Enhancing the Resilience of the Nation's Electricity System

DETAILS

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Enhancing the Resilience of the Nation's Electricity System

Committee on Enhancing the Resilience of the Nation's Electric Power Transmission and Distribution System

Board on Energy and Environmental Systems

Division on Engineering and Physical Sciences

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NOTE: See Appendix C, Disclosure of Conflicts of Interest.

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Preface

Electricity and the underlying infrastructure for its production, transmission, and distribution are essential to the health and prosperity of all Americans. It is important to make investments that increase the reliability of the power system within reasonable cost constraints. However, the system is complex and vulnerable. Despite all best efforts, it is impossible to avoid occasional, potentially large outages caused by natural disasters or pernicious physical or cyber attacks. This report focuses on large-area, long-duration outages—considered herein as outages that span several service areas or even states and last upward of 3 days. When such major electricity outages do occur, economic costs can tally in the billions of dollars and lives can be lost. Hence, there is a critical need to increase the resilience of the U.S. electric power transmission and distribution system—so that major outages are less frequent, their impacts on society are reduced, and recovery is more rapid—and to learn from these experiences so that performance in the future is better.

The many high-profile electric-service interruptions that have occurred over the last two decades, along with recent efforts to enhance the capabilities of the nation's electricity delivery system, prompted several observers to seek an independent review of the vulnerability and resilience of the nation's electricity delivery system. In its 2014 appropriations for the Department of Energy (DOE), Congress called for an independent assessment to "conduct a national-level comprehensive study on the future resilience and reliability of the nation's electric power transmission and distribution system. At a minimum, the report should include technological options for strengthening the capabilities of the nation's power grid; a review of federal, state, industry, and academic research and development programs; and an evaluation of cybersecurity for energy delivery systems."[1]

The National Academies of Sciences, Engineering, and Medicine established the Committee on Enhancing the Resilience of the Nation's Electric Power Transmission and Distribution System to conduct the study. On the basis of this mandate, the National Academies asked the committee to address

[1] H.R. 113-486, page 103.

technical, policy, and institutional factors that might affect how modern technology can be implemented to improve the resilience of the electric system; recommend strategies and priorities for how this might be achieved; and identify barriers to its implementation. The full statement of task for the committee is shown in Appendix A. The biographies of the committee members that authored this report are contained in Appendix B.

Committee members included academicians, retirees from industry, current or former employees of state government agencies, and representatives of other organizations. They brought considerable expertise on the operation and regulation of electric power networks, security, and energy economics. The committee met six times in 2016 and 2017 to gather information from public sources (listed in Appendix D) and to discuss the key issues. It also held several conference calls.

The committee operated under the auspices of the National Academies of Sciences, Engineering, and Medicine's Board on Energy and Environmental Systems and is grateful for the able assistance of K. John Holmes, Elizabeth Euller, Jordan Hoyt, Janki U. Patel, Ben A. Wender, E. Jonathan Yanger, Linda Casola, and James Zucchetto of the National Academies' staff.

Acknowledgment of Reviewers

This Consensus Study Report was reviewed in draft form by individuals chosen for their diverse perspectives and technical expertise. The purpose of this independent review is to provide candid and critical comments that will assist the National Academies of Sciences, Engineering, and Medicine in making each published report as sound as possible and to ensure that it meets the institutional standards for quality, objectivity, evidence, and responsiveness to the study charge. The review comments and draft manuscript remain confidential to protect the integrity of the deliberative process.

We thank the following individuals for their review of this report:

Mr. William Ball, Southern Company Services, Inc.,
Mr. Joe Brannan, North Carolina Electric Membership Corporation,
Mr. Gary Connett, Great River Energy,
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Mr. Rich Sedano, Regulatory Assistance Project, and
Dr. Paul Stockton, Sonecon, LLC.

Although the reviewers listed above provided many constructive comments and suggestions, they were not asked to endorse the conclusions or recommendations of this report nor did they see the final draft before its release. The review of this report was overseen by Julia M. Phillips, NAE, Sandia National Laboratories (retired), and John G. Kassakian, NAE, Massachusetts Institute of Technology (retired). They were responsible for making certain that an independent examination of this report was carried out in accordance with the standards of the National Academies and that all review comments were carefully considered. Responsibility for the final content rests entirely with the authoring committee and the National Academies.

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Summary

Americans' safety, productivity, comfort, and convenience depend on the reliable supply of electric power. The electric power system is a complex "cyber-physical" system composed of a network of millions of components spread out across the continent. These components are owned, operated, and regulated by thousands of different entities. Power system operators work hard to assure safe and reliable service, but large outages occasionally happen. Given the nature of the system, there is simply no way that outages can be completely avoided, no matter how much time and money is devoted to such an effort. The system's reliability and resilience can be improved but never made perfect. Thus, system owners, operators, and regulators must prioritize their investments based on potential benefits. Most interruptions result from physical damage in a local part of the distribution system caused by weather, accidents, or aging equipment that fails. Less frequently, major storms and other natural phenomena, operations errors, and pernicious human actions can cause outages on the bulk power system (i.e., generators and high-voltage power lines) as well as on distribution systems.

RESILIENCE IS BROADER THAN RELIABILITY

This report of the Committee on Enhancing the Resilience of the Nation's Electric Power Transmission and Distribution System focuses on identifying, developing, and implementing strategies to increase the power system's *resilience* in the face of events that can cause large-area, long-duration outages: blackouts that extend over multiple service areas and last several days or longer. Resilience is not just about lessening the likelihood that these outages will occur. It is also about limiting the scope and impact of outages when they do occur, restoring power rapidly afterwards, and learning from these experiences to better deal with events in the future.

The power system has been undergoing dramatic changes in technology and governance. In some parts of the United States, power is still supplied by regulated, vertically integrated utilities that generate electricity in large power plants, move that power out over high-voltage transmission systems, and distribute it to end-use customers—all under that single utility's control. In other parts of the country, electric utilities have been restructured to promote competitive markets, particularly in wholesale power sales between generators and electricity distribution companies. In the more market-oriented parts of the country, high-voltage transmission lines that connect wholesale buyers and sellers are regulated or publicly owned, as are most distribution systems that provide the poles, wires, and equipment to serve retail customers. However, the flows over those wires and customers' responses are increasingly determined by market forces. Efforts to improve resilience must accommodate institutional and policy heterogeneity across the country.

There has been significant growth in instrumentation and automation at the level of the high-voltage, or bulk, power system. This allows the system to operate more efficiently and provides system operators with much better situational awareness; this can improve grid reliability and resilience in the face of outages, but this added complexity can also introduce cybersecurity vulnerabilities. Analogous technological advancements on distribution systems (i.e., "smart grids")—including improved sensing, communication, automation technologies, and advanced metering infrastructure—are occurring piecemeal across the country.

In some states, such as Hawaii and California, distributed energy resources, including distributed generation, demand response, energy efficiency, customer-owned storage, microgrids, and electric vehicles, are a rapidly growing fraction of the overall resource mix that must be planned and managed to maintain grid reliability, resilience, and security. However, despite these developments, for at least the next two decades, most U.S. customers will continue to depend on the functioning of the large-scale, interconnected, tightly organized, and hierarchically structured electric grid.

Strategies to enhance electric power resilience must accommodate both a diverse set of technical and institutional arrangements and a wide variety of hazards. There is no "one-size-fits-all" solution to avoiding, planning for, coping with, and recovering from major outages.

FRAMEWORK AND ORGANIZATION

Chapter 1 provides a brief introduction to the electricity system and motivation for this report. Chapter 2 summarizes the present state of the electricity system and the various ways it may evolve in the future, as well as metrics used to monitor grid reliability and resilience. Chapter 3 identifies, discusses, and compares a range of natural hazards and accidental and pernicious human actions that could cause major disruptions in service. Many of these, listed in Box S.1, have caused outages or impacted electricity system functions at varying scales over the last 30 years, either in the United States or globally. Others hold the potential to become major causes of disruption in the future.

BOX S.1
Causes of Most Electricity System Outages (shown in alphabetical order and reviewed in Chapter 3)

Cyber attacks	Hurricanes	Space weather and other electromagnetic threats
Drought and water shortage	Ice storms	Tsunamis
Earthquakes	Major operations errors	Volcanic events
Floods and storm surge	Physical attacks	Wildfires
	Regional storms and tornadoes	

Building a strategy to increase system resilience requires an understanding of a wide range of preparatory, preventative, and remedial actions, as well as how these impact planning, operation, and restoration over the entire life cycle of different kinds of grid failures. Strategies must be crafted with awareness and understanding of the temporal arc of a major outage, as well as how the needs differ from one type of event to another. It is also important to differentiate between actions designed to make the grid more robust and resilient to failure (e.g., wind-resistant steel or concrete poles rather than wood poles) and those that improve the effectiveness of recovery (e.g., preemptively powering down some pieces of the system to minimize damage). Some actions serve both strategies, some serve one but not the other, and some serve one while inhibiting the other. Similarly, the timing of repairs is different depending on the cause. For example, repairs can begin immediately after a tornado has passed, but flooding following a hurricane can delay the start of repair and impede repair efforts. Good planning and preparation are essential to mitigating, coping with, and recovering from major outages. Both human and technical systems must be designed before grid failure so the responders can assess the extent of failure and damage, dispatch resources effectively, and draw on established component inventories, supply chains, crews, and communication channels.

Anticipating and Preparing for Disruption

While the possibility of large-area, long-duration blackouts cannot be totally eliminated, there is much that can be done to decrease their likelihood and reduce their magnitude, should they occur. Chapter 4 assesses a variety of techniques that can be employed before an event occurs in order to enhance system resilience. These include improving the health and reliability of the individual grid components (e.g., through asset health monitoring and preventive- and reliability-centered maintenance), improving system architectures to further reduce the criticality of individual components, better simulating high-impact events, and considering the criticality of the grid's underlying cyber infrastructure. Further work can be done in the area of real-time operations to enhance resilience. This includes improving situational awareness in the control room, with a focus on severe events and an inclusion of the cyber infrastructure, adding more wide-area monitoring and control, and developing control systems that better tolerate both accidental faults and malicious attacks. Finally, there is a need to deal with myriad regulatory entities and incentives to fund resilience investments.

Mitigating the Impacts of Disruption

While large failures of the bulk power system are rare, some will occur, and restoration can take a long time. It is essential that society prepare for periods of prolonged outage, because many vital public infrastructures—such as heating and cooling, water and sewage pumping, traffic control, financial systems, and many aspects of emergency response and public security—depend on the electric power supply. These issues are explored in Chapter 5. The effects of power outages vary with weather, for different types and locations of users, and over different durations. A central theme of this report is the need to improve how different elements of society perform the difficult task of imagining the diverse consequences of prolonged power outages. Also important is to ensure that equipment that has been purchased or contracted for backup power supply will be available and reliable when needed.

Recovering from and Learning after Disruption

After the bulk power system has failed, first responders, utilities, and public agencies must work together to restore service. Recovery involves coordinated activity on the physical side—for example, repairing, replacing, and reconfiguring the hardware of the grid—as well as a variety of activities to rebuild the cyber and industrial control systems. These issues are the focus of Chapter 6. Effective restoration must begin well before the disaster through numerous preparatory activities, including drills and stockpiling of key equipment. Utilities and other electric service personnel must think about how they will assess damage, plan restoration, and marshal and deploy the necessary resources. This is complicated by the fact that restoration processes are starkly different depending on the nature of the event. The keys to restoration are to envision a broad range of threats, work through failure scenarios, plan, and rehearse. Regardless of the cause of the outage, restoration always involves agility, collaboration and communications across multiple institutions, and an understanding of the state of the grid and its supporting systems. Technical readiness is the ultimate determinant of the ability to restore, but technical readiness rests firmly on organizational readiness. A process of continual learning and improvement, informed by detailed incident investigations following large outages, is essential for enhancing the resilience of the grid.

OVERARCHING INSIGHTS AND RECOMMENDATIONS

No single entity is responsible for, or has the authority to implement, a comprehensive approach to assure the resilience of the nation's electricity system. Because most parties are preoccupied dealing with short-term issues, they neither have the time to think systematically about what could happen in the event of a large-area, long-duration blackout, nor do they adequately consider the consequences of large-area, long-duration blackouts in their operational and other planning or in setting research and development priorities. Hence the United States needs a process to help all parties better envision the consequences of low-probability but high-impact events precipitated by the causes outlined in Chapter 3 and the system-wide effects discussed in Chapter 5. The specific recommendations addressed to particular parties that are provided throughout the report (especially in Chapters 4 through 6) will incrementally advance the cause of resilience. However, these alone will be insufficient unless the nation is able to adopt a more integrated perspective at the same time. Hence, in addition to the report's *specific* recommendations, the committee provides a series of overarching recommendations.

One of the best ways to make sure that things already in place will work when they are needed is to conduct drills with other critical infrastructure operators through large-scale, multisector exercises. Such exercises can help illuminate areas where improvements in processes and technologies can substantively enhance the resilience of the nation's critical infrastructure.

Overarching Recommendation 1: Operators of the electricity system, including regional transmission organizations, investor-owned utilities, cooperatives, and municipally owned utilities, should work individually and collectively, in cooperation with the Electricity Subsector Coordinating Council, regional and state agencies, the Federal Energy Regulatory Commission, and the North American Electric Reliability Corporation, to conduct more regional emergency preparedness exercises that simulate accidental failures, physical and cyber attacks, and other impairments that result in large-scale loss of power and/or other critical infrastructure sectors—especially communication, water, and natural gas. Counterparts from other critical infrastructure sections should be involved, as well as state, local, and regional emergency management offices.

The challenges that remain to achieving grid resilience are so great that they cannot be achieved by research- or operations-related activities alone. While new technologies and strategies can improve the resilience of the power system, many existing technologies that show promise have yet to be fully adopted or implemented. In addition, more coordination between research and implementation activities is needed, building on the specific recommendations made throughout this report. Immediate action is needed both to implement available technological and operational changes and to continue to support the development of new technologies and strategies.

> **Overarching Recommendation 2:** Operators of the electricity system, including regional transmission organizations, investor-owned utilities, cooperatives, and municipals, should work individually and collectively to more rapidly implement resilience-enhancing technical capabilities and operational strategies that are available today and to speed the adoption of new capabilities and strategies as they become available.

The Department of Energy (DOE) is the federal entity with a mission to focus on the *longer-term* issues of developing and promulgating technologies and strategies to increase the resilience and modernization of the electric grid.[1] No other entity in the United States has the mission to support such work, which is critical as the electricity system goes through the transformational changes described in this report. The committee views research, development, and demonstration activities that support reliable and resilient electricity systems to constitute a public good. If funding is not provided by the federal government, the committee is concerned that this gap would not be filled either by states or by the private sector. In part this is because the challenges and solutions to ensuring grid resilience are complex, span state and even national boundaries, and occur on time scales that do not align with business models. At present, two offices within DOE have responsibility for issues directly and indirectly related to grid modernization and resilience.

> **Overarching Recommendation 3:** However the Department of Energy chooses to organize its programs going forward, Congress and the Department of Energy leadership should sustain and expand the substantive areas of research, development, and demonstration that are now being undertaken by the Department of Energy's Office of Electricity Delivery and Energy Reliability and Office of Energy Efficiency and Renewable Energy, with respect to grid modernization and systems integration, with the explicit intention of improving the resilience of the U.S. power grid. Field demonstrations of physical and cyber improvements that could subsequently lead to widespread deployment are critically important. The Department of Energy should collaborate with parties in the private sector and in states and localities to jointly plan for and support such

[1] The Department of Homeland Security, the Federal Energy Regulatory Commission, and other organizations also provide critical support and have primacy in certain areas.

demonstrations. Department of Energy efforts should include engagement with key stakeholders in emergency response to build and disseminate best practices across the industry.

The U.S. grid remains vulnerable to natural disasters, physical and cyber attacks, and other accidental failures.

Overarching Recommendation 4: Through public and private means, the United States should substantially increase the resources committed to the physical components needed to ensure that critical electric infrastructure is robust and that society is able to cope when the grid fails. Some of this investment should focus on making the existing infrastructure more resilient and easier to repair, as follows:

- The Department of Energy should launch a program to manufacture and deploy flexible and transportable three-phase recovery transformer sets that can be pre-positioned around the country.[2] These recovery transformers should be easy to install and use temporarily until conventional transformer replacements are available. This effort should produce sufficient numbers (on the order of tens compared to the three produced by the Department of Homeland Security's RecX program) to provide some practical protection in the case of an event that results in the loss of a number of high-voltage transformers. This effort should complement, instead of replace, ongoing initiatives related to spare transformers.
- State and federal regulatory commissions and regional transmission organizations should then evaluate whether grids under their supervision need additional pre-positioned replacements for critical assets that can help accelerate orderly restoration of grid service after failure.
- Public and private parties should expand efforts to improve their ability to maintain and restore critical services—such as power for hospitals, first responders, water supply and sewage systems, and communication systems.[3]
- The Department of Energy, the Department of Homeland Security, the Electricity Subsector Coordinating Council, and other federal organizations, such as the U.S. Army Corps of Engineers, should oversee the development of more reliable inventories of backup power needs and capabilities (e.g., the U.S. Army Corps of Engineers' mobile generator fleet), including fuel supplies. They should also "stress test" existing supply contracts for equipment and fuel supply that are widely used in place of actual physical assets in order to be certain these arrangements will function in times of major extended outages. Although the federal government cannot provide backup power equipment to everyone affected by a large-scale outage, these resources could make significant contributions at select critical loads.

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[2] As noted in Chapters 6 and 7, the Department of Energy's Office of Electricity Delivery and Energy Reliability is supporting the development of a new generation of high-voltage transformers that will use power electronics to adjust their electrical properties and hence can be deployed in a wider range of settings. The committee's recommendation to manufacture recovery transformers is not intended to replace that longer-term effort. However, the Department of Energy's new advanced transformer designs will not be available for some time; in the meantime, the system remains physically vulnerable. While in Chapter 6 the committee notes several government and industry-led transformer sharing and recovery programs, it recognizes that high-voltage transformers represent one of the grid's most vulnerable components deserving of further efforts.

[3] In addition to treatment, sewage systems often need to pump uphill. A loss of power can quickly lead to sewage backups. Notably, a high percentage of the hospital backup generators in New York City failed during Superstorm Sandy.

In addition to providing redundancy of critical assets, transmission and distribution system resilience demands the ability to provide rapid response to events that impair the ability of the power system to perform its function. These events include deliberate attacks on and accidental failures of the infrastructure itself, as well as other causes of grid failure, which are discussed in Chapter 3.

Overarching Recommendation 5: The Department of Energy, together with the Department of Homeland Security, academic research teams, the national laboratories, and companies in the private sector, should carry out a program of research, development, and demonstration activities to improve the security and resilience of cyber monitoring and controls systems, including the following:

- Continuous collection of diverse (cyber and physical) sensor data;
- Fusion of sensor data with other intelligence information to diagnose the cause of the impairment (cyber or physical);
- Visualization techniques needed to allow operators and engineers to maintain situational awareness;
- Analytics (including machine learning, data mining, game theory, and other artificial intelligence-based techniques) to generate real-time recommendations for actions that should be taken in response to the diagnosed attacks, failures, or other impairments;
- Restoration of control system and power delivery functionality and cyber and physical operational data in response to the impairment; and
- Creation of post-event tools for detection, analysis, and restoration to complement event prevention tools.

Because no single entity is in charge of planning the evolution of the grid, there is a risk that society may not adequately anticipate and address many elements of grid reliability and resilience and that the risks of this system-wide failure in preparedness will grow as the structure of the power industry becomes more atomized and complex. There are many opportunities for federal leadership in anticipating potential system vulnerabilities at a national level, but national solutions are then refined in light of local and regional circumstances. Doing this requires a multistep process, the first of which is to anticipate the myriad ways in which the system might be disrupted and the many social, economic, and other consequences of such disruptions. The second is to envision the range of technological and organizational innovations that are affecting the industry (e.g., distributed generation and storage) and how such developments may affect the system's reliability and resilience. The third is to figure out what upgrades should be made and how to cover their costs. For simplicity, the committee will refer to this as a "visioning process." While the Department of Homeland Security (DHS) has overarching responsibility for infrastructure protection, DOE, as the sector-specific agency for energy infrastructure, has a legal mandate and the deep technical expertise to work on such issues.

Overarching Recommendation 6: The Department of Energy and the Department of Homeland Security should jointly establish and support a "visioning" process with the objective of systematically imagining and assessing plausible large-area, long-duration grid disruptions that could have major economic, social, and other adverse consequences, focusing on those that could have impacts related to U.S. dependence on vital public infrastructures and services provided by the grid.

Because it is inherently difficult to imagine systematically things that have not happened (Fischhoff et al., 1978; Kahneman, 2011), exercises in envisioning benefit from having multiple groups perform such work independently. For example, such a visioning process might be accomplished through the creation of two small national power system resilience assessment groups (possibly at DOE national laboratories and/or other federally funded research and development centers or research universities). However such visioning is accomplished, engagement from staff representing relevant state and federal agencies is essential in helping to frame and inform the work. These efforts can build on the detailed recommendations in this report to identify technical and organizational strategies that increase electricity system resilience in numerous threat scenarios and to assess the costs and financing mechanisms to implement the proposed strategies. Attention is needed not just to the average economy-wide costs and benefits, but also to the distribution of these across different levels of income and vulnerability. It is important that these teams work to identify common elements in terms of hazards and solutions so as to move past a hazard-by-hazard approach to a more systems-oriented strategy. Producing useful insights from this process will require mechanisms to help these groups identify areas of overlap while also characterizing the areas of disagreement. A consensus view could be much less helpful than a mapping of uncertainties that can help other actors—for example, state regulatory commissions and first responders—understand the areas of deeper unknowns.

Of course national laboratories, other federally funded research and development centers, and research universities do not operate or regulate the power system. At the national level, the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) both have relevant responsibilities and authorities.

Overarching Recommendation 7A: The Federal Energy Regulatory Commission and the North American Electric Reliability Corporation should establish small system resilience groups, informed by the work of the Department of Energy/Department of Homeland Security "visioning" process, to assess and, as needed, to mandate strategies designed to increase the resilience of the U.S. bulk electricity system. By focusing on the crosscutting impacts of hazards on interdependent critical infrastructures, one objective of these groups would be to complement and enhance existing efforts across relevant organizations.

As the discussions throughout this report make clear, many different organizations are involved in planning, operating, and regulating the grid at the local and regional levels. By design and of necessity in our constitutional democracy, making decisions about resilience is an inherently political process. Ultimately the choice of how much resilience our society should and will buy must be a collective social judgment. It is unrealistic to expect firms to make investments voluntarily whose benefits may not accrue to shareholders within the relevant commercial lifetime for evaluating projects. Moreover, much of the benefit from avoiding such events, should they occur, will not accrue to the individual firms that invest in these capabilities. Rather, the benefits are diffused more broadly across multiple industries and society as a whole, and many of the decisions must occur on a state-by-state basis.

Overarching Recommendation 7B: The National Association of Regulatory Utility Commissioners should work with the National Association of State Energy Officials to create a committee to provide guidance to state regulators on how best to respond to identified local and regional power system-related vulnerabilities. The work of this committee should be informed by the national "visioning" process, as well as by the work of other research organizations. The mission of this committee should be to develop guidance for, and provide technical and institutional support to, state commissions to help them to more systematically address broad issues of power system resilience, including decisions as to what upgrades are desirable and how to pay for them. Guidance developed through this process should be shared with appropriate representatives from the American Public Power Association and the National Rural Electric Cooperative Association.

Overarching Recommendation 7C: Each state public utility commission and state energy office, working with the National Association of Regulatory Utility Commissioners, the National Association of State Energy Officials, and state and regional grid operators and emergency preparedness organizations, should establish a standing capability to identify vulnerabilities, identify strategies to reduce local vulnerabilities, develop strategies to cover costs of needed upgrades, and help the public to become better prepared for extended outages. In addition, they should encourage local and regional governments to conduct assessments of their potential vulnerabilities in the event of large-area, long-duration blackouts and to develop strategies to improve their preparedness.

Throughout this report, the committee has laid out a wide range of actions that different parties might undertake to improve the resilience of the United States power system. If the approaches the committee has outlined can be implemented, they will represent a most valuable contribution. At the same time, the committee is aware that the benefits of such actions—avoiding large-scale harms that are rarely observed—are easily eclipsed by the more tangible daily challenges, pressures on budgets, public attention, and other scarce resources. Too often in the past, the United States has made progress on the issue of resilience by "muddling through" (Lindblom, 1959). Even if the broad systematic approach outlined in this report cannot be fully implemented immediately, it is important that relevant organizations develop analogous strategies so that when a policy window opens in the aftermath of a major disruption, well-conceived solutions are readily available for implementation (Kingdon, 1984).

SPECIFIC RECOMMENDATIONS

The committee assessed potential threats to the grid, and the conditions on the grid, and provides findings and recommendations throughout the report. In Chapter 7, these specific recommendations are summarized and sorted in terms of the issues they address and the entities to which they are directed. The high-level descriptions of each are listed below. The specific actions that should be taken to implement each one are laid out in Chapter 7.

Recommendation 1 to DOE: Improve understanding of customer and societal value associated with increased resilience and review and operationalize metrics for resilience. (Recommendations 2.1 and 2.2)

Recommendation 2 to DOE: Support research, development, and demonstration activities to improve the resilience of power system operations and recovery by reducing barriers to adoption of innovative technologies and operational strategies. (Recommendations 4.1, 4.6, 6.5, and 6.7)

Recommendation 3 to DOE: Advance the safe and effective development of distributed energy resources and microgrids. (Recommendations 4.2, 5.6, 5.12, and 6.3)

Recommendation 4 to DOE: Work to improve the ability to use computers, software, and simulation to research, plan, and operate the power system to increase resilience. (Recommendations 4.3, 4.4, 4.8, 4.9, and 6.12)

Recommendation 5 to DOE: Work to improve the cybersecurity and cyber resilience of the grid. (Recommendations 4.10 and 6.8)

Recommendation 6 to the electric power sector and DOE: The owners and operators of electricity infrastructure should work closely with DOE in systematically reviewing previous outages and demonstrating technologies, operational arrangements, and exercises that increase the resilience of the grid. (Recommendations 4.5, 5.10, 6.2, 6.4, and 6.14)

Recommendation 7 to DHS and DOE: Work collaboratively to improve preparation for, emergency response to, and recovery from large-area, long-duration blackouts. (Recommendations 3.2, 5.3, 5.5, 6.1, 6.6, and 6.9)

Recommendation 8 to DHS and DOE: With growing awareness of the electricity system as a potential target for malicious attacks using both physical and cyber means, DHS and DOE should work closely with operating utilities and other relevant stakeholders to improve physical and cyber security and resilience. (Recommendations 3.1, 6.10, 6.11, and 6.13)

Recommendation 9 to state offices and regulators: Work with local utilities and relevant stakeholders to assess readiness of backup power systems and develop strategies to increase investments in resilience enhancing technologies. (Recommendations 5.1, 5.7, 5.9, and 5.11)

Recommendation 10 to the National Association of Regulatory Utility Commissioners and federal organizations: Work with DHS and DOE to develop guidance regarding potential social equity implications of resilience investments as well as selective restoration. (Recommendations 5.2, 5.4, and 5.8)

Recommendation 11 to FERC and the North American Energy Standards Board: FERC, which has regulatory authority over both natural gas and electricity systems, should address the growing risk of interdependent infrastructure. (Recommendation 4.7)

Recommendation 12 to NERC: Review and improve incident investigation processes to better learn from outages that happen and broadly disseminate findings and best practices. (Recommendation 6.15)

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1

Introduction and Motivation

THE NATION DEPENDS ON A RESILIENT ELECTRIC SYSTEM

The modern world runs on electricity. As individuals, we depend on electricity to heat, cool, and light our homes; refrigerate and prepare our food; pump and purify our water; handle sewage; and support most of our communications and entertainment. As a society, we depend on electricity to light our streets; control the flow of traffic on the roads, rails, and in the air; operate the myriad physical and information supply chains that create, produce, and distribute goods and services; maintain public safety, and help assure our national security.

The incredibly complex system that delivers electricity in the United States was built up gradually. It started with numerous small local systems in the early 1880s and grew to become three large independent synchronous systems[1] that together span the lower 48 United States, much of Canada, and some of Mexico, each of which is one of the largest integrated machines in the world. These interconnected grids have achieved significant gains in efficiency with increasing scale, as well as improved reliability owing to redundant paths over which electricity can flow. Today, power plants using fossil fuels, nuclear energy, and renewable resources supply these machines. They move power to consumers over hundreds of thousands of miles of high-voltage transmission lines and thousands more miles of local distribution lines.

While our society is becoming ever more dependent upon electricity, the electric system is undergoing a complex transformation that includes changing the mix of generation technologies; adding

[1] As explained in Chapter 2, the U.S. portions of these systems are divided into three interconnections: Eastern, Western, and Texas. Within each interconnection, 60 Hz power is synchronized across the entire system.

small-scale energy resources connected to the distribution system; incorporating generation and storage on customers' premises; and improving the capability to monitor and control electricity generation, flows, and uses.

While major pollution-control investments and activities have reduced the electric system's environmental impacts over the past century, these impacts remain a problem locally and globally. The need for environmental improvement will continue to be a major force shaping the power system for decades to come. Not only will the electric system continue to shift to a lower-carbon resource mix, but this lower-emission electricity will also be called upon to provide energy to activities, such as transportation and industrial processing, that currently operate on fossil fuels.

Our economy and lifestyles require that electricity be accessible, affordable, reliable, and continuously available. For that to happen, the grid[2] must perform at two levels: (1) The network of high-voltage power lines that spans the country must be able to move power from large generating plants out to local regions; and (2) Lower-voltage distribution systems must be able to move the power to, and occasionally from, factories, businesses, homes, and other end users. The grid must continue to perform these actions as it evolves to accommodate increasing numbers of distributed energy resources, which are often customer-owned, attached to local distribution systems, and have more "smart" technology—the ability to sense and interact with conditions on the grid and with customers' usage patterns and preferences. These many changes are introducing large shifts in the way the system operates. And these changes are occurring during a period of flat or declining growth in electricity generation (EIA, 2016).

For at least the next several decades, few electricity consumers, let alone whole communities, will go completely "off grid." Many consumers will install equipment that meets their needs for at least some of the time. Sometimes they will also want to sell surplus power back to the grid. But the fraction of consumers who are able to provide their own resilient electric supply, in entirety, without connecting to the grid will be limited for both economic and social equity reasons.

> **Finding:** For at least the next two decades, most customers will continue to depend on the functioning of the large-scale, interconnected, tightly organized, and hierarchically structured electric grid for resilient electric service.

In this context, interruptions in the power supply are disruptive for consumers and for the electric system itself. Interruptions typically arise from physical damage in a local part of the system—for

[2] Some use "the grid" only to refer to the high-voltage transmission system. Others use "the grid" to refer to the entire system of wires that moves electricity, including the lower voltage distribution system. In this report, the committee adopts the latter usage. Chapter 2 provides an overview of the physical structure, operation, and governance of both the high-voltage transmission and lower voltage distribution systems.

example, lightning strikes, trees that fall on wires, cars or trucks that crash into power poles, or aging equipment that fails. Indeed the majority of the outages that affect the typical customer in the United States in any given year are the result of events that occur to the distribution system. Less frequently, large storms, other natural phenomena, and operator errors cause outages across the large high-voltage, or "bulk power," system.

A wide variety of events—hurricanes, ice storms, droughts, earthquakes, wild fires, solar storms, and vandalism or malicious attacks on the hardware and software elements of the electric system—can lead to outages. When the power goes out, life becomes difficult. Communications, business operations, and traffic control all become more challenging. If the outage is brief, most people and organizations can and do cope. As the duration and spatial extent of an electricity system outage increase, costs and inconveniences grow. Critical social services—such as medical care, police and other emergency services, and communications systems—can be disrupted and people can even die.

This report is about minimizing the adverse impacts of large electric outages through building a resilient electric system.[3] A complex modern economy that depends on reliable electric supply requires a resilient electric system. While any outage can be problematic, in this report the committee focuses on large-area, long-duration outages—blackouts that last several days or longer and that extend over multiple service areas or even several states.

RESILIENCE AND RELIABILITY ARE NOT THE SAME THING

While utilities work hard to prevent large-scale outages, and to lessen their extent and duration, such outages do occur and cannot be eliminated. Given the many potential sources of disruption to the power system, what is perhaps surprising is not that large outages occur, but that they are not more common. For decades, the planners and operators of the system have taken care to assure that the electric system is engineered and routinely operated to achieve high levels of reliability. Increasingly, the system's planners and operators are focusing on resilience as well.

The North American Electric Reliability Corporation (NERC)—the federally approved organization responsible for developing reliability standards for the bulk power system—defines *reliability* in terms of two core concepts:

[3] In parallel with the preparation of this report, which was requested by the Department of Energy (DOE), DOE has also been sponsoring a 3-year Grid Modernization Initiative. That initiative includes a project to develop metrics to measure progress on grid modernization. It is pilot-testing metrics on reliability, resilience, flexibility, sustainability, affordability, and security (DOE, 2015; GMLC, 2016). This report focuses specifically on the issue of resilience.

1. *Adequacy.* The ability of the electricity system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
2. *Operating Reliability.* The ability of the bulk power system to withstand sudden disturbances, such as electric short circuits or the unanticipated loss of system elements from credible contingencies, while avoiding uncontrolled cascading blackouts or damage to equipment.[4]

In practice, the system is planned and operated to varying reliability standards. The bulk power system achieves a relatively high degree of reliability across the United States as a whole. For example, adequacy of electricity generation capability is usually measured against a one-day-in-ten-years (1-in-10) loss of load standard, which is typically interpreted to mean that the generation reserves must be high enough that voluntary load shedding due to inadequate supply would occur only once in 10 years (Pfeifenberger et al., 2013). By its very nature, however, the highly complex electrical system—the very epitome of a "cyber-physical system"[5]—is spread out all across the continent. Because it is built up from millions of complex physical, communications, computational, and networked components and systems, there is simply no way it can be made perfectly reliable.

The concepts of reliability differ from *resilience*, which is the focus of this report. *The Random House Dictionary of the English Language* defines resilient as follows: "the power or ability to return to the original form, position, etc. after being bent, compressed, or stretched . . . [the] ability to recover from illness, depression, adversity, or the like . . . [to] spring back, rebound." Resilience is not just about being able to lessen the likelihood that outages will occur, but also about managing and coping with outage events as they occur to lessen their impacts, regrouping quickly and efficiently once an event ends, and

[4] NERC goes on to state that "Regarding adequacy, system operators can and should take controlled actions or procedures to maintain a continual balance between supply and demand within a balancing area. These actions include: Public appeals; Interruptible demand (i.e., customer demand that, in accordance with contractual arrangements, can be interrupted by direct control of the system operator or by action of the customer at the direct request of the system operator); Voltage reductions (also referred to as "brownouts" because lights dim as voltage is lowered); and Rotating blackouts (i.e., the term used when each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, and so on, rotating the outages among individual feeders). All other system disturbances that result in the unplanned or uncontrolled interruption of customer demand, regardless of cause, fall under the heading of operating reliability. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When they spread over a wide area of the grid, they are referred to as cascading blackouts—the uncontrolled successive loss of system elements triggered by an incident at any location" (NERC, 2013).

[5] The National Science Foundation describes "cyber-physical systems" as "engineered systems that are built from, and depend upon, the seamless integration of computational algorithms and physical components" (NSF, 2016).

learning to better deal with other events in the future. Also, a detailed analysis of failure data (Figure 1.1) reveals additional insights which will be explored further in the subsequent chapters of this report.

