

Levels of Risk

- Low
- High
- Moderate
- Unknown

Current Status of Risk Management Practice

- ○ Nascent: critical vulnerabilities exist
- ◑ Established, but opportunities for improvement remain
- ● Well-established and robust

Threat	Intensity	System Components					
		Electricity Transmission	Electricity Generation	Electricity Substations	Electricity Distribution (above)	Electricity Distribution (below)	Storage
		Assessment of Risk & Resilience					
Human Threats							
Physical	Low	●	●	●	●	●	●
	High	◑	◑	◑	●	●	◑
Cyber	Low	◑	◑	◑	○	○	
	High	○	○	○	○	○	○
Electro-magnetic	Low (Ambient EMI)	●	●	●	●	●	●
	High (NEMP & HEMP)	●	○	○	●	●	○
Equipment Failure		●	●	●	●	●	●
Combined Threats		○	○	○	○	○	○

Levels of Risk

- Low
- High
- Moderate
- Unknown

Current Status of Risk Management Practice

- ○ Nascent: critical vulnerabilities exist
- ◑ Established, but opportunities for improvement remain
- ● Well-established and robust

Electricity system owners and operators must manage risks in a comprehensive manner for a broad range of threats. This chart provides an integrated portrait of current risks to the electricity system and the maturity of current risk management practices. The sector generally has well-established practices for managing familiar threats (e.g., wildlife), but much more work is needed to effectively manage risks from high-impact, low-frequency events (e.g., high-intensity hurricanes), combined threats, and unfamiliar threats for which information is lacking or unknowable (e.g., cyber and physical attacks). Additional attention is needed to reduce risks for above-ground distribution systems, substations susceptible to large-scale geomagnetic disturbances. This assessment does not reflect the status of risk management with respect to threats that are expected to worsen, such as extreme weather and cyber attacks. Acronyms: annual return interval (ARI), electromagnetic interference (EMI), high-altitude electromagnetic pulse (HEMP), nuclear electromagnetic pulse (NEMP), Incident Management Team (IMT), Palmer Drought Severity Index (PDSI).

Grid Operator Reliability Risk Management Is Increasingly Important

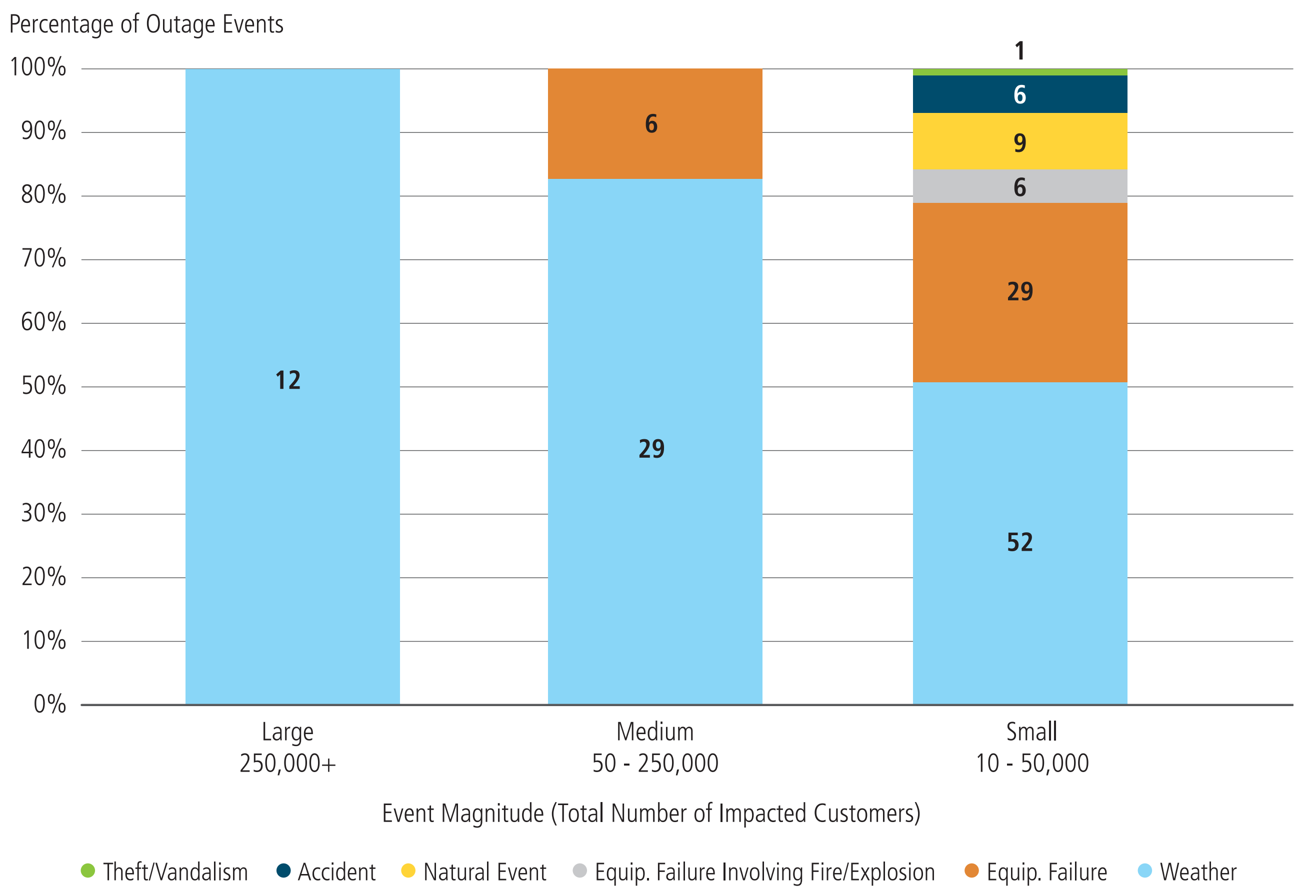
Delivery system reliability remains high and robust in today's world, but emerging threats create a higher risk profile that, in turn, creates challenges for ensuring sustained high delivery system reliability. There are many electricity sector risks that are continuously managed, such as investment risks, regulatory risks, and grid operational risks. Operational risks encompass all variables that can produce outages or disrupt frequency and voltage—from new types of power generation, to changing customer behavior, to extreme weather. Despite risk management practices, the risk of system disruption remains particularly high to certain system segments (e.g., above-ground distribution systems) or threats (e.g., large-scale earthquakes). Further, there remain evolving or dynamic threats for which the levels of risk are unknown and the risk management practices could be improved (e.g., high-intensity physical attacks, high-intensity cyber attacks, or combined threats).

Key policy questions include how investments should be prioritized, how cyber threats to ICT infrastructure should be managed, how emerging climate threats should be mitigated and planned for, and whether a highly dispersed power supply system contributes to a more resilient and secure electricity sector. Finally, longstanding high-voltage transmission and baseload power supply assets now must be analyzed as possible insurance assets for reliability

Extreme Weather Is a Leading Threat to Grid Reliability

Some types of extreme weather are becoming more frequent and intense due to climate change, and these trends have been the principal contributors to an observed increase in the frequency and duration of power outages in the United States between 2000 and 2012.[87] Figure 4-9 summarizes the main sources of contemporary outage events in 2015, excluding consideration of cyber-related effects.

Figure 4-9. U.S. Electric Outage Events by Cause and Magnitude, 2015[88]

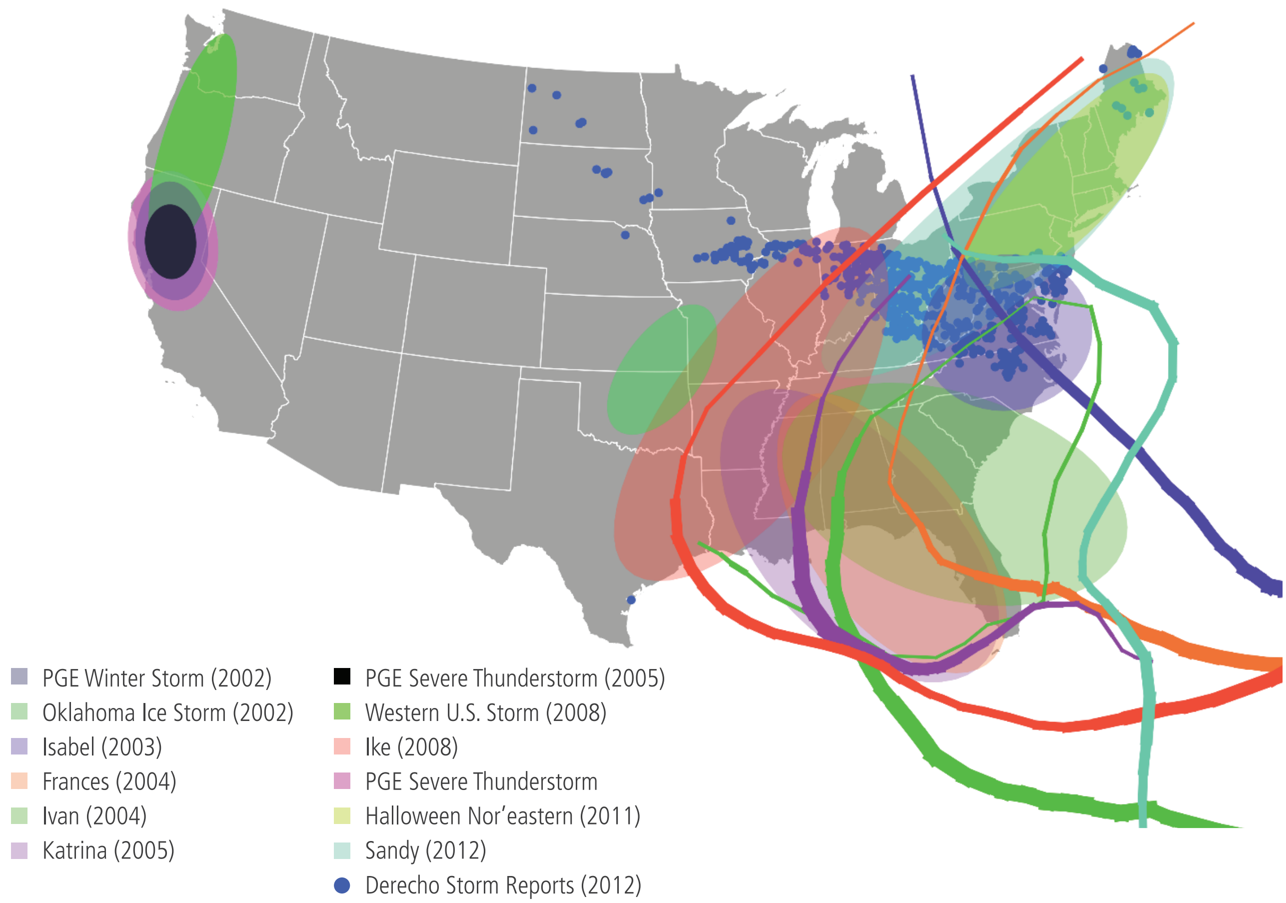


Extreme weather is the leading cause of electric power outage events, especially for the most significant disruptions. All 12 of the large-scale events in 2015 were weather related, while just over half of the small-scale events were caused by weather.

Superstorm Sandy demonstrated the severe impacts of a large storm and the interdependencies of electricity and other infrastructures. The storm knocked out power to 8.66 million customers from North Carolina to Maine and as far west as Illinois and Wisconsin. Electric utilities deployed over 70,000 workers to the affected areas, the largest-ever dispatch of utilities workers.[89] The nearly 1,000-mile-diameter storm caused flooding and power outages that shut down many other major infrastructure components, illustrating the dependence of other critical infrastructures on electricity.[90] Oil refineries were shut in, as well as many East Coast product import terminals—which act as the primary backup method for securing bulk product supplies during refinery outages—due to the loss of power. A week after the storm, product deliveries in New York Harbor had returned to only 61 percent of pre-storm levels, and less than 20 percent of gas stations in New York City were open for business. The Department of Defense provided 9.3 million gallons of fuel, though fuel shortages still greatly hindered the ability of emergency response personnel to respond to the crisis.[91]

Weather-related events, including lightning and storms, have historically posed the greatest operation risk to the electricity system.[92] Strong winds, especially hurricane-force winds, are the primary cause of damage to electric T&D infrastructures. Failures on the distribution system are typically responsible for more than 90 percent of electric power interruptions, both in terms of the duration and frequency of outages.[93] Damage to the transmission system, while infrequent, can result in more widespread major power outages that affect large numbers of customers and large total loads.[94] Figure 4-10 summarizes major weather-induced reliability disruptions from 2002 to 2012.