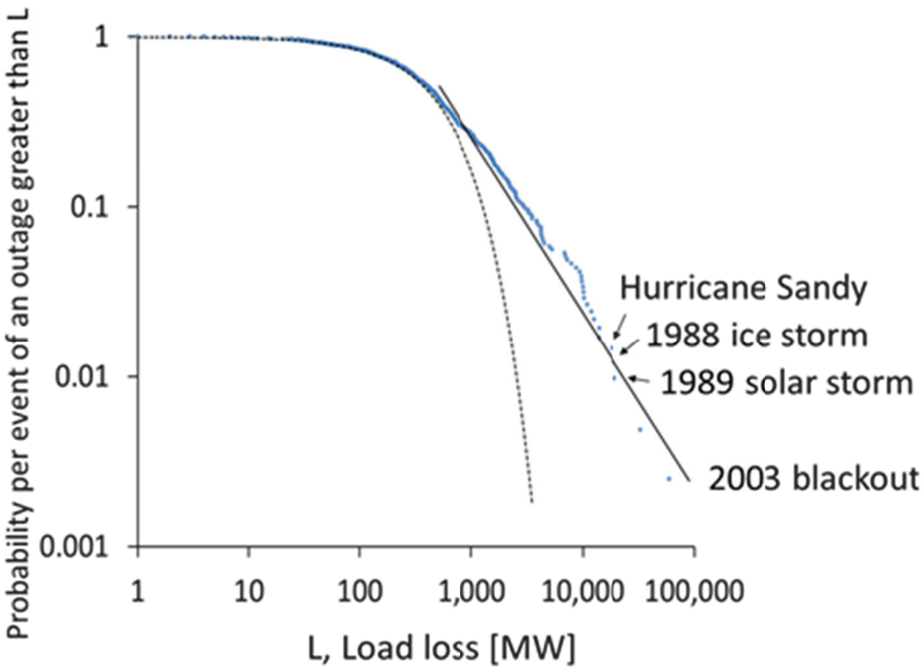

FIGURE 1.1 The relative frequency of outages in the U.S. bulk power system over the period from 1984 to 2015. The figure includes 1,002 events with load loss (loss in electricity demand) greater than 1 MW. The dashed line fits an exponential distribution to the more frequent events with load loss below 500 MW. Note that large outage events do not fit this line and are much more common than one might expect from an extrapolation of the frequency of smaller events. SOURCE: Data are from EIA (2000-2015), NERC (2000-2009), and NRC (2012).

Flynn (2008) has outlined a four-stage framing of the concept of resilience: (1) preparing to make the system as robust as possible in the face of possible future stresses or attacks; (2) relying on resources to manage and ameliorate the consequences of an event once it has occurred; (3) recovering as quickly as possible once the event is over; and (4) remaining alert to insights and lessons that can be drawn (through all stages of the process) so that if and when another event occurs, a better job can be done in all stages.

The National Infrastructure Advisory Council created a diagram that illustrates this framing (NIAC, 2010). The committee has adopted this diagram, modifying it only slightly to add verbs at each stage (Figure 1.2A), and has structured this report to follow these stages. Because the power system is hierarchical, these same concepts apply at several different levels of the system, including at the interconnection, region (some of which are operated by regional transmission organizations), local transmission and distribution systems (typically the domain of utilities), and the end-use level (on the customer side of the meter). Figure 1.2B shows this hierarchy in the abstract, and Figure 1.2C illustrates it for the Western Interconnection. While these figures display a physical hierarchy, there is an analogous hierarchy, but with different boundaries, for the information systems that support sensing and provide control.

> **Finding:** Resilience is not the same as reliability. While minimizing the likelihood of large-area, long-duration outages is important, a resilient system is one that acknowledges that such outages can occur, prepares to deal with them, minimizes their impact when they occur, is able to restore service quickly, and draws lessons from the experience to improve performance in the future.

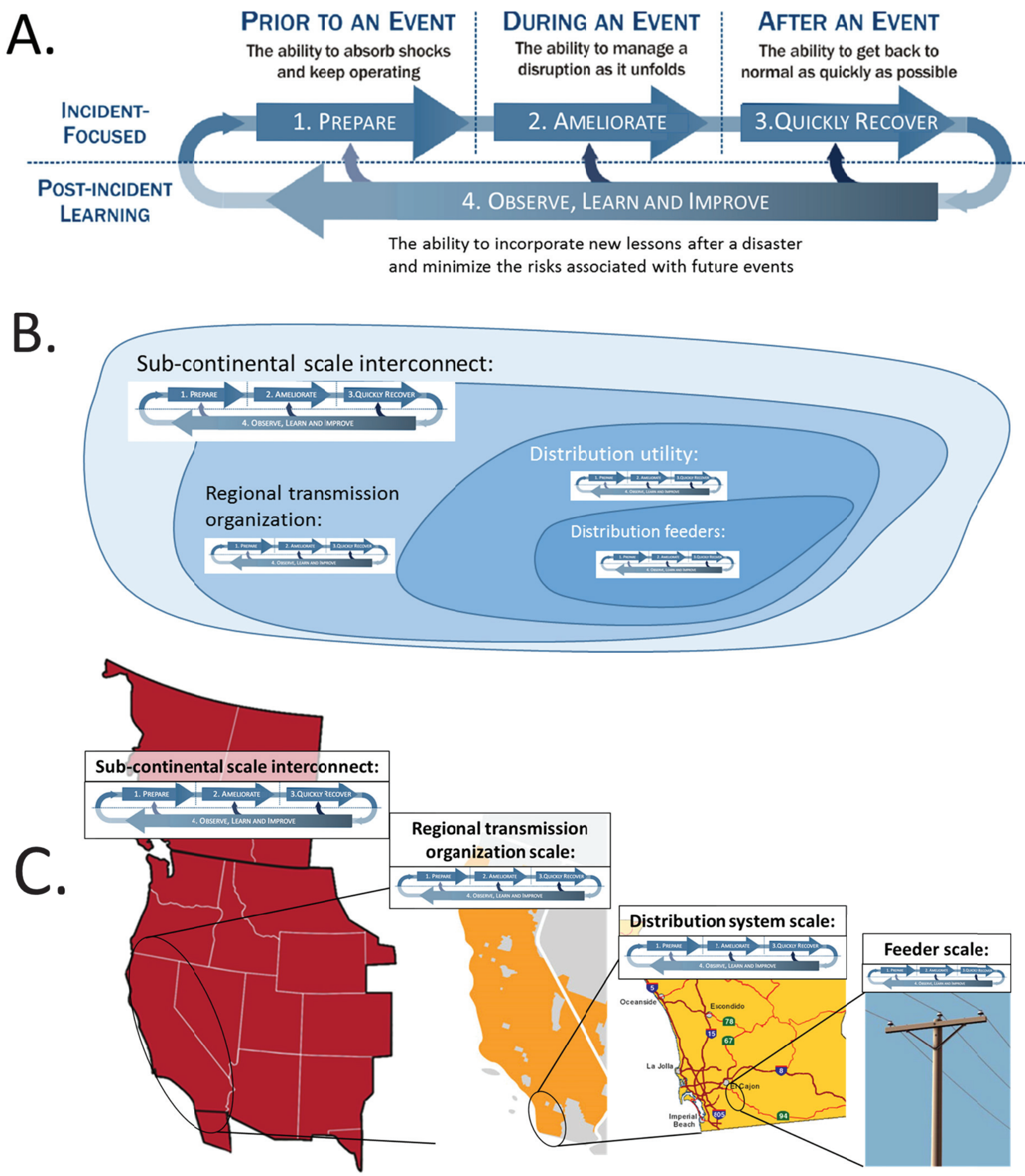

FIGURE 1.2 (A) A four-stage process of resilience based on a framing by Flynn (2008) and as illustrated by NIAC (2010); (B) In the case of the hierarchically organized power system, these concepts apply at several different levels of the system with different specific actions and lessons; and (C) Illustration of scales of resilience processes. SOURCE: (A) Modified with permission from NIAC (2010).

THE NEED FOR MORE RESILIENT TRANSMISSION AND DISTRIBUTION SYSTEMS

As the committee elaborates in the chapters that follow, the 21st-century power system in the United States is not just technically complicated; it is also comprised of diverse and often overlapping institutions and actors. Across the United States, there are differences in the resilience threats faced by power system operators, in the resources dedicated to mitigating them, and in the capabilities available to utilities and other grid operators in restoring their systems after an outage event. These variations play out in numerous ways. For example, some regions have a single grid operator that administers competitive wholesale power markets and reliability functions. In other parts of the country, individual utilities dispatch and balance power supplies on their own in response to changing demand. In some states, there are multiple market participants (e.g., generating companies, "wires" companies that transmit power, marketing companies). In other states, the utilities remain vertically integrated with the same firm having responsibility for both power delivery and generation. Some areas have seen the reliable introduction of many new and different pieces of electrical equipment (e.g., small-scale solar panels, large wind turbines, flywheel storage systems, large-scale electric generating power plants) owned by parties other than the utility or the local grid operator. Other regions are just beginning to manage such changes on the system.

Some utilities have embraced high-speed information and communications technologies to provide them with greater awareness of the state of their system, including the location of outages, while others have made fewer investments in such technologies. Some utilities have substantial resources dedicated to improving cyber security while others have close to none. As noted earlier, it is NERC's responsibility to set minimum reliability requirements to address the risks associated with the "weakest link" in the bulk power system. As discussed in more detail in Chapter 2, there is much more variability among states in terms of reliability standards, with individual states setting their own reliability requirements through public utility commissions (and boards for publicly or customer-owned distribution utilities).

Over the last 30 years, numerous headline-making outages have resulted from diverse human and natural causes, including operational errors and meteorological events. A few such outages disrupted electricity service to more than 10,000 MW of customer load (demand).[6] The events that cause outages of

[6] More than 10,000 MW means more load than that required to power all of New York City. In 2015, the summer coincident peak demand of Zone J (New York City) of the New York grid was 10,410 MW. The population of New York City's five boroughs is 8.5 million people, and the population of the New York City Metropolitan Statistical Area (which includes parts of New Jersey, Connecticut, and Pennsylvania) is over 20 million. The New York City Metropolitan area accounts for roughly $1.431 trillion in economic activity (NYISO, 2016; USCB, 2016; IHS Global Insight, 2013).

this scale leave millions of customers without power, result in economic damages[7] estimated in the billions of dollars, pose serious threats to health and public safety, and could potentially compromise national security. While the United States has fortunately not experienced a major outage caused by a physical or cyber attack, both are a serious and growing risk. Regarding cyber attacks, many attempts to penetrate the system occur every day. Box 1.1 describes four large-area, long-duration outage events that occurred in the past two decades in North America, ranging from the January 1998 ice storm that affected the interconnected power systems in the Northeast United States and Eastern Canada, to the impacts resulting from Superstorm Sandy in 2012.[8] Box 1.1 also includes description of a cyber attack that disrupted service on the Ukrainian power system in 2015, which did not result in a large-area, long-duration outage but is noteworthy as one of the most prominent examples of cyber disruption of electricity infrastructure. As Box 1.1 makes clear, there is a wide variety of human and natural causes of outages, with significant impacts on economic and human quality of life.

Finding: Large-area, long-duration electricity outages that leave millions of customers without power can result in billions of dollars of economic and other damages, and cause risk of injury or death. A variety of human and natural events can cause outages with a variety of consequences. The risks of physical or cyber attacks pose a serious and growing threat.

An all-hazards approach to resilience planning is essential, but, with the exception of a few general strategies, there is no "one size fits all" solution to planning for and recovering from major outages. The notion of resilience has to address multiple types of events and operate in a system with multiple overlapping institutions, service providers, grid configurations, ownership structures, and regulatory systems. As outlined above, the system is also comprised of multiple and changing technologies and is constantly evolving. Together this complex physical–cyber–social system is the context and motivation for the National Academies' study presented here.

[7] The events that cause such large-scale outages cause damages to physical structures, including the electricity system, as well as impacts on economic activity. The costs of weather-related power outages are estimated to be billions of dollars annually, with estimates for Superstorm Sandy at $14–26 billion (EOP, 2013). The potential long-term economic effect of such events in terms of losses and gains in economic activity and accounting for rebound is a more difficult estimate but clearly can be very large.

[8] Most of the damage from Sandy occurred after the winds had dropped below hurricane force and the storm had lost it tropical cyclone characteristics. Thus, the committee uses the term "Superstorm Sandy" and not "Hurricane Sandy" when it refers to this event.

BOX 1.1
Examples of Outages on Bulk Power Systems and Their Consequences

The five events summarized below exemplify the types of outages that can result from weather conditions, operational failures, or malicious hacking of the grid. (See Appendix E for a more comprehensive list and description of major outages in the United States.)

New England/Eastern Canada Ice Storm (1998)

Between January 4 and January 10, 1998, a series of storms generated along a stationary weather front brought warm Gulf of Mexico precipitation events across a stationary cold air mass (National Weather Service, 1998). While ice storms are common in Eastern Canada, this storm was unique for its long duration (more than 80 hours of freezing rain and drizzle), large geographical extent, and extraordinary freezing rain precipitation totals, with an accumulation of freezing rain greater than 3.1 in (80 mm) thick stretched from southeastern Ontario and northern New York State into southwestern Québec (RMS, 2008). The tremendous weight of accumulated ice resulted in the collapse of 770 electric transmission towers, the replacement of more than 26,000 distribution poles and 4,000 pole-top transformers, and the re-stringing of 1,800 miles of transmission and distribution circuits. At its peak, more than 5.2 million customers in the interconnected areas of Eastern Canada, New York, and New England were without power. Three weeks after the storm, hundreds of thousands of customers still had no power, with some customers not getting power restored until more than a month later (RMS, 2008). Storm damage was estimated to be approximately $4 billion (National Weather Service, 1998).

Northeast Blackout (2003)

The August 2003 blackout is the single largest loss of power in U.S. history and was caused by a confluence of factors. A combination of software and operator errors occurring at the Cleveland utility (FirstEnergy) and at the regional reliability coordinator (Midwest Independent Transmission System Operator) greatly reduced the ability of the grid to withstand a reliability event. The regional system operator experienced diminished situational awareness, limiting its ability to intervene to assure system reliability. For example, loss of generation capacity in the Cleveland area adversely affected the ability of key transmission lines into the area to operate at a higher load than usual, but not enough to cause an equipment failure in and of itself. But other factors then triggered outages: contact with overgrown trees in transmission easements into Cleveland ended up tripping several 345 kV lines out of service, and FirstEnergy and Midwest Independent Transmission System Operator were unable to effectively monitor and respond to these losses of electric supply (NERC, 2004). The resulting power flows then redistributed from high-voltage system to lower voltage lines, leading 16 lines to trip out of service in a 30-minute period, which ultimately caused a cascading collapse of the bulk power system across eight states and two Canadian provinces. The cascading failure left more than 50 million people without power. In certain parts of the outage area, power was not restored for 4 days. The blackout is estimated to have cost between $4 billion and $10 billion and contributed to 11 deaths (USCPSOTF, 2004).

Hurricane Katrina (2005)

Hurricane Katrina—the all-time most costly weather-related event in the United States—first hit land in Florida as a Category 1 storm, then grew to a Category 5 storm in the Gulf of Mexico before weakening to a strong Category 3 storm at second landfall, with severe storm surges along the Alabama, Mississippi, and Louisiana coastlines (NOAA, 2016). New Orleans experienced devastating flooding and widespread electricity outages, but ultimately damaging storm impacts were felt in eight states across the Southeast (NOAA, 2016). Katrina's impacts included loss of electric service to 2.7 million customers in these states; even 4 weeks after the storm, approximately 250,000 electric customers remained without service (DOE, 2009). In all, the storm destroyed 72,447 utility poles, 8,281 transformers, and 1,515 transmission structures; it took 300 substations off line, and multiple power plants, including three nuclear plants, either shut down or had to reduce power (DOE, 2009). The flooding in New Orleans prevented full restoration of power for several months. At Southern Company's Mississippi Power, every customer lost power, "nearly two-thirds of the transmission and distribution system was damaged or destroyed, and all but three of the company's 122 transmission lines were out of service . . . . In the distribution system, about 65 percent of facilities were damaged . . . . Mississippi Power's second-largest electricity generating plant was damaged by floodwaters, which affected the company's emergency operations center and backup control center located in the plant . . . . Mississippi Power began tracking Katrina's progress, and 3 days before it hit Mississippi, Mississippi Power began making requests for manpower, material, and logistics . . . . Within 7 days after Katrina, 10,800 workers from 23 states and Canada were assisting Mississippi Power" (Ball, 2006). Katrina's estimated damage ranges from $84.8 billion to $157.5 billion (CBO, 2005).

Superstorm Sandy (2012)

In October 2012, Superstorm Sandy struck the Eastern United States, impacting 24 States in its path. During the 7 days from Sandy's formation to its dissipation, the storm caused swells in excess of 3 meters, flooding in densely populated centers, and extensive damage to infrastructure, with a majority of the damage occurring in New York and New Jersey (FEMA, 2013). Considerable advance notice of the storm allowed electric utilities to make several preemptive steps to mitigate damages, including requests for more assistance from teams from other utility systems, for tree trimming along transmission lines, and for increased readiness of utility outage repair teams (EOP, 2013). It has been estimated that 8 million customers lost power (Sandalow, 2012). Restoration services reported that 10 to 11 percent of customers in New York and New Jersey remained without power 10 days following the storm. During the outages, 50 deaths were attributed to the lack of electricity, with causes including hypothermia and improperly operated generators. The cost from the post-Sandy power outages has been estimated between $14 billion and $26 billion (EOP, 2013).

Cyber Attack on Ukrainian Power Grid (2015)

In December 2015, a synchronized multi-target cyber attack was executed on three electric grid control centers in eastern Ukraine (DHS, 2016; Volz, 2016). Months previously, the attackers had used "spear-phishing" tactics on employees via a Microsoft Office document to access the corporate networks (E-ISAC and SANS ICS, 2016). The attackers spent the following months learning about the system and its users to gain the necessary credentials to remotely access the communications networks (i.e., SCADA systems) that control the operation of the electric grid. In December 2015, the attackers began the intrusion by shutting down power to the control center to prevent utility employees from effectively handling the outage (E-ISAC and SANS ICS, 2016). With that response capability compromised, the cyber attackers took control of the electric-system substations themselves and opened substation breakers to shut down power to a larger customer base. Simultaneously, the cyber attackers executed a "denial of service attack" on the customer support facilities, which made the related computer facilities unavailable to customers who sought to report outages and then released malicious software targeted at the master boot record. The attack left approximately 225,000 people without electricity for up to 6 hours. The release of malicious software wiped out personnel computers, servers, and remote terminal units (RTUs), which in turn delayed restoration of service and increased the amount of time required to bring control systems back online. Several substations suffered damage due to the attacks. Although NERC has classified the impacts of these attacks as low due to the short duration of the outage, the relatively small number of infrastructure affected, and the low population percentage of Ukraine that lost power (E-ISAC and SANS ICS, 2016), the attack nonetheless had far-reaching impacts. As of Fall 2016, the utility in Ukraine has yet to reach operational levels experienced prior to the attack, and it is currently unknown when the organization will reach peak operational capabilities again (E-ISAC and SANS ICS, 2016). Thus, in contrast to the other events described here, the Ukraine event was not a long-duration outage event for customers.

IMPROVING RESILIENCE PRESENTS FUNDAMENTAL CHALLENGES

Throughout this report, the committee identifies and discusses a range of technical, institutional, and other strategies that, if adopted, could significantly increase the resilience of the U.S. electric power transmission and distribution systems. It is relatively easy to identify actions and strategies that could improve resilience. Much harder, however, is fostering and realizing the political and organizational support to implement these strategies and actions. The very structure of governance and investment in the electric grid is decentralized. And investment in the grid competes with other social and economic demands as well as for the time and attention of stakeholders. This is especially hard in the face of scarce resources, fragmented government, and the reality that many of the scenarios of large-area, long-duration outages are beyond the realm of experience of most individuals and governing systems.

Some causes, like major solar coronal mass ejections (see Chapter 3), have very low probabilities of occurrence—sometimes measured in centuries. Others, such as cyber attacks, may become increasingly likely to impact the operations of the grid. Drawing on the tools of decision analysis, an analyst can help a unitary utility-maximizing actor determine how much to spend either to harden a system or to minimize the consequences of disruptive events. However, neither U.S. society, nor its power system, is governed by a single rational actor, but rather are collectively managed by many.

By design and of necessity in our constitutional democracy, making such decisions is an inherently political process. This committee of experts can identify risks and options, outline strategies to improve the understanding of relevant public and private decision makers, and suggest ways to assure that relevant factors are identified and considered. However, ultimately, the choice of how much resilience our society should and will buy must be a collective social judgment.

Large-area, long-duration outages are rare events. And investing in a more resilient system has the classic characteristics of "public goods" issues—localized and concentrated costs with broadly diffused and difficult-to-measure benefits—that are inherently difficult to address. It is unrealistic to expect firms to make voluntary investments whose benefits may not accrue to shareholders within the relevant commercial lifetime for evaluating projects. Moreover, much of the benefit from avoiding such events, should they occur, will not accrue to the individual firms that invest in these capabilities. Rather, the benefits are diffused more broadly across multiple industries and society as a whole.

In some parts of the United States, rural electric cooperatives, vertically integrated utilities, and utility regulators may be better able to take a longer-term perspective that considers such broader societal benefits. But too often decision makers are pressed by short-term considerations of cost and choices about where expenditures should be directed for various and sometimes competing purposes, and so they must have a strong basis for approving expenses for activities that may not yield benefits for decades or longer. At the national level, the Federal Energy Regulatory Commission and NERC have the ability to adopt a somewhat longer-term perspective, although they too face short-term pressures and fiscal constraints.

No single entity is responsible for assuring the system is resilient in the face of all of them. Strategies to assure more systematic planning and to cover the costs of needed investments are discussed in Chapter 7. Many of the actions designed to reduce system vulnerability to one specific event can actually provide effective protection against a variety of events. For example, in regions where flooding is not an issue, undergrounding power lines can make the system less vulnerable to the impacts of severe storms as well as vehicle accidents. This may make such actions and investments easier to justify. Experience demonstrates the normal cycle of public reactions to major events with big impacts on society: there is a tendency not only to identify parties that can be blamed for failing to prevent the event and its impacts, but also to call for greater protective action against exactly the type of event just experienced. Regulators and other decision makers need to have well developed plans that can be implemented during such a "policy window" and designed for robustness against a wide range of threats.

There are some communities at considerably greater risk than others, including those at vulnerable locations in the electricity system or those within or close to natural hazards. When those communities take action, the results can serve as a stimulus and template for others to follow. Some modest government pilot funds to initiate such examples can be a socially prudent investment. At the same time, it is important that the United States devise ways to increase the likelihood that lessons learned from demonstrations can be diffused more widely. National organizations such as the National Association of Regulatory Utility Commissioners, the Edison Electric Institute, the National Rural Electric Cooperative Association, the American Public Power Association, and the National Governors Council, can play important roles, raising awareness, sharing best practices, and providing guidance to members. Public and private partnerships such as the Electricity Subsector Coordinating Council, which gained importance following Superstorm Sandy, also serves as a viable forum for enhancing coordination and communication; conducting drills and exercises; and sharing tools and technologies to enhance grid resilience.

Throughout this report, the committee has tried to be attentive to the tension between two competing realities. One is that the electric power system and its regulation are decentralized across the many states and regions. The other is that a coherent strategy will not emerge without stewardship at the federal level and/or from organized leadership from public and private institutional partners that support actions in the national interest. The Department of Homeland Security (DHS) is specifically charged with identifying potential vulnerabilities and assisting in the development and implementation of strategies to reduce risks and increase resilience. However, neither DHS nor the set of local actors that typically interact with DHS control or run the power system. Moreover, the department is stretched very thin and has relatively modest technical expertise in the context of electric power systems.

As the energy sector lead agency and with its focus on research, the DOE does have a longer-term perspective and hence is in a position to lay the groundwork and demonstrate the feasibility of a variety of technologies and strategies that, when adopted by others, can considerably enhance the resilience of the grid. Multiple DOE offices have programs related to electric power grid resilience. Specifically, the Office of Electricity Delivery and Energy Reliability and Office of Energy Efficiency and Renewable Energy have responsibility for directing work on many of the nation's grid modernization and system integration programs, and thus have a vital role to play in this area.

The Electric Power Research Institute can also make important contributions—including improving awareness of technologies and practices that are emerging globally—but the amount of fundamental longer-term work they can support is limited. The National Rural Electric Cooperative Association is undertaking a range of research activities that adopt a longer-term perspective. Many states around the country are also working on specific resilience projects, often in the aftermath of those states having experienced disruptive events that have focused policy makers' attention on the issue.

In the chapters that follow, the committee identifies and discusses many things that both the federal government and industry can do to advance the resilience of the power system. In Chapter 7, the committee returns to the broader issues of who is in charge, how electricity system operators, regulators, and society more broadly should choose what is worth doing, and how to pay for it.

STRUCTURE OF THE REPORT

Chapter 2 describes the nation's electric system as it now exists and as it is integrating and adapting to new technologies and changing regulatory and market environments. This chapter provides context for the rest of the report by describing current conditions and factors affecting grid resilience and discussing how these systems might evolve over the coming decades (even if they are changing in unpredictable ways). Chapter 3 describes the many causes of grid failure: the range and types of threats that can, and at least in some case definitely will, arise to disrupt the operations of the electric grid. Chapters 4 through 6 discuss ways that grid planners and operators, along with the rest of society, can prepare for and reduce the frequency and duration of disruptions (Chapter 4), manage and mitigate the consequences of outages as they occur (Chapter 5), and restore the system to normal operations as rapidly as possible (Chapter 6). These three chapters identify and discuss things already taking place, things that could improve the performance of each aspect of resilience, and things that deserve further attention from researchers and analysts; from owners, operators, and planners of the grid; and from government policy makers. Discussions of topics such as distributed energy resources and microgrids are spread throughout these chapters. Depending on how they are deployed, distributed energy resources and microgrids can be used for many purposes—they can help mitigate and prevent outages (Chapter 4), can help sustain electricity service to critical facilities during an outage (Chapter 5), and can aid in system restoration (Chapter 6). Throughout these chapters, as well as Chapters 2 and 3, the committee makes many specific recommendations for strategies to increase the resilience of the U.S. electricity transmission and distribution system. While these specific recommendations will advance this purpose, the committee believes that the nation should adopt a more integrated perspective across the numerous, diverse institutions responsible for the resilience of electricity system. Thus, the final chapter (Chapter 7) brings together a broader set of overarching recommendations intended to bring such an integrated perspective to the issue of electricity system resilience. The report Summary contains both the overarching recommendations and a synopsis of the chapter-specific recommendations.

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2

Today's Grid and the Evolving System of the Future

INTRODUCTION

This chapter describes the U.S. electric system as it now exists and discusses how it may evolve over the next several decades. First, the committee provides background on the physical, ownership, legal/regulatory structure, and operational characteristics of the nation's electric system, with an emphasis on transmission and distribution infrastructure. The committee focuses on aspects of the national grid that are relevant for understanding electricity system resilience and the strategies employed to enhance it.[1] This overview of transmission and distribution also highlights the sensing, communications, and control systems that currently exist to support a variety of functions on the grid. Then, the committee describes the complex and dynamic forces driving changes in the electricity sector, both in the near term and the long term.[2] Finally, the committee discusses a variety of ways in which the system may change and some of the implications of these changes for the future resilience of the grid. Together, these conditions and trends set the stage for a subsequent discussion of threats to the system (in Chapter 3) and activities associated with each stage of resilience in the electric system (in Chapters 4 through 6).

Strategies to increase the resilience of today's transmission and distribution systems need to accommodate possible future changes in its character, because most of the physical assets and other pieces of the infrastructure have long lifetimes. Planning to enhance resilience should take this into account, along with the often uncertain ways these systems might evolve over the coming decades.

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[1] Readers interested in a more detailed description might look at DOE (2017a), NAS (2016), DOE (2015), MIT (2011), NRC (2012), and Bakke (2016).

[2] Readers interested in a more detailed description might look at MIT (2016).

Finding: Approaches to assure resilience should consider that components of electricity infrastructure have long lifetimes and that how the grid and its various institutions, technological features, legal structures, and economics will change is inherently uncertain.

ELECTRIC INDUSTRY STRUCTURE, ASSET OWNERSHIP, AND OPERATIONAL ROLES AND RESPONSIBILITIES

Since the 1930s in the United States, most electric service to households, businesses, and other customers has been provided by investor-owned or publicly owned electric utilities responsible for all elements of electric supply: generation, transmission at high voltage, and local distribution of power at low voltage. That said, in the first half of the last century the federal government promoted electrification and developed hydropower resources aggressively. This led to the federal government operating several electricity generation and transmission organizations, perhaps the most famous of which are the Tennessee Valley Authority in the southeastern United States and the Bonneville Power Administration in the Pacific Northwest. Figure 2.1 depicts the "bulk energy system,"[3] comprised of central-station power plants and high-voltage transmission lines, and the local "distribution operations" that move power from the bulk system to end-use customers.

[3] The Federal Energy Regulatory Commission has approved the following definition of "bulk energy system" as developed by The North American Electric Reliability Corporation: "All transmission elements operated at 100 kV or higher and real power and reactive power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electrical energy" (NERC, 2016a). There are specific technical exclusions of certain facilities from this definition, but the 100-kV dividing line between bulk energy system (and transmission-level voltage) and lower-voltage (and distribution-system-level voltage) is useful for our purposes here.

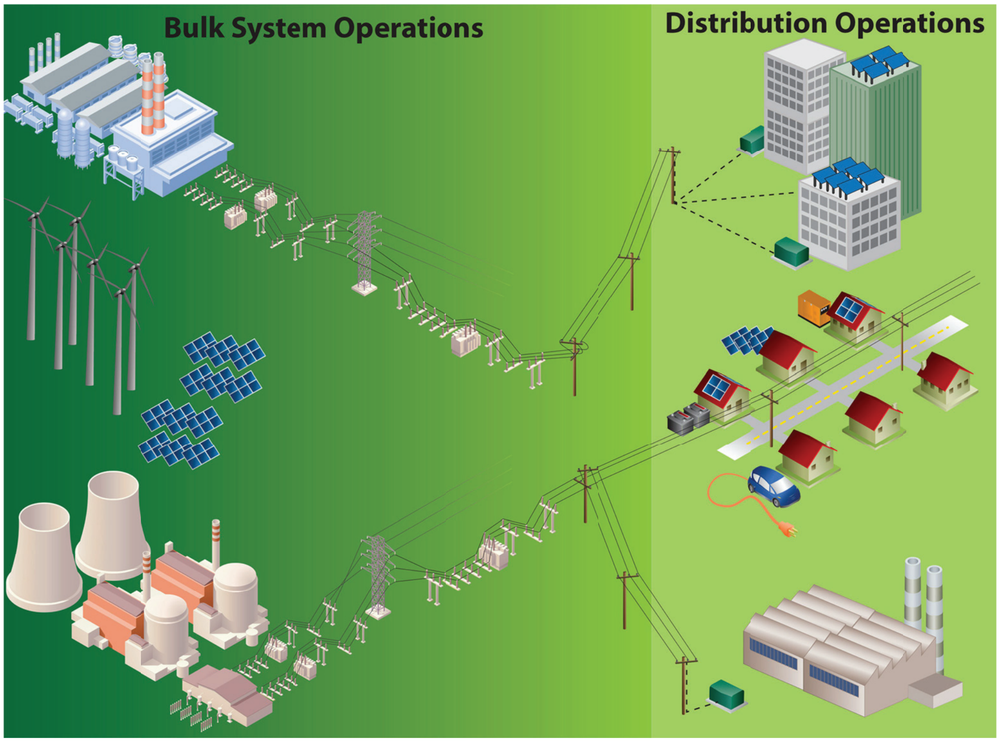

FIGURE 2.1 The bulk energy system encompasses the facilities and control systems for generation and transmission of electricity but does not include local distribution systems. SOURCE: Courtesy of the Electric Power Research Institute. Graphic reproduced by permission from the Electric Power Research Institute from its research report, The Integrated Grid: A Benefit-Cost Framework. EPRI, Palo Alto, CA: 2015. 3002004878.

Several decades ago, most electric utilities were vertically integrated, meaning that the utility owned the power plants and/or contracts for power; owned or had rights to use high-voltage transmission lines that carry power from remote power plants to their local systems; and owned and operated the low-voltage distribution system to deliver power to consumers. State utility regulators (or, in the case of publicly owned utilities, the governing boards of the local utility) set rates for vertically integrated utilities based on the cost of providing service. But nearly 20 years ago, a number of states and federal regulators began to move aggressively to break up vertically integrated utilities, separating the ownership of generation, high-voltage transmission, and distribution systems. In those states, only the distribution part of the system has continued to operate as a regulated monopoly.

As the electric system developed over the decades, investor-owned electric utilities in many parts of the United States merged so as to provide power to customers over larger and larger service territories. In other parts of the country, utilities serve smaller numbers of customers, particularly in rural regions where local electric cooperatives and municipally owned utilities continue to be the dominant providers of electric service. The result is today's patchwork of local distribution utilities (Figure 2.2): thousands of electric utilities provide monopoly service within their local footprint but with a complex system of interconnected facilities that operates, in effect, as a single "machine" within each interconnection (NAE, 2003).

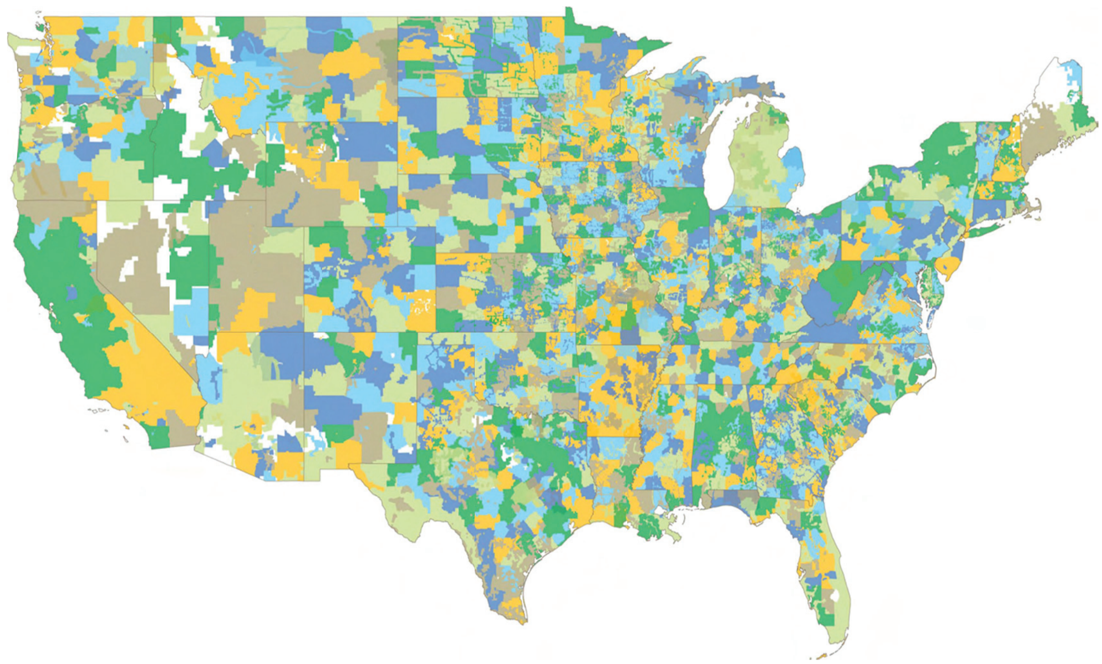

FIGURE 2.2 Map of electric distribution utility service territories in the continental United States. SOURCE: Image reproduced with permission from Platts (2014), "Utility Service Areas of North America" available for purchase online at: https://www.platts.com/products/utility-service-territories-north-america-map.

According to the Energy Information Administration (EIA), there are more than 2,000 utilities that own and/or operate some part of the generation, transmission, or distribution infrastructure in the United States (Table 2.1). More than 70 percent of end-use electricity customers are served by just 174 large investor-owned utilities, while the remaining customers are split roughly evenly between publicly owned utilities and electric cooperatives. Although these investor-owned and publicly owned systems are physically connected, their transmission and distribution systems often have different configurations, voltage ranges, and technology demands; are owned and/or operated by different parties; are subject to different types of regulatory oversight; and are frequently discussed separately.

These many utilities operate as part of three separate interconnected "synchronous" regions within the United States (and parts of Canada), as shown in Figure 2.3. Within each interconnection, the utility systems are physically tied together by major transmission lines. The 60 Hz voltage and current waveforms are synchronized across the entire region, and power flows within each region according to the laws of physics. The three interconnections operate with only a few (asynchronous) direct current

(DC) connections that allow transfer of energy between them. The major transmission lines serving the lower 48 States are shown in Figure 2.4. This figure also illustrates the strong synchronous connection with Canada for both the eastern and western interconnections, and the DC lines connecting the asynchronous Québec grid. The integrated North American power system mutually depends on close and continuing collaboration between the United States and Canada. And while there is also a connection to a small portion of Mexico within the western interconnection, that dependency is less significant for either country as most of the Mexican grid is a separate system.

TABLE 2.1 Breakdown of Utilities That Own and Operate Generation, Transmission, or Distribution Infrastructure

Utility Ownership Structure	**Number**
Rural electric cooperatives	809
Investor-owned	174
Municipally owned	827
Political subdivision	101
State power authorities	20
Federal utilities/Power marketing administrations	8
Other transmission companies	15
TOTAL	1,954

NOTE: Investor-owned utilities deliver 68 percent of electricity service to retail customers. Cooperatives, municipal utilities, and other publicly owned utilities deliver 13 percent, 12 percent, and 6 percent to retail customers, respectively. (As of 2015, 96 percent of electricity used by customers was sold through utility wires, with 4 percent generated on customers' own premises.) SOURCE: EIA (2016a).

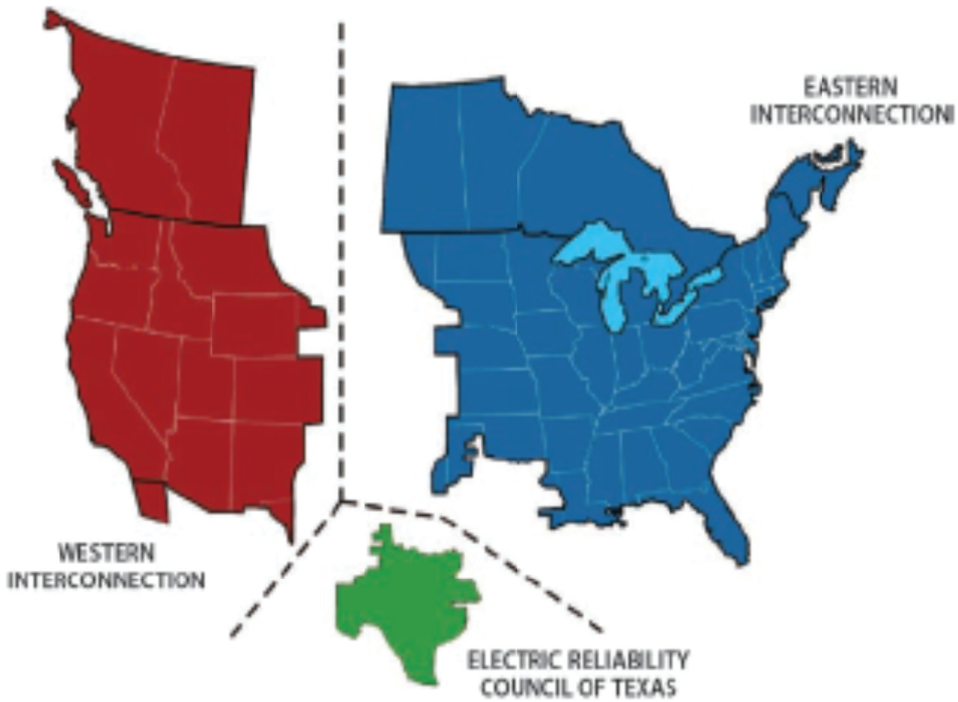

FIGURE 2.3 The three large electric interconnections that span the United States, large parts of Canada, and a small part of Mexico. A very modest amount of power flows between these three regions over direct current cables so that the 60 Hz power is not synchronized between the regions. Hydro Québec, which is not shown, provides power to many states in the northeastern United States. SOURCE: DOE (2016a).

Regulation of the electric grid takes place at two levels. The operations, cost allocation, and cost-recovery of the interstate transmission system, as well as wholesale sales of electricity,[4] are largely regulated by the Federal Energy Regulatory Commission (FERC). FERC derives its authorities from the Federal Power Act (FPA), which was initially enacted in 1935 and has been amended multiple times. The second level of regulation occurs on distribution systems that deliver electricity to the end user. The terms and conditions of sales to retail electricity customers, including operations, cost allocation, and cost recovery for local transmission and distribution service, are subject to regulation by state regulatory agencies in those areas served by investor-owned utilities and by publicly accountable boards of public utilities.

[4] "Wholesale sales of electricity" are sales of power for resale to others, while "retail sales of electricity" are sales to ultimate, end-use customers. Retail sales are typically regulated by state utility regulatory agencies for investor-owned utilities (and by the governing entities of publicly owned or member-owned utilities).

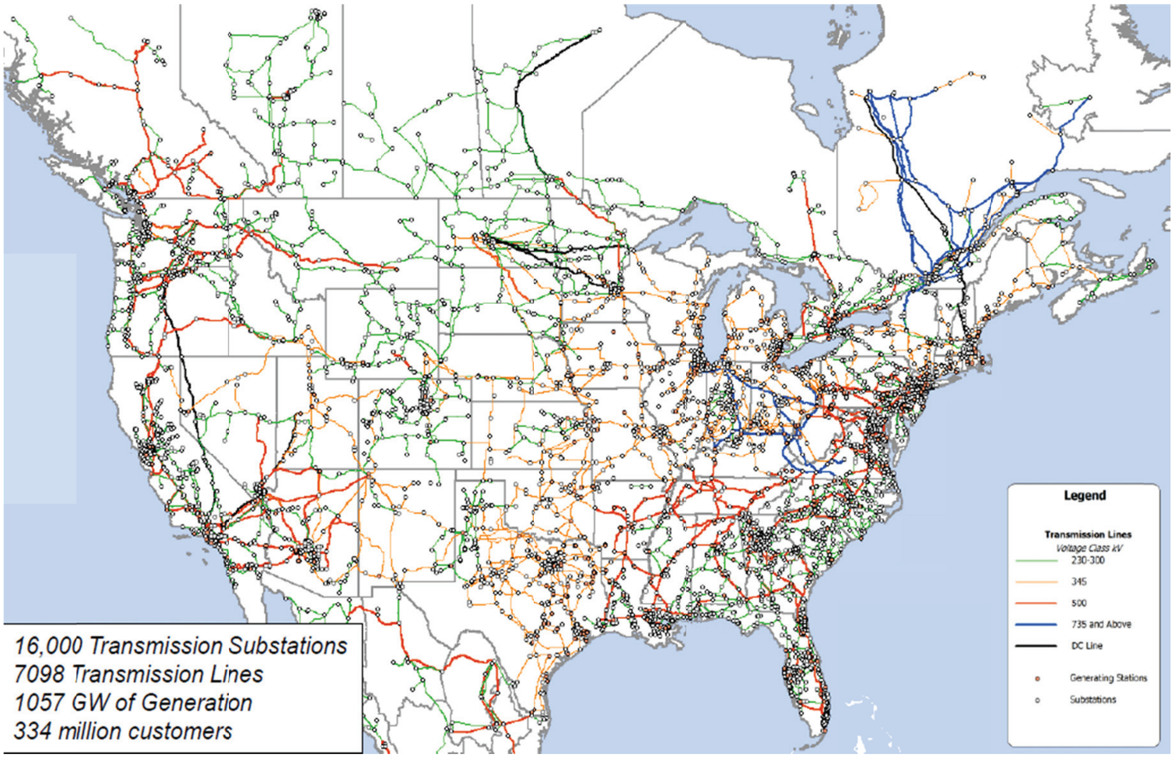

FIGURE 2.4 The North American transmission system. SOURCE: This information from the North American Electric Reliability Corporation's website is the property of the North American Electric Reliability Corporation and is available at http://www.nerc.com/comm/CIPC/Agendas%20Highlights%20and%20Minutes%202013/2015%20December%20Compiled%20Presentations.pdf.

This regulatory division between the federal government and the states over the higher- and lower-voltage portions of the electric transmission system first appeared in its current form in the early 20th century and has largely remained in place since then.[5] Although seemingly straightforward, this division of authority is complex in practice and often gives rise to tensions. For example, although the FPA gives FERC authority over transmission service in interstate commerce and wholesale sales of electricity, the states have regulatory authority over siting of transmission lines (including the right to condemn right of way). Some states also retain regulatory authority over the costs of transmission as part of the bundled delivery of retail electricity (in vertically integrated states as described later). Further, many states have the ability to adopt a variety of tax, siting, environmental, and other regulatory policies that affect the mix of power plants in a state.

[5] As long-distance transmission lines emerged and utilities started to send power onto the grid across long distances, electricity began to cross state lines. Congress created FERC's predecessor, the Federal Power Commission, in 1935 when it passed the Federal Power Act to address states' inability to regulate interstate sales of electricity.

More than 20 years ago, the electric industry began to undergo pressures for structural change, in part owing to the experiences of deregulating other commercial sectors such as airlines, interstate trucking, and telecommunications. Additional impetus came from federal policies that supported the introduction of relatively small-scale, economical generating technologies owned by non-utility companies, which led to requirements that utilities open up their transmission systems for use by third parties (e.g., the Public Utilities Regulatory Policies Act [PURPA] of 1978). Efforts began in a number of states in the mid-1990s to separate the ownership of generation assets from ownership of the transmission system (the "wires") and to create competitive wholesale electricity markets. A primary motivation in doing this was a belief that introducing market forces into the industry would result in lower costs to end users.[6] In fact, creation of competitive wholesale markets in many regions of the country required that non-discriminatory access to transmission infrastructure be provided to all generators. After an initial flurry of "restructuring," some states began to have second thoughts and decided not to break up their vertically integrated utilities.

Today, there is a patchwork of restructured and vertically integrated utilities across the United States. In much of the country, there are hundreds of non-utility entities involved in the power generation, system operations, power marketing, power trading, and other affiliated activities. The market participants in the electric regions serving two-thirds of the population in the United States are members of organized wholesale electricity markets where a regional transmission organization (RTO) (sometimes called independent system operators [ISOs]) operates the transmission system, prepares regional transmission plans for the market footprint, and conducts competitive product markets (covering energy, capacity, and/or ancillary services markets).[7] Figure 2.5 shows the boundaries of the current RTOs.

[6] In fact, in most cases, rates did not decrease (Lave et al., 2004; Blumsack et al., 2008).
[7] As of 2015, these seven RTOs serve 213.5 million, out of the total estimated U.S. population of 321 million (IRC, 2015; USCB, 2016).

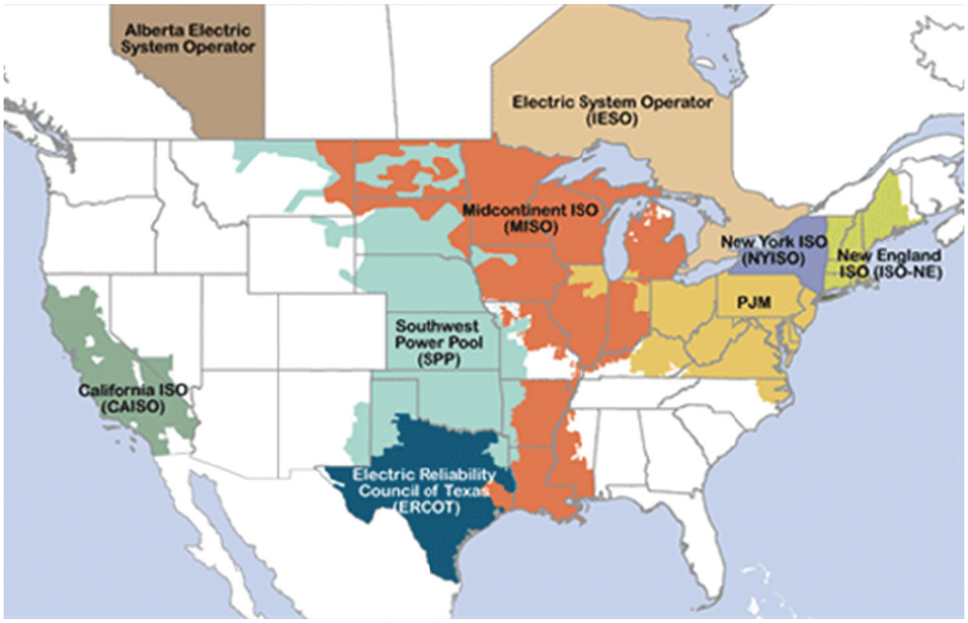

FIGURE 2.5 Map of regional transmission organizations' (RTO) and independent system operators' (ISO) service areas in the United States and Canada. The parts of the country shown in white do not participate in an RTO, although as of this writing, several utilities in the Western states have joined an "Energy Imbalance Market" administered by the California ISO. SOURCE: FERC (2016a).

While retaining monopoly ownership of the distribution wires, several states also took steps to open up their electric systems to retail competition. In those shown in green in Figure 2.6, retail customers have the right to choose to buy electricity from competitive retail suppliers. Some states (shown in yellow) took initial steps toward allowing retail choice but then suspended it, while the remaining states (shown in white) did not introduce retail choice.

Across all of these areas, the specific terms and conditions of utility service, and any competitive supply, vary considerably. This makes it very hard to generalize about industry structure across, and even within, states. At present this heterogeneous "electricity industry" reflects the varied choices that states and localities have made with regard to electric sector structure and regulation. The majority of states retain a vertically integrated structure, pursuant to which retail utilities maintain monopoly status with regard to the generation, sale, and delivery of electricity. Many states that have vertically integrated utilities without retail choice (e.g., California and many states in the Northern Plains and Upper Midwest) nonetheless have utilities participating in RTOs.

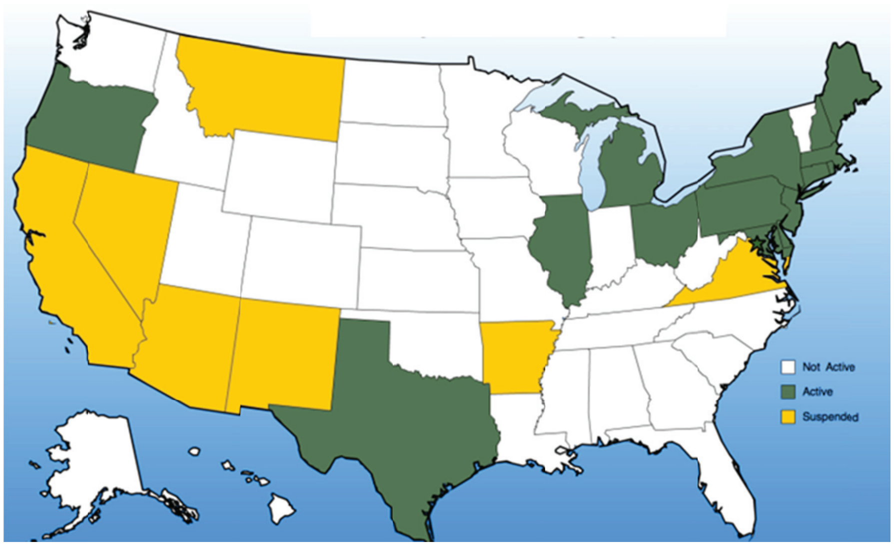

FIGURE 2.6 End consumers can choose their electricity provider in restructured states (green), while other states have suspended restructuring activities (yellow) or never initiated them (white). SOURCE: EIA (2010).

As shown in Figure 2.6, one-third of the states decided to introduce retail choice, and a majority of the states' utilities participate in the competitive generation markets administered by RTOs (shown in Figure 2.5), although the design of these markets varies across the seven RTOs.[8] In some states without retail choice—for example, in Colorado—non-utility companies may own rooftop solar panels that are physically located on a customer's building and sell that power to that customer. But, other such states without retail choice, such as Florida, do not allow anyone besides the utility to sell any form of electricity to consumers, although customers are able to install distributed generation on their premises. As a result of these variations across the states, the regulatory framework under which the electric grid operates takes on several forms. The FPA applies to the entire country but has differing impacts depending on which type of state-regional regulatory regime exists. This complicates the landscape in which the resilience of the interconnected grid is implemented.

The ownership of transmission infrastructure also varies widely across the United States. In some regions, vertically integrated utilities and large public power providers such as the Bonneville Power Administration and the Tennessee Valley Authority both own and operate the transmission infrastructure. In regions with competitive power markets, operation of the transmission system is delegated to RTOs/ISOs. These organizations may not own the transmission infrastructure under their control, but they are responsible for meeting reliability standards and conducting regional planning efforts, while assuring

[8] The only states that do not have any utilities participating in an RTO are Alabama, Alaska, Arizona, Colorado, Florida, Georgia, Hawaii, Idaho, Oregon, South Carolina, Utah, and Washington.

non-discriminatory access to transmission services for all generators and load-serving entities in the region.

With respect to reliability issues, FERC has responsibility for assuring adherence to mandatory reliability standards for the electric industry. FERC has delegated responsibility for developing reliability standards to the North American Electric Reliability Corporation (NERC), which had originally formed as a voluntary reliability organization following a large blackout in 1965 and is now the designated reliability organization in the United States. NERC develops industry-wide standards, submits them to FERC for approval, and enforces approved standards in the industry. Thus, FERC does not develop reliability standards on its own. Compliance with NERC standards became mandatory with the passage of the 2005 Energy Policy Act (EPAct), and utilities and system operators now face substantial penalties for non-compliance.

Among many other things, NERC has defined the essential system functions necessary to ensure reliability in a framework that accommodates operational and structural differences across regions with and without competitive wholesale markets (NERC, 2010). Within each large region, there is a reliability coordinator with a wide-area perspective on system conditions necessary to ensure that the actions undertaken by one entity do not compromise reliability in another. Currently there are 12 reliability coordinators covering the Continental United States, much of Canada, and a small part of Mexico (Figure 2.7).

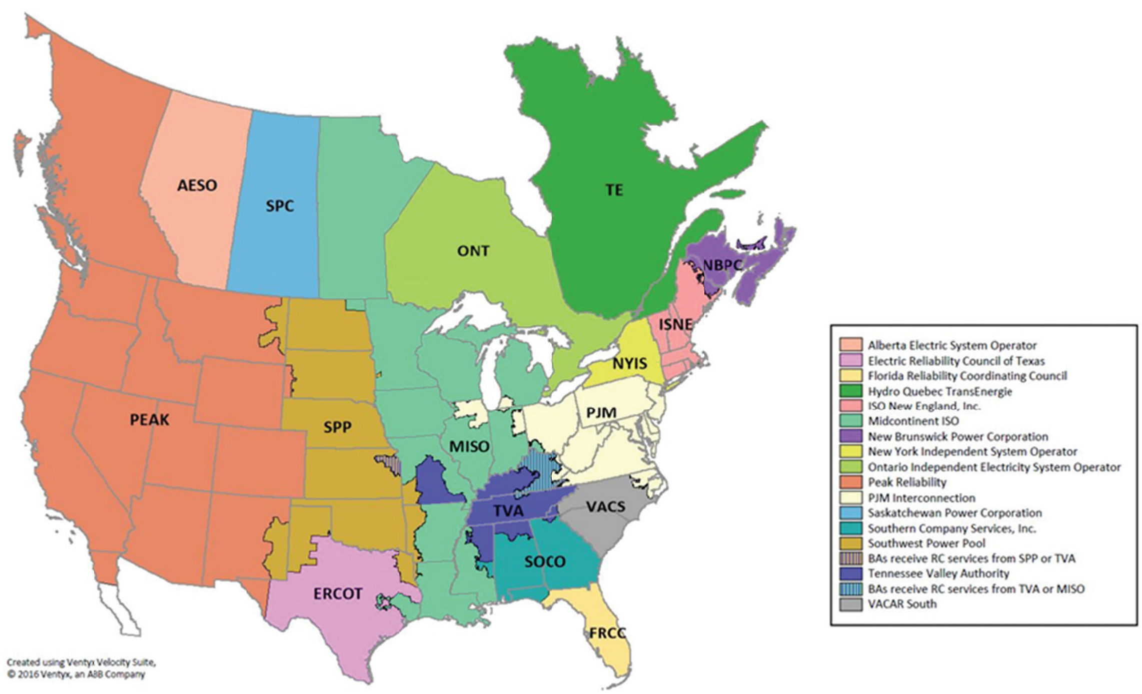

FIGURE 2.7 North American Electric Reliability Corporation reliability coordinators are responsible for ensuring reliability across multiple utility service territories. SOURCE: This information from the North American Electric Reliability Corporation's website is the property of the North American Electric Reliability Corporation and is available at http://www.nerc.com/pa/rrm/TLR/Pages/Reliability-Coordinators.aspx.

Under the purview of these reliability coordinators, more than 100 "balancing authorities" have responsibility for keeping generation and load equal at all times within smaller balancing areas. Regions with a history of tight coordination of operations and planning across utilities within the region, such as New England, New York, and the Mid-Atlantic region (e.g., Pennsylvania, New Jersey, and Maryland which were the original location of the PJM territory), have only a single balancing authority, whereas the majority of reliability coordinators interact with multiple balancing authorities within their footprint. Box 2.1 has examples of transmission system oversight and operation that vary by region.

BOX 2.1
Examples of Four Different Electric Operational/Reliability/Ownership Structures

Southern Company (SoCo) is a large vertically integrated utility operating in several Southeastern states. SoCo owns generation assets with a total capacity over 44,000 MW, transmission lines, and 4 subsidiary distribution utilities. SoCo's electric utilities collectively serve a population of approximately 9 million people (SoCO, 2017). Through these four subsidiaries, SoCo serves the functions of transmission owner, distribution provider, and generation owner while another subsidiary, Southern Company Services, serves as the reliability coordinator, transmission operator, and balancing authority.

PJM is an RTO serving all or part of 13 states and the District of Columbia, ranging from Pennsylvania and New Jersey in the East, southward to Virginia, and westward to northern Illinois. PJM provides service in a region with approximately 61 million people and 171,000 MW of generating capacity (PJM, 2017). PJM serves as reliability coordinator, transmission operator, and balancing authority, while also administering the organized competitive wholesale electricity market. However, PJM is not a market participant per se, as other entities own the physical assets associated with generation, transmission, distribution, and power marketing.

Bonneville Power Administration (BPA) is a federally operated power marketing administration in the Pacific Northwest, which markets electricity generated from hydroelectric dams owned and operated by the U.S. Army Corps of Engineers or the Bureau of Reclamation (approximately 22,500 MW of capacity), a nuclear power plant, and other renewable generation assets operated by Energy Northwest. BPA's service territory includes Oregon, Washington, western Montana, and small parts of northern California, Nevada, Utah, and Wyoming. BPA owns and operates more than 15,000 circuit miles of transmission (BPA, 2017) and acts as a balancing authority that reports to the regional reliability coordinator. BPA does not own generation or distribution assets.

Arizona Public Services (APS) is a vertically integrated utility that owns and operates generation, transmission, and distribution assets. APS provides power to 1.2 million customers in 11 counties in Arizona and generates more than 6,100 MW of capacity (Hoovers, 2017). APS is a balancing authority that reports to the regional reliability coordinator, and, as of the last quarter of 2016, is participating in the Western-states' Energy Imbalance Market administered by the California Independent System Operator (CAISO).

NERC directs several industry working groups and activities related to preparing for, riding through, and recovering from events with high impacts on the bulk power system. In addition, the Electricity Subsector Coordinating Council (ESCC), formed in response to recommendations from the National Infrastructure Advisory Council, provides a high-level forum for utility executives and federal decision makers to engage and maintain open communication channels in preparation for large-scale outages. To help reduce risks of cyber and physical attacks, for example, NERC operates the Electricity Information Sharing and Analysis Center (E-ISAC), which disseminates information and alerts to electric industry and government representatives, conducts training exercises, and also maintains the Cyber Risk Information Sharing Program that covers nearly 80 percent of operators of the bulk power system. Through the Spare Equipment Working Group, NERC maintains a database of system components, particularly large transformers, which are available to participating utilities should their assets be physically damaged (NERC, 2011). Similar programs are maintained by industry trade organizations, such as the Edison Electric Institute's (EEI) Spare Transformer Exchange Program and the Grid Assurance™ initiative recently launched by the private sector. Parfomak (2014) has prepared an excellent review of the issue of spare transformers for the Congressional Research Service. This report makes it clear that, while the past few years have seen progress, there is still much that needs to be done. The committee returns to the issue of replacement transformers in Chapter 6.

For many years, electric utilities have widely employed mutual-assistance agreements at both the transmission and distribution level to facilitate sharing of skilled workers and equipment to speed restoration efforts following outages. Typically restoration teams are composed with at least one local utility worker so that system-specific and regional knowledge is available on every team. After Superstorm Sandy, EEI developed a National Response Event Framework for pooling resources and coordinating restoration at the nation-scale from outages that overwhelm regional resources (discussed further in Chapter 6).

Thus, a hallmark of the U.S. electric system is that there are a myriad of bodies engaged in the ownership, planning, operation, and regulation of different elements of the system. Although the system itself operates as if it were a unified and coordinated machine, that occurs in spite of—or in the context of—a system in which the many component parts are subject to varied sets of institutional, legal, cultural, and financial incentives and penalties. Asset owners and operators must, and do tend to, operate with awareness of the fact that their systems can be impacted by events and developments occurring on other parts of the machine.

Finding: The "electric industry" is different across different parts of the United States in ways that reflect the varied choices that states and localities have made with regard to electric sector structure, asset ownership, and regulation. The specific terms and conditions of utility service, power system planning and operations, and transmission planning vary considerably, making it hard to generalize about industry structure across and within the states. This complicates the landscape in which the issue of resilience of the interconnected grid must be addressed.

PHYSICAL STRUCTURE AND OPERATION OF THE HIGH-VOLTAGE TRANSMISSION SYSTEMS

Physical Structure

Most of the electricity supplied to today's bulk power system is generated by large, central generating stations, often located far from population centers. Roughly one-third of the U.S. electricity supply comes from power plants that use natural gas, and another one-third comes from coal-fired generation. This reflects a significant increase in gas-fired generation in recent years, up from just 10 percent in 1990 (Tierney, 2016a). The fraction being generated by coal plants has fallen in large part because of competition from low-cost natural gas. Slightly less than 20 percent of generation comes from large nuclear plants. This share has been shrinking slowly, again because of competition from low-cost natural gas (and, to a lesser degree, flat demand and entry of renewable energy technologies) and the high cost of nuclear plant life extension. Hydropower produces 6 percent of the total U.S. power supply, with other renewables accounting for 7 percent of supply—most of that coming from wind (EIA, 2015). While power provided by large-scale wind and solar projects and from equipment such as solar panels located on customers' premises is rapidly growing, it still constitutes a relatively small share of the total supply. These national averages do not reflect that some systems, such as those in California and Hawaii, have much higher percentages of distributed generation and intermittent renewables.

Hundreds of thousands of miles of transmission lines operate in interconnected networks across the United States, which carry alternating current (AC) electricity. Example voltages include 115, 230, 345, 500, and occasionally 765 kV. A few long-distance point-to-point lines use high-voltage direct current (DC) transmission.[9] Electricity moves through the transmission system following the laws of

[9] Direct current transmission is used selectively in the United States as a way to transfer power between asynchronous interconnects, occasionally to transfer bulk power over long distances (e.g., from the Pacific Northwest to California and from Labrador to the Northeast United States), and for underwater transmission (e.g., between Connecticut and Long Island and from offshore wind farms).

physics and typically cannot be controlled precisely without expensive equipment.[10] The bulk power system relies on large step-up transformers to convert electricity generated at central generating stations to high voltages; this allows for more efficient transmission of power across long distances because there are lower resistive losses of power at higher voltages.

Within the three U.S. bulk-power transmission interconnections, generators operate synchronously at 60 Hz. Large-scale electricity storage is relatively rare;[11] thus, power production and consumption must be kept in balance near instantaneously by increasing or decreasing electricity generation to match changing demand as customers increase and decrease their electricity use. In some areas, in addition to changing the amount of power being generated, grid operators use demand response (DR) programs and technologies to reduce certain loads in lieu of providing more generation. Maintaining the stability of this complex and dynamic interconnected electric system is an immense operational and technical challenge. Nonetheless, this balancing act is successfully accomplished around-the-clock throughout the grid but not without the complex array of tools, techniques, systems, and equipment dedicated to the task.

The high-voltage transmission network enables power to travel long distances from generating units to substations closer to local end-use customers where the voltage is stepped back down and sent into the distribution system for delivery to consumers. Many of the approximately 15,000 substations have minimal physical protection, exposing them to natural hazards, vandalism, and physical attacks (NERC, 2014). Given that there is no standard design for substations, and especially for the transformers they contain, repairs and replacements of custom-designed facilities can be costly and take many months or even years to complete.

Most power outages occur on the local distribution system. Outages are less frequent on the transmission system. However, when outage events happen on the transmission system, they tend to result in wider impacts and can impose greater costs. Several of the largest outages—introduced in Box 1.1 and listed in greater detail in Appendix E—have resulted from operational or control-system errors followed by equipment tripping off-line due to close proximity with vegetation, as was the case with the 2003 blackout. Given the underlying network configuration of the high-voltage grid, system imbalances caused by events in one place can propagate across the transmission system near instantaneously, with the risk of

[10] Technologies that allow control of AC power flows include phase-shifting transformers and other emerging power electronics-based flexible AC transmission system devices that are becoming more available and giving operators more control than ever.

[11] At present, the primary form of large-scale storage capability resides in hydroelectric pumped-storage facilities.

causing cascading blackouts that impact customers hundreds of miles from the site of the initial disturbance.

> **Finding:** Given the interconnected configuration of the high-voltage grid, events in one place can propagate across the transmission system in seconds or a few minutes, potentially causing cascading blackouts that can affect customers hundreds of miles from the initial disturbance. Thus, outage events on the transmission system can result in large-area impacts.

Sensing, Communication, and Control in the Transmission System

If electricity generation and consumption are not kept in balance, frequency will begin to rise or fall depending on whether there is a surplus or deficit of generated power, respectively. Deviations of voltage or frequency outside of relatively narrow boundaries can lead to physical damage to equipment and can increase the probability of a large-area cascading blackout. System operators depend upon various communications and other systems—for example, supervisory control and data acquisition (SCADA) systems in conjunction with software-based energy management systems (EMS)—to monitor the operating status (or state) of the transmission network and to control specific grid components to maintain stability. These systems rely on various sensors located primarily at substations (and, to a lesser extent, on transmission lines) to collect and transmit a wide variety of data, including voltage and current characteristics at specific geographic locations; environmental variables such as temperature, wind speed, and ice formation; and measures of asset health like transformer oil temperature and dissolved gas levels (PNNL, 2015).

Autonomous local controls (called "governors") at individual generators that boost power output proportional to declining system frequency (and vice versa) are fundamental components of system control responsible for regulating system frequency. The rotational inertia provided by spinning generators and some loads in each interconnection determines the rate of frequency change. On a slower timescale, the 60 Hz frequency is regulated by each balancing authority re-dispatching generation every few seconds through a wide area control scheme called automatic generation control.

Protective relays on the transmission network locate, isolate, and clear faults by triggering the appropriate circuit breakers to disconnect at-risk parts before the system becomes unstable and damage results. Depending upon their vintage, protective relays may be electromechanical (the oldest), solid state, or programmable and microprocessor based. They can act and take effect within tens or hundreds of milliseconds. To maintain acceptable voltage across long distance transmission lines, devices such as capacitor banks and static volt-amp reactive[12] compensators are used to control voltage.

A complex system of communications infrastructure is essential to the reliable operational performance of the electric grid, and this dependence is growing. There is, however, wide variation in the sophistication and speed of communication technologies used across the nation's varied electricity systems, with equipment ranging from twisted wire, wireless, rented telephone line, to fiber optic cable dedicated for utility use. The control of electricity systems is inherently challenging both because changes in the electricity system can occur very rapidly and because control needs to operate over time scales that range from milliseconds to multiple days.

To help system operators maintain system reliability, power systems have sensors, communications, and software that automatically perform analyses so as to constantly monitor the state of the electric system. The overall monitoring and control systems for transmission networks include displays and limit checking of all measurements for operators. A principal tool known as the State Estimator filters the various measurements and estimates the operational characteristics of the power system at regular intervals (e.g., every 30 seconds, although the time period used to be longer and continues to get shorter). This helps provide real-time assessments of system conditions that might not otherwise be observable by operators and improves their situational awareness. These assessments also enable other real-time analytic tools that can alert the operator to possible contingencies that could endanger the reliable operation of the grid.

Maintaining the security of these communication networks is critical to the operational integrity of the electricity system. Conversely, the integrity of these other systems (e.g., the internet and communications technologies) depends upon the operational integrity of the electricity system. Conventional approaches to cybersecurity such as firewalls, security software, and "air gaps" (i.e., no connection between systems) are used by utilities to protect their systems from intrusion. However, such measures are being recognized as inadequate, and the growing likelihood that breaches will happen motivates increased emphasis on cyber resilience, including intrusion detection and post-breech restoration. The importance of such activities is illustrated by the 2016 cyber attack on Ukraine's electricity infrastructure. It took grid operators many months to even recognize that their systems had been compromised, at which point it was too late to prevent substantial outages from occurring.

To date, NERC has mandated nine cybersecurity standards as part of the overall mandatory standards it has established for the electric industry. These critical infrastructure protection (CIP)

[12] Delivered power is the product of voltage and current. In AC systems, only that portion of the current waveform that is in phase with the voltage waveform produces power. However, the out-of-phase current does flow in the lines and causes losses, so utilities strive to keep voltage and current waveforms in phase as close as possible.

standards address the security of cyber assets essential to grid reliability.[13] In addition to the cybersecurity standards from the Nuclear Regulatory Commission, these are the only mandatory cybersecurity standards for any of the critical infrastructure sectors across the United States (NERC, 2017).

> **Finding:** System operators depend upon SCADA systems in conjunction with software-based EMS to monitor the operating status of the transmission network and to control specific grid components to assure safe and reliable operation. Control is inherently challenging because it must operate over time scales that range from milliseconds to multiple days. Maintaining the security of power system communication networks and control systems is critical to the operational integrity of the electric system.

> **Finding:** CIP standards dictate minimum cybersecurity protections for the bulk power system, and the electricity sector is the only critical infrastructure sector with mandatory standards. However, these standards do not apply to local distribution systems.

PHYSICAL STRUCTURE AND OPERATION OF THE DISTRIBUTION SYSTEM

Physical Structure

The electric distribution system moves power from the bulk energy system to the meters of electricity customers. Typically, power is delivered to distribution substations from two or more transmission lines, where it is converted to a lower voltage and sent to customers over distribution feeders. Although distribution system outages tend to be more frequent than those occurring on transmission facilities, the impacts of such outages are smaller in scale and generally easier to repair.

Most local distribution systems in the United States are physically configured as “radial” systems, with their physical layout resembling the trunks and branches of a tree. Customers on radial systems are exposed to interruption when their feeder (i.e., their branch) experiences an outage. In metropolitan areas,

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[13] NERC has nine mandatory CIP standards related to cyber issues. These cover such things as reporting of sabotage (CIP-001): identification and documentation of the critical cyber assets associated with critical assets that support reliable operation of the bulk power system (CIP-002); minimum security management controls to protect critical cyber assets (CIP-003); personnel risk assessment, training, and security awareness for personnel with access to critical cyber assets (CIP-004); identification and protection of the electronic security perimeters inside which all critical cyber assets reside, as well as all access points on the perimeter (CIP-005); a physical security program for the protection of critical cyber assets (CIP-006); methods, processes, and procedures for securing critical cyber assets and other cyber assets within the electronic security perimeters (CIP-007); identification, classification, response, and reporting of cybersecurity incidents related to critical cyber assets (CIP-008); and recovery plans for critical cyber assets, relying upon established business continuity and disaster recovery techniques and practices (CIP-009) (NERC, 2017).

these trunks and branches typically have switches that can be reconfigured to support restoration from an outage or regular maintenance. When a component fails in these systems, customers on unaffected sections of the feeder are switched manually or automatically to an adjacent, functioning circuit. However, this still exposes critical services such as hospitals or police stations to potential outages, so these facilities are often connected to a second feeder for redundancy. In high-density urban centers, distribution systems are often configured as “mesh networks,” with a system of interconnected circuits and low-voltage equipment able to provide high reliability service to commercial and high-density residential buildings. Such mesh networks—found in Manhattan, parts of Chicago and San Francisco, and other high-density urban areas—provide multiple pathways through which electric service may be provided to customers.

Most distribution systems’ wires are located aboveground. However, areas with high population density, including some suburban areas, frequently locate electricity and other infrastructure underground. This provides some physical protection and reduces risks posed by vegetation, but it can make identifying faults and implementing repairs more difficult and increase the risk of equipment damage in earthquake and flood-prone locations. In less densely populated areas, distribution feeders are usually located aboveground, with smaller distribution transformers located on local utility poles that step down to lower voltage for delivery to customers’ premises.