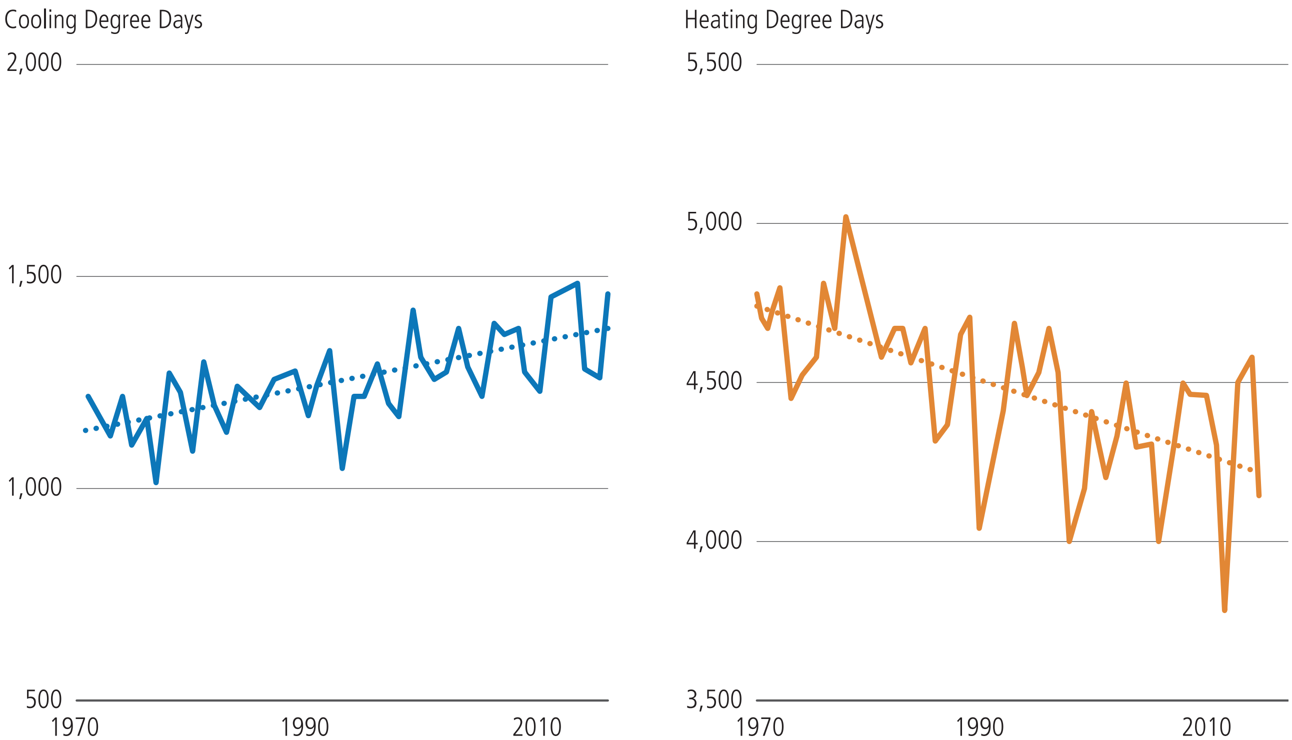
Figure 4-10. Major Weather-Related Outages Requiring a National Response, 2002–2012[95, 96]



There are regional variations in outage causes in the United States. While the East and Gulf Coast regions are subject to hurricanes, large, weather-related outages in the West are more often caused by winter storms. Major outages from weather events are more common than from cascading failures.

Further, 2016 is on track to be the third consecutive year of record-breaking global temperatures.[97] Cooling degree days[t] have already increased in the United States by roughly 20 percent over the last few decades (Figure 4-11), and this trend is projected to continue in the future.[98] These changes in temperature are expected to result in increased electricity use, particularly during the mid- to late-afternoon peak hours, primarily to meet rising demand for air conditioning.[99]

Figure 4-11. Heating and Cooling Degree Days in the Contiguous 48 States, 1970–2015[100]



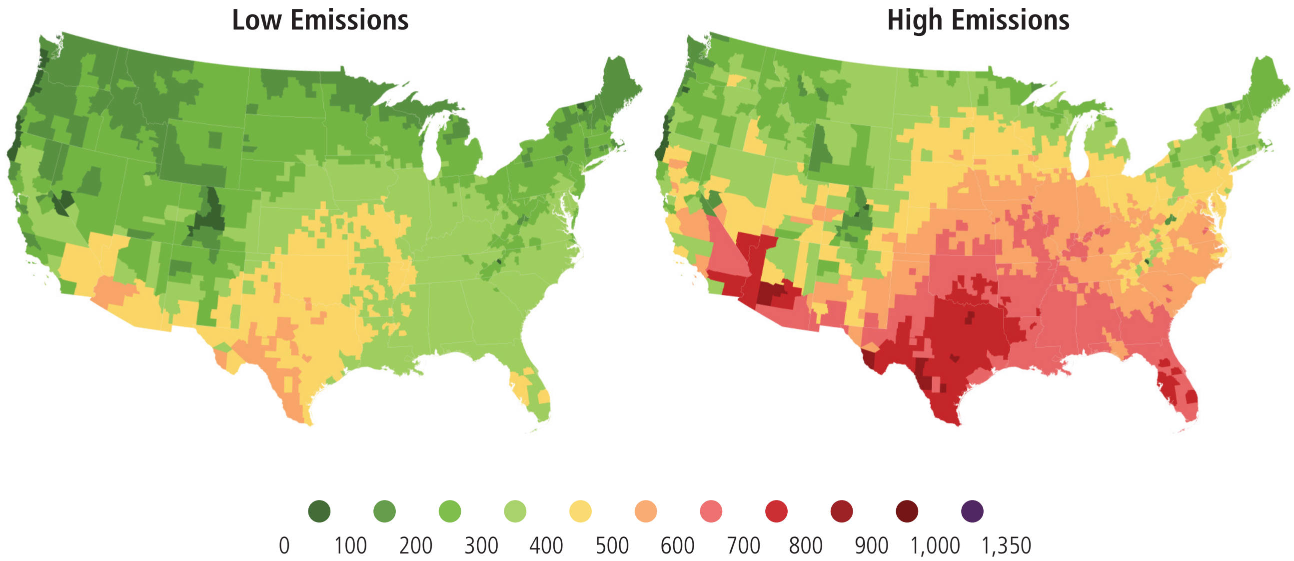
As air temperature continues to rise, since 1970, the number of cooling degree days has increased in the United States by roughly 20 percent, while the number of heating degree days has declined.

The maps in Figure 4-12 show projected median changes in cooling degree days by 2040 under two global greenhouse gas emissions scenarios, based on analysis of output from several global climate models,[u] which were downscaled to the county level.[101] This analysis found that while the average American has historically experienced around 2 weeks of days over 95°F each year, this could rise to 3 to 6 weeks, on average, by 2040.[102]

[t] The number of degrees that a day's average temperature is above 65º Fahrenheit, indicating that consumers need to use air conditioning to cool their buildings, and there is an increase in electricity demand.

[u] To account for uncertainty surrounding future emissions pathways, the study cited here uses a plausible range of scenarios developed for the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. The highest emissions scenario corresponds to a world where fossil fuels continue to power global economic growth. The lowest emissions scenario reflects a future in which global greenhouse gas emissions are reduced through a rapid transition to low-carbon energy sources.

Figure 4-12. Median Change in Cooling Degree Days from Historical (1981–2010) Average for Average Year under Two Emissions Scenarios, 2030–2049[103]



The average number of cooling degree days are expected to increase significantly by 2040, particularly in southern parts of the country. Projected changes for the higher emissions scenario (*right panel*) are much greater than under the lower emissions scenario (*left panel*).

Power sector system costs increase with higher temperatures, particularly as additional capacity is built to meet higher peak demand.[104] Higher air temperatures also reduce the generation capacity and efficiency of thermal generation units.[105] Both factors were taken into consideration by modeling conducted for the QER. Models showed the likely range of total temperature-related power system costs[v] increasing by 2 percent to 7 percent (with a median value of 4.5 percent) under the lowest greenhouse gas emissions scenario, rising to 4 percent to 11 percent under the highest emissions scenario.[106] The scale of these modeled costs illustrates why electricity system planners should consider how best to incorporate projected changes in climate into load forecasting and other considerations that affect investment planning for the electric power sector. Increased earth observation and modeling of local-scale climate effects to improve forecasting would benefit electricity system planning and could reduce costs.

Extreme temperatures also increase the potential for electrical equipment to malfunction. For example, transformers do not last as long when overloaded to meet peak demand, particularly when they are simultaneously exposed to high temperatures that exceed the heat ratings for which they were designed.[107] When planning for future investments, it may become important for utilities to proactively invest in transformers with higher heat ratings to reduce the potential for overloading under future, warmer conditions.

A continuation of sea-level rise, in conjunction with storm surges caused by tropical cyclones, hurricanes, and nor'easters, will increase the depth and the inland penetration of coastal flooding, thus increasing the frequency with which electricity assets are exposed to inundation during storm events.[108] These challenges are exacerbated by the fact that some coastal areas may be experiencing load growth—rapid population growth and development in coastal areas—which is expected to continue in the coming decades.[109, 110]

Another aspect of uneven impacts is that low-income and minority communities are disproportionately impacted by disaster-related damage to critical infrastructure.[111] These communities often do not have the means to mitigate or adapt to natural disasters, and they disproportionately rely on public services, including community shelters, during disasters. As a result, there may be a Federal role in providing technical and

[v] Calculated in net present value terms, between 2016 and 2040, using a 5 percent discount rate.

financial resources to help states and localities prioritize resilience investments in critical public infrastructure that would protect the most vulnerable communities.

Electricity and Natural Gas System Interdependencies

A key interdependency (and vulnerability) for all economic sectors and critical infrastructures is reliance on electricity, making its reliability a fundamental need and requirement across the entire economy. Many of these interdependencies are growing, such as the interdependency of electric and natural gas systems.

The reliability of the Nation's electricity system is increasingly linked to the reliability of natural gas pipelines and associated infrastructure. On May 24, 2016, NERC released a special assessment of gas-electric interdependencies, which included an investigation of the potential reliability risks to the Nation's bulk power system due to increased reliance on natural gas. NERC found that areas with growing reliance on natural gas–fired generation are increasingly vulnerable to gas supply disruptions. These concerns were reinforced by NERC's latest long-term reliability assessment, which was released in December, 2016.

Unlike other fossil fuels, natural gas is not typically stored onsite and must be delivered as it is consumed.[w] In many regions, sufficient gas infrastructure is a key requirement for electric reliability. An interruption in natural gas deliveries could result from extreme weather or *force majeure* events, as well as from low-probability events that could unexpectedly remove infrastructure from service, such as a well malfunction, as seen in the underground storage leak in Aliso Canyon, California. Extreme weather events, such as in the Southwest outages of 2011, can simultaneously increase energy demand for gas and electric heating, while reducing supplies in the affected region.[112] Operators may be able to respond to disruptive events by rerouting gas onto other pipelines, as was the case during a 2016 disruption to the Texas Eastern Pipeline.[113] Electric curtailments also have the potential to reduce gas available to gas-fired generators. For example, in 2011, power outages disabled electric-powered gas compressors on well gathering lines, which reduced supplies of natural gas to New Mexico.[114] In addition to physical natural gas disruptions' impact on the electricity system, the electricity sector's increasing reliance on natural gas raises serious concerns regarding the need to secure natural gas pipelines against emerging cybersecurity threats. Thus, the adequacy of cybersecurity protections for natural gas pipelines directly impacts the reliability and security of the electric system.

The vulnerabilities due to natural gas and electric system interdependency are the subject of ongoing regulatory reforms, physical upgrade efforts, and industry collaboration. Some ISOs have undertaken surveys of critical gas facilities to ensure that these facilities are exempt from potential load-shedding plans in the event of a system emergency, and FERC has allowed communication of proprietary and other non-public operational information between the gas and electric industries to continue in order to facilitate further sharing of critical reliability issues.[115] To date, many stakeholders have performed extensive analysis to improve real-time and near-term operations and planning in order to address natural gas–electricity interdependencies. One result has been FERC issuing a final ruling requiring interstate natural gas pipelines to change their pipeline nomination schedules to better conform to dispatch scheduling in organized electricity markets.[116] Most coordination efforts have been focused on short-term planning and operations. Mid- and long-term planning coordination is also being explored to properly plan for long-term assets like electric transmission and natural gas pipelines. However, coordinated long-term planning across natural gas and electricity can be challenging as the two industries are organized and regulated differently.