There is no single organization responsible for establishing or enforcing mandatory reliability standards in distribution systems, although state utility regulators and boards of publicly or customer-owned utilities often assess performance using quantitative reliability metrics and set goals for the allowable frequency and duration of system and customer outages. Typically, utilities collect data on the length and frequency of outages that result from events on the local distribution systems, and some utilities (particularly investor-owned utilities with encouragement from regulators) disclose this information to the public. However, there is wide variation across the states and the utilities within them with regard to their tracking, publication, and/or enforcement of local reliability indicators. In light of their role in approving rates and in deciding what costs and other investments can be recovered through rates, public utility commissions (and boards of publicly or customer-owned distribution utilities) have significant influence on the reliability, cost, and resilience of distribution systems, as FERC does at the bulk energy system level.

In recent years in some parts of the United States, distribution systems have also experienced substantial additions of distributed energy resources (DERs). DERs are electrical resources that are attached to the local distribution system behind a customer’s meter. Examples include rooftop solar panels, customer-owned batteries, fuel-cell technologies, wind turbines, back-up generators, and combined heat and power (CHP) systems.[14] Although DERs, and distributed generation specifically, account for a relatively small fraction of total generation nationally, their installation varies significantly from one state to another, with some local distribution systems (e.g., in Hawaii, California, New Jersey, and Arizona) seeing hundreds of MW of growth in installed capacity in recent years (DOE, 2017a). Because many DERs provide surplus power beyond the amount of electricity consumed on the customer's premises, they inject power into a distribution system designed to operate in a one-way flow of power from the substation to the customer. (See "Near-Term Drivers of Change and Associated Challenges and Opportunities for Resilience" for a longer discussion of DERs and their implications for grid planning, operation, and resilience.)

Even with increasing numbers of consumers installing generating equipment on their own premises, and using the distribution system to access the bulk energy system when on-site generation is not available, it is unlikely that the majority will go entirely "off grid" in the near future. Although many technologies and service offerings are enabling an increasing number of customers to meet larger portions of their electricity needs with on-site generation, for economic, technical, and regulatory reasons most observers (and the committee) do not anticipate that the dominant customer profile will be self-sufficient and disconnected from the grid during the time frame of interest in this study (i.e., in the next two decades). Moreover, individual self-sufficiency is unfeasible for the majority of the population, and local distribution system planners have to plan to meet the uncertain loads of customers for the foreseeable future.

> **Finding:** There is no single organization responsible for mandatory reliability standards in electric distribution systems in the United States. State utility regulators often set standards for the allowable frequency and duration of system and customer outages. In many cases, outages caused by major events are *excluded* when computing reliability metrics.

Sensing, Communication, and Control in the Distribution System

The technological sophistication, penetration of sensors, deployment of advanced protection devices, communications technologies, computing, and level of automation deployed by distribution utilities vary significantly across the United States. As in the case of transmission systems, distribution

[14] These technologies are "dispatchable," meaning they can be turned on or off when needed by the utility. Other definitions do not emphasize that DERs be dispatchable—for example, FERC's definition at https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-1.pdf.

networks have been undergoing a transition from analog devices to digital. However, in many distribution systems, it is more difficult to justify large investments in modernization and digital controls, in part owing to factors such as customer density on circuits, circuit configurations, existing performance, and component age. Thus, many distribution systems still operate as they did when built after World War II. However, given the substantial investments (exceeding $25 billion annually [EEI, 2017]) under way in replacing aging distribution infrastructure, there is an opportunity to enhance the reliability and resilience of the distribution systems through incorporation of advanced technologies, and some distribution utilities have made extensive upgrades.

Protective relays located at distribution substations are used to sense faults, such as a downed wire, and in turn signal the feeder circuit breaker to open. Some feeders have switches that can detect and isolate faults, albeit less frequently (as discussed previously). Distribution laterals that extend from the main feeders have fuses installed that protect the main feeder from faults that occur on the lateral branch. Together, protection devices are critically important for maintaining public safety and for limiting the extent of an outage, in some cases preventing disturbances from cascading higher up in the system.

Each of these devices, relays, switches, and fuses are designed to operate in a coordinated manner. These distribution protection schemes are undergoing a similar analog to the digital transformation occurring on transmission systems. Over the last 20 years, electromechanical relays have increasingly been replaced with digital, and now communicating, software-based relays as old equipment reaches end-of-life or when new substations are constructed. Similarly, switches on some feeders have been replaced with more advanced and automated switches when it is cost-effective and justifiable. Protective fuses also have digital communicating alternatives, but these are still largely in demonstration studies to evaluate cost-effectiveness and applicability.

Beginning in the 1990s, many utilities selectively installed SCADA on distribution systems for feeder breakers, mid-point reclosers, and back-tie switches (as well as capacitor bank controls), along with distribution management systems to operate these devices. These first-generation automation systems allowed utilities to operate circuit breakers, switches, and components remotely, which previously required personnel in the field. By sectionalizing circuits in half, these early systems allowed more rapid restoration of the faulted half of the circuit. Such systems have been implemented by many utilities in metropolitan areas where high customer densities enable cost-effective applications.

More recently, a second generation of distribution automation technologies has been adopted. Outage management systems (OMS) that provide greater visibility into distribution circuits and support operators in making restoration decisions have been deployed over the last decade. Some utilities have implemented advanced automation technologies that locate faults, isolate faulted sections, and automatically restore remaining sections to service. Similar to first-generation automation systems, these systems are typically cost-effective only in areas with high customer density per mile of line and on overhead lines with exposure to environmental conditions that reduce reliability and impair restoration.

Although at present these technologies have only been implemented on a fraction of distribution systems across the country, continued deployment of distribution substation SCADA and first- or second-generation automation has the potential to improve the reliability and resilience of the nation's distribution systems, albeit if implemented selectively and as part of a long-term improvement plan. For example, select utilities in areas with significant exposure to environmental threats (e.g., Southern Company in the southeastern United States), or with the need to have greater visibility and control over DERs (e.g., Southern California Edison), have installed or are pursuing advanced automation technologies for automatic reconfiguration of feeders based on outage and load/local generation conditions. However, it is unlikely that these second-generation automation technologies will be deployed in lower-density rural areas or in newer underground systems, as the potential benefits do not typically justify the increased costs.

Compared to transmission systems, which have greater deployment of sensors and therefore provide operators with much better awareness of system behavior and operation, often local distribution utilities only monitor circuit breaker status and measure feeder current and voltage as they leave the substation, and not at other locations on the circuit. However, some utilities installed automation sensing and fault current indicators on feeders themselves, although this level of monitoring is uncommon. Thus, most distribution utilities continue to rely on customer calls to assist in the location of faults. In the most rudimentary cases, utilities without distribution substation SCADA use customer calls to report outages and direct service restoration and repairs.

Utilities have yielded significant benefits from first-generation distribution automation, where cost-effective, but second-generation automation systems are still early in adoption (DOE, 2017b). One utility that adopted second-generation automation with the help of federal demonstration grants reported significant reductions in the severity and duration of outages, as well as economic and operational benefits (Glass, 2016). Of course, actions that increase automation, reliance on software, and communications infrastructure also add complexity and can inadvertently increase a utility's exposure and vulnerability to cyberattack.

Within the last decade, utilities have completed over 60 million advanced metering infrastructure (AMI, sometimes also called "smart meter") installations across the United States. These investments were greatly accelerated by incentives arising from funding available in the 2008 American Reinvestment and Recovery Act. Figure 2.8 shows the percentage of electric meters with AMI by state. In distribution systems where it has been installed, AMI can provide information to assist in identifying the extent and location of customer outages, as well as the primary benefit of reducing the cost of meter reading. However, the outage data from AMI systems tend to be of poor quality and inconsistent for use in real-time fault identification and initial restoration. This is in part because the messages sent to operators are a "last gasp" from a meter losing power, and often the message itself cannot get back to the operations center as the communications network also loses power (most AMI systems installed are based on radio frequency mesh communications networks). As a result, most AMI systems today are used to validate that electricity service to customers has been restored and for postmortem analyses. More advanced AMI systems, which are available today, have addressed this issue and will be able to support real-time operational restoration and improved communication with customers. Furthermore, to take full advantage of AMI, utilities must make substantial investments in database management and analysis software to utilize the large amount of data flowing back to operators.

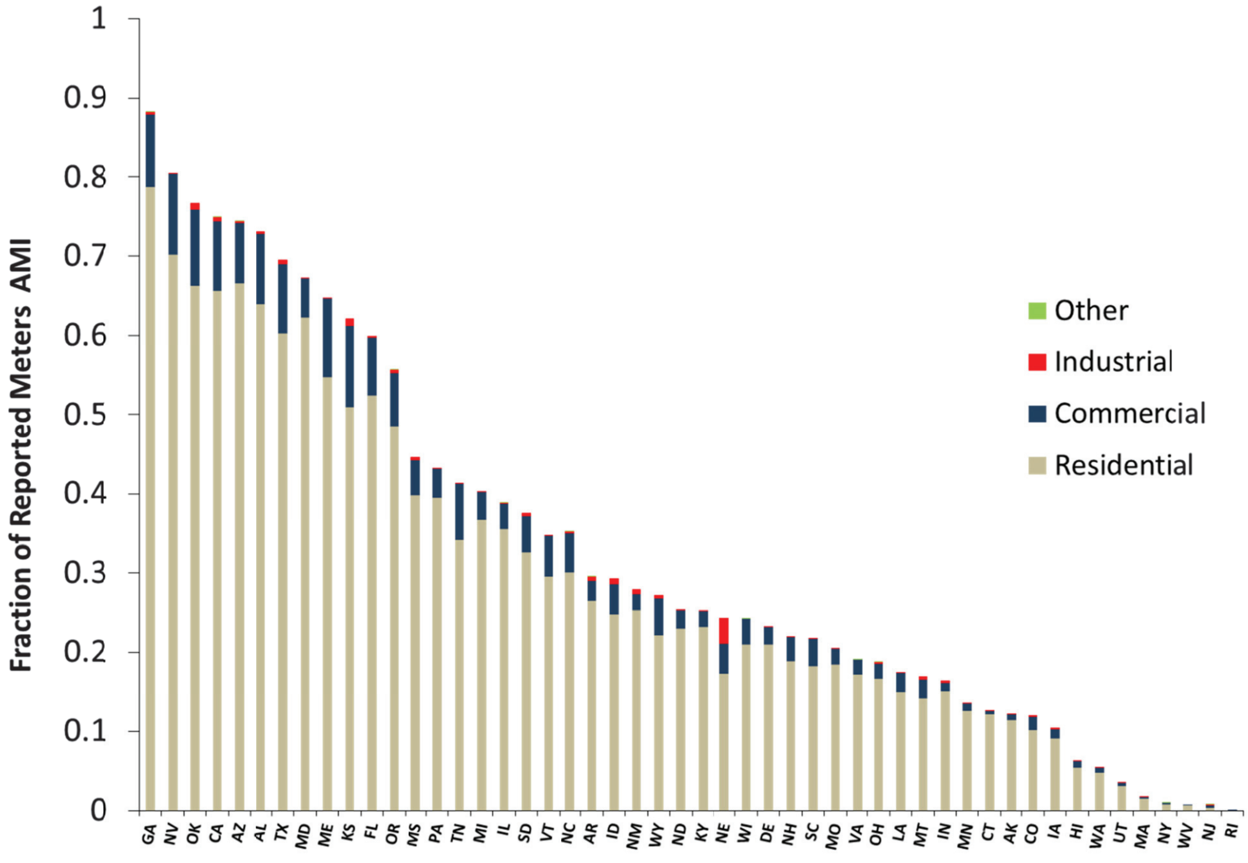

FIGURE 2.8 Fraction of customer meters with advanced meters by state in 2015. SOURCE: EIA (2016a).

Deployment of advanced meters has been met with mixed reactions. Some state regulators remain skeptical of the benefits of AMI or contend that equivalent benefits can be achieved at a lower cost to customers (Reuters, 2010; AEE, 2015; NJBPU, 2017). Some customers have been suspicious of technologies that they view not only as expensive, but also as potentially dangerous for their health[15] and for the security of their private data. (Karlin, 2012; Spence et al., 2015). AMI roll-outs in some communities have experienced backlash for these reasons, although other AMI deployments have been much smoother.

Inverters convert the DC signal produced by solar panels or batteries to the AC power used on the distribution system and serve as the interface between many DERs and the distribution system. While the main task of an inverter is as an electric power conversion device, modern technology permits inverters to perform a broader array of ancillary tasks, which can be leveraged in power conditioning to support the grid in various ways (these are sometimes referred to as “Smart Inverters”). Currently, inverters operate with a spectrum of capabilities—for example, some are able to stay connected and ride through disturbances (and in some cases can contribute to solutions), while others automatically disconnect during a disturbance. Interim standards issued by the Institute of Electrical and Electronics Engineers (IEEE) allow for such “ride through” of disturbances, and FERC now requires this capability. These standards remain under revision (IEEE, 2013).

Currently, relatively few of the inverters installed on the system can provide the local utility with visibility into the power injection of the DER into the grid or the ability to control it when necessary. At some point in the near future, when technical standards catch up with technology, it is possible that inverters will have the capability to communicate with utilities and system operators. This can be further leveraged to enhance system resilience under abnormal situations—for example, by changing inverter settings on the fly for adapting to changing grid conditions. Additional details are provided in the discussions in Chapters 4 and 5.

> **Finding:** There is wide variation across the United States in the level of technological sophistication, penetration of sensors, deployment of advanced communications technologies, and level of automation deployed by distribution utilities. Many utilities, particularly in metro areas with overhead infrastructure, have invested significantly in first-generation automation over the past 30 years. Where cost-effective, more advanced automation is beginning to be implemented to enhance reliability, resilience, and integration of DERs.

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[15] While the field strengths are miniscule, the concern is with the possibility of health consequences from exposure to the RF communication associated with the AMI. Similar concerns are expressed by some people about a wide range of RF sources in the world today. Of course, many of these same people routinely make use of cell phones and other wireless devices.

Finding: Actions that increase automation and reliance on software and communications infrastructure also add complexity and can inadvertently increase a utility's exposure and vulnerability to cyber attack. This is particularly acute with regard to DER integration.

Keogh and Cody (2013), researchers with the National Association of Regulatory Utility Commissioners (NARUC), explain the following:

> [The regulatory] frameworks used to evaluate reliability investments are not perfectly equipped to address investments dealing with these large-scale and historically unprecedented hazards, and some improvements to the frameworks may be needed [p. 1] . . . . Those metrics miss two components: (1) They often undervalue the impact of large-scale events and focus on normal operating conditions; and (2) they price lost load at a flat rate, when in fact the value of lost load compounds the longer it is lost [p. 7] . . . [M]aking every corner of our utility systems resistant to failure may prove cost-prohibitive, resilience should be selectively applied to the areas that need it most. Existing risk management frameworks can be better deployed to help prioritize where the best investments can be made. A resilience investment may be particularly valuable in the face of high-impact disasters and threats that utility systems have not faced before, like national-scale natural disasters or man-made cyber and physical attacks [p. 1].[16]

Thus, because the existing reliability metrics used to inform regulatory decision making are inadequate for informing resilience investments, continued research is needed to develop analogous metrics for electricity system resilience. Some regulators have begun to consider how resilience objectives should be incorporated by utilities in their jurisdictions, with several prominent examples promising to transform the electric industry today. In response to Superstorm Sandy, for example, New Jersey regulators approved more than $1 billion in storm-hardening investments for critical substations and building additional distribution circuits for greater redundancy (NJ Board of Public Utilities, 2015).

[16] The authors also explain, "If an investment avoids or minimizes service interruptions in the absence of an extraordinary event, it is just an everyday reliability investment, and the means already exist for utilities and regulators to thoroughly consider it. An important point . . . is that resilient infrastructure does more than one thing well, because a resilience investment needs to pay for itself and create value for ratepayers, even when it is not being used" (Keogh and Cody, 2013, p. 5).

Finding: The decisions made by state public utility commissions and the boards of public or customer-owned utilities have significant influence on the reliability, cost, and resilience of distribution systems. The committee agrees with a NARUC analysis that concludes that techniques for guiding and approving reliability investments are inadequate for resilience.

METRICS FOR RELIABILITY AND RESILIENCE

Reliability Metrics are Relatively Mature and in Widespread Use

Reliability has long been a component of utility planning and operation, and there are many mature metrics to quantify reliability and evaluate potential reliability improvements associated with different grid investments. Reliability metrics are grouped into those applied to generation and transmission systems (e.g., adequacy, loss of load probability) and those for the distribution system, with common examples defined in Box 2.2. Metrics for generation and transmission are used by FERC and NERC, whereas oversight of reliability at the distribution level is left to state regulatory agencies. As previously discussed, ownership and operation of the U.S. electric system is characterized by a mixture of public, private, and cooperative institutions with different incentives and organizational structures, and these different institutions are regulated differently. Thus, different organizations are responsible for maintaining different packages of standards in different locations, some of which can only be attained through collaboration with others.

BOX 2.2
Common Distribution System Reliability Metrics

SAIFI
"System Average Interruption Frequency Index (Sustained Interruptions)—This is defined as the average number of times that a customer is interrupted during a specified time period. It is determined by dividing the total number of customers interrupted in a time period by the average number of customers served. The resulting unit is 'interruptions per customer'" (APPA, 2014).

SAIDI
"System Average Interruption Duration Index—This is defined as the average interruption duration for customers served during a specified time period. It is determined by summing the customer minutes off for each interruption during a specified time period and dividing the sum by the average number of customers served during that period. The unit is minutes. This index enables the utility to report how many minutes customers would have been out of service if all customers were out at one time" (APPA, 2014).

CAIDI

"Customer Average Interruption Duration Index—This is defined as the average length of an interruption, weighted by the number of customers affected, for customers interrupted during a specific time period. It is calculated by summing the customer minutes off during each interruption in the time period and dividing this sum by the number of customers experiencing one or more sustained interruptions during the time period. The resulting unit is minutes. The index enables utilities to report the average duration of a customer outage for those customers affected" (APPA, 2014).

CAIFI
"Customer Average Interruption Frequency Index—The average frequency of sustained interruptions for those customers experiencing sustained interruptions" (APPA, 2014).

MAIFI
"Momentary Average Interruption Frequency Index—Total number of momentary customer interruptions (usually less than five minutes) divided by the total number of customers served" (APPA, 2014).

While reliability metrics are more established and widely used than resilience metrics, there remain many opportunities to improve their formulation and utilization. Although valuable, distribution system metrics that present average values lack details regarding the types of customers experiencing an outage and the severity of individual outage events. Thus, there is a need to increase the granularity of reliability metrics, and the Department of Energy (DOE)-sponsored Grid Modernization Laboratory Consortium (GMLC) is in the process of developing metrics for distribution reliability with greater spatial and temporal resolution (GMLC, 2017). Another critical opportunity for improvement is to better connect reliability metrics to the economic benefits of more reliable service, which requires an understanding of how different customers value reliable electric service.

As society becomes ever more dependent on continuous electricity supply, and the technologies and institutional structures employed to provide that service evolve, it is important to rethink the system's reliability criteria. To the extent that electricity supplies become more distributed, micro-sized local supply communities may take care of their own unique local needs; but to the extent that a significant component of supply is provided over a regional power grid, all users share equally in that bulk supplier's reliability (what is defined as a "public" good by economists) and so some centralized authority is needed to set and enforce the reliability standard for that supply entity. That standard could be based and routinely updated on some systematic estimate of the value of its reliability (and resilience, too).

It is important to note that reliability metrics provide only limited insight about resilience. A survey of publicly owned utilities in 2013 indicated that two-thirds of the responding utilities excluded outages caused by major events when calculating their performance on reliability metrics (APPA, 2014).[17] Thus, planning, operational strategies, and technologies used to reduce impacts and expedite recovery from large-area, long-duration outages may have no impact on a utility's performance measured by reliability criteria.

Development of Metrics for Resilience Lags Behind Those for Reliability

Unlike reliability, there are no generally agreed upon resilience metrics that are used widely today. This is in part because there is not a long history of large-area, long-duration outages that can be analyzed to guide future investments (which is the case for reliability). Nonetheless, the electricity sector is arguably more advanced in considering and evaluating resilience than other critical infrastructure sectors. There are myriad resilience metrics proposed in research and most remain immature (Willis and Loa, 2015). Some recent analyses have proposed resilience metrics based on concepts like resistance, brittleness, and dependency. Following the resilience processes introduced in Chapter 1, Kwasinski (2016) proposes that resilience is an attribute with four distinct metrics: (1) withstanding capability, (2) recovery speed, (3) preparation/planning capacity, and (4) adaptation capability. A study at Sandia National Laboratory lays out a broad framework for developing resilience metrics, frequently in combinations, and for valuing their respective contributions to overall customer value (SNL, 2014). Furthermore, individual utilities frequently establish their own metrics to guide decision making. For example, the committee was briefed by the Chicago utility Commonwealth Edison on metrics used in selecting optimal locations to site community microgrids,[18] based on a weighted sum of measures of customer criticality, historical reliability, projected capacity constraints, and measures of substation health.

As part of the GMLC metrics analysis, researchers from multiple national labs proposed a set of resilience metrics, shown in Table 2.2, that build on a resilience analysis process developed as part of the DOE Quadrennial Energy Review. Because many causes of large-area, long-duration outages have a low

[17] Also, of the 180 utilities responding to the American Public Power Association survey, 87 percent collected outage data at the system level, 47 percent also collected data at the feeder or circuit level, and 31 percent collected data at the substation level (APPA, 2014).

[18] A microgrid is an energy system consisting of distributed generation, demand management, and other DERs that can connect and disconnect from the bulk power system based on operating conditions.

probability and their impacts are highly uncertain (e.g., based on the types of customers impacted, the exact tract a hurricane follows), the GMLC metrics analysis emphasizes inclusion of statistical measures of uncertainty alongside reporting of resilience metrics and all consequences are estimated as probability distributions.

TABLE 2.2 Example Resilience Metrics Proposed by the DOE-supported Grid Modernization Laboratory Consortium

Consequence Category	Resilience Metric
Direct	
Electrical Service	Cumulative customer-hours of outages
	Cumulative customer energy demand not served
	Average number (or percentage) of customers experience an outage during a specified time period
Critical Electrical Service	Cumulative critical customer-hours of outages
	Critical customer energy demand not served
	Average number (or percentage) of critical loads that experience an outage
Restoration	Time to recovery
	Cost of recovery
Monetary	Loss of utility revenue
	Cost of grid damages (e.g., repair or replace lines, transformers)
	Cost of recovery
	Avoided outage cost
Indirect	
Community function	Critical services without power (e.g., hospitals, fire stations, police stations)
	Critical services without power for more than N hours (e.g., N> hours or backup fuel requirement)

SOURCE: GMLC (2017).

Development of resilience metrics and methods to defining resilience goals, as well as comparison of alternative strategies for increasing resilience, remains an active area of research, and the committee believes more research and demonstration is required before the electricity sector can reach consensus on a set of appropriate metrics. Metrics often drive decision making. Establishing and building consensus around metrics is an important prerequisite for comparing resilience enhancement strategies and for evaluating their costs and benefits. Many of the technologies and strategies for increasing the resilience of the electricity system described in the following chapters are expensive, particularly when implemented on a large scale. Without consistent resilience metrics, large amounts of money could be spent with little understanding of actual resilience benefits and with much of this cost passed on to ratepayers.

Economic Valuation of Resilience

Metrics for resilience should not be selected merely because they can be quantified easily. In deciding what level of resilience is appropriate, it is important at a minimum to estimate how much a lack of electricity system resilience costs individuals and society. Thus in developing resilience metrics, it is essential to be able to link those measures to the value retained or added to society. Furthermore, market responses and/or survey results may provide inadequate measures of resilience since they have attributes of both a private and a public good (many neighbors share the same benefit). Likewise the services provided by most public or private regulated utilities are combinations of pure public and private goods. This is why standards and regulations are important to maintain and restore quality in electricity markets, which are not classical competitive markets with fully rational decision makers (Hirschman, 1970).

Thirty years ago, with most electric supply utilities vertically integrated, the customers knew who to blame for outages. If the overseeing public utility commission (PUC) did not set and enforce adequate reliability standards, the resulting public outcry often resulted in a government response including public pillorying and/or financial penalties assessed against the responsible utility. In some instances of major outages, the outcry extended to elected officials in state or federal government. The principal example is the 2003 blackout that led to EPAct of 2005, granting new authority to FERC to set reliability standards for the bulk power system and to assess penalties for non-compliance.

Developing and enforcing resilience and reliability metrics will become increasingly complicated as technologies and customer preferences evolve alongside changes in public policies regarding equity and environmental goals. The emergence of competitive markets in some areas of the country has altered the institutional structure of the industry, the nature and form of its regulation, and the structure of its financing. So while competition has replaced regulation in some segments of the industry as the means of ensuring reasonable price levels, maintaining the reliability of the whole system has become more complicated with divided responsibility. At the bulk power supply level today, reliability standards are still maintained, but this is often done through market mechanisms that induce sufficient prices for adequate generation to be built at needed locations, as well as for generation operators to provide operating reserves and to be available to offer those services (provide adequacy), all as overseen by

FERC. At the distribution level, state regulation (and public outcry) is primarily relied upon to sustain the reliability to end-use customers.

In the end, reliability and resilience are for the benefit of the customer and society, and all actions, including rules and regulations, need to reflect customer values. Although a consistent principle should be developed for the nation, cost-effective instruments are likely to vary widely. The application of the principle should take into account variations in climate, nature of hazards, socio-economic and demographic patterns, and the nature of customers (industrial, commercial, residential, essential public services, etc.), all of which may lead to different distribution-system configurations (e.g., there are mesh network designs in some densely populated areas, whereas less populated areas have radial distribution system designs).

No rule is effectively implemented without rewards or penalties assigned for adherence. For private goods, if there is truth in labeling and no hidden defects are possible, the market can take care of those incentives. In the case of public goods furnished by a unique provider in each location, assessing penalties for non-compliance can have pernicious repercussions if the service must be sustained. If compliance requires substantial capital investments, arranging financing can be challenging if the entity is under attack by its regulators and its next period's earnings promise to fall because of the fines. If fines are pooled over a wide area of providers in order to support resilience and reliability investments, there is little incentive for the individual utility to provide reliable service. The nature of such problems will change if numerous local microgrids and community-based distribution consortiums become widespread. Furthermore, the shifting of reliability and resilience decisions to the local level also presents serious challenges for financing. One model might be parallel to the U.S. Department of Agriculture Rural Utility Service's (RUS's) funding of rural cooperative electricity suppliers.[19] In the end, regardless of the form of the institution, reliability and resilience begins at home—at the distribution level with the customer.

Because electricity customers value *both* the reliability and resilience of the system, developing metrics and incentives (or disincentives) for utilities based upon resilience and reliability separately is likely to be sub-optimal. It is important that the possibility of trade-offs between resilience and reliability is integrated into metrics, and that the costs of supplying the sum of the measures do not exceed their combined value to customers and to society as a whole (SNL, 2014). At present, such an overarching valuation of the burgeoning number of reliability and resilience metrics does not exist to aid in the development of reasonable and enforceable standards.

[19] The RUS provides loans and loan guarantees to help finance construction and operation of electric distribution and transmission systems (among other things) in rural areas. Electric cooperatives (and other utilities) may receive such financial support from the RUS (USDA, 2016).

In addition to developing better resilience metrics and using them to monitor and realize better outcomes, knowing much more about what individuals and society are willing and able to pay to avoid the consequences of large-area, long-duration grid failures is an important input to deciding whether and how to upgrade systems to reduce impacts of an outage. Much of what we know is anecdotal from looking backwards at such failures, such as from Katrina, Sandy, or the northeastern blackout of 2003. Most prior quantitative studies have only examined outages of much shorter duration. Willingness and ability to pay may differ substantially based on geography, electric customer class, and socioeconomic status. So work should proceed in parallel to develop better metrics and a better understanding of consumers' and society's willingness to pay.

Finding: While reliability metrics are relatively well established and widely used in electricity system planning and operation, the development of agreed-upon metrics for resilience lags significantly behind. Further, since there is currently no common basis for assessing the relative cost-effectiveness of the existing reliability metrics that differ by purpose, integrating the ongoing work on developing resilience metrics may lead to confusion and duplication in their implementation. Thus it may be difficult to evaluate, compare, and justify investments made to improve resilience and to assess progress made in enhancing both the resilience and the overall reliability of the grid.

Recommendation 2.1: The Department of Energy should undertake studies designed to assess the value to customers—as a function of key circumstances (e.g., duration, climatic conditions, societal function) and for different customer classes—of assuring the continuation of full and partial (e.g., low amperage and/or periodic rotating) service during large-area, long-duration blackouts.

Recommendation 2.2: The Department of Energy should engage the North American Electric Reliability Corporation, the National Association of Regulatory Utility Commissioners, the National Rural Electric Cooperative Association, and the American Public Power Association in a coordinated assessment of the numerous resilience metrics being proposed for transmission and distribution systems and seek to operationalize these metrics within the utility setting. That assessment should focus on how system design, operation, management, organizational actions, and technological advances are affected by those metrics. All metrics should be established so that their cost-effectiveness in bringing added value to the nation can be assessed. Complementarities between metrics should be identified, and double counting of their effects should be avoided.

NEAR-TERM DRIVERS OF CHANGE AND ASSOCIATED CHALLENGES AND OPPORTUNITIES FOR RESILIENCE

As described previously, significant transitions are currently under way in the power system and its associated institutions. Some changes result from market fundamentals including changing customer preferences, others from an array of state and federal policies, and yet others from technological innovations that offer both opportunities and new challenges for the grid, especially in terms of resilience. The future electric system will have a more complex array of central-station power plants on the bulk power system, as well as DERs behind customers' meters or otherwise attached to the local distribution system. Many more players will use technologies and applications that can expose the grid to greater risk of cyberattack. These changes may both facilitate and complicate the development of greater reliability and resilience. Starting with a description of these various trends that are affecting the grid, this section discusses some of the implications of those trends for the resilience challenges its owners, operators, and users will increasingly face in the years ahead.

Power Market Fundamentals

The nation's "shale gas revolution" began a decade ago and has contributed to a changing generation mix in many parts of the United States, particularly where coal-fired or nuclear generation have been major players. In combination with a decade of flat electricity demand (EIA, 2016b), loss of cost advantages for coal (Tierney, 2016a), declining costs for small-scale and utility-scale wind and solar generating technologies (Lazard, 2015), and controls on emissions of mercury and other toxic air pollutants, this has contributed to retirements of 49.3 gigawatts (GW) of coal-generating capacity since the year 2000 (EIA, 2016c). Most of these plants were older, relatively inefficient, and without modern pollution controls. Because of competition from low-cost natural gas and the high costs of plant life extensions, several nuclear plants have been retired in recent years with others facing premature closure (BNEF, 2016).

The vast majority (91 percent) of the 403 GW of generating capacity added since 2000 has been at gas-fired generating units (281 GW), as well as wind and solar installations (together, 87 GW) (EIA, 2016d). In 2016 alone, utility-scale wind, solar, and gas-fired capacity amounted to 93 percent of total generating capacity additions (EIA, 2016d). Another 2 GW of distributed solar capacity was added in 2015, which is the most recent year reported by EIA (EIA, 2016e). The changing electric generating mix is introducing new challenges for grid operators, who must keep generation and consumption balanced with a decreasing amount of baseload coal and nuclear assets and an increasing share of intermittent, non-dispatchable generating resources.

DERs differ from the large central generators that traditionally form the backbone of the grid in that DERs are much smaller, located closer to consumers, and often controlled in a decentralized fashion by local users themselves. The shift to DERs comes as a result of changes in technology, customer preference, and policy. Technologically, numerous new power supply, response, and control systems are emerging. At the same time, federal and state regulators, as well as others, are pushing for the adoption of DERs with a variety of goals that are described further in Box 2.3 and in the following section. As with almost any change in technology, these driving forces interact in many complex ways. Some of the changes in technology are purely exogenous, but most are responding at least partly to policy signals. These forces also interact with consumer preferences, as is typically observed with changes in other technologies. New technologies for local supply and power conditioning have seen early adoption by users who have a particularly strong preference for reliable power, such as hospitals and server farms.

BOX 2.3
Federal and State Policy Drivers of Change in the Electric System

Federal Drivers

- Encouraged the development of alternative energy produced by non-utility generation (e.g., PURPA in 1978);
- Promoted competition in wholesale electricity markets (e.g., through the EPActs of 1992 and 2005);
- Mandated the introduction of increasingly efficient electric appliances into the marketplace;
- Supported utilities' investments in advanced meters and other technologies (e.g., through the American Recovery and Reinvestment Act of 2009);
- Required mandatory reliability standards and authorized incentive rate of returns on some transmission investments on the bulk power system (both under the EPAct of 2008);
- Introduced investment and production tax credits for renewable electricity;
- Adopted new regulations under the decades-old Clean Air Act to control air toxic and carbon-dioxide emissions from existing fossil-fuel generators; and
- Standardized small generator interconnection procedures.

State and Local Drivers

- Opened retail commodity markets to competition and third-party innovation (see Figure 2.6);
- Encouraged the development and adoption of renewable resources (DSIRE, 2016a, 2016b, 2016c);
- Developed state tax incentives for energy efficiency and renewable energy (DOE, 2016b; DSIRE, 2016d);
- Installed advanced metering devices and microgrids in New York and California, for example (Tierney, 2016b);

- Developed rate designs (such as net metering[20] tariffs or time-of-use rates) to encourage DER adoption;
- Implemented energy efficient appliances, green buildings, and other measures to increase the efficiency of energy use (ACEEE, 2012; Alliance to Save Energy, 2013);
- Promoted adoption of electric vehicles and installation of the charging infrastructure to support them (Plug-in America, 2016); and
- Adopted technologies to control carbon emissions from power plants (RGGI, 2016; CARB, 2014).

Federal and State Policy Drivers

The federal government and most states have been active in adopting policies aimed at promoting the introduction of efficient and renewable energy technologies, controlling emissions associated with power generation, and fostering innovation and grid modernization. These policies, many of which are mentioned in Box 2.3, have impacted both the bulk power and local distribution systems. Importantly, but with notable exceptions, federal and state policies that have encouraged development of advanced technologies and DERs have been motivated by considerations of economic development, environmental impacts, or clean-energy goals, rather than by concerns for resilience and reliability.

While many of these federal and state policies have been directed toward regulated utilities, many have encouraged non-utility entrants to make investments, operate programs, and bring new technologies to the marketplace. Today, many of the devices (e.g., central-station power plants, rooftop solar installations and their accompanying smart inverters) attached to the grid are owned by third parties. There are many more actors affecting the operations of the grid, and grid operators and others need to take into account a wide variety of facilities and resources as they assure the operational reliability and security of the grid.

To gain a better appreciation of the state of DER and microgrid adoption in jurisdictions across the country, the committee sent a questionnaire to public utility commissions in all 50 states and the District of Colombia and received nearly 25 responses. The questionnaire sought anecdotal information about variations in deployment of smart meters, distribution automation, organized DR programs, CHP facilities, and questions regarding legal constraints on microgrids across the country. Answers called attention to wide differences in adoption of these technologies and views on their potential to increase system reliability and resilience across the United States, as summarized in Box 2.4. Although not quantitative and not used to make any comparative statements, the answers received by the committee

[20] Net metering is a billing arrangement in which a customer with distributed generation receives credit for the energy he/she provides to the grid, sometimes at full retail rates or a fraction thereof.

broadly align with previous studies done by FERC (2016b) and stakeholder groups (Gridwise Alliance, 2016).

BOX 2.4
Example Comments to the Committee on DER and Microgrid Deployments across the United States

Staff of the Pennsylvania PUC noted that "there are no utility-owned or operated microgrids in Pennsylvania at this time. However, there are some campus and commercial test beds, especially in the Philadelphia and Pittsburgh areas . . . . The Pennsylvania PUC encourages distribution utilities to make use of advancing technologies and support CHP projects. Smart meters are mandated for all large electric distribution companies."

The New Jersey Board of Public Utilities was the only state utility regulatory organization that indicated a microgrid was able to sell electricity directly to "one customer across one right of way," as well as being able to sell power into the wholesale market operated by the RTO PJM.

The Georgia Public Service Commission (PSC) described major investments made by Southern Company in advanced metering and distribution automation: "The resulting smart grid network will greatly improve reliability for Southern Company customers . . . . Georgia Power reports its reliability statistics (SAIDI, SAIFI) annually since 2003. Since the installation of the smart grid equipment, these metrics have trended downward."

According to staff of the Illinois Commerce Commission (ICC), "The Illinois General Assembly has enacted laws, and the ICC has adopted ratemaking policies that support and encourage the development and deployment of new technologies and facilities. Utilities report that their actions combined with customers' responses to programs tied to new technologies result in reliability and resiliency improvements."

In Kansas, the state Corporation Commission staff responded, "So long as these technologies are dispatchable by the incumbent utility, staff views them as supportive of system reliability and resiliency."

Staff of the North Carolina Utility Commission informed the committee, "The Commission encourages utility consideration and deployment of cost-effective new technologies that would improve the reliability and resiliency of the electric grid. The utilities are required to address these technologies in their integrated resource plans and smart grid technology plans filed with, and reviewed by, the commission."

The Montana PSC staff indicated, "The PSC supports regulated utilities to engage in pilot projects and studies to gain insight into potential benefits of [advanced DER] technologies." One utility in their jurisdiction is "currently engaged in a smart meter pilot project with some use of distribution automation."

Staff of the Idaho PUC told the committee that advanced DERs and automation technologies "improve outage control, system monitoring, and reduction in system peaks to reduce overall costs."

Staff from the Iowa Utilities Board indicated, "With market refinements, these technologies enable the utilities to flatten the demand (load) curve by passing appropriate price signals. Proper price signals result in build-up of generation only as needed and thus improve system reliability and resiliency."

Staff of the Delaware PSC noted that there are “a few installations where [distribution] feeders are automatically reconfigured upon loss of service. These installations are limited to critical service customers such as sewage pumping or water pumping stations.” Staff went on to say that “reliability and resiliency need to be balanced with the costs that ratepayers will incur with the new technologies.”

In Wisconsin, PSC staff explained that they have “not taken any formal action related to the ability of these technologies to improve grid reliability and resiliency . . . . Wisconsin utilities typically have good reliability indices and high customer satisfaction, and [advanced DER technologies] do not necessarily result in improvements in SAIFI, SAIDI, and CAIDI, so it is difficult to measure how these technologies directly affect reliability.”

The Regulatory Commission of Alaska observed, “The electricity infrastructure in Alaska differs from that in the lower 48 states in that Alaskans are not linked to large, interconnected grids . . . . Most of the state’s rural communities have no grid access and rely on community electric utilities to provide service via diesel generators.”

Changing Time Scales for Grid Operators

Along with the changes to the fundamentals of the generation mix, the electricity power system is undergoing changes to the time scales for operations, especially in the area of power markets for restructured utilities. The future will see continued shortening of time scales for grid operations: data on system conditions come in on time scales under a second, and the dispatch of resources and market settlements happens every 5 minutes. The requirements for such rapid dispatch and analysis have impacted the tools used to manage the system, causing the energy management systems within RTOs to be custom built. The operational concerns of the collapsing time frames and the human interface are real. Though the resilience impacts of these changes are complex, these challenges motivated the committee to recommend research on improvements to system operator control rooms and the application of artificial intelligence to power system monitoring and control within Chapter 4. These concerns also help motivate overarching recommendations to improve the security and resilience of the cyber monitoring and controls systems within Chapter 7.

Industry-Structure and Business-Model Transitions

There are new industry structure and business model issues that are also in transition, with uncertainty about which direction they will take in the future (NAS, 2016; MIT, 2016). Competitive forces, often stimulated by actions of federal and state legislatures and regulators, have prompted an array of new actors (e.g., non-utility generating companies and independent non-utility transmission companies), new institutions (e.g., RTOs and ISOs), and new issues subject to FERC regulation in wholesale electricity markets and the bulk power system. Most of these institutional changes have already occurred. Unlike the bulk power system that has undergone significant restructuring and regulatory reform over the last decade, the structure and regulation of electric distribution systems has, until recently, experienced much less change. Thus, the committee considers that the largest changes to the structure of the electricity system in the future will occur within the distribution side of the system.

At the distribution-system and retail electric level, the relatively rapid emergence of DERs has accelerated pressure on regulators, utilities, and other stakeholders to address aspects of the traditional utility business model, which has supported grid investments largely through rates that recover significant quantities of utilities' fixed costs through usage-based charges. All else equal, as new small-scale technologies generate power from customers' premises and inject it into the grid (Figure 2.9), causing revenues from volumetric rates charged to customers to drop, utilities and others have begun to look for regulatory frameworks and new rate designs that assure that all customers pay their fair share of the costs of maintaining a reliable and resilient grid. The approaches under discussion across the country for the future roles of the local distribution utility include the "enhanced status quo," the "network service provider," the "market enabler," and the "solutions integrator" (De Martini and Kristov, 2015; State of New York, 2014; Tierney, 2016b; TCR, 2016). These new business models are relevant for resilience considerations in light of the fact that each poses different implications for the entity(ies) responsible for supporting resilience on the grid:

- *Enhanced Status Quo.* In this model, utilities will continue to manage their generation and/or delivery infrastructure to supply power to customers as today. At the same time, utilities will continue to invest in replacing aging infrastructure and advanced grid technologies to improve system reliability and resilience under traditional regulatory cost-of-service, ratemaking, and cost-recovery models (including revenue decoupling, in which utility cost recovery is delinked from volumetric electricity sales).

- *Network Service Provider*. As a more distributed energy future unfolds, the distribution system becomes a platform for enabling DERs to provide services to the wholesale market and as "non-wires alternatives" (so called because targeted installation of DERs can defer the need for transmission expansion). This model expands the role and value of the distribution system. This is accomplished by providing open access distribution services enabled by advanced technologies to allow the integration of high levels of DERs. Distribution services are based on network access fees comprised of demand charge and fixed charge components.

Financial incentives for operational performance (e.g., for reliability and interconnections) and earnings mechanisms on DER non-wires grid services are employed. Otherwise, the traditional regulatory and utility economic model remains.

- *Market Enabler*. This model focuses on expanding the role of the utility distribution operations to become the distribution system (or market) operator (DSO). This "total DSO" (De Martini and Kristov, 2015) has responsibility for balancing demand and supply as well as distribution network reliability for a distribution area to an interchange point with the bulk power system operator. In this role, the DSO provides a single aggregated interface with the ISO/RTO, requiring the DSO to optimally dispatch DERs within its area. Traditional regulatory and utility economic models apply, along with the incentives above and market-based pricing for optional competitive services.
- *Solutions Integrator*. This model focuses on developing customer DER assets alongside other energy services, such as power and natural gas commodity supply, energy information services, and energy efficiency retrofits. In this model, utilities provide turn-key or selected engineering, procurement and construction services to support reliability, enhancement projects, customer high-voltage infrastructure, microgrid, and DER implementation. Services may also include customized engineering and operational consulting as well as emissions management and equipment condition assessment to ensure safety and reliability.

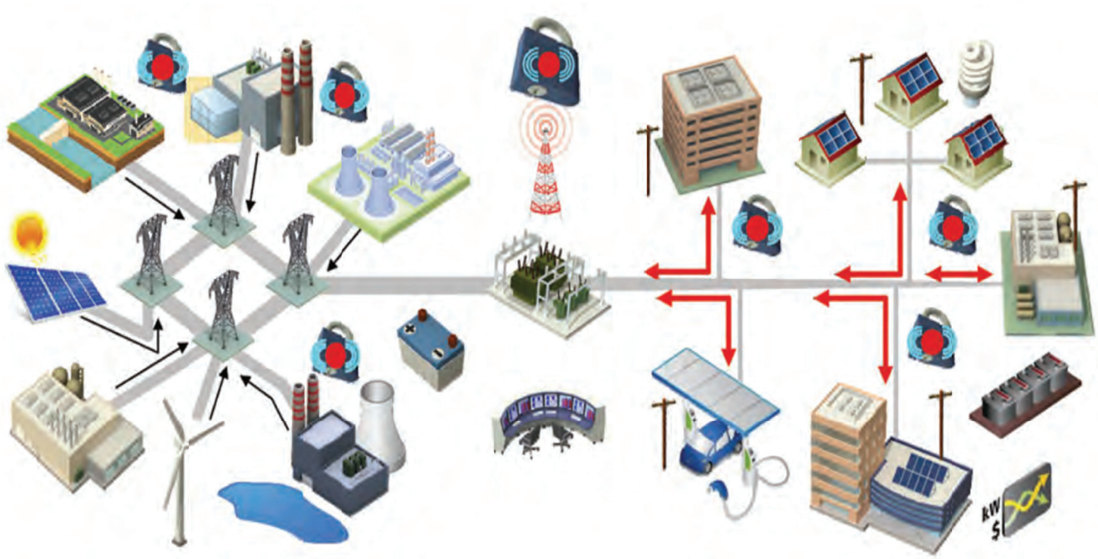

FIGURE 2.9 Schematic of possible electric system configurations and interactions in the future.
SOURCE: EPRI (2011).

A critical factor in the transitions of the electricity sector is that continuing reductions in the cost and accelerating deployment of DERs is leading to a new class of customer that is both an electricity consumer and producer ("Prosumer"). There are now large and small prosumers who are increasingly interested in managing various aspects of their own electricity usage and supply. This is also enabling greater customer choice for installing select DER technologies to satisfy individual customer requirements associated with reliability, redundancy, and power quality. Whereas most backup power requirements in the past relied on diesel generators, numerous other DER technologies can supplant or even replace the diesel generator as a backup power option. However, DERs have complex impacts on resilience, which are discussed in the following sections and throughout the report.

Distributed Energy Resources and the Distribution and Transmission Systems

DERs can provide benefits not only to the customers that employ them directly, but also to the broader transmission and distribution system. For example, DERs may help avoid or defer the need for new generation, transmission, or distribution infrastructure to address congestion, localized reliability, or resilience issues. The value of DERs for reliability, efficiency, and resilience depends upon their location and their particular attributes (e.g., their durability, their ability to be controlled, their availability when needed, the times of day when they reduce net load to the grid). Absent effective planning, DERs can also impose costs on the electricity system—for example, through equipment upgrades necessary to handle generation on distribution circuits, sub-optimal DER placement that contributes to congestion as opposed to alleviating it, and incomplete or inefficient sharing of information across the distribution-transmission interface.

This is particularly true at the distribution-system level, but also for interactions with the transmission grid. On the planning side, DERs can interact with the transmission system in several ways. First, behind-the-meter DERs complicate regional load forecasting, the process used to predict customer electricity demand at least 10 years into the future. Transmission system planners design the high-voltage system to meet forecasted demand. DERs behind the meter that provide energy to their owners have the potential to decrease load forecasts by the local retail utilities, which may account for DERs in their forecasting. Bulk power system planners may not be aware of DERs, and their load forecasts may not reflect the locations and types of DERs appearing or expected to appear on the system (NERC, 2016b).[21]

DERs can also be used in transmission-system planning processes to address specific system needs identified through modeling that informs planning. If a planned generating unit retirement or predicted demand increase may lead to a localized reliability issue, DERs could be employed to address that issue in lieu of a more traditional solution like a substation upgrade or new transmission line. Several legal, operational, and institutional barriers to employing DERs as transmission-system solutions exist, but the potential is real.[22] The use of DERs to address transmission-system limitations may also increase resilience in that the resources are more readily available after an outage or disturbance that could knock out a substation or transmission line for significant periods of time.

On the market design and operations side, DERs also have implications for the transmission system. In addition to potentially reducing the capacity-procurement needs of a region, DERs are legally able to participate in wholesale energy, capacity, and ancillary service markets. These centralized markets exist only within the RTO and ISO regions shown in Figure 2.5; the rest of the transmission-owning utilities rely on bilateral contracting or self-supply to meet their electricity needs.[23] Some DERs have made progress in wholesale market participation. In PJM, for example, demand response resources participating in the wholesale market totaled over 9,800 MW, with resources positioned at over 17,000 locations across the PJM footprint (McAnany, 2017).

On both the transmission planning and wholesale market sides, a lack of operational awareness and coordination between distribution utilities (or, in the future, "distribution system operators") and transmission-owning utilities, or the RTOs or ISOs operating the transmission system and wholesale power dispatch, serve as additional barriers to capturing the full potential value of DERs to the electric system. DER owners must understand what planning and market opportunities exist at both the distribution and transmission levels, and utilities and market operators must understand when resources are available for their use and when they are otherwise committed to provide grid services that render them unavailable for other uses.

[21] For example, the RTO that covers 13 Mid-Atlantic states and the District of Columbia, called PJM, was able to decrease its load forecast by 6,000 MW for 2020 by incorporating the energy efficiency and distributed solar that exists or is planned to come online between now and then (PJM, 2016).

[22] See Southern California Edison and Consolidated Edison projects discussed in Tierney (2016b).

[23] One notable exception is the recent development of an Energy Imbalance Market (EIM) administered by the CAISO, with participation by a growing number of utility systems in the Western grid. As of 2017, several electric utilities in Arizona, California, Idaho, Nevada, Oregon, Utah, and Wyoming had joined or are planning to join the EIM (CAISO, 2017).

Finding: The value of DERs for reliability, efficiency, and resilience depends upon their location, their attributes, the planning process behind their installation, and the legal and regulatory environment in which they are operated. While they can contribute to reliability and resilience, absent effective planning and an appropriate regulatory environment, DERs can also impose vulnerabilities and costs on the distribution system.

Other Technology Developments

Other new and emerging technologies may have important impacts on the structure and operation of the power system, including lower cost batteries as well as falling cost and growing capabilities of power electronics. Energy storage in the distribution system and on the customer side of the meter is a relatively new phenomenon. Some distributed energy storage (DES) is provided by thermal systems such as hot water heaters. Other DES technologies involve chemical (e.g., battery) solutions. There is large variation in projected battery costs, potentially declining from today's levels of about $600/kWh for whole battery systems to the range of $200-$300/kWh by the early 2020s. Lower cost batteries are providing interesting opportunities. Customers are installing on-site battery systems behind the meter in service areas with high charges for peak power consumption to shift their usage to off-peak periods. In general, energy storage has the potential to enable the electric system to become more efficient while enabling customer-side energy management (Navigant Research, 2013).

Over the next 20 years, customers will likely have greater technological opportunities to go entirely off grid, satisfying their electricity requirements with a combination of on-site generation and storage technologies. Customers capable of investing in such packages of technologies (or purchasing such services from the utility or a third party) may be able to take personal responsibility for their own resilient electric service. Although the committee believes the share of total customers taking advantage of such approaches will be limited, trends in grid defection and the technologies that could enable it should be closely monitored. Broader impacts on social equity will also warrant attention.

The controllability of DERs is enabled by low-cost computing and communications technologies. The internet of things and edge computing have progressed to the point where the capability to control DERs at low cost has become much more practicable, with significant advances even over the past few years. There is also significant experience among a number of utilities and third-party aggregators implementing and operating "smart grid" technologies that include operation of distributed generation, storage, and demand response. Fundamentally, the computing and communications technologies are not the limiting factor for adopting these control strategies, although they will require increasing sophistication and resolution in the monitoring and control systems used at the individual feeder and substation scale to understand and optimize circuit health and behavior.

Most organizations that have employed various DER strategies on a large scale have discovered that the need for "big data" analytics and other strategies to optimize the operation and control of these distributed assets is nascent, and more effort is needed to further develop the algorithms to enhance system operations and resilience by managing DER deployment. This is particularly true during off-normal conditions where the DER might be providing emergency backup power to support system restoration. Finally, these DER assets will necessarily need to interact with each other seamlessly, including during normal and off-normal or emergency situations, and not create or exacerbate any adverse conditions. These include but are not limited to hazards to utility workers and the public, equipment damage, and sub-optimal operation of the remaining electrical assets.

Interdependencies Between the Electric and Natural Gas Infrastructure

One outcome of the trends under way in the electric system is the industry's overall reliance on natural gas to fuel power generation, which increases the electric system's reliability on conditions in the gas industry. This has potential implications for the resilience of the grid. The conventional wisdom is that the electric industry will become even more dependent upon natural gas than it has in recent years, and the natural gas industry looks to a future in which significant growth in demand depends upon developments in the power sector. For the electric system to become more reliable and resilient, attention must be paid to assure robust systems and practices across the two industries.

For many years, these two systems developed on largely different paths, from physical, economic, engineering, institutional, industrial-organizational, and regulatory perspectives. Both industries evolved with some degree of vertical integration and with aspects of each industry's value chain regulated as monopolies by federal and/or state governments. The interconnected networks of each industry expanded over larger and larger geographic footprints. Recently, both systems have undergone eras of significant industry restructuring, with new players emerging as functions became unbundled and as competition entered into different parts of the business.

Today, however, each industry has its own set of cost structures, operating protocols and standards, commercial instruments, and pricing arrangements. Further, while the electric system operates as a network, following laws of physics on an interconnected grid rather than ownership or contract paths, the natural gas system is not a network industry. Individual companies own segments of the pipeline system, and users contract for access to and use of specific facilities. These changes also have occurred in parallel with dynamic developments in real-time, internet-based communications systems, complicating the interdependencies and allowing opportunities for new arrangements and solutions.

Today, natural gas supply still tends to move long distances from production sources to users' sites, typically to locations where there is little to no storage close to or on the end-user's property. This means that from an operational point of view, gas resources need to move "just in time" (i.e., they are used as they are delivered) to the end user through pipelines. During certain seasons and times of the day, many of these pathways—for example, those serving the Mid-Atlantic and Northeast regions—can become quite congested with firm gas deliveries, recognizing that gas injections at the production locations are intended to balance withdrawals of gas from the delivery system while taking in to account a variety of operational issues along the pathway from production to use. ("Just in time" delivery, however, sits within a context in which natural gas moves between 15-20 miles per hour on the interstate pipeline system, while electric system operations occur at the sub-minute and multi-minute time frame.) Further, the growth in the power sector's use of natural gas has not been accompanied in all relevant regions by expansions in pipeline capacity or increases in the efficiency of existing gas delivery infrastructure. Without change in some of the key features in current business models for competitive generators or in market rules, that situation is not expected to change dramatically in the near term, making it hard to drive investment in pipeline/storage infrastructure based on demand from the electricity sector. (In some regions like New England, however, changes in market rules have led many gas-fired generators to invest in dual-fuel [oil/natural gas] capability with on-site storage of oil as a lower-cost means to assure the ability to operate during periods when delivery of natural gas over pipelines is otherwise constrained.)

Regulatory issues at the intersection of gas and electric markets are complicated. While FERC may have responsibility for a broad set of policy issues on electric/gas integration issues, and NERC is evaluating the interdependencies from an operational and planning perspective, the states have strong interests and, in some cases, regulatory responsibilities that can affect market participants' behaviors as well. Importantly, the structure of the natural gas production and delivery system in the United States does not have the same reliability requirements as now exist in the electric industry, and parts of that supply chain (e.g., production of natural gas) are effectively outside of FERC's regulatory jurisdiction.

The electric and gas systems are already experiencing strains at their intersection. To date, integration issues related to increased gas-fired generation have caused rotating power outages in the Electric Reliability Council of Texas during the big freeze of 2011. And, owing to winter gas shortages and extreme cold weather, natural gas was either unavailable or priced too high for generators in PJM and the New York ISO during the polar vortex of 2014 (See Box 4.2 for a description of these events). In some regions, for example, generators need to commit to move gas volumes before knowing whether their offers into the RTO's daily power markets have been accepted; conversely, generators need to offer prices into such energy markets without fully knowing the price and/or availability of their natural gas. There are other instances where gas customers that have contracted for firm gas supply and transportation service face potential (or real) curtailments as operational conditions change upstream and downstream. Tensions are visible across the business models of different players in the two industries and in the market rules in different regions. Further, there are different attitudes across the two industries regarding the urgency of anticipated changes in natural gas supply associated with growing use for electricity generation—specifically, the need for increased total supply and for that supply to be more nimble. It is hard enough to introduce change into a single industry, where there may be players who perceive themselves as winning or losing from different options for resolving small and large issues. It will undoubtedly be even harder to introduce sensible but meaningful changes affecting market participants in two industries.

Decisions by myriad market actors and institutions do not typically reflect coordinated information about the performance of systems either across industry segments (e.g., across the electric and gas industries) or within industry supply chains (e.g., from production sources across interstate transmission systems). In the context of the events that occur in one or more parts of the industries' systems, this absence of coordination mechanism may make some aspects of resilience—preparing for outages so as to limit their impact, sustaining service during an outage, and/or in restoring the systems to normal operations after the event—difficult to realize.

Finding: The electric industry has become highly dependent upon natural gas, and the natural gas industry looks to a future in which significant growth in demand depends upon developments in the electricity sector. For the electric system to become more reliable and resilient, attention must be paid to assuring the availability of adequate natural gas resources at all periods of time, including through investment in natural gas infrastructure (e.g., contractual arrangements and siting and construction of pipelines or storage), where it is economical to do so, fuel diversity for electric generators and natural gas compressors, and the alignment of planning and operating practices across the two industries.

Emerging Electric Grid Jurisdictional Challenges

Historically, and despite the state-to-state and regional variations in grid regulation around the country, FERC, the states, and regulated utilities have operated within relatively clear jurisdictional boundaries. In an electric grid consisting predominantly of large and dispatchable central station power plants, it was clear that FERC had jurisdiction over wholesale electricity rates and interstate transmission, whereas states had regulatory authority over retail sales and delivery over local transmission and distribution systems into our homes, businesses, and industrial facilities. Power on the system generally flowed in one direction, from the generator all the way to the end-use customers.

Over the last decade, however, the increasing penetrations of DERs and smart grid technology that are relevant for resilience have begun to change the very way the grid operates (see Figures 2.1 and 2.9). The grid is increasingly an interconnected web rather than a straightforward series of one-way pathways. However, the federal, state, and other legal constructs dictating the role of DERs on distribution and transmission systems are in active review by FERC and states in the relevant regions. Although this is a constructive response, there remain many jurisdictional ambiguities, policy mismatches, and an inability to maximize the potential value of technological change toward grid reliability and resilience. The emerging relationships between DERs and the transmission and distribution systems have greatly outpaced the laws and regulations that govern their interactions. The 80-year-old FPA never contemplated the modern and complex system that exists today. As a result, the relatively clear boundary between state and federal authority over the electric system has blurred to some extent, causing uncertainty, if not confusion, among policy makers and energy industry participants. Recent legal challenges taken up to the Supreme Court have begun to sort through aspects of unresolved jurisdictional questions, but several questions remain.[24]

Jurisdictional issues are also emerging within the distribution and transmission systems themselves. On the distribution system side, regulations typically assume one-directional power flow and fail to contemplate most DERs, including microgrids. From a resilience perspective, microgrids are a

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[24] These recent cases have clarified a few different jurisdictional principles: First, one Supreme Court decision called *EPSA v. FERC* determined that FERC has the authority to regulate DER participation in wholesale markets. This authority means that, under certain circumstances, states and the federal government will both have the ability to regulate DERs in the performance of different activities. Second, another high court decision (known as *Hughes v. Talen Energy Marketing, LLC*) recognized that states have the authority to engage in their own preferred resource procurement efforts, but that they cannot cross a line that would invade FERC's exclusive authority to set wholesale energy rates. The *Hughes* decision has fewer direct implications for DERs that may be procured for resilience purposes than it does for supply-side generating resources like wind, solar, or natural gas power plants, but it is nonetheless important to keep in mind in resilience program design. Third, a Supreme Court case called *Oneok v. Learjet*, considering the Natural Gas Act, emphasized that the ability of the federal government to regulate one particular area does not necessarily preclude state regulation in the same area. Other challenges around the ability of states and the federal government to regulate certain aspects of grid activities that have implications for DERs are working their way through federal courts. Although the mentioned cases have provided certainty in some respects, a general climate of uncertainty exists in states' attempts to design new DER-centered regulations and programs.

particularly interesting development—but they are not without legal uncertainties. Most state regulations obligate utilities to provide distribution service to all customers within their territories. With that obligation often comes the right to be the exclusive distribution provider. Microgrids that would connect buildings or a broader area technically involve their own distribution service and so, in many cases, are prohibited by existing utility regulations.

On the transmission system, the FPA itself remains a barrier to increased DER participation. For example, in the regional system planning processes, the FPA allows for transmission owners to allocate and recover the costs of new transmission investment except for non-wires alternatives, which includes DERs that are traditionally regulated by the states. As noted, the relationship among emerging technologies, evolving business models, and outdated laws and regulations that dictate authority over electric grid activities are stressed by the rapidly changing composition of resources and services involved with the delivery of energy, resulting in significant uncertainty. This, in turn, creates challenges for resilience planning.

Finding: Any new local, state, or federal programs, regulations, or laws designed to increase grid resilience will have to navigate a labyrinth of existing state and federal laws (some of which are out of date) that shape the incentives (or disincentives) for undertaking investments and actions aimed at enhancing resilience. This creates challenges for resilience planning, especially in light of the essential role of electricity in providing critical services and powering the economy.

LONGER-TERM DRIVERS OF CHANGE AND ASSOCIATED CHALLENGES AND OPPORTUNITIES FOR RESILIENCE

There is, of course, no way to reliably predict what the power system will look like in 30 to 50 years. On the other hand, it is possible to identify a variety of developments that could shape that future and then seek strategies that will be robust across that range of possibilities. To that end, here the committee identifies and discusses a variety of factors that might shape the future evolution of the system. Planning for grid resilience needs to take into account the expectation that the grid and its various institutions, technological features, legal structure, and economics will change—and in ways unknown today.

The Nature and Scope of the Future Regulatory Environment

Recent years have witnessed a dramatic shift in the structure and regulatory environment in which the high-voltage transmission system operates. A similar transformation has not yet occurred at the level of the distribution system. Whether such a transformation will occur, and what form it might take, will likely have profound effects on the future evolution of the system. Will federal authority be expanded to include a larger role at the level of the distribution system (Figure 2.10), as could occur, for example, where customers with on-site generation sell surplus back into the grid and thus set up the possibility of federal jurisdiction where such injections of power were considered sales for resale? Many states would likely oppose such an expansion, in a continuing tension between state and federal oversight seen in previous legislation including various provisions of PURPA and EPAct 2005.[25] The latter specifies the following:

> Each electric utility shall make available, upon request, interconnection service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term "interconnection service" means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements and procedures shall be established whereby the services offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable and not unduly discriminatory or preferential.

While the legal justification under which federal jurisdiction might be further expanded is unclear, there is certainly a possibility that such justification might evolve over time.

There is of course also the possibility that in some domains, local, state, or even regional regulatory responsibilities might be expanded. If larger differences develop among regulatory structures in different parts of the country, this could present a variety of complications. As pressure grows to adopt

[25] For example, PURPA's Sections 1251, 1252, and 1254, and section 1254 of EPAct 2005.

more innovative strategies to address resilience issues that impact large areas of interconnected systems, states and regions may decide they need to adopt more innovative approaches.

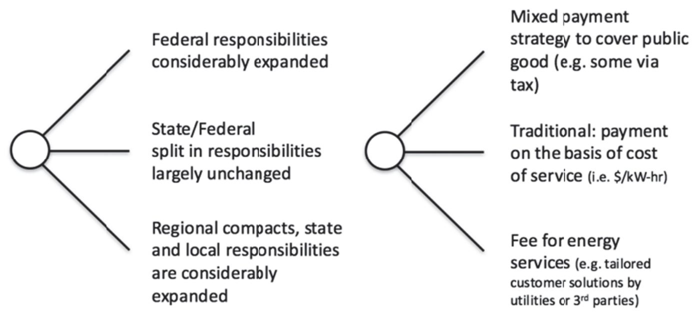

FIGURE 2.10 Different ways in which the nature and scope of the future regulatory environment might evolve.

The possibility of greater grid defection by customers may result in those customers providing their own electricity, entirely removed from federal and state rate jurisdiction altogether. It is likely that this would occur only in situations where the customer disconnects entirely from the grid. In such instances, states may have to address the terms and conditions under which customers may exit from or reenter the local distribution to assure (among other things) that legacy costs associated with utilities' planning to provide service to those customers are addressed, according to traditional cost-incurrence and equity principles of utility regulation.

Penetration and Characteristics of Distributed Energy Resources

Closely linked to the way in which the future regulatory environment might evolve is the degree of penetration of distributed resources (Figure 2.11). The pace and extent of further deployment of DERs is the subject of major discussion in the industry. If the DOE SunShot targets are met, for example, rooftop solar will likely become cost competitive across much of the country without significant subsidies (Hagerman et al., 2016). Penetration of CHP has been much slower. Its future will depend in part on how the policy environment evolves and the wholesale-to-retail markup of natural gas. Costs are falling for local storage technology, but it is still only commercially viable in niche applications. Adoption could accelerate if costs fall and suppliers begin to offer storage with photovoltaic systems—with inverters and local intellegent control that reduces electricity bills and allows customers to continue to operate when grid power is unavailable.

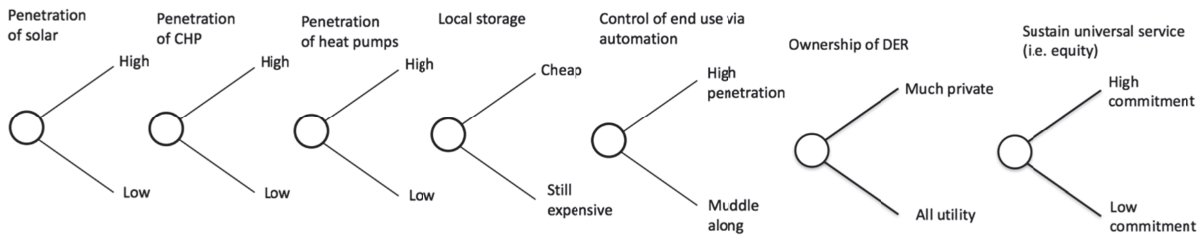

FIGURE 2.11 Different ways in which distributed resources might evolve in the future.
NOTE: CHP, combined heat and power; DER, distributed energy resource.

There has been considerable discussion of smart controls for end-use devices, including the idea of "prices to devices" that would allow larger customers to decide when they will and will not operate particular electricity-using equipment given time-of-use pricing. While very extensive intelligent control is possible, what is less clear is when and whether the added hardware and intelligence will make economic sense.

Legal Implementation of Non-Utility Microgrids

Today in most of the United States, state law grants exclusive service territories to legacy distribution utilities, although there are a few exceptions.[26] This means that with the exception of a customer selling power back to the local utility, only that utility can distribute power to another entity. It also means that only a traditional utility can move power across a public road or other public right-of-way. If state laws were changed in such a way as to allow small-scale microgrids (larger than a few MWs) to be operated by private entities—with tariffs that symmetrically recognize the contributions of DERs while keeping the distribution company whole—the adoption of DERs could accelerate. Utility executives often argue that such a change would impose serious operational problems. However, from a technical point of view, there is very little difference between the two situations shown in Figure 2.12.

[26] New York is one exception where the state may grant multiple franchises to serve a particular location; however, it is then up to local municipalities to grant easements along public streets and roads in order for the utility to install necessary facilities. Some Pennsylvania communities have been granted multiple franchises resulting in different utilities' distribution lines on opposite sides of the street with service drops to customers crossing overhead. Nonetheless, in most regions service franchises are granted exclusively to one provider.

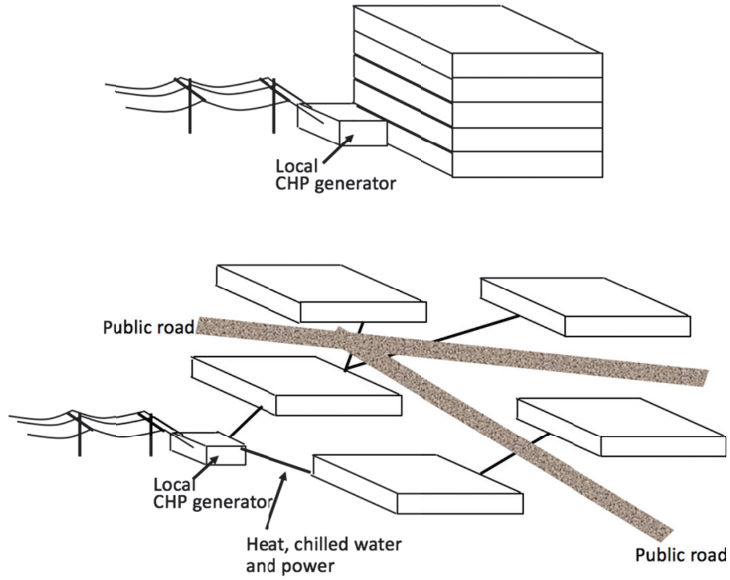

FIGURE 2.12 Under most state laws, there is legal distinction between a utility that serves a multi-story building with its own distributed energy resource and combined heat and power, as shown at the top of this figure, and the situation in which the same loads are distributed across space and are served by a small microgrid. There is virtually no technical difference between these two situations. If laws were changed to allow private ownership of such microgrids (with equitable symmetric tariffs), future distribution systems could look very different.
NOTE: CHP, combined heat and power.

The committee asked several state regulatory agencies whether, in their jurisdictions, an entity other than the local distribution utility could build a small microgrid (e.g., less than a few 10s of MW), sell electric power to other entities, and be interconnected to the distribution utility. Several states noted that, as a matter of law, this was simply impossible in their states. Others indicated that the answer was more complex—an entity that wanted to engage in such activity would need to become a licensed and regulated utility. For example, staff of the Pennsylvania PUC said, “It is conceivable that an entity could perform such a function if they were properly licensed by the commission and the RTO and PJM. There may be some other legal factors that could limit their ability to sell power to entities other than the distribution utility and/or PJM Pennsylvania does allow net metering (see footnote 21) up to 3 MW.” Staff from the ICC noted, “Third parties that sell electric power to retail customers of an investor-owned utility must be licensed by the (ICC).” Staff of the New Hampshire Commission noted that in addition to having net metering, their state also has “group net metering (up to 1 MW).”

For years, the regulatory framing under which electric power has been provided in the United States was built on a foundation of universal service—that is, that access to basic electric power is to some degree a right that all citizens should enjoy. Indeed, it was this belief that prompted the creation of the Rural Electrification Administration in 1935 to supply power across rural America to customers whose locations were too remote to be attractive to privately operated utilities.

Today, the technical capability exists to provide different levels of service to different customers. This raises policy questions about whether all customers deserve some basic level of reliable service on the grounds of equity. As discussed in Chapter 5 of this report, there are ways in which distribution systems that contain advanced automation and distributed generation could be "islanded" so as to provide some limited service in the event of a large-area, long-duration blackout of the bulk power system. How the incremental cost of such upgrades should be covered, and whether they should only be based on an end-use customer's ability to pay, raises obvious issues of social equity.

Over time, there will likely be greater opportunities for customers to defect from the grid (i.e., provide all of their electricity needs with customer-owned generation and storage). The goal of ensuring that all customers have access to electricity service that is affordable and reliable, combined with society's larger interest in assuring that a resilient electric system supports the availability of critical social services, suggests that policy makers should continue to pay close attention to this trend. Policy makers may need to pursue mechanisms that encourage grid integration as part of service and to ensure that grid defection does not adversely impact those customers who have no practical economic choice but to remain dependent on the electric system to serve their needs.

Impacts of a Changing Climate

There remains uncertainty regarding how climate change and associated concerns will impact the electric power system (Figure 2.13). While the impacts of climate change will unfold over the coming decades, policy choices made in the near future can have a profound impact on the extent of that change (White House, 2016). The changing climate will result in more frequent and more intense extreme events (Melillo, 2014) that will impose damage and other challenges on the power system. Higher ambient temperatures will create increased demand for system cooling. In some parts of the country, it will also bring deeper and more prolonged droughts that, in turn, will result in problems of securing sufficient water for system cooling unless traditional wet cooling is replaced with dry cooling. In some locations, such as coastal regions prone to rising sea levels and storm surge or inland locations prone to frequent wildfires or flooding, it may prove necessary to relocate some facilities. Climate change will likely also result in new demands for electric power including larger air conditioning loads and, in some locations, an increased demand for power to pump water.