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[w] Some natural gas power plants also have the ability to operate on alternatives to pipeline-delivered natural gas, such as fuel oil and local stores of liquefied natural gas or liquefied petroleum gas. In addition, note that potential deliverability challenges for coal have also been documented. For example, see Tim Shear, "Coal Stockpiles at Coal-Fired Power Plants Smaller than in Recent Years," *Today in Energy*, Energy Information Administration, November 6, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=18711. See also Department of Energy (DOE), *Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector* (Washington, DC: DOE, 2015), v, http://energy.gov/epsa/downloads/report-natural-gas-infrastructure-implications-increased-demand-electric-power-sector.

Underground Storage Leak in California Driving Natural Gas Storage Safety and Reliability Improvements[x]

On October 23, 2015, the largest methane leak from a natural gas storage facility in U.S. history was discovered by the Southern California Gas Company at well SS-25 in its Aliso Canyon Storage Field in Los Angeles County. The leak continued for nearly four months until it was permanently sealed on February 17, 2016. In the interim, residents of nearby neighborhoods experienced health symptoms consistent with exposure to odorants added to the gas; thousands of households were displaced; and the Governor of California declared a state of emergency for the area. Approximately 90,000 metric tons of methane were released from the well, although estimates vary, and the State of California is continuing its analysis. The incident also created serious energy supply challenges for the region and prompted broader public concerns about the safety of natural gas storage facilities.

From an electric reliability perspective, the continued shutdown of this facility has been significant because it is a key component of the Southern California gas system serving customers in the Los Angeles Basin and San Diego, particularly many gas-fired power plants. Curtailments of gas deliveries were expected to cause electric reliability problems in the summer of 2016. Such disruptions were avoided, however, due to the combined effects of comparatively mild summer weather, intensified electric demand response efforts, coordinated maintenance programs, and extraordinary management of the region's gas delivery system. The possibility of gas and electric delivery problems remains a concern, however, for the winter of 2016–2017, and additional preparation and coordination are required in order to avoid gas and electric curtailments.

In April 2016, the Obama Administration convened an Interagency Task Force on Natural Gas Storage Safety to support state and industry efforts to ensure safe storage of natural gas. Congress codified the Task Force through the Protecting our Infrastructure of Pipelines and Enhancing Safety Act, which was signed into law by President Obama in June 2016. The legislation created a task force established by the Secretary of Energy that consists of representatives from the Department of Transportation, Environmental Protection Agency, Federal Energy Regulatory Commission, and the Department of the Interior. The Protecting our Infrastructure of Pipelines and Enhancing Safety Act tasked the group with performing an analysis of the Aliso Canyon event, making recommendations to reduce the occurrence of similar incidents in the future, and required that Pipeline and Hazardous Materials Safety Administration promulgate minimum safety standards for underground gas storage that would take effect within 2 years.

In October 2016, the Task Force released a report, called "Ensuring Safe and Reliable Underground Natural Gas Storage," and 44 recommendations. These recommendations address concerns regarding the integrity of wells at underground natural gas storage facilities, public health and environmental effects from leaks like the one at the Aliso Canyon facility, and energy reliability concerns that could arise in the case of failures at such facilities in the future.

[x] Interagency Task Force on Natural Gas Storage Safety, *Ensuring Safe and Reliable Underground Natural Gas Storage* (Washington, DC: Department of Energy, October 2016), https://www.energy.gov/sites/prod/files/2016/10/f33/Ensuring%20Safe%20and%20Reliable%20Underground%20Natural%20Gas%20Storage%20-%20Final%20Report.pdf.

Combined Threats to the Grid

The stochastic nature of certain events such as hurricanes and earthquakes makes the probability of two closely spaced, co-located events very low. However, an intelligent attacker may plan to use the occurrence of one naturally occurring, high-intensity, and low-frequency event to amplify the impact of a physical, cyber, or electromagnetic pulse attack.[117] While electric power systems are generally resilient and quick to recover from failures caused by most natural and accidental events, the National Academy of Sciences concluded that an intelligent multi-site attack by knowledgeable attackers targeting specialized components, like power transformers, could result in widespread, long-term power outages from which it could take several weeks to recover.[118] Another combined threat is the simultaneous occurrence of a severe heat wave during a prolonged drought,[119] which is expected to become increasingly likely in certain regions, such as the U.S. Southwest.[120]

Physical Attacks on the Grid

Incidents such as a series of as-yet unexplained attacks on exposed electricity substations—including the Metcalf incident in California and the attack on the Liberty substation in Arizona—have raised the public's consciousness about the vulnerability of the U.S. electricity grid and the need for the United States to address these vulnerabilities. With an increased focus on physical security, NERC developed Critical Infrastructure Protection (CIP) Standards (CIP-014) in 2014 to address the physical security risks and vulnerabilities of critical facilities on the bulk power system.[121] The Reliability Standard requires transmission owners that meet specific voltage criteria to identify and then protect facilities that, if rendered inoperable or damaged, could result in instability or uncontrolled separation within an interconnection. Transmission owners must also complete third-party verification of their analyses and mitigate the identified areas of concern. Per NERC, the initial risk assessments of critical facilities (including transmission stations, substations, and control centers) were completed by October 1, 2015, while the third-party review of proposed changes to security plans and mitigation strategies was to be completed by November 24, 2016.[122] All entities subject to NERC CIP-014 Standards must retain data and/or evidence of compliance, as described by NERC guidance.[123]

Evolving Cyber Threats to the Grid

The integration of cyber assets to electricity infrastructure presents unique and significant challenges for maintaining and planning for reliable and resilient grid operations. The current cybersecurity landscape is characterized by rapidly evolving threats and vulnerabilities juxtaposed against the slower-moving prioritization and deployment of defense measures. This gap is exacerbated by difficulties in addressing vulnerabilities in operational technologies that cannot easily be taken offline for upgrades, the presence of significant legacy systems, and components that lack computing resources to incorporate new security fixes. Also, any operational changes must be implemented by the thousands of private companies that own and operate electricity infrastructure.

Sector transformation based on a two-way flow of energy and information between grids and consumers brings to the foreground the importance of Federal Government engagement in helping to manage and mitigate vulnerabilities inherent in 21st-century modernization. Interoperability standards, in particular, have the potential to enhance cybersecurity. Improved tools, analytic methodologies, and demonstrations would serve to clarify the circumstances where improved interoperability can improve grid cybersecurity by standardizing security solutions such that utilities can select "plug-and-play" options to mitigate cybersecurity issues. To this end, there is a role for the Federal Government to facilitate state and utility adoption of interoperability standards that provide high societal net benefits through providing high-quality and trusted information to decision makers.[124]

While cyber attacks on the U.S. grid and affiliated systems have had limited consequences to date, attacks across the globe on energy systems should be viewed as indicators of what is possible. Threats can emerge from a range of highly capable actors with sufficient resources, including individuals, groups, or nation-states under the cloak of anonymity.

As noted, the 2015 cyber attack on the Ukrainian electric grid was the most sophisticated cyber incident on a power system to date. On December 23, 2015, Ukraine experienced widespread power outages after malicious actors remotely manipulated circuit breakers across multiple facilities in a series of highly coordinated attacks.[125] The event compromised six organizations, including three electric distribution companies; disconnected seven 110 kilovolts and 23 35-kilovolt substations (which would straddle Federal and state jurisdiction in the United States); rendered equipment inoperable; overwhelmed the call center with a denial-of-service[y] event to prevent people from reporting outages; and left 225,000 without power for 1 to 6 hours.

[y] Distributed denial of service refers to the prevention of authorized access to multiple system resources or the delaying of system operations and functions.

Grid Communication and Control Systems

Deploying smart grid technologies can support increased grid systems' observability and reliability by allowing more real-time awareness via sensors, which enable self-healing systems like fault location and service restoration. At the same time, deployment of smart technologies and DER can provide new vectors for cyber attacks. While not yet a significant issue, this is a growing and significant concern in a grid with two-way, end-to-end flows of electricity. While the likelihood that a malicious actor could bring down large regions of the electric grid by manipulating distributed energy and behind-the-meter equipment is currently low, the risks may change as distributed energy and other advanced technologies increase in number, are operated in aggregation, and are used by the bulk power system to manage and shape load. Smart meters track detailed power usage and allow for two-way communication between the utilities and end users via smart grid technology, which can include remote customer connection and disconnection. Hackers targeting this technology could cause erroneous signals and blocked information to cut-off communication, cause physical damage, or more, and disconnect large numbers of customers to disrupt the grid.

Recently, some utilities have been moving toward combining their physical security and cybersecurity business centers to create a "centralized operations center" organized under a chief information security officer responsible for cybersecurity.[126] These centralized operations centers generally work toward meshing informational technologies with physical operational technologies. Other utilities have their cybersecurity risk management program located in existing information technology (IT) security departments.[127] However, some utilities suffer from a lack of practical cyber expertise. A recent survey showed that 37 percent of utilities surveyed make cybersecurity decisions at the executive level, 47 percent at the management level, and only 16 percent by professional staff.[128]

Reported cybersecurity incursions into industrial control systems (ICS) within the U.S./Canadian energy sector, have decreased slightly, from 111 reported incidents in 2013,[129] to 79 incidents in 2014,[130] and 46 in 2015.[131] This is occurring despite an overall increase in the number of reported ICS incidents across the broader economy, and so far, these incursions have been unsuccessful at inhibiting or disrupting power system operations.[132] Typical cybersecurity events impacting the grid have been mainly limited to gaining access to networks through phishing emails or infecting flash drives with the hope that they will be connected to a network. Russian hacking of utility systems as seen in the Ukraine incident, however, underscores that such events should not be viewed simply as information theft for business purposes. The more common cyber intrusions impacting the electricity subsector today could be preparatory activity for disruptive attacks in the future.

Mitigation of Threats to the Grid

Detecting anomalies and sharing information across organizations are critical measures to enhance grid security; this covers everything from prevention to mitigation and recovery from cyber attacks. However, it is difficult to identify cyber intrusions when no changes or disruptions to system operations are evident or detectible. Furthermore, utilities report a lack of intrusion detection systems,[133] which allow security personnel to identify anomalies in cyber systems and to obtain forensic data.[134] Organizations vary monitoring systems, and nearly every utility will require distinct intrusion detection system specifications due to utility-specific IT and operational technology system configurations.[135, 136]

Even in optimized detection environments, programs and institutions that wish to facilitate sharing within and across industry and government face challenges, including human delays in sharing information, procedural barriers related to classified information, and liability and privacy concerns from industry that inhibit sharing. For example, Federal agencies maintain classified information related to cyber and physical security threats. While some of this information is shared via existing mechanisms, including the Electricity

Information Sharing and Analysis Center and DOE's Cybersecurity Risk Information Sharing Program,[z] sector representatives routinely ask for more in-depth, synthesized, and timely security information.

When digital components of the grid have been compromised, manual operations[aa] can be a temporary alternative. Utilities may need to maintain mechanical controls to prevent degradation and loss of operability.[137] Some subject matter experts suggest utilities are also leveraging decades of experience with mutual assistance agreements to set up cyber assistance in the event of a cyber attack, but response and recovery from cyber attacks pose distinct challenges that are generally not covered by existing mutual assistance programs. The Electricity Subsector Coordinating Council established the Cyber Mutual Assistance Task Force to convene industry experts and develop a cyber mutual assistance framework. The Federal Government could play a convening role for the electricity sector and thereby accelerate efforts to design and employ cyber mutual response programs and ensure swift grid recovery after a cyber attack.

Grid Cybersecurity Workforce Gaps

A shortage of skilled cybersecurity personnel across government and electricity industry presents challenges to meeting response and recovery needs in the aftermath of a large, disruptive cyber event. The power grid is a cyber-physical system, requiring a cross-disciplinary workforce dedicated and trained to design, manage, and protect such complex systems.[138] Companies face challenges in designating sufficient personnel for system security.[139] In addition to the challenge of incorporating sufficient cyber and physical security expertise into their businesses, recruiting and maintaining a workforce that is adequately trained is a growing challenge. To address emerging cybersecurity risks, the United States requires a workforce adept in a variety of skills, such as risk assessment, behavioral science, and familiarity with cyber hygiene.[ab]

Smart Grids and Related Risk

Deployment of smart grid technologies—sensors and the ability to collect and analyze more data faster—supports increased observability of grid systems and thereby contributes to increasing grid reliability. However, in the absence of adequate cyber protections, deployment of smart technologies and DER could increase system vulnerabilities. Because the deployment of these technologies is still in the relatively early stage, electricity regulatory bodies should ensure that cyber protection planning includes advanced cyber protection protocols when execution occurs.