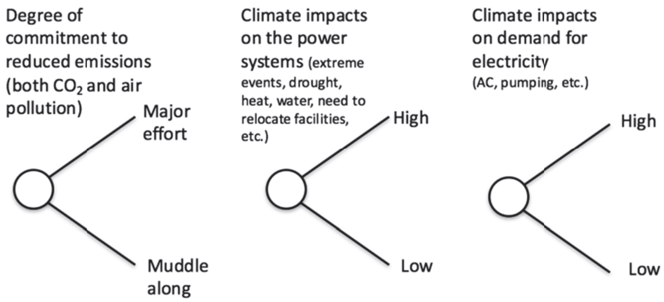

FIGURE 2.13 Climate change can affect, and be affected by, the power system.

Changes in the Sources of Bulk Power

The last few decades have seen dramatic shifts in the sources of bulk power employed in the United States, and uncertainty persists regarding the future (Figure 2.14). Natural gas has displaced generation at many coal-fired baseload power plants, and even existing nuclear plants are retiring before the end of their operating licenses. However, if prices once again become higher or more volatile, investors may shy away from putting capital into natural gas plants and the trend could be reversed, as it was in the past.

Many observers anticipate significant penetration of new renewables, especially wind, solar, and hydro power. Today, wind generation constitutes approximately 5 percent of total U.S. generation, but a number of analyses suggest that there is no technical reason why the nation could not generate more than 60 percent of its electricity from wind. However, achieving such a high level of penetration would impose considerable requirements on land use, both for siting the wind turbines and for constructing the necessary transmission infrastructure, much of which will need to cross state lines (MacDonald et al., 2016). Hence there is considerable uncertainty about the degree of future penetration of wind generation. Similar observations have been made with respect to solar generation. Many have argued that extensive use of biomass fuel, perhaps also with carbon capture and sequestration, will be necessary to achieve the objective of holding global warming to ≤ 2°C. At the same time, the widespread use of biomass imposes considerable logistical requirements and demands on land use (LaTourrette et al., 2011). Hence, it remains unclear how much future development will occur.

Nuclear power has contributed roughly 20 percent of the nation's electricity generation for the last few decades. Many forecasts of U.S. energy production continue to assume their continued contribution of roughly the same share of supply. With the cost pressures that nuclear plants are facing from inexpensive natural gas and subsidized renewables, and uncertainties about the cost and likelihood of life extension and relicensing, a number of plants have closed recently. New York state and Illinois recently adopted policies desigend to keep existing plants operating (McGeehan, 2016). The only new plants under construction in the United States are in the service territory of vertically integrated utilities in the Southeast, where costs can be included in the rate base. In addition, the nation has largely abandoned aggressive research on more advanced reactor designs, so that for at least the next several decades the only options for new nuclear construction will likely be existing light-water reactor designs (DOE, 2017c; Ford et al., 2017). There may be some renewed interest in advanced reactor design research (DOE, 2017c), but the extent of programmatic support for this vision remains uncertain. Small modular reactors have received a lot of attention in part because they require less capital investment and offer much greater siting flexibility. Despite these benefits, however, long standing efforts have never reached commercial construction (Larson, 2016). Investment in new, small, and advanced reactors may require a number of changes in business models and reactor designs that allow standardized and quicker manufacturing of components and construction of reactors.

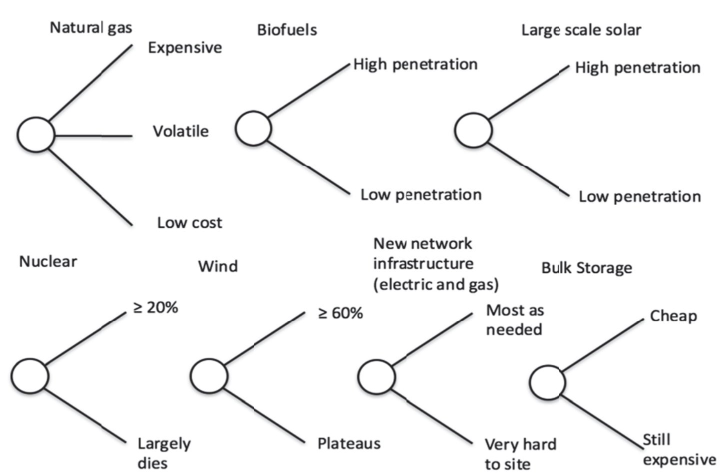

FIGURE 2.14 Possible change in the sources and nature of bulk power.

Today, technologies for cost-effective bulk storage are limited. Pumped hydro storage imposes considerable land use and other environmental costs, and only a few facilities for compressed air storage have been built. Battery storage is beginning to have some impact on the power system, especially in behind-the-meter applications. In 2012, the U.S. DOE established the Joint Center for Energy Storage Research (JCESR) as one of its "Energy Innovation Hubs." JCESR's stated goal is to "deliver electrical energy storage with five times the energy density and one-fifth the cost" of present storage technologies (Crabtree, 2016). In addition to striving to develop batteries that would allow all electric passenger vehicles to be profitably marketed at a cost of approximately $20,000 and with a range of 200 miles, JCESR director George Crabtree has articulated remarkably aggressive goals for affordable grid storage, including battery technology that would be competitive with pumped hydro storage, chemically based, and capable of seasonal storage. However, battery experts with whom the committee discussed the JCESR goals for bulk grid storage have expressed considerable doubt about achieving those goals, especially on the time scale of the next several decades.

Nonetheless, all electric vehicles with those capabilities would have an impact on both the transportation sector and on electricity demand. Whether or not the JCESR goals are met, a much higher penetration of electric or hybrid vehicles may well occur on the time scale of the next several decades. With greater adoption of electric and plug-in hybrid vehicles, there may be greater opportunities for using connected vehicle batteries to improve grid resilience—for example, by using electric vehicle batteries to provide a fraction of a home's electricity demand during a large-area, long-duration outage (See Chapter 5).

SUSTAINING AND IMPROVING THE RESILIENCE OF A GRID THAT IS CHANGING RAPIDLY AND IN UNCERTAIN WAYS

From all of the foregoing, five things are apparent:

1. The grid is undergoing dramatic change. This will be especially true over the next few years at the distribution level where DERs continue to increase and change the relationship of utilities to end users. While DERs may provide many opportunities to increase grid resilience, this will require regulatory changes and effective planning and coordination. Over the next decade or two, major changes are also likely in bulk power transmission.
2. Much of the hardware that makes up the grid is long lived, which limits the rate of change in the industry. However, over periods of a decade or two, many changes are possible, and it is virtually impossible to know how the future grid will evolve.

3. No single entity is in charge of planning the evolution of the grid. That will become ever more true as more and more players become involved, particularly regarding deployment and operation of DERs at the distribution level.
4. All players will be concerned about reliability, both for themselves and collectively. Only a few are likely to be focused in a serious way on identifying growing system-wide vulnerabilities or identifying changes needed to assure resilience.
5. Today, virtually no one has a primary mission of building and sustaining increased system-wide resilience or developing strategies to cover the cost of investments to increase resilience in the face of low probability events that could have very large economic and broader social consequences.

These five observations carry profound implications for the future resilience of the power system. In Chapter 3, the committee explores the many types of events that can give rise to large-area, long-duration outages. Chapters 4, 5, and 6 correspond to the three stages of the resilience framework illustrated in Figure 1.2, making specific recommendations in the course of the discussion. Finally, in Chapter 7 the committee both summarizes those recommendations and comes back to the broader implications of the five observations above to consider an integrated perspective to the issue of electricity system resilience and how best to assure that continued attention is directed at building and sustaining system-wide resilience of the nation's power system.

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3

The Many Causes of Grid Failure

INTRODUCTION

A wide variety of events can cause disruption of the power system. As noted in Chapter 1, given the numerous and diverse potential sources of disruption, it is impressive that relatively few large-area, long-duration outages have occurred. The causes of outages differ in a number of important ways. Two of the most important differences are as follows: (1) how much warning system operators have that a disruption is coming so they can take protective action, and (2) how much of the physical and cyber control systems that make up the power system remain operative once the disruption has passed. Figure 3.1 categorizes disruptions by the amount of advanced warning that operators and others are likely to receive and the amount of time it takes to recover. Figure 3.2 categorizes the range of damages that may result after a disruption occurs.

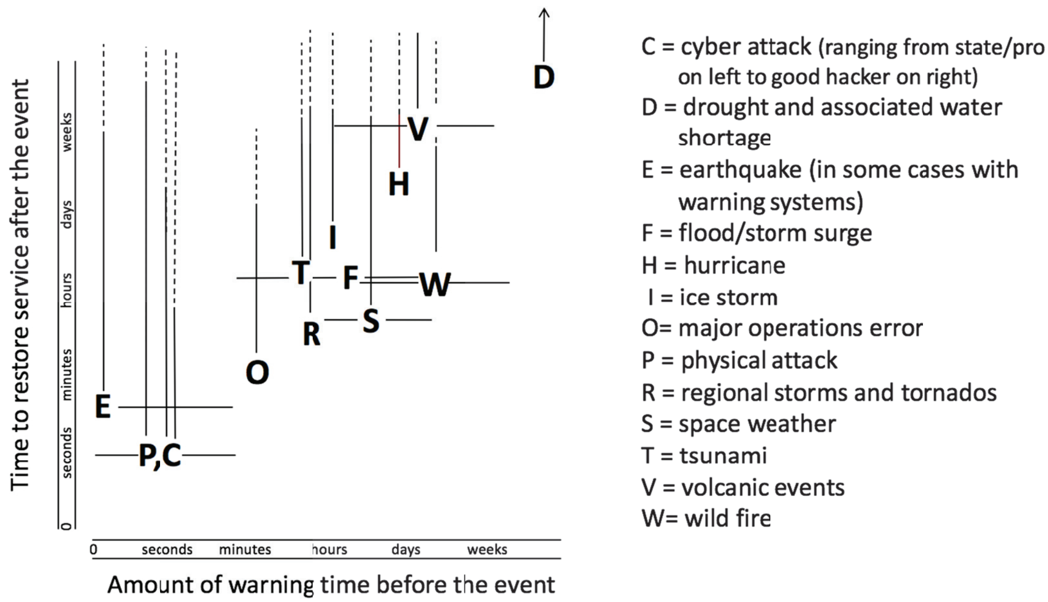

FIGURE 3.1 Mapping of events that can cause disruption of power systems. The horizontal placement provides some indication of how much warning time there may be before the event. The vertical axis provides some indication of how long it may take to recover after the event. Lines provide a representation of variability in these estimates.

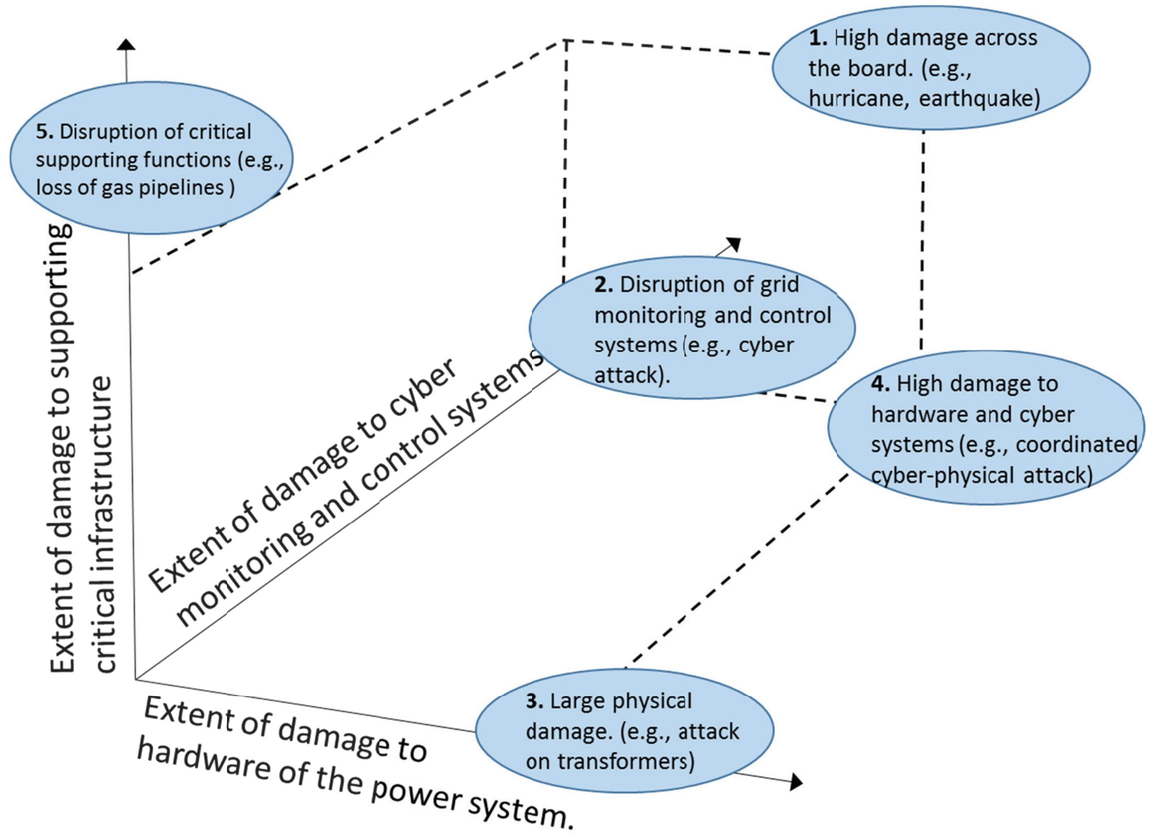

FIGURE 3.2 Illustration of distinct types of damages that can affect power systems. Major disruptive events such as hurricanes or earthquakes can cause damage across the board—to the physical and cyber components of the power system and supporting critical infrastructure (case 1). While it is possible to do physical damage with a cyber attack, many cyber attacks would not give rise to physical damage but could cause considerable disruption in the ability to monitor and control the power system (case 2). In contrast, a terrorist attack on high-voltage transformers could result in extensive damage to critically important hardware while leaving monitoring and control capabilities intact (case 3). A coordinated cyber-physical attack can simultaneously cause serious physical damage to grid components and impede operators' ability to monitor and control the grid (case 4). Loss of other infrastructure such as natural gas pipelines or communication systems can have impacts on the ability of the system to operate (case 5).

DIFFERENT CAUSES REQUIRE DIFFERENT PREPARATION AND HAVE DIFFERENT CONSEQUENCES

Building a strategy to increase system resilience requires an understanding of a wide range of preparatory, preventative, and remedial actions and an awareness of how these actions impact planning, operation, and restoration over the entire life cycle of different kinds of grid failures. Strategies must be crafted with awareness and understanding of the temporal arc of a major outage, as well as how this differs from one type of event to another.

It is also important to differentiate between actions designed to make the grid more robust and resilient to failure (e.g., wind resistant steel or concrete poles rather than wood poles; opaque fences around substations to protect against damage from firearms) and those that improve the effectiveness of recovery (e.g., preemptive powering down of select pieces of the system to minimize damage). Some actions serve both strategies, some serve one but not the other, and some serve one while inhibiting the other. For example, good substation design with clear separation of functions makes the substation more resistant to damage and helps repair crews. Building a coffer dam around a transformer may make it more resistant to flooding, but by limiting access for heavy equipment it can also make it harder to complete repairs when it actually fails. Of course a coffer dam does nothing to guard against the effects of earthquake or cyber attack. Similarly, concrete poles may be more resistant to wind but offer no clear advantage or disadvantage in restoration.

The timing of repairs is different depending on the cause. For example, repairs can begin immediately after a tornado has passed, but flooding following a hurricane can delay the start of repairs for weeks and impede restoration efforts. Good planning and preparation are essential to mitigating, ameliorating, and recovering from major outages effectively. Systems—both human and technical—must be built prior to grid failure to allow the responders to assess the extent of failure and damage, dispatch resources effectively, and draw on established component inventories, supply chains, crews, and communications. The next section reviews the major causes of outages depicted in Figure 3.1, beginning with those for which operators have the least warning and ending with those for which they have the most. The chapter then makes a number of general findings and recommendations related to both human and natural threats to the power system.

REVIEWING THE CAUSES OF OUTAGES

Earthquake

Moving through Figure 3.1 from left to right, the first point is labeled E for earthquake. Especially in the west, the central Mississippi valley, the coastal area of South Carolina, and southern Alaska and Hawaii (Figure 3.3), the potential for disruption of major power system equipment by earthquake is significant. Severe damage to distribution poles, transmission towers, and substations can result. Generators may be damaged or subjected to enough stress that they have to be taken off-line. For example, the North Anna Nuclear Power Station was taken off-line following a magnitude 5.8 earthquake in Virginia in 2011 and remained off-line for more than 10 weeks as the owner and operator conducted thorough damage assessments and the Nuclear Regulatory Commission granted approval for restart (Vastag, 2011; Peltier, 2012). In addition, there is substantial risk of the loss of fuel, particularly from natural gas systems, given the long supply chain and vulnerability of pipelines to earthquakes.

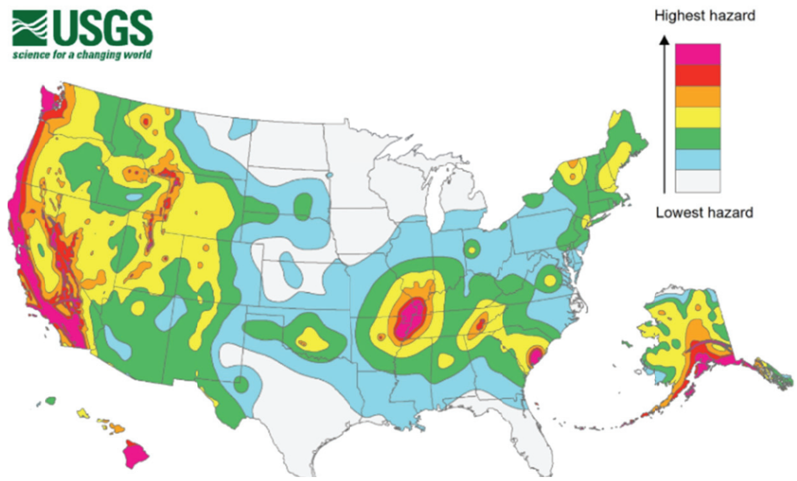

FIGURE 3.3 U.S. Geological Survey assessment of earthquake hazard across the United States.
SOURCE: Petersen et al. (2014).

While earthquakes typically come without warning, the propagation velocity of earthquake waves is much slower than the speed of light, so that in some cases it is possible with appropriate instrumentation to obtain several seconds of advance warning (hence the horizontal line that runs to the right of point E in Figure 3.1). When possible, such warning could give time to de-energize critical components so as to minimize damage. Research is continuing on a wide range of grid-specific technologies. Organizations like the Pacific Earthquake Engineering Center are working on technologies such as more durable ceramic and non-ceramic insulators, flexible electrical connectors, and advanced materials for towers and attachments. Restoration following a major earthquake is a massive problem requiring a wide range of difficult engineering and construction projects in a compromised environment, with competition from other restoration priorities. For example, key bridges or roads required to access damaged facilities may be impassable. If an earthquake destroys key generating, substation, or transmission equipment, it may take weeks or months to restore service.

Physical Attack

A physical attack, denoted by point P, could occur without warning or with only limited warning. Physical attacks on major system components could cause serious physical damage, especially to large transformers and other hard to replace substation and transmission equipment such as high voltage circuit breakers. The possibility of such attacks has been a concern for many years (OTA, 1990; NRC, 2012; DOE, 2015; Parfomak, 2014). Globally, transmission and distribution systems have been a focus of physical attacks, bombings, and terrorist activity—for example, in Afghanistan, Colombia, Iraq, Peru, and Thailand (NRC, 2012). In the United States, there have been relatively few well-planned attacks on the electricity system, though the 2013 sniper attack of the Metcalf transmission substation (Box 3.1) provides a reminder of the physical vulnerability of the system. Recovery could easily require many days or weeks. Generation facilities tend to have greater physical security and thus are less vulnerable to physical attack than substation and transmission facilities.

BOX 3.1
Summary of the Metcalf Substation Attack

In April 2013, the Pacific Gas and Electric-owned Metcalf Transmission Substation outside of San Jose, California, was attacked by one or more gunmen. The attack was well planned and executed, with the attacker(s) severing several fiber optic cables to disrupt local communications prior to beginning the attack with military-style rifles. In the hour between when communications lines were cut and the first law enforcement officers arrived, 17 transformers had been seriously damaged as oil leaked from bullet holes allowing electric components to overheat. No major outages occurred, as operators were able to re-route power flows from nearby generators, but the attack caused more than $15 million in damages. Of course, compared with the havoc that would result from a coordinated attack on multiple key substations, the Metcalf event was rather minor.

Cyber Attack

Like a physical attack, a cyber attack, denoted with a C, could also occur with limited or no warning. The best defense against cyber attacks is preventing intrusions to critical systems and detecting and expunging malware before it becomes activated. However, if that is not possible, the consequences of a successful cyber attack may be almost instantaneous, they could take a few seconds to some minutes to be fully realized, or an attacker may lay dormant for months collecting information as happened in the 2015 cyber attack on the Ukrainian power system (Box 3.2). It is difficult to determine how many cyber attacks have been attempted against U.S. utilities, by what means, and with what consequences.

In the time between detection of an intrusion and manifestation of any consequences, it may be possible to take some steps to limit the potential disruptive impacts. In many cases a cyber attack may not give rise to major physical damage to the system, although in some circumstances physical damage can result, especially if the attackers are sophisticated. Depending on the nature of the attack, just how long it would take to restore is unclear. The unique issues associated with cyber risks and restoration are discussed in Chapters 4 and 6. There are also diverse types of cyber attacks and vulnerabilities within the electricity system. According to recent analysis done for the Quadrennial Energy Review (Argonne National Laboratory et al., 2016), the electricity system vulnerabilities include the following:

- *Supervisory Control and Data Acquisition Systems* that rely on modern communication infrastructure to collect data and send control signals in both the bulk power system (generation and transmission) and at the substation level;
- *Large Power Plant Distributed Control Systems* that use local communications channels to perform local control on large power plants;
- *Smart Grid Technologies*, including software-based components with communication capabilities, used to increase the reliability, security, and efficiency of the grid as well as communicate data between utilities and customers;
- *Distributed Energy Resources* that are connected to open networks for communication and can include smart inverters with remote access;
- *Supply Chain* that might have vulnerabilities of legacy software systems from commercial vendors; and
- *Corporate Communication Networks* that might have an entry point to electricity systems' control networks.

The modern power system also makes extensive use of the global positioning system (GPS), especially for time synchronization. Hence, disruption of GPS by space weather, or through cyber attack, could cause disruption in the bulk power system.

BOX 3.2
Summary of the Cyber Attack on the Ukrainian Grid

In a recent, well-publicized cyber attack, approximately 225,000 people were left without power for approximately 6 hours on December 23, 2015. in Ukraine. The attackers gained access to internal networks of three utilities through spear-phishing[1] schemes, malware, and manipulation of long-known Microsoft Office macro vulnerabilities. Rather than try to engineer breaches through the firewall, the attackers patiently harvested the credentials needed to gain access to the supervisory control and data acquisition (SCADA) system and learned how to operate the SCADA software. The attackers executed a well thought out strategy, including the following:

- Creating virtual workstations inside SCADA systems that were trusted to issue system commands;

[1] Spear phishing is a targeted email that appears to be from a known business or individual but is not. It is designed to gain unauthorized access to internal systems by prompting the target to download unwanted software.

- Co-opting remote terminal units within SCADA systems to issue “open” commands to specific breakers at substations;
- Severing communications by targeting firmware in serial-to-Ethernet devices, making most unrecoverable;
- Installing and running a modified KillDisk program that deleted information on what was occurring while making recovery reboots nearly impossible;
- Shutting down uninterruptible power supplies at control centers; and
- Executing a large denial-of-service attack on utility call centers that prevented customers from reporting outages and reduced the utilities’ understanding of the extent of outages.

These actions prevented operators from accessing the SCADA systems, left control centers without power, and left cyber monitoring and control systems inoperable. Service was restored by shutting off the SCADA system and resorting manual operation. Although power was restored relatively quickly, control centers were not fully operational for months following the attack (E-ISAC and SANS ICS, 2016).

Operations Error

A number of historical blackouts have been caused by one or more faults, typically when the system is heavily loaded, that could have been managed if not for a sequence of subsequent operator errors. The network structure of the grid allows large-scale disruptions to result from distant, localized electrical faults, and system irregularities can propagate near instantaneously, generally through the work of protection relays acting unexpectedly to unusual system conditions. For example, the infamous 2003 Northeast blackout was triggered by a simple fault—a tree caused a transmission line short circuit—but within hours it became the largest blackout in U.S. history, owing to two computer/software errors that caused a lack of situational awareness from grid operators. A smaller but similar cascading failure occurred in 2011 in the southwestern United States, when a problem at a single substation in Arizona grew into a major outage across Southern California in a few minutes.

There are a vast number of potential types of operations error—in both control rooms and in the field—that can lead to cascading blackouts, which makes planning difficult. Fortunately, because virtually all key components of the power system have protective devices that disconnect before damage can occur, cascading blackouts typically do not cause serious physical damage to system components beyond the initiating failure. Depending on system conditions and the nature of faults, operator error can unfold over periods of minutes to hours, and there may be opportunities to detect errors and take corrective action. With improved training and drilling, better instrumentation, improved situational awareness, and improved control methods, the risks of operator error leading to cascading failure have been, and can continue to be, reduced. At the same time, other external threats such as terrorist attacks and pandemics can place operators under stress and potentially increase the probability of errors. In Figure 3.1, operations errors are denoted by point O.

Tsunamis

The domain of damage for tsunamis, denoted T in Figure 3.1, is limited to coastal regions. Figure 3.4 shows locations in the United States that have experienced major tsunami events over the past millennium, which are almost entirely on the Pacific coast. A large international warning system, involving 26 nations, monitors and provides warning across the Pacific basin. As part of that system, the United States hosts the Pacific Tsunami Warning Center near Honolulu, Hawaii, and also operates the Alaska Tsunami Warning Center in Palmer, Alaska. With advanced warning, critical facilities can be shut down to reduce damage. Although the best way to reduce the risks to the power system is to place major facilities in locations that are not vulnerable to tsunamis, abandoning and moving existing installations is expensive, and there may be other protective steps that can be taken such as elevating backup generators. This is increasingly a factor in utility planning in Hawaii and along the west coast.

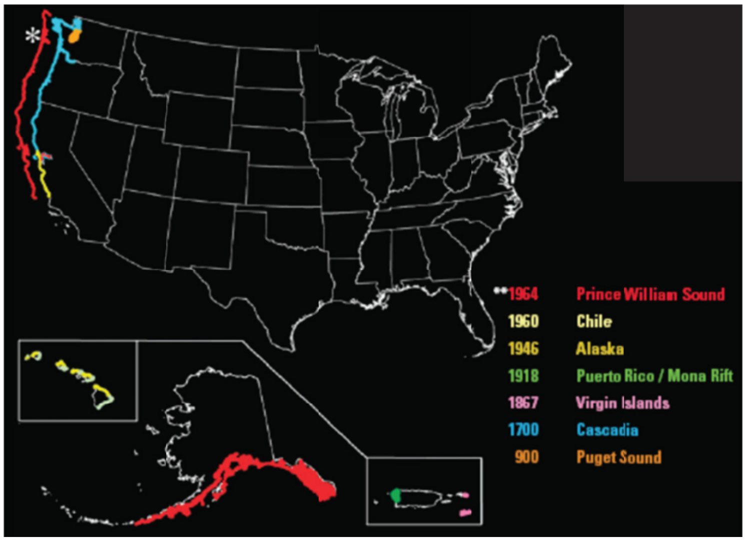

FIGURE 3.4 U.S. coastal locations that have experienced major tsunamis over the course of the past 1,000 years. SOURCE: USGS (2016a).

Regional Weather

Weather events can be a major cause of disruption for the power system. Scientific knowledge about both the causes of severe weather events and the ability to detect changes in the risks varies considerably. Some changing risks, such as the likelihood of more frequent and extreme precipitation events and more frequent heat waves, are reasonably well understood in both regards. Others, like the frequency and intensity of ice storms (which can devastate power systems), are not understood in either regard. Figure 3.5 displays this considerable variation in the level of scientific understanding of weather and how the frequency and intensity of different weather events may evolve as a consequence of natural variability, climate system oscillations (El Niño–Southern Oscillation, North Atlantic Oscillation, etc.), and secular climate changes (IPCC, 2013; NASEM, 2016).

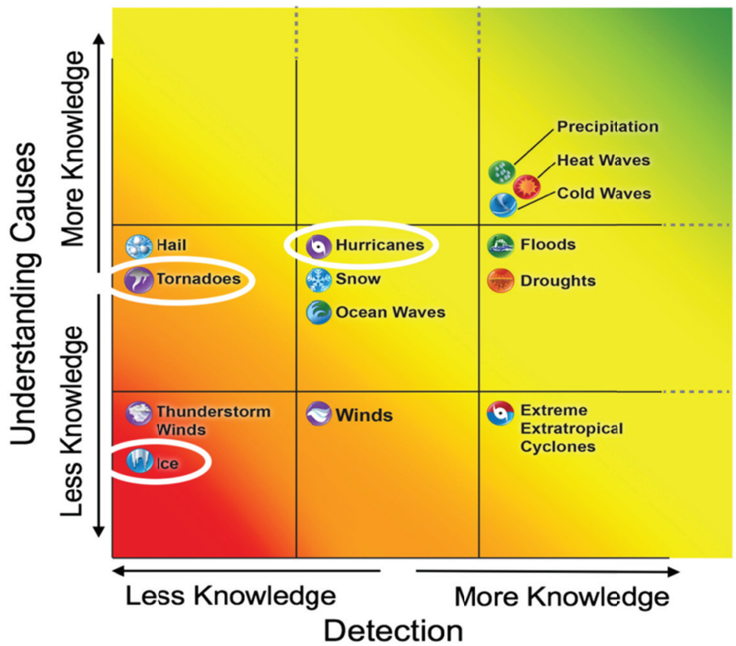

FIGURE 3.5 Summary of the state of knowledge of how the frequency and intensity of various weather events may evolve over time. SOURCE: Wuebbles et al. (2014). ©American Meteorological Society. Used with permission.

In Figure 3.1, point R denotes regional weather events such as intense convective storms and tornadoes that are capable of wide-spread damage, especially to distribution systems. Generally, individual tornadoes impact only a small area, and the specific locations at which damages occur are often difficult to anticipate. However, increasing resolution in weather forecasts does provide system operators with some ability to prepare and be ready to respond quickly once damage has occurred—for example, by pre-positioning repair crews.

Tornadoes have occurred in all parts of the country, but they are rare west of the Rocky Mountains. Similarly, tornadoes do not occur at a uniform rate across the year and are most frequent in April, May, and June (Figure 3.6). Utilities and communities in high-frequency areas are aware of the risk and routinely prepare, building shelters for people and hardening the utility infrastructure.

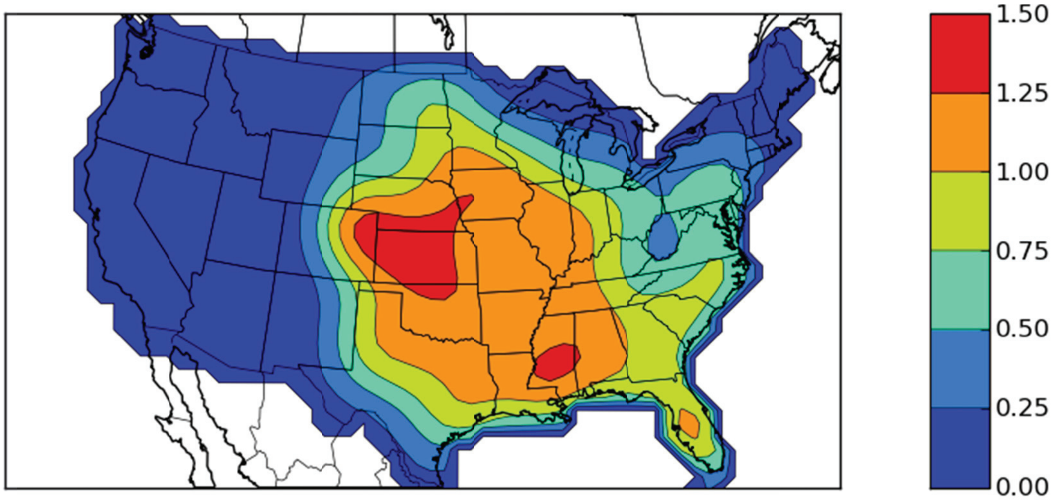

FIGURE 3.6 Map of tornado frequency from 1990 to 2009 (days per year within 25 miles of any point). SOURCE: NOAA and NSSL (2009).

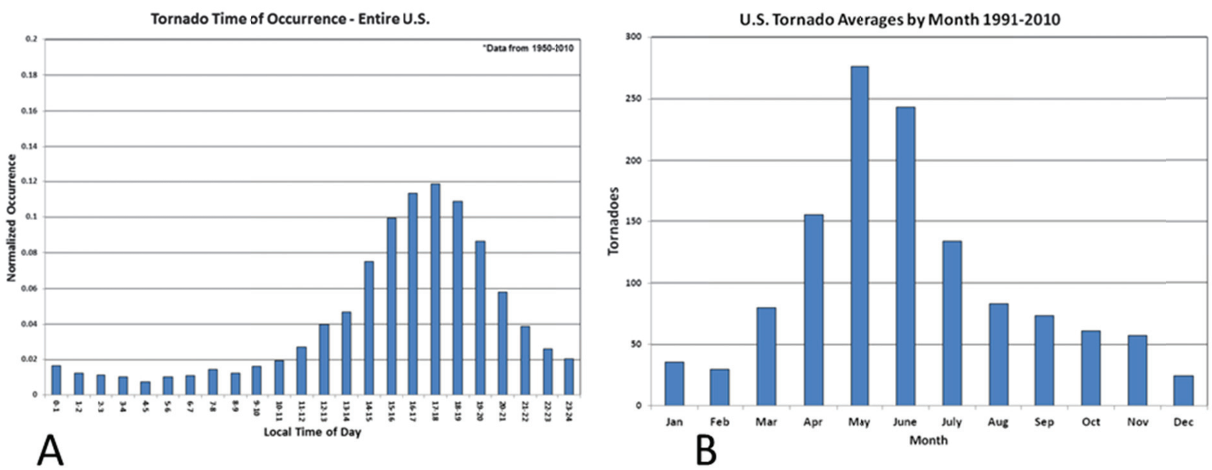

FIGURE 3.7 Tornadoes show a strong (A) temporal and (B) seasonal variation. SOURCE: NOAA (2016).

The frequency of tornadoes shows a strong temporal and seasonal variation (Figure 3.7). The annual frequency of tornadoes strong enough to cause damage to power lines shows no apparent time trend. On the other hand, Tippett et al. (2016) report that "the largest U.S. effects of tornadoes results from tornado outbreaks . . . we find that the frequency of U.S. outbreaks with the many tornadoes is increasing and that it is increasing faster for more extreme outbreaks." Tippett et al. (2016) report that, to date, they have been unable to link this increase to climate change. While not ruling out climate change, they speculate that low-frequency climate variability may be a contributing factor, among others. Figure 3.8 shows a track of storms on April 21 and 22, 2006, impacting four states from Mississippi to North

Carolina. Often these different events are not connected by local authorities, each of which is responsible for recovery from a fraction of the total impact.

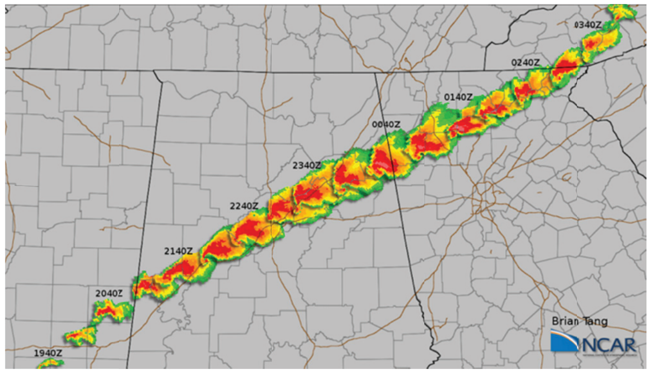

FIGURE 3.8 In 2006, a cluster of tornadoes caused damage across four states in 10 hours from one super cell. SOURCE: Tang (2008).