Automated smart meters, for example, are increasingly relied on to track actual power usage and allow for two-way communication between the utilities and end users. Hackers targeting this technology could cause disrupted power flows, create erroneous signals, block information (including meter reads), cut off communication, and/or cause physical damage. Also, some supervisory control and data acquisition (SCADA) systems rely on modern communication infrastructure or a blend of modern and conventional, (i.e., telephone lines communication channels to achieve the same ends), which could make SCADA communications more accessible to hackers and more vulnerable to disruptions. Hacking may come through access to hardcoded

[z] In partnership with industry, the Department of Energy's Office of Electricity Delivery and Energy Reliability has been supporting the Cybersecurity Risk Information Sharing Program (CRISP), which is a collaborative effort with private energy sector partners to facilitate the timely sharing of threat information and the deployment of situational awareness tools to enhance the sector's ability to identify threats and coordinate the protection of critical infrastructure. In August 2014, the North American Electric Reliability Corporation and the Electricity Subsector Coordinating Council agreed to manage CRISP for its sector.

[aa] Use of mechanical switches and controls rather than computer-based controls.

[ab] Cyber hygiene is a set of practices designed to maintain cyber security and keep out the "bugs" from a digital system. Just as hand washing keeps germs from entering the body, practices such as deleting data from cloud storage when it is no longer needed or prohibiting the download of non-essential applications, which might contain viruses, are intended to keep intrusions out of a computer system.

passwords,[ac] system backdoors,[ad] passwords in clear text,[ae] lack of strong authentication,[af] and firmware vulnerabilities.[ag, 140, 141]

Development of Security Metrics

A major impediment to common metrics is variation in how to measure benefits (or conversely, the cost of interruptions), such as "freight cost per mile" or "value at risk." After the attack on the Metcalf substation in April 2013, the California Public Utilities Commission analyzed methods of quantifying distribution system security.[ah] Metrics included copper theft, successful or unsuccessful intrusion or attack, and false or nuisance alarms; the condition of all monitoring equipment and the performance of security personnel in training exercises and on tests; results of substation inspections; instances of vandalism or graffiti; and problems with access control, number of malfunctions of security equipment, or camera coverage.

[ah] Ben Brinkman, Connie Chen, Arthur O'Donnell, and Chris Parkes, *Regulation of Physical Security for the Electric Distribution System* (California Public Utilities Commission, February 2015), http://docplayer.net/816940-Regulation-of-physical-security-for-the-electric-distribution-system.html.

Comprehensive Vulnerabilities Assessments

Reliability requirements in the face of human and natural threats require enterprises, as well as state and Federal entities, to seriously assess vulnerabilities and prioritize investments to ensure that highly reliable service continues. These entities diligently work to identify and mitigate risks to grid reliability. However, given the scope and complexity of risks, especially related to new vectors such as cyber attacks, there may be a need to improve coordination not only around assessing event outcomes, but also around maintaining contemporary assessments of vulnerabilities, their associated risks, and professional estimates of their likelihood.

Gaps in National Reliability, Security, and Resilience Authorities and Information

The primary Federal entities with roles related to security and resilience of the electric grid under normal and emergency conditions are DOE, the Department of Homeland Security (DHS), the Department of Commerce, and FERC.[142] These entities' roles span research and development, standards and guidance, information-sharing mechanisms, and the coordination of resource deployment during emergency events.

Existing authorities cover a wide breadth of Federal Government responsibilities, yet certain gaps remain in implementing comprehensive reliability, security, and resilience measures. For example, the Fixing America's Surface Transportation (FAST) Act granted the President new authorities to protect critical infrastructure against electromagnetic pulse, cyber, geomagnetic disturbances, and physical threats, but not to take anticipatory action for natural disasters and extreme weather. Nevertheless, certain extreme weather events (e.g., heat waves, hurricanes) can be easier to anticipate,[143] and to date, they have caused significantly more

[ac] Passwords that cannot be changed by the user.

[ad] Alternative access (to secure data or functions) that bypass normal security procedures.

[ae] Passwords stored without encryption.

[af] Not scrambling login information, which enables a digital eavesdropper to capture passwords.

[ag] Generic catch-all for hardware-based exploits (rather than software-based).

direct physical harm to the electric grid than have malicious acts. Taking actions in advance of an impending threat can have significant positive effects in reducing power outages,[144] so extending this authority for all hazards would be a great benefit for protecting the grid.

The lack of access to data represents another challenge to Federal agencies to enhance the security and resilience of the grid. Given that the majority of electricity infrastructure is privately owned, the Federal Government must rely on industry data collection activities to understand the vulnerability and security landscape of the electric grid. Furthermore, as noted earlier, utilities report SAIDI, SAIFI, and CAIDI statistics in inconsistent ways,[145, 146] limiting the ability of governments to independently conduct robust risk assessments of the grid. DOE and FERC in particular lack access to data on critical grid assets and their vulnerabilities. In order to support the President in executing new anticipatory security authorities under the FAST Act, addressing this information deficit is a priority.

NERC collects certain data in its role of performing grid reliability assessments and supporting the development of reliability and security standards, but NERC does not make all of that data available to government agencies. DOE has some limited visibility into critical electricity infrastructure through tools like EAGLE-I;[ai] additional system data—to determine, for example, where there are critical vulnerabilities—are needed to exercise the new emergency authorities granted to the President and the Secretary of Energy under the FAST Act.

One of the most prominent examples of this data gap is a lack of information on risk mitigation practices at the utility level, including information regarding participation in risk mitigation programs, a utility's specific risk mitigation practices, and spare equipment specifications and numbers for critical infrastructure, such as transformers. With enhanced and appropriately protected data on utility practices, component part reserves, and an increase in awareness on a range of additional topics—such as transformer configuration, the direct current resistance of various components, and substation grounding resistance values—DOE's ability to understand the extent to which infrastructure will be improved can enable DOE to better fulfill key statutory and executive responsibilities.

Markets and Their Impact on Reliability and Resilience

Centrally organized wholesale markets are recent innovations in the century-plus life of the electricity sector. They were developed and implemented beginning in the 1990s on the heels of state legislative and regulatory direction, but are considered Federally regulated structures that adhere to rules set by FERC and reliability standards set by NERC. Centrally organized markets operated by ISO/RTO include time-delineated markets (e.g., day-ahead, hour-ahead, and real-time), as well as system support services such as spinning reserve and non-spinning reserve, often referred to as Ancillary Services. Commodity exchanges, such as the Intercontinental Exchange (ICE) and the New York Mercantile Exchange, offer future contracts for location-specific electricity trading (referred to as hubs in U.S. markets). These short-term markets are designed to provide price discovery on the marginal cost of power production and delivery.

Seven U.S. regions have operating ISOs/RTOs that manage centrally organized wholesale markets for energy trades (i.e., MW-hour only, as compared to capacity trades that are for MW-only transactions). Together, these trades play an important role in operating and economically optimizing regional grids and ultimately delivering fair-priced electricity to the Nation's consumers. Aspects of the bilateral model exist in the RTO/ISO regions, particularly in the SPP and Midcontinent ISO. Also, several RTO/ISOs operate ancillary services

[ai] EAGLE-I, which stands for Environment for Analysis of Geo-Located Energy Information, is an interactive geographic information system created and managed by the Department of Energy. It allows participants to view and map the Nation's energy infrastructure and obtain near real-time informational updates concerning the electric, petroleum, and natural gas sectors within one visualization platform.

markets and some run capacity markets designed to help ensure that total electricity resources will be sufficient to meet the immediate demand for electricity.

Wholesale electricity trade occurs through bilateral transactions and are predominant in the Southeast and non-California West. These transactions vary in duration of contract, as well as in volume, daily timing, and duration of delivery. Trade differs regionally as a function of distinctive characteristics of regional grids. Bilateral trade volumes tend to be much larger than daily trade in ISO/RTO short-term markets.

There are many reasons that wholesale markets developed—from requirements for open-access transmission systems, which enable development of competitive power generation, to the need to value resources in more refined ways, which help ensure that system reliability is maintained across a broad spectrum of possible disruptive situations. For example, peak mitigation requires generators to perform differently than a traditional baseload production model might specify, and therefore, it may be more valuable than day-ahead committed baseload generation. Increasingly, frequency regulation is as important as peak mitigation, but frequency regulation methods may differ at the transmission level compared to the distribution level.

As noted, an array of new and evolving business models—aggregators, consumer generators, and an evolving generation mix—have emerged from the adoption and integration of new technologies and their associated economics. These developments are raising jurisdictional and market questions. For instance, at the bulk power (wholesale) level, regulators deem short-run markets as workably competitive, but concerns have been raised about the ability of short-run markets to address longer-term issues, such as ensuring that adequate capacity will be available when needed. Also, wholesale markets have successfully integrated independent generation into system operations, and efforts have been underway for some time to make individual DER providers (principally DR) and aggregators of DER (also principally DR) active market participants. More visibility of and reliance on these potential resources is needed, however, to maximize their value.

At the local and utility level (retail), electricity choice markets that are intended to bring new services and lower prices to consumers have seen minor successes, and consumer demand for these services is a significant driver of change. Some states are exploring new structures that would open retail commodity trade to markets. These models are under consideration in the State of New York, for instance, and are often referred to under the rubric Distribution System Operator models.

Centrally Organized Wholesale Markets and Reliability

Electricity production and delivery have traditionally been organized around large centralized power stations and high-voltage transmission lines. Power is shipped over long distances before voltage is stepped down to flow through distribution systems for delivery to consumers. This system often is referred to as the "bulk power system." Centrally organized wholesale markets are structured to provide price discovery of wholesale electricity costs in the bulk power system. Costs relating to bulk power are more than half—and up to two-thirds—of most customers' electricity bill. The significance of costs to customers and the associated economic value of electricity to them is why the functioning of wholesale markets is so important to the overall operation of the electricity supply chain.

High-voltage transmission infrastructure tends to be much more networked than distribution systems. Networked infrastructure increases system resilience by enabling grid operators to reroute power flows when a single line or multi-line pathway is compromised. Transmission infrastructure already is significantly automated (through such tools as Automated Generator Control and advanced SCADA systems) and information intensive. New tools, such as highly granular system visualization solutions, synchrophasors, smart relays, and smart inverters increase network resilience. While changing weather patterns and storm intensity are impactful, the structure of most transmission networks is already hardened against such disruptive factors. What remains to be addressed more comprehensively is how transmission grids can resist cyber incursions that could paralyze wide areas of a large-scale interconnect, such as the Western or Eastern Interconnection. These considerations were discussed in the preceding section.

Stakeholder input as part of the QER process, FERC dockets, National Association of Regulatory Utility Commissioner meetings, and other venues have consistently raised the following issues concerning ISO/RTO wholesale markets: [147]

- The roles of mandatory capacity markets in PJM, ISO-New England, and parts of New York ISO
- The ability of bulk power markets, especially in RTO/ISO markets, to incentivize new generations in addition to natural gas and state renewable portfolio standard mandated renewables, thus helping with resource diversity, resource adequacy, and long-term decarbonization
- The incorporation of state policy and environmental goals in RTO/ISO markets
- The ability to integrate increasing wind and solar generation at lower costs, while allowing remaining traditional sources of generation to earn sufficient revenue to continue to provide needed generation and reliability services
- The ways to address the increasing changes occurring at the distribution level
- The continued evolution of transmission planning and seams issues between major bulk power market regions.

In addition to the issues noted above, analysis of markets with high volumes of VER, notably California, point to emerging impacts, which eventually will affect other regions as their VER increase as an overall share of the resource mix. It is in these emerging issues that new resilience and flexibility considerations come into focus. A 2014 study, "Investigating a Higher Renewables Portfolio Standard in California," which involved Los Angeles Department of Water and Power, Pacific Gas & Electric, Sacramento Municipal Utilities District, Southern California Edison Company, and San Diego Gas & Electric as sponsors. The study identified emerging operations and planning issues under a 50 percent renewable portfolio standard (note that California ISO already consistently handles up to 40 percent renewable resources on its system).[148] Concerns in the study included over-generation as a critical management challenge that occurs when "must-run" generation—non-dispatchable renewables, combined-heat-and-power, nuclear generation, run-of-river hydro, and thermal generation that is needed for grid stability—is greater than loads plus exports. The principal mitigation for over-generation in many current systems is curtailing renewable resource contributions to the overall resource mix. Future systems may increase the role of storage, DR, and flexibility to manage over-generation. Second, renewable resources can change supply patterns suddenly, and as the sun sets, significant solar production disappears, requiring a need for fast ramping generation to fill in for lost solar resources.

The study also found that a variety of integration solutions can reduce the cost of a high renewable scenario. Improvements in regional coordination—which address jurisdictional challenges when state regulation cannot reach beyond state borders, and Federal regulation cannot easily reach into distribution systems—could improve integration. DR, especially advanced practices that increase overall DR reliability, can support higher levels of VER integration. Energy storage is an important technology that must be developed and deployed as a key tool for VER impact mitigation. Finally, VER portfolio diversity is a key success factor as more VER volume impacts grids.

Resilience is an important transmission network matter, but its traditional treatment has occurred as part of ongoing, FERC-approved investments to meet NERC standards and to ensure reliable operations in regionally distinct conditions. The emergence of VER and their growing contributions to resource mixes in some U.S. regions bring with them a need to more robustly differentiate reliability investments from resilience investments. As noted, resilience in transmission networks with high VER requires behavioral changes in system operations, as noted above. In bulk power systems with wholesale market overlays, resolving valuation matters where curtailment of VER is a valid resilience methodology is a serious matter. To avoid complex issues of how to compensate curtailed VER adjustments in market designs and new market developments are required. For example, in California, one element in an overall VER management model is the Energy Imbalance Market created by California ISO, which involves PacifiCorp, a large multi-state utility based in the Pacific Northwest. These initiatives tend not to be considered resilience efforts when they are important contributors to both system reliability and longer-term resilience in high VER systems. In short, as resource mixes change with decarbonization efforts of grid operators and power producers, the role of resilience grows more important as a distinct complement to established reliability management investments and techniques.

The Role of Markets in Downstream Electricity Delivery Services

Presently, downstream electricity delivery services provided by the distribution function of electric utilities—whether integrated with retail customer service or separated into wires operations and competitive retail services—do not function with organized "retail commodity markets" that emulate upstream ISO/RTO wholesale markets. But, there are aspects of market mechanisms that impact grid operations and provide proxies for valuing various types of grid investments for reliability assurance, system flexibility, and network resilience. For example, some distribution systems allow net metering, which involves the sale of power from consumers to grid operators. Pricing of these services is based on state regulatory and ratemaking processes, not auction platforms like those used by ISOs/RTOs. Energy service providers, retail competitors, and aggregators compete through various sales channels for consumers interested in controlling and/or reducing energy costs, deploying onsite power generation, and adopting microgrids that optimize sources and uses of electricity as an integrated onsite system.

Downstream electricity markets may not yet value commodity electricity in a manner that allows for effective pass-through of wholesale clearing prices in real-time to end-use consumers. Wholesale and retail linkages may develop over time; the New York Reforming the Energy Vision process and consideration of distribution system operator models may provide meaningful guidance for such evolution. Whether realized or not, under appropriate and necessary requirements for visibility of such generation, downstream electricity delivery services achieve enhanced resilience by systematically promoting and integrating advanced DR and energy storage solutions into local grid operations.

Similar to wholesale markets and resilience considerations, distribution system resilience measures can be enhanced by incorporating behavioral systems and processes into specific asset-based investments that harden systems against severe weather-related impacts, physical threats, and cyber attacks.

Electricity Markets, Reliability, and Resilience

Reliability investments are typically incorporated into ratemaking processes for all electric utilities. Supplementary investments for recovery from outage events also are handled through established ratemaking processes. Resilience requirements tend to be valued as contributions to reliability and incorporated as part of ratemaking processes. These processes are more easily executed in structures that are traditional end-to-end, vertically integrated electricity delivery services; other market structures complicate reliability and resilience investment decision making. Short-run markets may not provide adequate price signals to ensure long-term investments in appropriately configured capacity. Also, resource valuations tend not to incorporate superordinate network and/or social values such as enhancing resilience into resource or wires into investment decision making. The increased importance of system resilience to overall grid reliability may require adjustments to market mechanisms that enable better valuation.

Grid Operations Planning and Resilience

Resilience of the electricity system is increasingly important. Recent weather extremes, climate change impacts, physical security and cybersecurity threats, and a changing workforce have added to the challenges faced by electric utilities, prompting industry to develop new multidisciplinary all-hazards approaches for managing these issues and making the grid more resilient.

Resilience Measures Expedited Restoration after Hurricane Matthew[aj]

Hurricane Matthew began impacting the southeast United States on Thursday, October 6, 2016, and the flooding caused by the storm continues to affect North Carolina and South Carolina. The initial effects of the storm were felt from Florida to Virginia, with increased rain and wind causing damage to energy infrastructure. Industry efforts to restore that damaged infrastructure are ongoing and have involved mutual assistance from utilities from across the country. More than 99 percent of customers who lost power had their power restored within 8 days, by 11:00 a.m., on October 14, 2016.

Florida Power and Light has invested $2 billion over the last 10 years, leveraging $200 million in Federal investment through the American Recovery and Reinvestment Act of 2009, to advance smart grid functionalities with technologies, such as advanced smart meters, distribution automation, and advanced monitoring equipment, for the utility's transmission system. Early damage assessments suggest that investments in resilience measures expedited Florida Power and Light's restoration timeline; without these new technologies and functions, it is estimated that restoration efforts would have taken 10–15 days. Florida Power and Light reports that 98 percent of the 1.2 million customers who lost power had their power restored within 3 days.

Government, industry, and the various state energy offices helped coordinate the national effort to restore power following the storm. Government responders helped industry crews access impacted areas, facilitated waivers requested by utilities to use unmanned aerial systems for damage assessments, and provided energy sector situational awareness reports that informed decisions about where to place limited Federal and state resources. Government responders remained in Georgia, as well as North Carolina and South Carolina, providing assistance until restoration was complete. The response effort built on lessons learned from Hurricane Sandy of 2012.

[aj] Department of Energy (DOE), "Final Hurricane Matthew Situation Report: October 14, 2016 12:00pm," DOE, October 14, 2016, 3, accessed January 4, 2017, http://energy.gov/sites/prod/files/2016/10/f33/2016_SitRep_12_Matthew_FINAL.pdf.

Resilience enhancement initiatives are generally focused on achieving at least one of three primary goals: (1) preventing or minimizing damage to help avoid or reduce adverse events; (2) expanding alternatives and enabling systems to continue operating despite damage; and/or (3) promoting a rapid return to normal operations when a disruption occurs (i.e., speed the rate of recovery). Resilience relates both to system improvements that prevent or reduce the impact of risks on reliability and to the ability of the system to recover more quickly.

Unlike reliability, there are no commonly used metrics for the resilience of the electric grid, and threats to system resilience are typically associated with disasters or high-intensity and low-frequency events. An additional complication is that the responsibility for maintaining and improving grid resilience lies with multiple entities and jurisdictions, including Federal and state agencies and regulatory bodies, as well as multiple utilities. For investments in electricity sector resilience, approval is generally up to the discretion of state public utilities commissions or equivalent bodies, which are balancing competing, more near-term interests. Furthermore, from the societal perspective, building resilience of critical infrastructure to future disasters involves decision making that also considers social, cultural, and environmental issues, which have both qualitative and quantitative value, from a risk assessment standpoint.[149] Therefore, building resilience to disasters depends upon close coordination among multiple entities, which have varying approaches to measuring electricity system performance and outcomes for society.

Perhaps most relevant is the underlying barrier to prioritizing investments in reliability and resilience that utilities and regulators face.[150] There is no established method for quantifying the benefits of investments, which depend on the occurrence of some events with low probabilities. One exception to this is an order recently released by the New York State Public Service Commission;[151] however, there is a clear need for a set of commonly used methods for estimating the costs and benefits of reliability and resilience investments.

Real-Time Electricity System Monitoring Enhances Situational Awareness

Maintaining situational awareness is an important aspect of overall resilience management in service to maintaining high electricity system reliability. Utilities rely on field personnel to assess and report grid system conditions through site inspections. During emergency situations, utilities' abilities to assess and communicate system status after a large disruption tend to be significantly degraded. Where there is a widespread disruption beyond electricity infrastructure damage, personnel may be responding to a specific emergency situation, which limits work scope. Transportation challenges, such as road blockages and traffic, may also prevent the movement of utility personnel and equipment to assess electricity infrastructure throughout the affected area. Furthermore, wide communication system outages will also limit utilities' ability to assess system conditions. These initial assessment limitations then impede response and recovery planning.[152]

When distribution-level SCADA pairs with a distribution management system, operations can be conducted remotely, increasing the speed at which a utility can identify and locate faults on the distribution system and restore service, as well as manage voltage and reactive power to reduce energy losses and integrate distributed generation and storage technologies.[153]

Analyses of the August 2003 Northeast blackout concluded that it was preventable and that the reliability of the U.S. and Canadian power systems needed an immediate and sustained focus on investments in technologies to promote "situational awareness" and adequate responses to major disturbances.[154] New institutional structures and processes were developed to coordinate information among power pools for improved coordination across systems and across NERC regions for improved coordination of system resource adequacy requirements.

Grid Operations and Communications Redundancy

With the increasing interdependence between communications and electricity, redundancy in communications systems is essential to continuity of grid operations. Some utilities have expanded satellite communications capabilities with mobile satellite trailers that can be deployed to field staging areas and include full capabilities for email, Internet, outage management systems, voice-over Internet protocol telephones, and portable and fixed satellite phones. Others have redundant and diversely routed dedicated fiber-optic lines to enable continued operations.[155, 156]

Dynamic Line Rating Systems for Transmission Systems

Current transmission system operations rely on fixed ratings of transmission line capacity that are established to maintain reliability during worst-case conditions (e.g., hot weather). Line ratings may also be reduced if ambient conditions are abnormally hot and still. There are times when the conditions associated with establishing line ratings are not constraining, and transmission lines could be operated at higher usage levels. Dynamic line rating systems help operators identify available real-time capacity and increase line transmission capacity by 10 to 15 percent. Dynamic line rating systems can help facilitate the integration of wind generation into the transmission system.[157] This real-time information about overhead conductors can help further enhance situational awareness, while simultaneously providing economic benefits. Incremental investments that increase the capacity of the existing transmission system can provide a low-cost hedge, as well as enhanced real-time awareness. However, economic, financial, regulatory, and institutional barriers limit incentives for regulated entities to deploy these low-capital cost technologies that could increase transmission capacity utilization.[158] NERC has an important role to play in setting relevant standards, which would drive increased operational focus on dynamic line ratings as part of overall response and recovery planning and execution.

Information Collection and Sharing Can Mitigate Threats to the Grid

The Federal Government has established programs and launched pilots to analyze cyber and physical threat information, share information with industry, and provide technical assistance to state and utility decision makers in their mitigation efforts. The electric sector utilizes resources and participates in these programs, while also collaborating with one another through industry-led initiatives.[ak] While several Federal programs facilitate the sharing of threat information with industry, challenges remain with respect to the Federal Government's ability to provide data quickly enough to be useful. Several factors limit timely and effective exchange of information, including human delays in sharing information, procedural barriers related to classified information, and liability and privacy concerns from industry.

One particular challenge is that some government intelligence on threat indicators and vulnerabilities is classified, preventing power sector owners and operators who lack the appropriate security clearances from accessing relevant information. Many sector owners and operators and Federal employees often lack the security clearances to access this information.

Another important information gap is a national repository for all-hazard event and loss data, which would help utility regulators, planners, and communities analyze and prioritize resilience investments. In 2012, the National Academy of Sciences recommended the establishment of such a database[159] to support efforts to develop more quantitative risk models and better understand structural and social vulnerability to disasters.