Ice Storms

Point I in Figure 3.1 denotes ice storms (freezing rain). As is evident from the experience in 1998 in Québec, Ontario, and in upstate New York, ice storms (freezing rain) can result in very widespread damage after which full recovery may take many weeks. Figure 3.9A shows the historical distribution of freezing rain events in the United States over the last 50 years. Figure 3.9B shows the slight upward trend in event frequency over the period 1975 to 2014. Figure 3.9C shows the likely trend in the frequency of future ice storms across the different regions at risk.

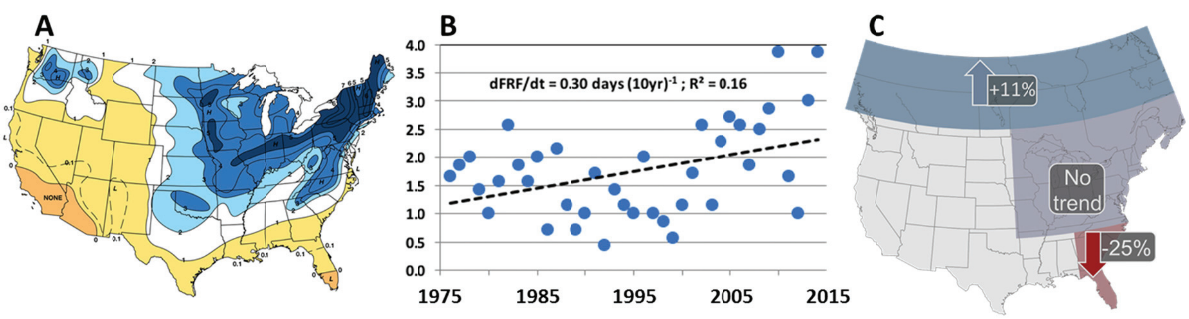

FIGURE 3.9 (A) Distribution of freezing rain from 1948 to 2000, (B) slight recent trend toward more events, and (C) best estimate of trend by region. SOURCES: (A) Changnon and Karl (2003) ©American Meteorological Society. Used with permission. (B) Groisman et al./CC BY (2016). (C) Kunkel (2016).

Ice storms interrupt power through the accumulation of ice on distribution and transmission lines, as the added weight brings lines down and causes damage to poles and towers. In addition to increased weight, wind blowing against ice-laden transmission lines can cause low-frequency (1 Hz) high-amplitude (1 m) oscillations (called conductor gallop) that further stress towers and insulators. Ice accumulation on nearby trees can cause branches to fall on lines or bring vegetation close enough to allow arcing current to cause a short. Impacts to distribution systems are common, whereas damage to transmission towers is less common but requires more resources and time to recover from. Many evocative pictures of damaged transmission and distribution infrastructure are available, dating back nearly 100 years. Figure 3.10A illustrates the extent to which ice can accumulate on distribution systems, and Figure 3.10B shows towers that collapsed due to ice accumulation during a massive storm in Québec in 1998. After the first tower failed, others were pulled down.

Winter storms are a leading cause of power outages nationally but do not receive as much national attention as concentrated events like hurricanes. However, they often do not meet Department of Energy (DOE) reporting requirements and might be exempt from the system average interruption duration index and the system average interruption frequency index reliability metric reporting. Because winter storm outages may be underreported, accurate statistics are not available. The majority of outages are relatively localized and handled by utility crews experienced with recovering from them.

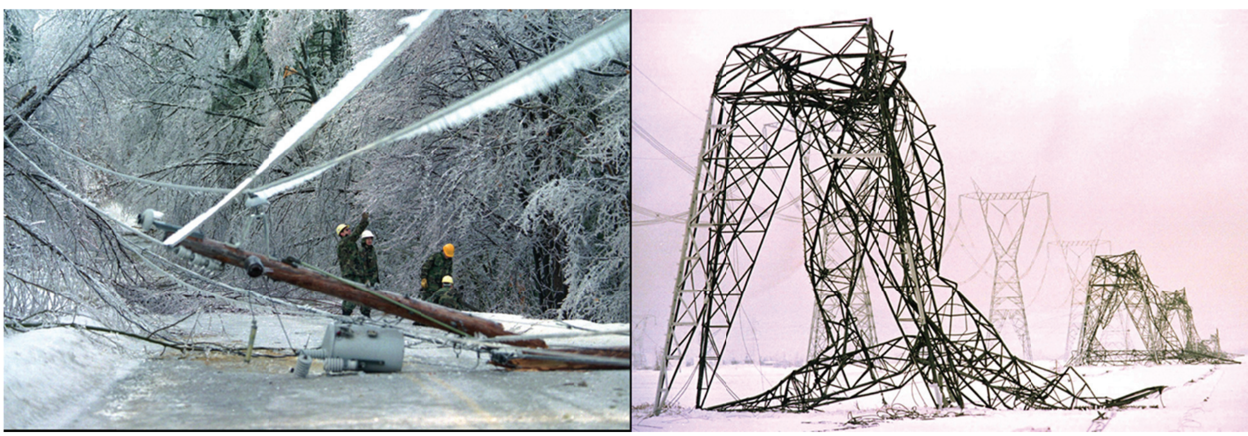

FIGURE 3.10 (A) Ice accumulation of several inches on distribution lines caused these poles to collapse, and (B) images from the infamous 1998 ice storm across southeastern Canada and the northeastern United States. SOURCE: (A) ©1998 The Associated Press (B) Robert Laberge/AFP/Getty Images.

There are established and emerging techniques to reduce the risk of ice storms and accelerate restoration. Building towers to higher standards is a known strategy, but there is insufficient data on the likelihood of extreme ice events and the associated costs of outages to support greater investment. Techniques being explored for distribution systems include helically staked guying for poles, hydrophilic coating to help electrical infrastructure shed ice, and disconnecting wires that fall to the ground without damaging poles.

Floods

Floods (Point F in Figure 3.1) can take many forms, from very abrupt flash floods that follow a sudden rainstorm or the breach of a dam, to events whose buildup occurs over extended periods. Floods can damage distribution or transmission towers and their footings or damage equipment installed on the ground. Most utilities have used historical flood data to choose locations for major facilities, such as substations, that are unlikely to be inundated. However, as the climate changes, the frequency of inundation is also changing (e.g., in some places a "100-year event" may have a much more frequent return period).

Hurricanes and tropical storms are a principal cause of flooding. Detailed maps of the "100-year flood plan" are available for much of the United States from the Federal Emergency Management Agency (FEMA). As of 2005, about one million miles of stream have been mapped. Figure 3.11 shows an example map for an area impacted by the flood following Hurricane Agnes. The map reproduced here is compressed (and hence the legends are not readable), but it is included here to convey the type of information that is available.

The Intergovernmental Panel on Climate Change (IPCC) fifth assessment report anticipates that, in light of climate change, North America will experience "an increase in the number of heavy precipitation events" and "increased damages from river and coastal urban floods" (IPCC, 2014). These changes suggest that it is time to explore the development of more informative strategies to communicate the likely future extent and frequency of future flooding since the traditional 30-year or 100-year flood metric is problematic when the underlying physical processes are not stationary.

The National Research Council Committee on Floodplain Mapping Technologies examined map accuracy in 2007 in a report titled *Elevation Data for Floodplain Mapping* and recommended much greater use of lidar altimetry (NRC, 2007). There are several challenges to accurate flood mapping, including these two: (1) the changes in the rate of river flows (and height of crest) as land is developed in a watershed, and (2) popular pressure to understate risk to lower flood insurance costs and avert an adverse impact on real estate value. Despite these limitations, the FEMA flood maps, if interpreted conservatively, provide a superb basis for assessing flood risks to electrical assets and planning flood remediation.

In addition to disrupting the bulk power system, flooding can make access difficult for distribution system repair crews, cause damage by flooding manholes, and cause other problems in underground distribution systems and components. This suggests that care should be taken in design and building of underground systems in flood-prone areas.

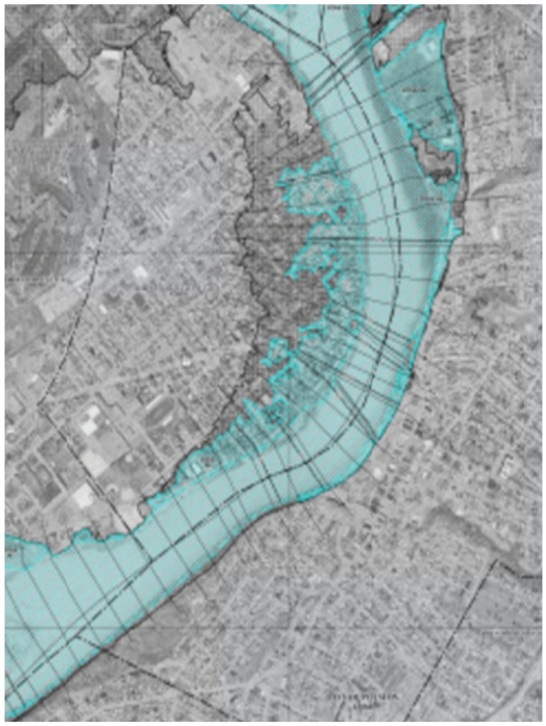

FIGURE 3.11 Example of a Federal Emergency Management Agency flood map for the Susquehanna River near West Pittston, Pennsylvania. The blue shaded areas on the east and west banks of the river are high risk. The dark gray areas beyond the blue area are at moderate risk. The areas outside of the shaded areas are not expected to be impacted by a 100-year flood. SOURCE: FEMA (2016).

Space Weather and Other Electromagnetic Threats

A variety of solar activities (referred to as space weather, point S in Figure 3.1) can impact Earth's environment (NRC, 2008). Large bursts of charged particles ejected by storms on the sun, called coronal mass ejections, can intersect the earth, causing fluctuations in earth's magnetic field that create very low frequency voltage gradients across land, generally at northerly latitudes, and induce quasi-steady-state current that can flow in long transmission lines. These low-frequency currents can cause saturation of transformer magnetic cores and result in damage from overheating. Transformer saturation can also result in reactive power and harmonic generation, which can impact the entire power system. The largest storm of this type in the historical record is the 1859 Carrington Event, which caused telegraph systems in the United States and Europe to fail. More recently, smaller solar storms have caused blackouts and very limited damage in power systems. In March 1989, approximately 6 million people lost power for up to 9 hours across Québec from a solar storm that damaged a few transformers and other equipment. A smaller hour-long outage occurred in Sweden in October 2003.

A risk summary prepared by Lloyds (2013) argues that "historical auroral records suggest a return period of 50 years for Québec-level storms and 150 years for very extreme storms, such as the Carrington Event." In a 2011 study, the Department of Defense's (DOD's) JASON advisory panel concluded that the federal response to the risk "is poorly organized; no one is in charge, resulting in duplications and omissions between agencies" (MITRE, 2011). In 2015, the North American Electric Reliability Corporation (NERC) published a Notice of Proposed Rulemaking that requires transmission operators to conduct a vulnerability assessment and update it periodically (FERC, 2015). In October 2016, President Obama issued a comprehensive executive order addressing space weather, which gave the Department of Homeland Security overall leadership in geomagnetic disturbance preparedness and the DOE leadership in addressing grid impacts.

In 1989, there was no warning for the impending geomagnetic disturbance, whereas now satellites can provide 30 minutes of advance warning and sun observation up to 2-3 days ahead of impact. This warning could provide utilities an opportunity to protect the grid—for example, implementing operating procedures that are designed to protect critical transformers. The time constants determining impacts on transformers from solar storms (or from the E3 portion of electromagnetic pulse [EMP] events) are slow enough that there is time to protect transformers even as the event is occurring. Developing standard approaches for real time monitoring of transformers that could be susceptible to damage during solar storms (which can be identified through vulnerability assessments required by NERC) would help operators minimize damage. Such real-time monitoring could be combined with automated protection schemes that prevent transformer damage from geomagnetic disturbances. Other engineering solutions exist to make electrical systems more resistant to geomagnetic disturbances, including building better protection into transformers and designing systems to provide more reactive power on demand.

The National Oceanic and Atmospheric Administration (NOAA) and the U.S. Airforce jointly operate the Space Weather Prediction Center that uses solar and satellite observations (including NOAA's DSCOVR satellite at the L1 point in deep space) to provide forecasts of space weather events. By observing the limb of the rotating sun, the addition of a satellite at L5 could provide valuable additional advance warning (Gibney, 2017). While coronal mass ejections are relatively slow moving, requiring a day or more to reach the earth, there are a number of events that can produce highly energetic particles that can arrive at the earth in hours, sometimes with little or no warning. These high energy particles can cause damage to GPS and other satellites, which are used by the power system.

Recent standards for transmission system performance in the event of geomagnetic disturbance

(GMD)—for example, NERC standard TPL-007-1—are currently under revision but require that responsible entities maintain detailed system and geomagnetically induced current system models, use these to perform GMD vulnerability assessments every 5 years, and document and communicate this information to other affected entities.

Finally, the committee notes that several of the protective strategies that power companies adopt to reduce vulnerability to solar storms may also provide protection against the lower energy frequencies of an EMP,[2] which is a surge of electromagnetic radiation (Box 3.3) with different components that impact the power system. The early time component of an EMP (E1) is an intense, rapid pulse on the order of tens of kV per meter that decays to nearly zero in less than 1 microsecond; the intermediate time component (E2) has an amplitude of several hundred volts per meter and a duration of one to several hundred microseconds; and the late time component (E3) is a very low amplitude pulse on the order of millivolts per meter with a duration between one and 100 seconds. The electric fields associated with EMP can impact power systems directly (E1 and E2) or induce currents in transmission lines similar to the low frequency currents associated with GMD events (E3). Small, suitcase-size EMP devices[3] can also cause electromagnetic disturbances that can impact the power systems' (especially substation) equipment, but the impacts will likely be very localized. A nuclear weapon or a dedicated non-nuclear EMP device detonated at a high altitude could cause widespread damage to the electricity grid; nonetheless, understanding of this risk is largely theoretical. The Electric Power Research Institute (EPRI) collaborated with the DOE recently to develop a Joint Electromagnetic Pulse Strategy that outlines broad objectives and research needs but stops short of presenting a plan for EMP hardening (DOE and EPRI, 2016).

While most critical satellites have been "hardened," a large enough space weather event could cause damage to earth-orbiting satellites including those used for communication and the GPS. Modern utilities use the GPS to provide time synchronization across their spatially distributed systems. Disruption of these precise timing signals can result in operational problems. While the GPS is well protected, it is also possible that sophisticated earth-bound hackers could disrupt GPS software and control systems. There are technologies that can minimize this risk, but to date their adoption has been limited (Achanta et al., 2015).

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[2] A continental-scale electromagnetic pulse caused by the detonation at high altitude of a specially designed nuclear weapon consists of several electromagnetic waveforms, the first of which has an extremely rapid rise time.

[3] "Suitcase-size EMP devices" are more accurately referred to as radio frequency weapons, essentially a class of non-nuclear weapons that have a local impact similar to that of an EMP E1 pulse. While the DOD is very experienced in this area, less attention has been directed to protecting civilian infrastructure. The concern is that one of these devices might target a control center, disrupting some or all of its computers and communications.

BOX 3.3
Electromagnetic Pulse

An electromagnetic pulse (EMP) is a short duration surge of electromagnetic radiation that can be human-made or natural in origin and have local or widespread impacts. While local impacts can be caused by lightning strikes or by radio-frequency weapons, wider EMP impacts could be caused by the high-altitude detonation of an appropriately designed nuclear weapon. Such a wide-area EMP induced by a high-altitude nuclear weapon is an issue most appropriately addressed by the DOD.

The DOE and EPRI (2016) created the Joint Electromagnetic Pulse Resilience Strategy to help reduce the grid's vulnerability to EMP and improve the energy sector's response and recovery. The initial plan is more of a research strategy than an actual plan for EMP hardening and will take several years to realize. The plan sets five objectives:

1. Improve and share understanding of EMP threat, effects, and impacts;
2. Identify priority infrastructure;
3. Test and promote mitigation and protection approaches;
4. Enhance response and recovery capabilities to an EMP attack; and
5. Share best practices across government and industry, nationally and internationally.

Hurricanes or Tropical Cyclones

As we have learned repeatedly, tropical cyclones can create enormous havoc in power systems. Modern forecasting methods typically provide several days of advance warning, with increasingly more precise and accurate predictions about intensity and the location of land-fall as a storm comes closer. Over their lifetime, tropical storms have three basic impacts on power systems: (1) initial impact of wind and rain, (2) storm surge in coastal areas and near major inland waters (e.g., Lake Pontchartrain during Katrina), and (3) flooding due to precipitation. Hurricane risk is concentrated on the Atlantic and Gulf coasts of the United States and in the state of Hawaii (Figure 3.12A).

A 2016 report of the National Academies of Sciences, Engineering, and Medicine concludes that a "broad consensus has emerged as to the expected future trends in their levels of certainty . . . tropical cyclones are projected to become more intense as the climate warms. There is considerable confidence in this conclusion . . . the global frequency of tropical cyclone formation is projected to decrease . . . but there is less confidence in this conclusion than in the expectation of increasing intensity," as indicated with historical data in Figure 3.12B (NASEM, 2016).

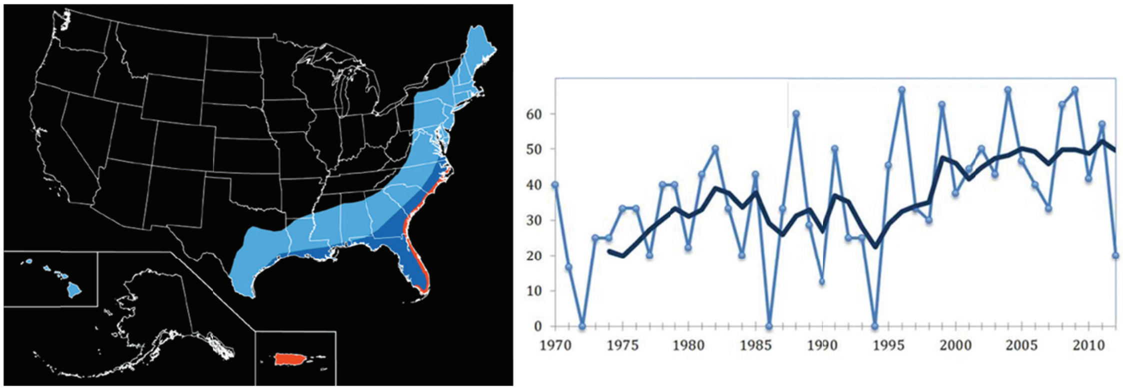

FIGURE 3.12 (A) The region of hurricane risk is greatest on the Atlantic and Gulf coasts of the United States and (B) recent years have seen a trend of Atlantic hurricanes becoming more intense. This is probably the result of both warmer sea-surface temperatures and natural climate variations. The lighter color line is the percentage of hurricanes that reach category 3 or greater each year, and the dark is the 5-year running average. SOURCE: (A) The National Atlas and USGS (2005) and (B) UCS (2016) at www.ucsusa.org.

Along with winter storms, hurricanes and tropical storms[4] (Point H in Figure 3.1) are some of the largest sources of disruption of power systems. As illustrated by Superstorm Sandy and Hurricane Katrina, the resulting destruction can be widespread. Sandy was an immense and meteorologically complex storm that caused outages in 17 states and the District of Columbia, with the impacts beginning over a relatively short period of time. In contrast, Hurricane Katrina was a very different storm. While its impact on New Orleans (due largely to dike failures) and coastal Mississippi was the focus of press coverage, the total impact on electricity infrastructure was much broader because the storm had more rainfall, had higher sustained wind speed over larger areas, and traveled up the Mississippi River valley causing outages as far inland as Tennessee. Both Katrina and Sandy were devastating, but while Sandy was essentially a concentrated event, Katrina caused damage to power systems across a much larger region. While advanced models allow scientists to project the course and development of hurricanes with greater precision than ever before, weather events still have the capacity to surprise. In planning and preparation, it is important to remember that the evolution of a hurricane can involve substantial uncertainty.

Wildfire

[4] In this discussion, the committee includes post-tropical cyclones like Superstorm Sandy where most of the damage was done after the winds had dropped below hurricane force and the storm had lost its hurricane structure.

Climate scientists have long predicted more frequent and more intense wildfires as a result of ongoing climate change (NCAR, 1988). While fire typically does not cause widespread damage to power systems, it can have major impacts on specific substations and transmission systems, and operators may have to re-route power flows to avoid affected areas. Vulnerability can often be limited with vegetation control, although very large fires can often jump even the most aggressive protective margins. Restoration of fire-damaged facilities can require days or weeks. Fire is denoted as point W in Figure 3.1.

Volcanic Activity

In much of the country volcanic activity (V in Figure 3.1) is not a concern, but in the Pacific Northwest, and parts of Alaska and Hawaii, it presents a low probability but high consequence risk from eruption, ash fall, lava flow, and lahars. The U.S. Geological Survey maintains an active warning program (USGS, 2016b). Clearly the best strategy to avoid problems is to locate critical facilities away from vulnerable locations. However, as Figure 3.13 illustrates, in the case of Mount Rainier, the impacted region can be quite large. Additional damage can be caused by fine particulate dust and falling ash, which can cause insulator flashovers and potentially disable transformers. The geographic extent of falling ash may greatly exceed the immediate hazard area.

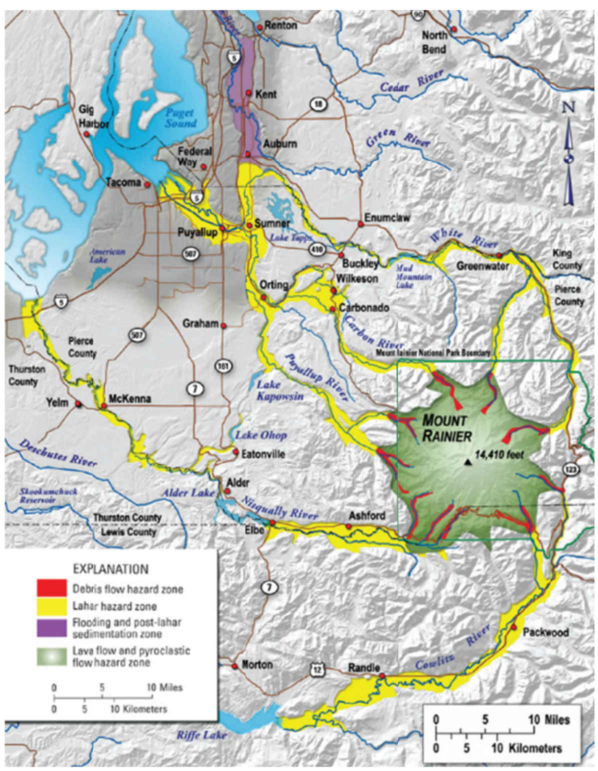

FIGURE 3.13 Volcanic hazard map for the region around Mount Rainier. A "lahar" is a mud and debris flow that can burry everything in its path such as the communities marked as "hazard zones." SOURCE: USGS (2008).

Drought

Finally, in the extreme upper right corner of Figure 3.1 is point D, for drought. Droughts have multiple implications for power systems, ranging from reduced hydroelectricity generation, limited availability of cooling water for power stations, or increased demand for power needed for pumping and treatment. The IPCC report on extreme events concluded that "there is *medium confidence* that droughts will intensify in the 21st century in some seasons and areas, due to reduced precipitation and/or increased evapotranspiration. This applies to regions including . . . central North America" (Seneviratne et al., 2012).

While the power system can become very stressed during extreme heat (heat waves), ordinarily the it manages to deal with such events. Of course, when the power system is highly stressed, the probability of hardware failures or operator error resulting in significant outages increases. The IPCC Fifth Assessment Report (2014, p. 10) concluded, "It is *virtually certain* that there will be more frequent hot and fewer cold temperature extremes over most land areas on daily and seasonal timescales, as global mean surface temperature increases. It is *very likely* that heat waves will occur with a higher frequency and longer duration." The 2014 U.S. National Climate Assessment drew similar conclusions (USGCRP, 2014).

Findings and Recommendations

The hazards reviewed in this section fall broadly into two categories: (1) those in which human action is the primary contributing factor, and (2) those that involve natural causes. The committee divides its findings and recommendations in this same way. With respect to hazards resulting from human actions, the committee finds the following:

> **Finding:** While to date there have been only minor attacks on the power system in the United States, large-scale physical destruction of key parts of the power system by terrorists is a real danger. Some physical attacks could cause disruption in system operations that last for weeks or months.

Finding: The United States has been fortunate that none of the cyber attacks that are being mounted against the power system have caused significant service disruption. However, the risks posed by cyber attacks are very real and could cause major disruptions in system operations.

Finding: While it is tempting to think of physical and cyber attacks as separate and discrete hazards, they could occur together, and attacks could also occur repeatedly. Furthermore, because the power system is essential to the operation of many important infrastructures, physical and/or cyber attacks on that system can impact delivery of other critical services. An attack on the power system undertaken in conjunction with other terrorist action could be especially harmful.

Recommendation 3.1: To better protect the grid from physical and cyber attacks, the intelligence communities, the Department of Homeland Security, the Department of Energy, and operating utilities should sustain and enhance their monitoring and information-sharing activities and continue to assure that adequate communication channels are maintained among all responsible parties. Additional steps, such as the creation of teams to test weaknesses in existing systems, should be taken to avoid the risks of complacency and to drive a culture of continual improvement.

With respect to hazards resulting from natural causes, the committee finds the following:

Finding: Good data on the causes, probabilities, and spatial and temporal distribution of natural hazards that can disrupt power systems are essential to assuring the resilient operation of those systems. Government and other responsible parties should support and strengthen the activities of organizations that collect these data.

Finding: The probability, intensity, and spatial distribution of many of the hazards that can disrupt the power system are changing. These changes are due in part to the consequences of ongoing climate change. Traditional measures, based on an assumption of statistical stationarity (e.g., 100-year flood), may need to be revised to produce measures that reflect the changing nature of some hazards.

Finding: Some organizations that are responsible for monitoring and preparing for natural hazards, such as floods and tornadoes, have a local focus that can overlook spatial correlation and broader system risks. Nonetheless, local assessments such as the "Threat and Hazard Identification and Risk Assessment,"[5] encouraged by the Federal Emergency Management Agency, can provide valuable resources for utilities to build upon.

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[5] See, for example, https://www.fema.gov/media-library-data/8ca0a9e54dc8b037a55b402b2a269e94/CPG201_htirag_2nd_edition.pdf.

Recommendation 3.2: On a periodic basis (e.g., every 5 years), the Department of Homeland Security and the Department of Energy, as the energy sector lead, should work with state and local authorities and electricity system operators to undertake an "all-hazards" assessment of the natural hazards faced by power systems. Local utilities should customize those assessments to their local conditions and build on existing local assessments to include detailed electricity system information, keeping in mind that the past may not be an accurate predictor of the future.

THE LIFE CYCLE OF A POWER OUTAGE

Although the type and extent of damage varies among the different threats previously described, a notional time-series model of a power outage is shown in Figure 3.14, which provides elaboration of some of the key steps in the four-stage process of resilience displayed in Figure 1.2A. The committee also uses these steps in Chapter 6 to illustrate strategies to achieve resilience in the face of a specific cause of disruption.

The blue line in Figure 3.14 illustrates the percentage of load that may be served over time, from the initial full level until the start of the event, at which point load begins to drop off. Load persists at a reduced level for some period until restoration beings. Power is then restored, although sometimes not to the full pre-event level, as electricity-consuming entities may have been damaged or destroyed. If the event caused significant physical damage, load may continue to build slowly during a multi-year recovery period as electricity systems are restored, homes are reoccupied, and businesses reopen.

The relative length of each stage and the activities undertaken by utilities and other organizations involved in the response are different depending upon the type of disruption. Likewise, the activities undertaken by utilities during each of these stages also varies significantly based on the resources available and the technological characteristics of the impacted system. As briefly introduced below and as outlined in the following chapters, there are many strategies that can help utilities perform better through the entire outage life cycle.

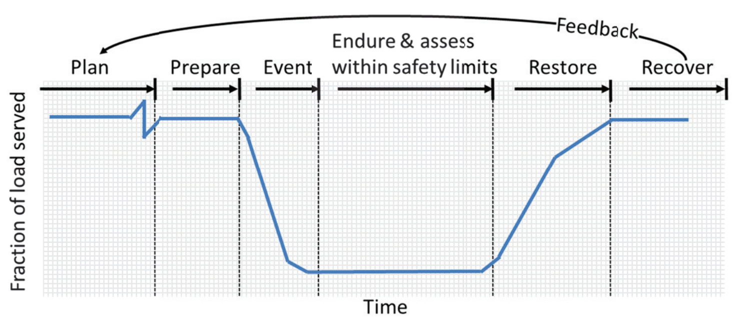

FIGURE 3.14 Notional time series of a major power outage divided into six stages. The length of each stage and the activities performed by utilities and others involved in the response vary for different disruptions.

Plan

The majority of time is spent in the planning stage, which occurs continuously and well before any specific hazard is identified. While there is variation among organizations, utilities—from large vertically integrated firms to small distribution cooperatives—generally know what the major hazards are in their service territories, may have first-hand experience with such hazards, and may even be required by regulators to prepare and submit plans regularly for addressing these risks. For example, utilities in the southeast prepare for hurricanes, whereas those in the far northeast focus more on ice storms. Utilities also generally know which parts of their physical systems are most vulnerable. This knowledge is acquired through experience and with diverse resources, such as data sets from NOAA and the National Weather Service. Nonetheless, the local impacts of most hazards, even those with a long history, are unknown during planning stages. Following Superstorm Sandy, the New Jersey utility Public Service Enterprise Group believed that the impact would have been much greater (perhaps double) if the storm track had been only 10 miles different, as more critical substations could have been affected by flooding in drainage basins. Utilities have less experience handling certain risks—notably those related to cyber attack—which makes assessing and planning more difficult.

Activities during the planning phase are both preventative and preparatory. At the distribution level, these include hardening system components and installing more advanced technologies such as automatically reconfigurable circuits. The level of investment by different utilities is closely tied to state regulatory or board oversight decisions; thus, there is wide variability across different states, and planning decisions are not solely determined by utilities. For investor-owned utilities, state regulatory commissions strive to keep costs low for ratepayers by approving investments that have net benefits for customers and not allowing a utility to "gold plate" its system. On the transmission level, utilities maintain, harden, and expand the physical and cyber infrastructure (both hardware and software) with investments and reliability standards overseen by NERC and FERC. As the complexity and scale of the grid as a cyber-physical system continues to grow, there are opportunities to plan and design the system to reduce the criticality of individual components and to fail gracefully as opposed to catastrophically. Equally important, utilities routinely plan for restoration—for example, by developing mutual assistance agreements, investing in spare parts sharing programs, and conducting restoration drills and exercises. Utilities must also engage and maintain strong relationships with local emergency management agencies to integrate their own planning into local and national efforts, as discussed in greater detail in Chapters 5 and 6. Additionally, there is a critical need to engage electricity end users during planning to define the locations and characteristics of critical loads in a service territory and ensure appropriate use of backup generation.

Prepare

The preparation phase begins when a specific threat is identified—for example, when a hurricane forms with a projected track that will impact a specific utility. Some hazards have no advance warning, while others can be identified and monitored with sufficient time for utilities and other responders to move beyond general planning and develop specific actions. For example, utilities preparing for impeding hazard may check the health of critical components (including the health of cyber systems), check stocks of spare equipment, activate mutual assistance agreements, and bring local crews to a state of readiness, potentially pre-staging supplies and repair crews at specific locations. Operators assess the level of generation available, likely bringing additional reserve generation online, evaluate the adequacy and vulnerability of different fuel stocks and supply chains, and verify the state of charge of utility-scale storage assets if available. During preparation, utilities can begin coordinating with relevant disaster response organizations and encourage the public to purchase fuel and test backup generators. Utilities that have built and maintained strong relationships with local emergency management organizations know whom to engage, whereas organizations that have not built these relationships may waste valuable time and resources trying to connect with local efforts. There are growing opportunities to engage distributed energy resource (DER) owners so that system operators know the state of these resources, although current interconnection standards and contractual arrangements need to be revised to promote utility visibility and controllability of DERs.

Event

The duration of disruptive events varies significantly, as do the capabilities and resources of different utilities. The duration of the actual disruptive event is always much shorter than the period from planning through final recovery. It can last many hours for hurricanes to minutes or even seconds for tornadoes and earthquakes. Floods can last many days or a small number of weeks. The longest duration, however, is for cyber events. The outage may only last a short time, but the period from cyber breach to detection and remediation may last many months. In the recent hack in Ukraine, the breach occurred 9 months before power was interrupted. The hackers used this time to learn how to control the breached systems.

Except in the case of a cyber attack, when the event may be ongoing for an extended period but undetected, the principal activity during the event is to monitor the damage and failures as they emerge and to develop as clear an understanding of system state as possible. Distribution systems with large amounts of advanced meter infrastructure and automated reconfiguration may lessen the number of customers experiencing outages. Some utilities may not be aware of outages until they are reported by telephone. Some events may be so destructive to physical and cyber systems that automation technologies have no benefit and could even be detrimental in the case of a cyber attack (e.g., if microprocessor-based relays with software installed by the manufacturer are hacked, the utility may have to replace the relay entirely or send it back to the manufacturer). There is a great deal of activity at the level of generation and transmission systems. System operators can balance generation and load through generation dispatch, load control (e.g., rolling blackouts), controllable DERs, or intentional islanding. It may be possible to continue with some preparatory activities, but, with limited time, telemetry, and communications, major changes may not be possible.

Endure and Assess Within Safety Limits

For some events, conditions may prevent dispatch of crews (either boots on the ground or man/unmanned aerial vehicles) because of safety concerns. This period may be zero (i.e., restoration can begin immediately), or it may stretch for a lengthy time if access to damaged facilities is blocked as by floodwater or landslides (utility crews can usually deal with downed trees). If cyber monitoring and control systems are intact, utilities can continue to assess the state of the system. During this phase, utilities communicate to understand the extent of damage, begin to prioritize repairs based on available information, and may even schedule the dispatch of restoration crews. As explained in Chapter 5 of this report, there are many strategies to reduce the adverse social and economic impacts of power outages, including using DERs, backup generators, and microgrids to provide local power to critical facilities.

Restore

Restoration is the most tangible and publicly visible phase of the event life cycle. As soon as conditions permit safe dispatch of crews, utilities develop a high-resolution understanding of damages with manned and unmanned aerial vehicles as well as crews on the ground. Based on this understanding, priorities for restoration are established and repairs initiated, often through the shared resources previously arranged in mutual assistance agreements. If a critical transformer without a replacement is damaged, the system may have to be operated in a reduced state until a suitable replacement can be provided. System operators manage switching to support physical restoration. Central operations also provides information to customers and supports field crews by providing the necessary materials, replacement components, repair equipment, and qualified workers, as well as transportation and provisioning. This may require coordinating with state or federal officials to waive regulations or even using military resources in extreme cases. If there are regions of the interconnection with power, restoration may proceed from the "edge"; alternatively, utilities may initiate black start[6] procedures. As installations of DERs continue to increase, there are growing opportunities to use these resources in restoration and black start; however, significant research is needed to demonstrate this capability.

Recover

After the electrical grid has been repaired and service has been restored from a large-area, long-duration outage, utilities and regulators typically evaluate the event to identify root causes and opportunities to improve performance. These investigations directly inform planning and investment decisions made by utilities and overseen by regulators. As discussed in later chapters, there is often scrutiny of utility and infrastructure performance following a major outage, and there may be public and political support for grid investments that impact regulatory proceedings. In many cases (excluding cyber attacks and cascading failures) the commercial, residential, and public infrastructure are also damaged, may be long in returning, or may be lost permanently. In this case, the immediate restoration may be concluded, but the load served may be slightly or substantially less than prior to the event. Presuming the economy recovers and the impacted region is restored, the utility may be engaged in new construction for a number of years. At a minimum, this will entail a sustained period of increased capital spending and staffing for construction.

[6] Most generators require power from the grid to energize their windings, which will not be available in the event of a major outage. "Black start" refers to the process of providing the necessary power to restore a generation plant when grid power is unavailable.

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4

Strategies to Prepare for and Mitigate Large-Area, Long-Duration Blackouts

INTRODUCTION

This chapter focuses on strategies that can help to avoid, prepare for, and reduce the likelihood, magnitude, and duration of large-area, long-duration outages.[1] Although this report is predominantly concerned with large-scale outages, many of the preventative approaches described in this chapter also decrease the likelihood of small localized outages and can help limit the spread and impact of small disruptions before major recovery efforts (see Chapter 6) are required.