The Grid and Emergency Response

As not all hazards to the grid can be prevented, local authorities and stakeholders focus on failing elegantly and recovering quickly. Response options can leverage existing capabilities, tools, and equipment to act immediately before, during, and after a disruptive event. Public and private sectors can provide emergency response resources, which can include mobile incident management and command centers, mutual aid agreements, and access to specialized materials.[160]

A utility's power restoration and business continuity planning includes year-round preparation for all types of emergencies, including storms and other weather-related events, fires, earthquakes, and other hazards, as well as cyber and physical infrastructure attacks. A speedy restoration process requires significant logistical expertise, skilled/trained certified workers, and specialized equipment. Utility restoration workers involved in mutual assistance typically travel many miles from different geographic areas to help the requesting utility to rebuild power lines, replace poles, and restore power to customers.[161]

[ak] For example, in 2011, Edison Electric Institute, in conjunction with private-sector experts and its member utilities, initiated the Threat Scenario Project to identify threats and practices to mitigate these threats. Identified threats included coordinated cyber attacks, as well as blended physical and cyber attacks. The project established common elements for each threat scenario, including likely targets, potential threat actors, specific attack paths, and the likely impacts of a successful attack. Edison Electric Institute, "EEI Business Continuity Conference Threat Scenario Project (TSP)" (presented on April 4, 2012), 1, http://www.eei.org/meetings/Meeting_Documents/2012Apr-BusinessContinuity-Treat%20Scenario%20Project_Engels.pdf.

Lessons Learned from Severe Outages[al, am, an]

After the immediate response to manage the adverse effects of an event, recovery activities and programs take place to effectively and efficiently return operating conditions to an acceptable level. This may entail restoring service to the same level as before the event or stabilizing service to a new normal. Recovery measures usually consist of longer-term remediation measures and include access to critical equipment, mutual aid agreements with other utilities, and after-action reporting that would make the grid more resilient to future disruptions.

Hurricane Sandy (and Katrina in 2005) caused significant damage to critical national energy infrastructure and stressed Federal capabilities to protect and restore critical infrastructure. In the aftermath, the White House and Federal Emergency Management Agency (FEMA) conducted detailed analyses of the Federal response to identify challenges and lessons learned and to make recommendations for future disaster preparedness and response efforts. Several common themes emerged about response and recovery:

Ensure mutual aid in the utility sector. In response to Hurricane Sandy, electric utilities mobilized the largest-ever dispatch of mutual aid workers (totaling approximately 70,000), primarily from the private sector but including some government workers.

Grant energy sector restoration crews the appropriate credentials to enter damaged work zones and have priority for fuel distribution. In the storm response, some energy sector repair crews were designated as first responders, giving them priority access to fuel and expediting travel into affected areas. However, not all energy infrastructure repair crews had this status or access. After Hurricane Sandy, the Department of Energy's (DOE's) Office of Electricity Delivery and Energy Reliability recommended that electrical workers, as well as refinery and terminal repair crews, be given appropriate credentials to enter damaged work zones quickly.

Coordinate Emergency Support Function (ESF) 12 functions across Federal agencies. ESF-12, under the National Response Framework, is an integral part of the larger DOE responsibility of maintaining continuous and reliable energy supplies for the Nation through preventive measures and restoration and recovery actions in coordination with other Federal Government and industry partners. In the "Hurricane Sandy FEMA After-Action Report," FEMA noted that ESF-12—coordinated by DOE—struggled to fully engage supporting Federal departments and energy sector partners in addressing energy-restoration challenges. A DOE report on the response to Sandy recommended that DOE permanently deploy DOE/ESF-12 responders to the states and regions so they could provide on-the-ground situational awareness of energy disruptions, establish relationships with State and local energy sector partners, and gain first-hand system knowledge to better coordinate energy preparedness efforts with state and local public and private sector partners.

[al] White House, *The Federal Response to Hurricane Katrina: Lessons Learned* (Washington, DC: White House, February 2006), 135, https://georgewbush-whitehouse.archives.gov/reports/katrina-lessons-learned/.

[am] Federal Emergency Management Agency (FEMA), *Hurricane Sandy FEMA After-Action Report* (FEMA, 2013), 10, https://www.fema.gov/media-library-data/20130726-1923-25045-7442/sandy_fema_aar.pdf.

[an] Department of Energy (DOE), *Overview of Response to Hurricane Sandy-Nor'Easter and Recommendations for Improvement* (Washington, DC: DOE, February 2013), 12, http://energy.gov/sites/prod/files/2013/05/f0/DOE_Overview_Response-Sandy-Noreaster_Final.pdf.

State governments play a major role in coordinating and directing response and recovery efforts to electricity disruptions. These responsibilities received a boost through DOE grants to states and local governments to support a State Energy Assurance Planning Initiative. Grants were awarded under this initiative in 2009 and 2010 to 47 states, the District of Columbia, 2 territories, and 43 cities.[162] The grants were used over a 3–4-year period to improve energy emergency preparedness plans and to enable quick recovery and restoration from any energy supply disruption. States also used these funds to address energy supply disruption risks and vulnerabilities, with the aim of mitigating the devastating impacts that such incidents can have on the economy and on public health and safety.[163]

Each state under the Energy Assurance Planning Initiative was required to track energy emergencies, to assess the restoration and recovery times of any supply disruptions, to train appropriate personnel on energy infrastructure and supply systems, and to participate in state and regional energy emergency exercises that were used to evaluate the effectiveness of their energy assurance plans. States were also required to address cybersecurity concerns and to prepare for the challenges of integrating smart grid technologies and renewable energy sources into their plans. Because of the initiative, nearly all state and territory governments and select local governments have Energy Assurance Plans in place. A review of the State Energy Assurance Plan was recommended to occur every 2 to 3 years, and to date some states have undertaken update efforts.[164]

Backup Power and Spare Transformers for Emergency Response

During outages and emergencies, fast but safe system recovery is the mission of a utility. Part of the effort to maintain service while power is being restored involves the use of backup power along with speedy deployment of equipment spares that may have failed.

Backup power sources can be used to bypass existing distribution service lines until they are restored, and they are used by customers in lieu of utility service. Critical facilities, such as hospitals, maintain robust backup power systems. Microgrids offer islanding solutions for large facilities and campuses by their integration of DG, storage, and demand side management solutions. According to an Argonne National Laboratory report, "One hundred percent of the following assessed facility groups have an alternate or back [-up] power in place: Banking and Finance; Critical Access Hospitals; Private or Private Not-for-Profit General Medical and Surgical Hospitals; State, Local, or Tribal General Medical and Surgical Hospitals."[165] More than 75 percent of other users, including manufacturing, wastewater, hotels, arenas, retailers, offices, and law enforcement offices, also maintain some form of alternate or backup power source.[166] Critical data centers and server centers also have robust backup systems that enable islanding from the impacts of grid failures.

It is also important to ensure that key grid components are available in the event of emergencies. Utilities have robust supply chains and inventory management systems that help ensure that spare transformers, including the stocking of interchangeable spare transformers,[167] the ordering of conventional spares in advance, and the early retirement of conventional transformers for use as spares. Conventional spares are typically used for planned replacements or individual unit failures; but these transformer spares can also be used as emergency spares. Under this approach, the spares are identical to those transformers that are to be replaced and often stored at the substation next to existing transformers—which allows for quick energization without the transformer being moved. The close proximity of such spares to the existing transformers can lead to potential high-intensity and low-frequency physical attacks or weather events. Some utilities retain retired transformers to repurpose them as emergency spares.[168] These are transformers that have retired but not failed, which would allow their use as temporary spares until a new transformer is manufactured and transported.[169] Utilities also use mobile transformers and substations to temporarily replace damaged assets, much in the way that mobile power is used for resilience and repowering efforts.

Nuclear Regulatory Commission Requirements

The Nuclear Regulatory Commission has issued several cyber and physical security regulations for nuclear power plants covering cybersecurity plans, response and recovery strategies from aircraft crashes, and training for security personnel, among other measures. For example, Title 10 of the Code of Federal Regulations, Section 73.54 stipulates that licensees provide "…high assurance that digital computer and communication systems and networks are adequately protected against cyber-attacks…" Each nuclear power plant must submit a cybersecurity plan and implementation schedule, which is then reviewed by the Nuclear Regulatory Commission.[ao] Additionally, the Nuclear Regulatory Commission is also required to conduct "force-on-force" exercises at nuclear power plants at least once every three years. These security exercises deploy a mock adversary force attempting to penetrate a plant's critical locations and simulate damage to target safety components. These exercises provide an evaluation of power plant security and identify deficiencies in security strategy, plans, or implementation. When these deficiencies are identified, additional security measures must be promptly implemented.[ap] These regulations have led to significant investments by nuclear power plant operators.

[ao] Mark Holt and Anthony Andrews, *Nuclear Power Plant Security and Vulnerabilities* (Washington, DC: Congressional Research Service, January 2014), 11, https://fas.org/sgp/crs/homesec/RL34331.pdf.

[ap] "Frequently Asked Questions About Force-on-Force Security Exercises at Nuclear Power Plants," Nuclear Regulatory Commission, accessed August 1, 2016, http://www.nrc.gov/security/faq-force-on-force.html.

Some utilities retain retired transformers to repurpose them as emergency spares. These are transformers that have retired but not failed, which would allow them to be used as temporary spares until a new transformer is manufactured and transported.[170] Utilities also use mobile transformers and substations to temporarily replace damaged assets. "A mobile substation includes a trailer, switchgear, breakers, emergency power supply, and a transformer with enhanced cooling capability. These units enable the temporary restoration of grid service while circumventing damaged substation equipment, allowing time to repair grid components. Mobile transformers are capable of restoring substation operations in some cases within 12–24 hours."[171]

Finally, utilities preparing for response after cyber disruptions are also taking measures to build redundancies for cyber infrastructure. Some of these measures include building backup control centers for full functionality and developing independent, secured control mechanisms that would provide limited vital functions during an emergency.[172] NERC CIP standards require utilities to maintain backup energy management systems to manage bulk electric system generation and transmission assets.[173]

Equipment Constraints on Speedy Restoration: Large Power Transformers

The shortage of critical electrical equipment can cause significant delays for power restoration. Specifically, the loss of multiple large power transformers (LPTs) may overwhelm the system and cause widespread power outages, possibly in more than one region, increasing vulnerability and the potential for cascading failures.

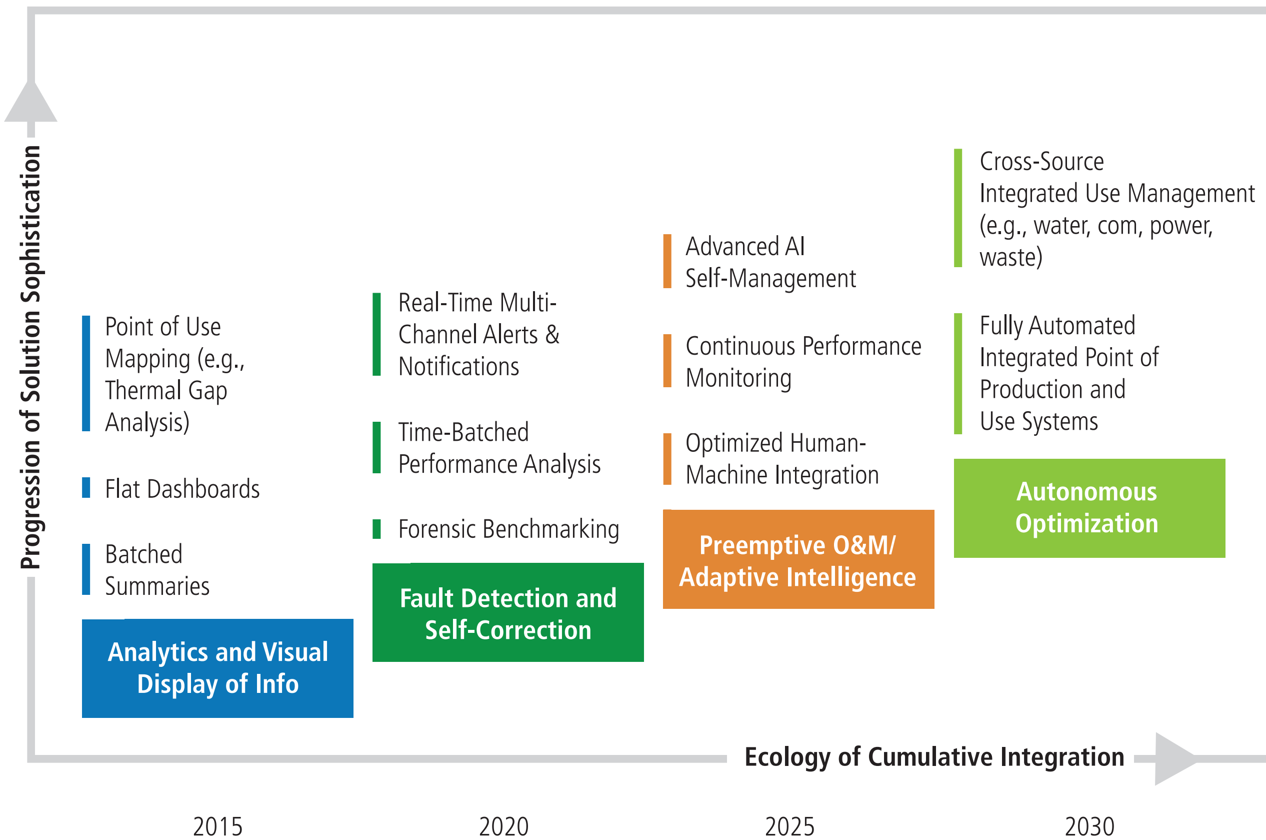
Replacement of multiple, failed LPTs is a challenge, due to the cost and complex and lengthy process involving the procurement, design, manufacturing, and transportation of this equipment. These processes can take months, depending on the size and specifications of the needed LPTs, even under an accelerated schedule and normal transportation conditions. Utilities mitigate the risk of losing LPTs through several strategies, including adopting measures to prevent or minimize damage to equipment, purchasing and maintaining spare transformers (conventional spares), identifying a less critical transformer on their system that could be used as a temporary replacement (provisional replacement transformer), and/or setting up contracts to procure a transformer through a mutual assistance agreement or participation in an industry sharing program.

There are currently three key industry-led, transformer-sharing programs in the United States—NERC's Spare Equipment Database program, Edison Electric Institute's Spare Transformer Equipment Program, and SpareConnect. Another program, Recovery Transformer, developed a rapidly deployable prototype transformer designed to replace the most common high-voltage transformers, which DHS successfully funded in partnership with Electric Power Research Institute and completed in 2014.[174] As of December 2016, three additional programs—Grid Assurance, Wattstock, and Regional Equipment Sharing for Transmission Outage Restoration (commonly referred to as RESTORE)—are in development. QER 1.1 recommendations noted that DOE should "analyze the policies, technical specifications, and logistical and program structures needed to mitigate the risks associated with the loss of transformers."[175] In December 2015, Congress directed DOE to develop a plan to establish a strategic transformer reserve in consultation with various industry stakeholders in the FAST Act. To assess plan options, DOE commissioned Oak Ridge National Laboratory to perform a technical analysis that would provide data necessary to evaluate the need for and feasibility of a strategic transformer reserve. The objective of the study was to determine if, after a severe event, extensive damage to LPTs and lack of adequate replacement LPTs would render the grid dysfunctional for an extended period (several months to years) until replacement LPTs could be manufactured. DOE's recommendations will be published in the report to Congress in early 2017.

Grid Analytics and Resilience

Both grid reliability and resilience increasingly depend on highly granular data about what is happening on grids in real time. Data analysis is an important aspect of today's grid management, but the granularity, speed, and sophistication of operator analytics must increase as greater distribution system complexity occurs. Regional differences may matter, but the core analytic engines that must be developed and configured for grid operator use will be the same across regions and systems.

Figure 4-13. Information Drives Solution Sophistication, Which Drives New Benefit Realization for Grids[176]



Grid information systems are expected to evolve over time, growing increasingly autonomous and self-managing. Increased autonomy and self-management also involves increased system integration, which amplifies the complexity of systems and requires a degree of human-machine interdependence that is unprecedented for grid operations. Acronym: operations and maintenance (O&M).

Smart Grid and System Resilience

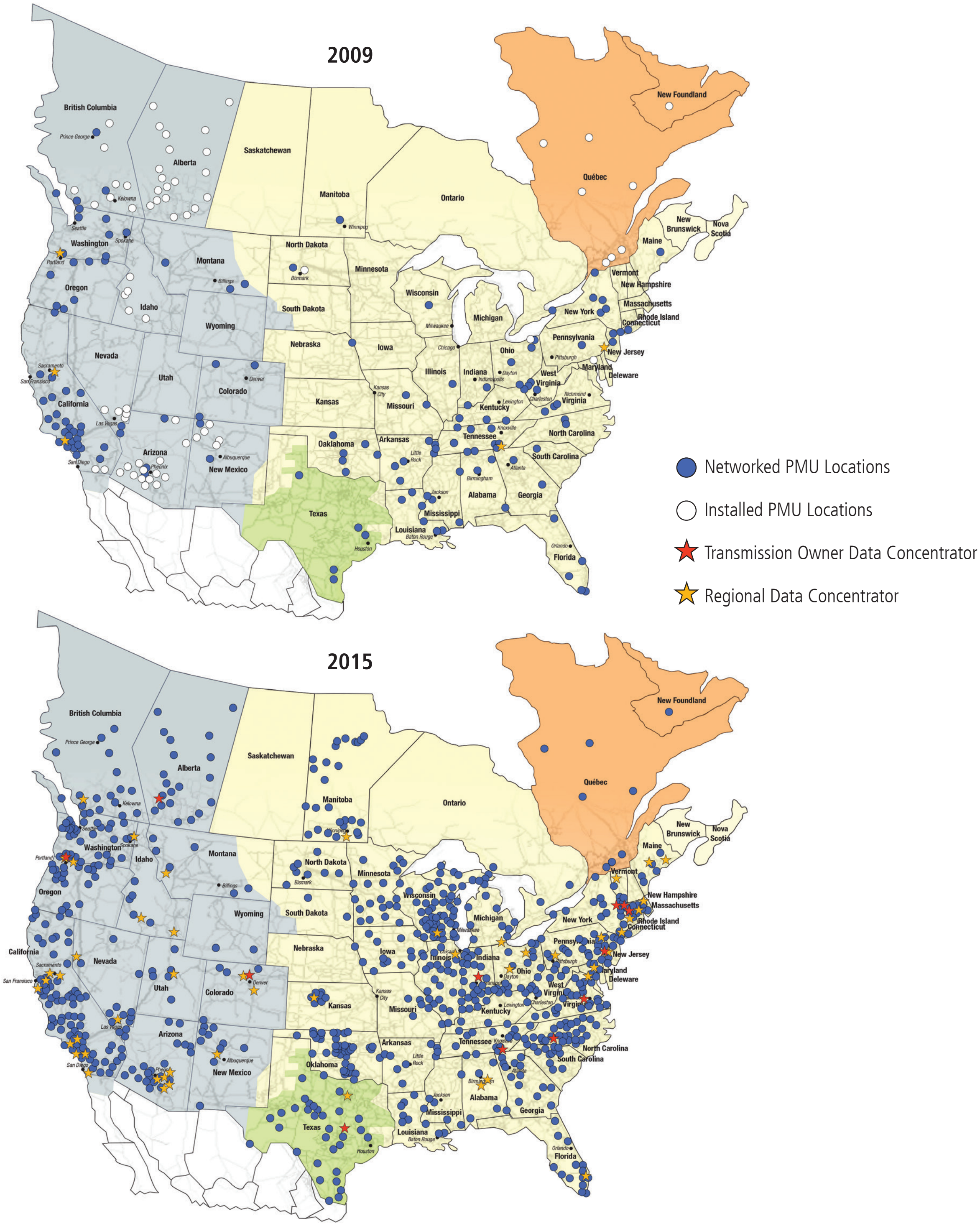
The installment and implementation of advanced meters and smart grid technology can make significant contributions to system resilience. Advanced smart grid systems can be used to expedite information flow; remotely monitor demand, performance, and quality of service; enhance system efficiency; and improve outage detection and restoration by identifying the location and description of damaged equipment. Real-time system monitoring can support hourly pricing and reactive power and/or DR programs, which allow utilities to make same-day operational decisions, near-term forecasts, and scenario evaluations. Historical data, coupled with predictive modeling of extreme weather events and the related effects on electric infrastructure, can also be used to inform management decisions, identify areas of greatest risk, ascertain system vulnerabilities, allocate resources, and help prioritize investments.

Still, system managers need better real-time information about system trends and changes, including the growth in VER, the rise of the "prosumer," two-way electricity and information flows, and real-time load management data—which means that demands on and expectations of SCADA systems are only increasing. Grid modernization requires changes in operational systems and processes, and in the way that system planners design for grid evolution. Critical to smart grid realization is systems engineering to determine the requirements for ICT infrastructure, which includes how latency factors (communications delays) and bandwidth requirements are embedded in operations to accommodate the proliferation of intelligent assets from relays to whole substations to automated customer DR controls that grid operators can access and use.

Fortunately, as the complexity of the electricity system increases, so do computer- and network-based capabilities. The growing electricity-ICT interdependence is enabled in part by new technologies, such as sensors and software that can provide greater situational awareness of grid conditions and operational efficiencies (although much more work is needed).[177] Large volumes of data are, however, unwieldy, and developing additional ways to translate data into usable and timely information is essential. Networks are evolving to include cloud computing and IoT technologies to help reduce costs, increase efficiencies, and increase system integration.[178, 179] Smart meters, synchrophasors, and other devices have also been deployed across the grid. Even electromechanical devices, like voltage regulators, are adopting digital control interfaces.

On transmission networks, SCADA systems traditionally have been used to monitor and control power systems by measuring grid conditions every 2 to 4 seconds. Synchrophasor technology, which addresses the lack of situational awareness provided by conventional instrumentation, uses high-resolution phasor measurement units (PMUs) that provide time-synchronized data at a rate of more than 30 times per second to detect destabilizing network oscillations that would otherwise be undetectable. Strategically located PMUs connected by high-speed communications networks provide grid operators with wide-area visibility to better detect system disturbances, improve the grid's efficiency, and prevent or more quickly recover from outages. In 2009, there were 166 PMUs in the United States—there are now over 1,700 PMUs located around the country (Figure 4-14).[180] The impact of this deployment is that it now takes 16 milliseconds for PMUs in the Western Interconnect to send signals over a dedicated fiber-optic system to transmission operators in control centers throughout the system—a system that covers western North America from Mexico to western Canada, from east of the Rockies to the Pacific Ocean.

Figure 4-14. Phasor Measurement Units, Technologies That Enable Superfast Network Management across Large Interconnected Systems, Are Being Deployed to Improve Grid Operations.[181]



Note the concentration of phasor measurement units (PMUs) in regions and interconnected systems where ISOs and RTOs dominate transmission service. PMU deployment can be interpreted as a first mover in the development of smart grids and as evidence that upstream transmission systems are advancing more consistently and at a faster pace toward smart grid realization than local distribution systems, although recent rate cases and public utility budgets for larger investor-owned utilities and public power indicate that smart grid investments are beginning to ramp up quickly. However, it should not be assumed that PMU deployment at the distribution level will mirror that at the transmission level because distribution smart grid deployment is much more complex in scale and scope. Note that the Western Interconnect is in gray.

The electricity sector has also been relying on a variety of redundant communications networks for operations since its inception. Internet Protocol-based communications (networking) systems—whether fiber-optic, radio, or other means for conveying data—can be owned by utilities or provided by telecommunication firms. Utilities have invested heavily in these ICT networks over the last decade, in part spurred by funding Congress provided through ARRA. Roughly one-third of customers are connected to the distribution grid by the 60 million smart meters that serve as an essential building block to grid digitization.[182, 183] Smart meters send data to utility control systems every 15–60 minutes through communications networks and can provide information back to customers in real time, often through the Internet. These meters enable remote meter reading, connections, and disconnections, and they allow for improved outage management and restoration. During Superstorm Sandy, smart meters reduced PECO Energy's restoration time by 2–3 days. Florida Power and Light has developed a tablet-based application for its field crews using AMI and geographic information systems data to improve emergency response; this was recently used to increase the speed of power recovery after Hurricane Matthew. Smart meters have an additional benefit—they give customers price information that enables them to respond to market conditions and reduce their electricity bills.

States and RTOs/ISOs will continue in their traditional regulatory roles as the system evolves. Given the increasing technical sophistication of grid operations, state regulatory staff may need additional support from the Federal Government in evaluating technical proposals from utilities as they seek to modernize their grids. Of concern are grid security standards across distribution delivery services. Proactive planning should be considered, as well as emergency response. The impetus to invest in mitigation and preparedness may only occur following a catastrophe, but proactive investments can prevent catastrophe and ultimately benefit ratepayers in the long term. However, distribution utilities face various challenges to implementing cybersecurity measures, including outdated legacy equipment, budgetary constraints, workforce readiness, and technology availability. Recent electricity response exercises demonstrate the nascent status of coordinated industry and government efforts to jointly respond to potential cyber incidents. The electricity industry has a long history of employing mutual assistance agreements to recover from most disruptions, and the Nation would benefit from the development of appropriate mechanisms for addressing cybersecurity disruptions.

Underinvestment in Research, Development, Demonstration, and Deployment, and Implications for System Resilience

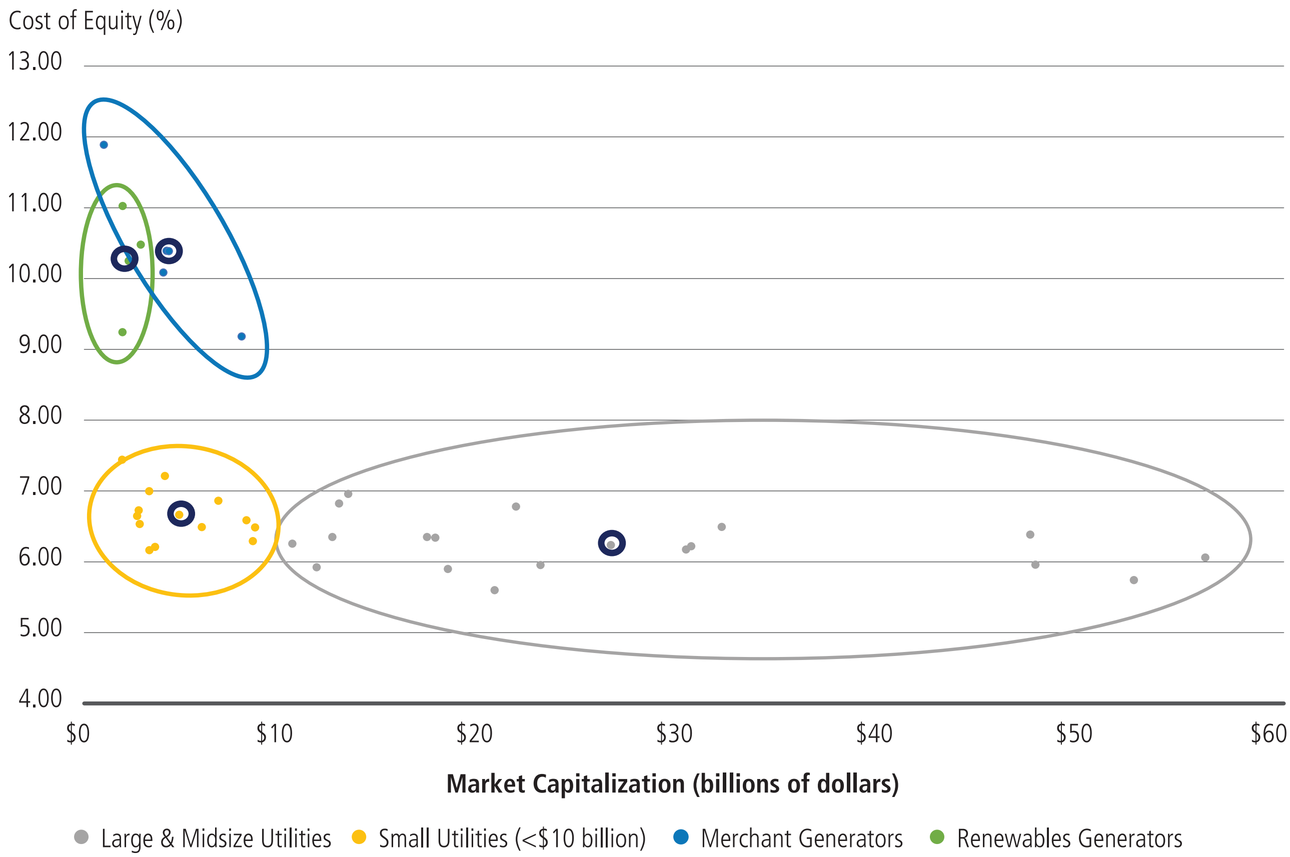
This chapter has emphasized the importance of resilience to overall grid reliability. From an investment perspective, high grid reliability is a key factor in the treatment by investors of utilities (both public and private) as low-risk investments with predictable returns. Analysis suggests that in an increasingly complex grid management environment, more focused investments are needed to ensure continued high system reliability and resilience. Future investments must focus on innovations that help mitigate new sources of system disruption, including VER, extreme weather, and physical and cyber attacks; these investments must occur in an environment that does not necessarily favor increased utility funds being used for research, development, demonstration, and deployment (RDD&D).

Despite existing RDD&D funding and activity in the electricity sector, there is systemic underinvestment in RDD&D of technologies, as described in Chapter III (*Building a Clean Electricity Future*). Also, private industry serving the electricity sector lacks incentives for investments in infrastructure resilience, in part, due to uncertainties in emerging risks.[184] Utilities acquiring resilience assets and solutions face rate proceedings that have an inherently conservative perspective on new technologies and approaches, which limits the ability to test new approaches in a timely manner and move to deploy successful efforts at an accelerated pace compared to traditional electricity sector norms. The lack of incentives, and preference for existing methods, constrains the innovation options that are pursued and tested, then enter the innovation process supply chain. These characteristics drive the need for additional Federal RDD&D opportunities to improve the resilience of electricity systems, as well as system security, rapid response, and recovery from disruptions.

Entities that operate distribution systems—the grid components most critical to reliability, security, and resilience—operate almost universally on a cost-of-service basis. The combination of stable revenues and low operational risk enables these entities—investor-owned utilities, Munis, Coops, and other entities—to acquire capital at lower rates (Figure 4-15). Investors view these entities as relatively low-risk investments compared with other electricity sector opportunities that face more competitive pressures.

As the operational characteristics of the industry evolve, traditional utility returns may not be compelling for investors, if sector transformations cause utilities to take on more or different types of risks. New types of regulatory structures may be needed to provide appropriate incentives to plan for an increasingly uncertain and more complex risk environment, as well as incorporate new approaches and technologies, which enable the kind of resilience investments that may be needed but not otherwise funded.

Figure 4-15. Cost of Equity by Company Type and Size for Sampled Power Sector Companies[185]



Regulated utilities, with their predictable revenues and low risks, tend to be viewed as safe investments, exhibiting a low cost of equity compared to the rest of the sector. As the industry addresses increasing risks and uncertainties, existing regulatory structures may evolve to meet risk appetite.

Planning Is Essential for System Reliability and Resilience

The responsibility for maintaining and improving grid reliability and resilience resides with a complex mix of entities with overlapping and sometimes inadequate jurisdictional responsibilities, which include Federal and state agencies and regulatory bodies, regional and national reliability organizations, and multiple utilities with various business models.

There are many existing planning platforms for reliability planning that are well understood by utilities, stakeholders, and other responsible entities. New, value-added planning contributions can help grid operators make tradeoffs among multiple investment options, strengthen the system, and help ensure resilience and reliability, which are needed for transforming a dramatically changing electricity system. Rigorous tradeoff analysis implies and includes rigorous risk analysis. Planning elements that should be added to existing platforms to accommodate system changes, challenges, threats, and opportunities include the following:

- Regional integrated resource planning that includes both T&D
- Integration of end-to-end options for optimal resource mix and operational integrity into existing planning
- Analyses with proposals for how to mitigate vulnerabilities.

In many parts of the country, investor-owned utilities conduct integrated resource planning in accordance with state requirements that were established through legislation or regulatory actions. While more than half of states in the Nation have integrated resource planning requirements, other states have adopted "Long-Term Procurement Planning" or other similar processes.[186, 187] Only a small number of distribution utilities conduct planning[188] in response to state policies,[189] aiming to increase resilience to extreme weather events or stressful system conditions. Also, with few exceptions, very few utilities take emerging threats from climate[190, 191] or cyber attacks into consideration when conducting integrated resource planning and distribution planning.[192]

In most cases, cybersecurity efforts are often funded out of the overall rate base. This means that funding for cybersecurity comes at the expense of profit or other investment needs, which may have a disproportionate budgetary impact on smaller distribution utilities. In rarer cases, distribution utilities have a separate security recovery factor in their rate structure.

Integrated Planning Considerations

The changing role of the consumer that drives the transformation of distribution also drives a need for new distribution planning approaches and tools to effectively integrate DER into the grid and to understand the benefits and costs for developing forward-looking investment plans. New solutions like smart inverters bring important issues to center stage, like whether such solutions can be fully valued prior to deployment. Because consumer preferences and needs are changing faster than the pace of grid planning, there may be misalignment of operating circumstances. Whatever investments are planned are likely to require revisions as actual events diverge from said plans. Continued and rapid changes on the customer side of the meter may require adjustments in regulatory processes to assist grid owners and operators in keeping systems up to date.

Methods are under development in leading states (e.g., California and New York) to incorporate DER and the growing role of "prosumers"—consumers that produce power for the grid—and third parties into the distribution system planning processes. Important considerations for the development of such methods should include hosting capacity of distribution feeders for DER and probabilistic DER growth scenarios, as well as balance utility investments in system upgrades versus the services provided by DER (e.g., in energy supply, supply/load balancing, storage, and support of both frequency and voltage regulation). These planning processes will need sufficient transparency to permit all stakeholders, including DER service providers, to participate in supporting long-term capacity and energy requirements. Contractual provisions between utilities and DER service providers will need to be established to ensure grid reliability and security, which might benefit from the development of standard offer DER contracts. As capacity and energy are increasingly being delivered at the distribution system level, distribution- and transmission-level planning will need to be integrated.

Integrated Probabilistic Planning as an Emerging Tool

Typically, reliability decisions are based on a deterministic, binary decision—a new facility is approved if it resolves a violation of a reliability standard. In contrast, economic decisions are based on a scenario framework, where the expected value of a facility is evaluated across a range of likely scenarios. The changing system topology, uncertain regulatory frameworks, decentralized market decisions, and evolving vulnerabilities introduce economic and reliability uncertainties and risks that cannot be adequately assessed through a deterministic framework.

Probabilistic risk assessment (PRA) methodologies offer a framework to consider underlying uncertainties and risks. PRA methods in transmission planning are still at a research stage and are not implemented widely. Currently, PRA is used to model topological changes, such as variations in renewable generation levels; variations in load level due to weather and DER output; generation and transmission equipment performance; variations in hydro-generation; and physical threats like weather.[193] However, considerable barriers to implementation of PRA approaches in transmission planning include the following:

Tradition of planning for worst-case scenarios using a deterministic approach

- Lack of industry-wide accepted approach for reliability indices in PRA framework
- Lack of standardization and availability of historic reliability data
- Lack of qualified workforce, skillset, and awareness of PRA approaches
- Lack of modeling tools for implementing PRA methodologies
- Lack of commercial tools for system security assessment under PRA framework.[194]

The Grid of the 21st Century

The electricity sector's long history is one of managing continuous, albeit slow, change while sustaining the same high reliability year in and year out. The stock of the sector is incrementally refreshed as needed, but changes highlighted in this chapter and other chapters of QER 1.2 call attention to several factors that place new emphasis on the sector's effort to sustain high reliability, security, and resilience.

A transformed 21st-century grid is likely to be one that invests more in flexibility and resilience to achieve the same desired outcome that is the prime directive of grid operators—sustained, high-service reliability. How the grid is managed depends on the capabilities built into the stock of assets that make up the end-to-end supply chain, but managing real-time operational flows also requires specific systems and processes to continuously succeed. The complexity of grid operations requires grid control tools that enable granular visibility and certain operational algorithms that help grid operators stay on top of second-to-second and millisecond-to-millisecond changes. The era of enhanced grid operations through artificial intelligence is here. Execution, however, must occur in a context that assiduously assures deflection of cyber attacks that could cripple grids; it must also occur through market mechanisms to help value and ensure cost-effective outcomes.

State and Federal regulatory bodies and policymakers play key roles in helping ensure system integrity, safety, and the ongoing financing of the electricity sector. Planning, which is central to ensuring long-term stock and flow integrity, must evolve as the sector itself evolves. More robust modeling, improved risk analysis, and better optimization realization at the two-way interface of information and energy flows between consumers and grid operators are important improvements that are likely to be significant contributors to enabling a transformation that ensure today's service reliability and quality can continue, if not improve.

This is the state of sector grid management as the Nation continues its march deeper into the 21st century. The scope of transformation required to adapt to new security concerns, coupled with the organic evolution of a sector that is qualitatively changing as consumers have more direct and indirect influence on grid reliability, are non-trivial costs that must be financed and paid for. There are many ways to facilitate transformation and assist grid operators and other stakeholders in the sector in adapting to the sector's changing physical and cyber "topography." The recommendations based on the analysis in this chapter are covered in Chapter VII (*A 21st-Century Electricity System: Conclusions and Recommendations*).

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