This chapter concentrates on two broad aspects of improving grid resilience, considering both physical and cyber impairments. The first, planning and design, describes actions to enhance resilience that can be taken well before a potentially severe physical or cyber event occurs. The second, operations, describes how the grid is operated and strategies to enhance resilience during a severe event. Certainly there is overlap between these two, and the dividing line can blur as the planning time horizon moves closer to the real-time world of operations.

PLANNING AND DESIGN

The electric utility industry has a long history of planning, and the present high levels of reliability attest to its success in this area. However, the majority of this planning and design work has been directed toward increasing system reliability, while focusing on designing the system for optimal

[1] Such events overlap with what the North American Electric Reliability Council (NERC) calls a "severe event," defined as an "emergency situation so catastrophic that complete restoration of electric service is not possible" (NERC, 2012a).

operations during normal conditions and creating the ability to respond to events similar to those that have been previously encountered by grid operators. Planning and design for resilience is different, with challenges that touch on essentially all aspects of the electric grid.

A resilient design requires a holistic consideration of both the resilience of the individual components that comprise modern electric grids and the resilience of the system as a whole. There is, of course, overlap between the two: system resilience can be enhanced by improved component resilience. However, improved resilience also involves consideration of the system as a whole, including not just the electric infrastructure itself, but also the interdependent infrastructures such as natural gas infrastructure, support infrastructure for the supply of other key inputs, and the commercial communications systems used in operating the grid. Last, improved resilience requires regulatory consideration of how upgrades will be funded.

Component Hardening and Physical Security

Creating reliable and secure components, investing in system hardening, and pursuing damage prevention activities are all strategies that improve the reliability of the grid and likewise play a role in preventing and mitigating the extent of large-area, long-duration outages. Utilities are generally aware of local hazards; however, these hazards may change over time, and utilities may not be aware of the compound vulnerabilities that become increasingly possible. Strategies used to address these hazards include appropriate design standards, siting methods, construction, maintenance, inspection, and operating practices. For example, a transmission line traversing high mountains must be designed for heavy ice loading, which may not be a design consideration for infrastructure located in desert environments. Design considerations for generation facilities, substations, transmission lines, and distribution lines frequently include environmental conditions such as extreme heat, cold, ice, and floods among other known threats. Utilities have less experience in design and hardening for uncommon threats such as geomagnetic disturbance (GMD) or electromagnetic pulse (EMP); nonetheless, these have been the focus of increasing attention and strategies to reduce system vulnerability.

Utility investment in system hardening is typically informed by a risk-based cost-performance optimization that strives to be economically efficient by investing in mitigation strategies with the greatest reduction in risk at the lowest cost (Figure 4.1). In principle, an infinite amount of money could be spent hardening and upgrading the system with costs passed on to ratepayers or taken from shareholder returns. However, utilities and their regulators (or boards) are typically conservative in these investments. All mitigation strategies have cost-performance trade-offs, and it may be difficult to estimate the actual reduction in risk or improvement in resilience associated with a specific action. In most cases, an electricity system that is designed, constructed, and operated solely on the basis of economic efficiency to meet standard reliability criteria will not be sufficiently resilient. If some comprehensive quantitative metric of resilience becomes available, it should be combined with reliability metrics to select a socially optimal level of investment. In the meantime, decision makers must employ heuristic procedures to choose a level of additional investment they believe will achieve a socially adequate level of system redundancy, flexibility, and adaptability.

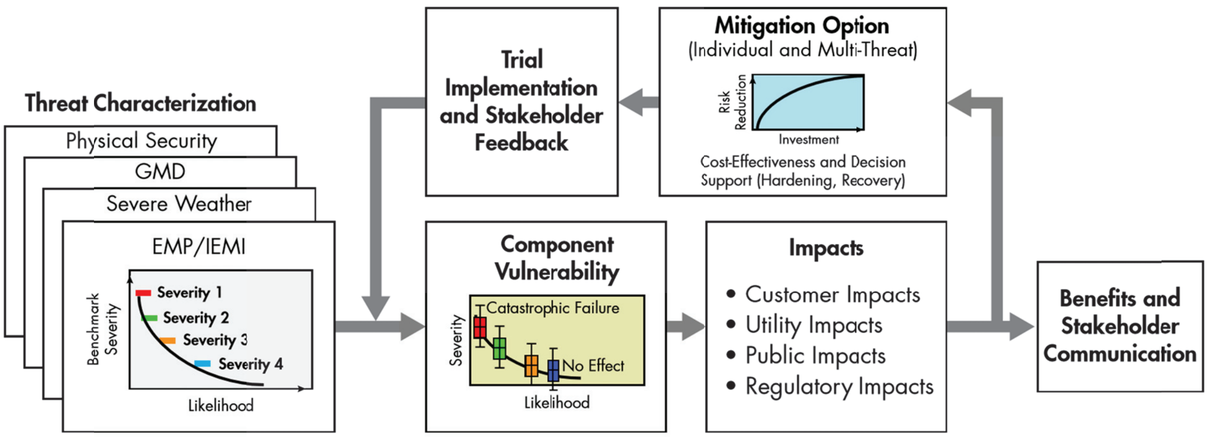

FIGURE 4.1 The process of considering and mitigating individual component vulnerability based on cost-performance optimization.
NOTE: GMD, geomagnetic disturbance; EMP, electromagnetic pulse; IEMI, intentional electromagnetic interference.
SOURCE: Courtesy of the Electric Power Research Institute. Graphic reproduced by permission from the Electric Power Research Institute from presentation by Rich Lordan to the NCSL-NARUC Energy Risk & Critical Infrastructure Protection Workshop, Transmission Resiliency & Security: Response to High Impact Low Frequency Threats. EPRI, Palo Alto, CA: 2016.

Finding: Design choices based on economic efficiency using only classical reliability metrics are typically insufficient for guiding investment in hardening and mitigation strategies targeted towards resilience. Such choices will typically result in too little attention to system resilience. If adequate metrics for resilience are developed, they could be employed to achieve socially optimal designs. Until then, decision makers may employ heuristic procedures to choose the level of additional investment they believe will achieve socially adequate levels of system redundancy, flexibility, and adaptability.

Hardening and mitigation strategies can improve electricity grid reliability and resilience, and utilities routinely employ many techniques when deemed cost appropriate. Common examples are described in the following paragraphs.

Vegetation Management

Many outages, particularly those in the distribution system, are caused by trees and vegetation that encroach on the right-of-way of power lines. Overhead transmission lines are not directly insulated and instead require minimum separation distances for air to provide insulation. If trees or objects are allowed to get too close and draw an arc, short circuits of the energized conductor can result. When they are heavily loaded, transmission line conductors heat up, expand, and sag lower into the right-of-way, which increases the likelihood of a fault at times of peak transmission loading. Therefore, inadequate vegetation management in transmission line rights-of-way is a common cause of blackouts. On the lower-voltage distribution system, separation requirements are much smaller, and line sag is less of a consideration. However, during high wind or icy conditions, falling trees and limbs can either create a short circuit or tear down the wires themselves. This can be extremely hazardous when the energized wires are in close proximity to people. So while there are different vegetation management practices for transmission (clearing vegetation below the wires) and distribution (clearing vegetation from around and above the wires), vegetation management is a key factor that influences the reliability of the transmission and distribution (T&D) system. Following the widely publicized blackout of August 14, 2003, new national standards for vegetation management of transmission lines were implemented. However, the vegetation management practices for distribution utilities vary dramatically, influenced by a variety of factors including geography, public sentiment, and regulatory encouragement.

Undergrounding

Undergrounding of T&D lines is often more expensive than building above-ground infrastructure. Outside of dense urban environments, T&D assets are typically not installed underground unless land constraints, aesthetics, or other community concerns justify the cost. Undergrounding protects against some threats to the resilience of the electric grid, such as severe storms—a leading cause of outages—but it does not address all threats (e.g., seismic or flooding) and may even make recovery more challenging. Furthermore, undergrounding may be impractical in some areas, based on geologic or other constraints (e.g., areas with a high water table.) Therefore, the decision of whether or not to underground T&D assets varies considerably based on local factors; while undergrounding may have resilience benefits in some circumstances, it does not offer a universal resilience benefit.

Reinforcement of Poles and Towers

Building the T&D network to withstand greater physical stresses can help prevent or mitigate the catastrophic effects of major events. Structurally reinforcing towers and poles (referred to as robustness) is more common in areas where heavy wind or ice accumulations are possible, but the degree to which they are reinforced presents a cost trade-off with clear resilience implications.

Dead-End Structures

To minimize cost, transmission towers are often designed to support only the weight of the lines, with lateral support provided by the lines themselves, which are connected to adjacent towers. Thus, if one tower is compromised, it can potentially create a domino effect whereby multiple towers fail. To limit this, utilities install dead-end structures with sufficient strength to stop such a domino effect. However, there is a cost trade-off associated with how often such structures should be installed (e.g., changing the spacing from having one dead-end structure every 4 miles versus one dead-end structure every 10 miles).

Water Protection

Flooding is often a greater concern for substations and generation plants than transmission and distribution lines, and storm surge is particularly challenging for some coastal assets. When siting new facilities, it is possible to avoid low lying and flood prone areas. There are, however, many legacy facilities located in high hazard areas. Given that much of the population lives in coastal areas, it is impossible to address this risk completely through siting alone. Common techniques include installing dikes and/or levees, if land permits, or elevating system components above flood levels, which can be expensive when retrofitting legacy facilities.

Emerging Strategies for Geomagnetic Disturbance and Electromagnetic Pulse

There are various electromagnetic threats to the power system, including GMD (naturally occurring) and EMP (man-made). Both of these threats have resilience considerations at the component level and from a system-wide perspective. While they have different mechanisms of coupling to the grid and inducing damage, they are similar in that they can damage high-value assets, such as transformers. The EMP threat is unique in that it can directly incapacitate digital equipment such as microprocessors and integrated circuits that are not military hardened. NERC has new planning requirements for mitigating GMD (NERC, 2016a), and various commissions (e.g., the Congressional Commission to Assess the Threat to the United States from EMP Attack) have explored the degree to which it is appropriate to harden civilian infrastructure to address the EMP threat.

Physical Security

The immense size and exposed nature of electricity infrastructure makes complete physical protection from attacks impossible; thus, there is a spectrum of physical security practices employed across the grid. Utilities selectively protect critical system components, and NERC standard CIP-014-2 (NERC, 2014a) is enforced on the transmission system. Distribution systems are outside the scope of NERC jurisdiction. Because many generation facilities are staffed, they are relatively well protected. Additional federal requirements apply to protecting nuclear and other key assets, such as federally owned dams. Other assets essential to the operation of the system, such as control centers, can resemble bunkers and are well guarded. Many substations are less protected and have only surveillance, locks, and other deterrents. However, historical events such as the Metcalf incident (See Box 3.1) and a recent "white hat" break-in and hack of a utility shared on YouTube call attention to the limitations of these strategies. Alternative strategies include redesigning substation layout to minimize exposure, deploying barriers, protecting information about the location of critical components, and improving adoption of best practices and standards (ICF, 2016). Examples of these practices learned from the Metcalf incident include greater emphasis on outside-the-fence measures, including camera coverage, lighting, and vegetation clearing.

Distribution System Resilience

As noted in Chapter 2, the wires portion of the electric grid is usually divided into two parts: the high-voltage transmission grid and the lower-voltage distribution system. The transmission system is usually networked, so that any particular location in the system will have at least two incident transmission lines. The advantage of a networked system is that loss of any particular line would not result in a power outage. In contrast, the typical distribution system is radial (i.e., there is just a single supply), although networked distribution systems are often used in some urban areas (NASEM, 2016a). Most aspects of resilience to severe events ultimately involve the transmission system; however, improved distribution system resilience can play an important role.

There is wide variation in the level of technological sophistication in distribution systems. The most advanced distribution utilities have dedicated fiber-optic communications networks, are moving away from the tradition radial feeder design toward more networked architectures, and have sectionalizing switches that allow isolation of damaged components. In response to damage on a distribution circuit, these systems automatically reconfigure the distribution network to minimize the number of customers affected. In one notable example, shown in Figure 4.2 and detailed in Box 4.1, the Chattanooga Electric Power Board (EPB) installed significant distribution automation technology with a $111 million grant from the Department of Energy (DOE) through its Smart Grid Investment Grant program (authorized by the 2009 American Recovery and Reinvestment Act). The sophisticated and extensive project entailed installing a dedicated fiber-optics communications system, smart distribution switches, advanced metering infrastructure, and other equipment to automate restoration (DOE, 2011). It decreased restoration times for EPB's customers, increased savings to EPB, and demonstrated possibilities for other utilities to emulate. However, pursuing a closed-loop fiber-optic system may be a challenge in other utility service areas that are larger geographically and in terms of population. While fiber-optic communication offers an advantage, it is not required to integrate the other technologies used at EPB. However, the deployment of a fiber-optic system lays the foundation for technologies that result in very high data exchange rates, such as phasor measurement units (PMUs), and offers the ability to provide broadband access to the community.

A distribution fault anticipation application based on "waveform analytics" (Wischkaemper et al., 2014; Wischkaemper et al., 2015) is another example of a technology that could be applied today. The key idea behind this approach is to utilize fast sensing of the distribution voltages and currents to detect precursor waveforms, which indicate that a component on a distribution circuit will soon fail. This is in contrast to the traditional approach of waiting for the component to fail and cause an outage before doing repairs. Examples of problems that can be detected by such pre-fault waveform analysis include cracked bushings, pre-failure of a capacitor vacuum switch, fault-induced conductor slap (in which a fault current in the distribution circuit induces magnetic forces in another location, causing the conductors to slap together), and pre-failure of clamps and switches.

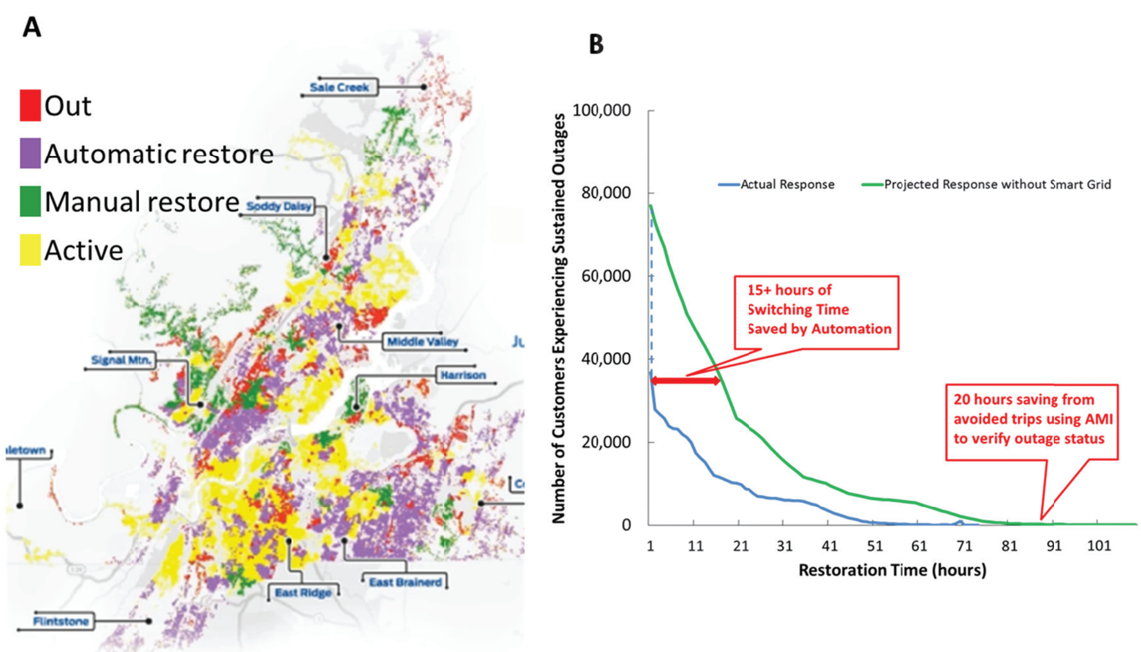

FIGURE 4.2 (A) Following a major storm that disrupted service on many distribution circuits operated by Chattanooga Electric Power Board, automatic reconfiguration prevented outages for many customers

(purple) and significantly reduced the number of circuits requiring manual repairs (green); and (B) such automation has greatly reduced the number of customer-hours (area under the curve) of outage experienced.
NOTE: AMI, advanced metering infrastructure.
SOURCE: Glass (2016).

BOX 4.1
Financial and Operational Benefits of Distribution Automation to Chattanooga Electric Power Board

Resilience and Reliability: The installed fiber-optic network allows EPB to manage a greater number of restoration crews following a storm event and, based on a limited time frame, improve its system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) reliability metrics (Glass, 2016; Wade, 2016).

Financial Savings: Annual savings of $200,000 due to decreased dispatch of restoration crews, $2.5 million from automated meter reading and remote disconnect, and $2.7 million in energy demand savings from demand response and voltage control. Taken together, EPB saves nearly $5.5 million as a result of its fiber-optic and automation technologies (Glass, 2016).

Finding: While many distribution automation technologies are available that would enhance system resilience, their cost of deployment remains a barrier, particularly in light of challenges in monetizing the benefits of such installations.

Recommendation 4.1: Building on ongoing industry efforts to enhance system resilience, the Department of Energy and utility regulators should support a modest grant program that encourages utility investment in innovative solutions that demonstrate resilience enhancement. These projects should be selected to reduce barrier(s) to entry by improving regulator and utility confidence, thereby promoting wider adoption in the marketplace.

Utility-Scale Battery Storage

Utility-scale battery storage is a relatively new tool available to operators to manage power system stability, which can potentially help prevent or mitigate the extent of outages. Of course even large batteries can only supply power for periods of hours, but such systems have value in other ways. They can be used to dispatch large amounts of power for frequency regulation, potentially preventing propagation of system disturbances, and provide additional flexibility for managing stability in lieu of demand response or load shedding. Installations of large utility-scale batteries (as opposed to behind-the-meter batteries) have increased significantly in several regions of the United States over the last 5 years. The DOE Global Energy Storage Database has information on more than 200 utility-scale battery projects in the United States, with more than 400 MW installed or approved capacity by the end of 2015 (Figure 4.3) (Hart and Sarkissian, 2016). Given potentially large installations in 2016, this data set may underestimate such storage capacity.[2] Other areas leading installation are in the Electric Reliability Council of Texas (ERCOT) and in California, driven largely by state policies (NREL, 2014). The small (relative to the scale of the three North American interconnections) Railbelt Electric System in Alaska was an early adopter (2003) of utility-scale battery energy storage, in part owing to instability challenges associated with operating a small, low-inertia "islanded" grid. Most utility-scale batteries on the grid employ lithium-ion chemistry and are used primarily for power conditioning and, to a lesser extent, for peak load management. Lithium-ion chemistry using existing electrolytes is not ideal for bulk storage of electricity from large-scale, variable renewable generation sources, but alternative battery chemistries have yet to reach the cost, performance, and manufacturing scale to impact utility operations.

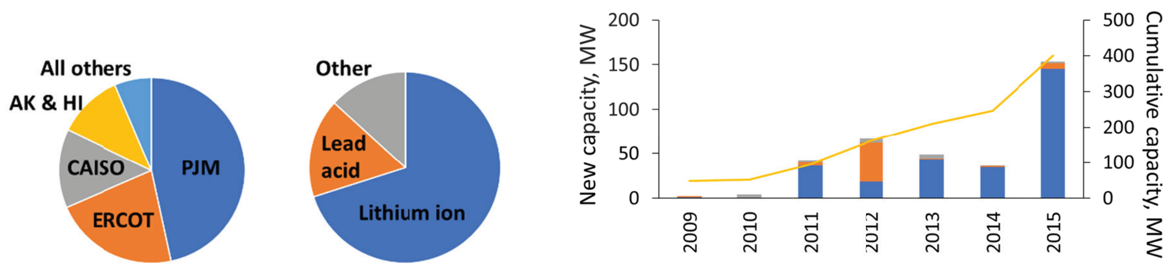

FIGURE 4.3 Installations of utility-scale battery storage have increased substantially over the last 5 years, although growth is concentrated in a few areas and dominated by lithium-ion chemistries.
NOTE: CAISO, California Independent System Operator; ERCOT, Electric Reliability Council of Texas.
SOURCE: Data from Hart and Sarkissian (2016).

Distributed Energy Resources

Distributed energy resources (DERs)—including distributed generation from photovoltaics, diesel generators, small natural gas turbines, battery storage, and demand response—have the potential to help prevent the occurrence of large-area, long-duration outages as well as to provide local power to critical services during an outage. In California, for example, storage aggregators are contracting with utilities to provide tens of MW of storage capacity—alongside 70 MW of utility-scale storage—to help manage local resource adequacy and reliability following the closure of the Aliso Canyon facility (see Box 4.2). However, the reliability and resilience benefits of DERs to the bulk power system vary significantly, based on their technical characteristics and capacities as well as their location and local grid

[2] The committee believes there is approximately 400 MW capacity installed in the PJM service territory alone.

characteristics. Historically, DER adoption has been driven by environmental considerations and consumer preferences; only recently has resilience become an explicit design consideration. The greatest resilience benefits can be realized through coordinated planning and upgrading of T&D systems, as well as by providing operators the ability to monitor and control the operating characteristics of DERs in real time and at scale. This may require changes to technical standards, regulations, and contractual agreements.

Strategically placed DERs (that are visible to and controllable by utilities) not only provide local generation at the end of vulnerable transmission lines, but also can be operated to relieve congestion and potentially avoid the need for new transmission infrastructure. Thus, some of the early applications of DERs for enhanced resilience were motivated by local system concerns—in locations with constraints on transmission expansion or at the end of lines that are known to be problematic.

Inverter Standards for Increased Visibility and Control

At current levels of installation (relatively low except in certain areas such as Hawaii), DERs are not likely to be used explicitly for the purpose of preventing or mitigating large-scale outages. Nonetheless, as DER installations continue to grow, it may become possible to coordinate their dispatch to help prevent outages (i.e., maintain system stability) and to expedite restoration (as described in Chapter 6). However, realizing these system benefits would require that system operators—whether distribution utilities or independent parties—have visibility and an appropriate level of control over the majority of DERs in a region.

This will require changes in interconnection standards, notably regarding inverters that are the interface between many types of DERs and the distribution system. In the past, these standards, which are under revision as of this writing, have required that DERs disconnect from the grid under fault conditions. This is undesirable behavior because it can jeopardize system stability under significant DER penetration levels. In the revised standards (IEEE, 2017), inverters will be required to ride through grid events, and they will have the ability to provide voltage and frequency regulation. Future inverters will provide operators with updated information on DER performance (e.g., generation level, state of charge), who could in turn actively utilize these resources in running the grid (e.g., when implementing adaptive islanding or intelligent load shedding schemes)

A non-exhaustive list of advanced inverter functionalities that could help prevent or mitigate outages, if they can be leveraged at scale, includes the following:

- *Frequency-watt function.* Adjusts real power output based on service frequency and can aid in frequency regulation during an event.
- *Volt-var and volt-watt function*. Adjusts reactive and/or real power output based on service voltage; this is necessary to maintain distribution feeder voltages within acceptable bounds when DER penetration is high, but it could also be used for transmission-level objectives.
- *Low/high voltage and frequency ride-through*. Defines voltage and frequency ranges for the inverter to remain on-line during a disturbance, which becomes a key feature at high DER penetration levels.
- *DER settings for multiple grid configurations.* Enables a system operator to provide a DER with alternate settings, which may be needed when the local grid configuration changes (e.g., during islanding or circuit switching).

Finding: DERs have a largely untapped potential to improve the resilience of the electric power system but do not contribute to this inherently. Rather, resilience implications must be explicitly considered during planning and design decisions. In addition, the possibility exists to further utilize DER capabilities during the operational stage.

Recommendation 4.2: The Department of Energy and the National Science Foundation, in coordination with state agencies and international organizations, should initiate research, development, and demonstration activities to explore the extent to which distributed energy resources could be used to prevent large-area outages. Such programs should focus on the technical, legal, and contractual challenges to providing system operators with visibility and control over distributed energy resources in both normal and emergency conditions. This involves interoperability requirements and standards for integration with distribution management systems, which are ideally coordinated at the national and international levels.

Interconnected Electric Grid Modeling and Simulation

From the start of the power industry in the 1880s, modeling and simulation have played a crucial role, with much expertise gained over this time period. Over the last 60 years or so, much of this expertise has been embedded in software of increasing sophistication, with power-flow, contingency-analysis, security-constrained optimal power-flow, transient-stability, and short-circuit analysis some of the key modeling packages (NASEM, 2016b). Modeling and simulation occur on time frames ranging from real-time, in the case of operations, to looking ahead for multiple decades when planning high-voltage transmission line additions.

While the tools are well established for these traditional applications, enhancing resilience presents some unique challenges. First, multidimensional modeling is needed because severe events are likely to affect not just the electric grid, but also other infrastructures. Second, in order to enhance resilience, simulations should be specifically designed to consider rare events that severely stress the grid. Many rare high impact events will stress the power grid in new and often unexpected ways; as a consequence, most will also likely stress existing the power system modeling software. The degree of power system impact often requires detailed modeling of physical and/or cyber systems associated with the initiating event. For example, correctly modeling the impacts of large earthquakes requires coupled modeling between the power grid and seismic simulations (Veeramany et al., 2016). This requires interdisciplinary collaboration and research between power engineers and people from a potentially wide variety of different disciplines. On the cyber side, for example, one must be able to correctly model the occurrence, nature, and impact of a large-scale distributed cyber attack like the one in Ukraine in 2015.

Because such events are rare, there is typically little or no historical information to accurately quantify or characterize the risk: some of the more extreme events could be considered extreme manifestations of more common occurrences (NASEM, 2016b). Thus, a large-scale attack could be considered a more severe manifestation of the more regular disturbances (such as those due to the weather). However, others would be more novel. As an example, consider the modeling and simulation work being done to study the impact of GMD on the power grid. GMDs, which are caused by coronal mass ejections from the sun, cause low frequency (<< 0.1 Hz) variations in the earth's magnetic field. The changing magnetic field can then induce electric fields on the earth's surface that cause quasi-direct current geomagnetically induced currents to flow in the high-voltage transmission system, potentially causing saturation in the high-voltage transformers. A moderate GMD, with a peak electric field estimated to be about 2 V/km, caused a blackout for the entire province of Québec, Canada, in 1989 (Boteler, 1994), while much larger GMD events occurred in North America in 1859 and 1921.

As noted by Albertson et al. (1973), the potential for GMD to interfere with power grid operations has been known at least since the early 1940s. However, power grid GMD assessment is still an active area of research and development; much of that work has occurred in the last few years through interdisciplinary research focusing not just on the power grid, but also on the sun, the earth's upper atmosphere, space weather hazards, and the earth's geophysical properties. The assumptions on modeling the driving electric fields in software have evolved from a uniform electric field (NERC, 2012b); to scaled uniform direction electric fields, based on ground conductivity regions (based on one-dimensional earth models) (NERC, 2016a); to varying magnitude and electric fields, based on three-dimensional earth models using recent National Science Foundation Earthscope results (Bedrosian and Love, 2015). Over the last few years, GMD analysis has been integrated into commercial power system planning tools including the power flow (Overbye et al., 2012) and transient stability analysis software (Hutchins and Overbye, 2016).

Determining the magnitudes of the severe events to model can be challenging since there is often little historical record. This was highlighted in 2016 by the Federal Energy Regulatory Commission (FERC) in their Order 830,[3] which directed NERC to modify its Standard TPL-007-1 GMD benchmark event so as not to be solely based on spatially averaged data. The challenges of using measurements of the earth's magnetic field variation over about 25 years to estimate the magnitude of a 100-year GMD are illustrated by Rivera and Backhaus (2015). Determining the scenarios to consider for human-caused severe events, such as a combined cyber and physical attack, are even more challenging.

Finding: Enhancing power grid resilience requires being able to accurately simulate the impact of a wide variety of severe physical events and malicious cyber attacks on the power grid. Usually these simulations will require models for either coupled physical and cyber infrastructures or physical systems. There is a need both for basic research on the nature of these simulations and applied work to develop adequate simulations to model these severe events and malicious cyberattacks.

Recommendation 4.3: The National Science Foundation should continue to expand support for research looking at the interdisciplinary modeling and mitigation of power grid severe events. The Department of Energy should continue to support research to develop the methods needed to simulate these events.

A key driver for the research and development of simulation tools for improved resilience is access to realistic models of large-scale electric grids and their associated supporting infrastructures, especially communications. Some of this information was publicly available in the 1990s, but, as a result of the Patriot Act of 2001, the U.S. electric power grid is now considered critical infrastructure, and access to data has become much more restricted. While some access to power grid modeling data is available under non-disclosure agreements, these restrictions greatly hinder the exchange of the models and results needed for other qualified researchers to reproduce the results. This need is particularly acute for resilience studies, in which models need to be shared among researchers in a variety of fields for interdisciplinary work.

A solution that protects critical infrastructure information is to create entirely synthetic models that mimic the complexity of the actual grid but contain no confidential information about the actual grid. Such models are now starting to appear, driven in part by the U.S. DOE Advanced Research Projects Agency-Energy Grid Data program (ARPA-E, 2016), which is focused on developing realistic, open-

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[3] 156 FERC ¶ 61,215.

access power grid models primarily for use in the development of optimal power flow algorithms. A quite useful characteristic of such synthetic models would be to include realistic geographic coordinates in order to allow the coupling between the power grid and other infrastructures or the actual geography. Birchfield et al. (2016) suggest using an electric load distribution that matches the actual population in a geographic footprint, public data on the actual generator locations, and algorithms to create an entirely synthetic transmission grid. As an example, Figure 4.4 shows a 2000-bus entirely synthetic network sited geographically in Texas. The embedding of geographic coordinates with the existing Institute of Electrical and Electronics Engineers' 145-bus test system is used by Veeramany et al. (2016) to present a multi-hazard risk-assessment framework for study of power grid earthquake vulnerabilities.

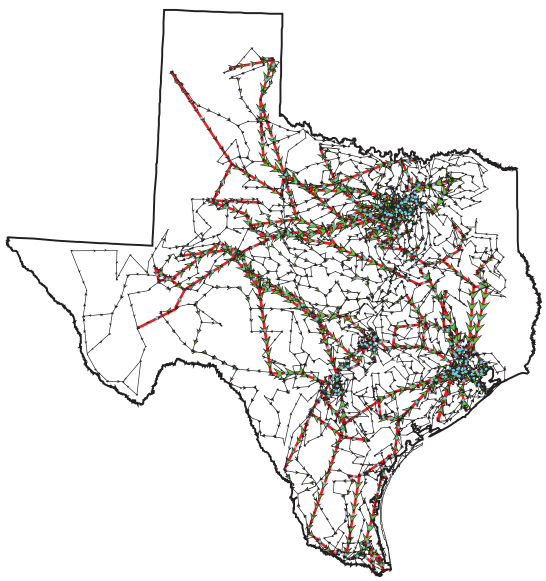

FIGURE 4.4 2000-bus synthetic network sited in Texas. The red lines show 345 kV transmission lines, the black lines show 115 kV lines, and the green arrows show the flow of power from the generators to the loads. SOURCE: © 1969 IEEE. Reprinted, with permission, from Power Systems, IEEE Transactions on Grid Structural Characteristics as Validation Criteria for Synthetic Networks

While there has been some progress in creating synthetic models for the physical side of the electric grid, there has been very little progress in creating realistic models for the communications that support grid operations, both to represent its complexity and extent and to represent its coupling with the physical portion of the grid. Such models are necessary to understand the overall resilience of the power grid. Without such models, it is impossible to understand the impact of a cyber attack on the physical portion of the grid and hence its ability to deliver power despite a cyber attack.

Finding: A key objective for research and development of simulation tools for improved resilience is shareable access to realistic models of large-scale electric grids, considering both the grid's physical and cyber infrastructure and, equally important, the coupling between the two infrastructure sides. Because the U.S. power grid is considered critical infrastructure, such models are not broadly available to the power systems research community. Therefore, there is a need to develop synthetic models of the power grid physical and cyber infrastructure that match the size and complexity of the actual grid but contain no confidential information and hence can be fully publicly available.

Recommendation 4.4: The Department of Energy should support and expand its research and development on the creation of synthetic power grid physical and cyber infrastructure models. These models should have geographic coordinates and appropriate cyber and physical model detail to represent the severe events needed to develop algorithms to model and enhance resilience.

Interconnected Electric Grid Planning

Planning for resilience requires providing sufficient redundancy in generation, transmission, and distribution capacity. Current reliability standards issued by NERC (that are mandatory for operators of the bulk electricity system) require that the transmission system have enough redundant paths to withstand an outage by one major line or other important component (NERC, 2005). In most cases, the transmission system can continue operating with the loss of several transmission lines. At the distribution level, some state public utility commissions provide performance-based incentives that encourage distribution utilities to improve reliability metrics such as SAIDI and SAIFI, although these measures do not typically include outages associated with major events. Although NERC standards have largely been effective in addressing credible contingencies and have been recently expanded to include consideration of extreme events,[4] designing the grid to ride through catastrophic events such as major storms and cyber attacks pushes their limit. Furthermore, designing and building the system to withstand such major events is expensive, and while the electricity system is designed to be economically efficient (subject to reliability-based constraints such as adequacy requirements in design and operational contingency requirements in operation), additional analyses and changes in planning, operational, and regulatory criteria may be needed to build incentives to design, plan, and operate the system to consider resilience in a cost-effective manner. Pushed too far, traditional strategies to make the system more robust can become cost-prohibitive, so planning and designing for graceful degradation and rapid recovery has become increasingly important for utilities.

[4] NERC TPL-001-4 requires studies to be performed to assess the impact of the extreme events; if the analysis concludes there is a cascading outage caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) must be conducted (NERC, 2005).

With respect to transmission system level generation planning, the reliability standard followed in North America is a loss of load probability (LOLP) of 1 day in 10 years—enough generation capacity available to satisfy the load demand 99.97 percent of the time. If one can predict the maximum yearly load demand over many years, and good statistics of the central generator outage rates are available, one can calculate the schedule and amount of new generation capacity construction to meet this level of reliability.

As growing amounts of intermittent solar power have been added to distribution systems, the central plant generator models used in the traditional generation planning studies may be inadequate. The availability statistics were either unavailable or inadequate as the technologies were evolving. If the availability of demand curtailment, which is the same as generation availability, is also considered, the model for that will again be different, as this is dependent on factors other than weather. Finally, the addition of storage requires models that are even more complicated, as these can behave as either loads or generation with their own optimal charge/discharge schedules.

Although the generation planning criterion of the LOLP being one day in 10 years assures that the available generation capacity exceeds the load demand, the process ignores whether the transmission grid can move the generation to the load centers. The transmission planning process assures this by running power flow and transient stability studies on scenarios of extreme loading of the transmission grid. The planning criterion is that the system would operate normally (i.e., without voltage and loading violations) even if one major piece of equipment (e.g., line, transformer, generator) is lost for any reason—this is known as the "N-1" criterion.[5] Note that this is a worst case deterministic criterion, not a probabilistic criterion like LOLP; this is because no one has yet found a workable stochastic calculation that can compute the probability of meeting all the operational constraints of the grid.

These generation planning requirements work well for scenarios where there are a few central generator stations but if meeting the generation reliability requires the availability of the DERs on the distribution side (including demand and storage management), then it is not enough to run studies on only the transmission system. On the other hand, modeling the vast numbers of distribution feeders into the contingency analysis studies would increase the model sizes by at least one magnitude. Even though this may not pose a challenge to the new generation of computers, it does pose a huge challenge to the present capabilities of gathering, validating, exchanging, and securing the model data.

The decision to invest in new generation, transmission, and distribution is more impacted by cost considerations where reliability objectives are otherwise being met. The least cost consideration must take

[5] The N-1 criterion , referring to surviving the loss of the single largest component, is shorthand for a more complex set of NERC standards that specify the analysis of various categories of "credible contingencies" and acceptable system responses.

into account not just the capital cost, but also the operational cost over the lifetime of the generation, transmission, or distribution. This cost optimization process has to include the operational scenarios over several decades, resulting in a dynamic optimization.

A major procedural hurdle has been the fact that generation (and even transmission, which is regulated) can be built by third parties whose optimal decision may or may not coincide with the optimal decision for the whole system. This multi-party decision making has essentially made the process much more difficult, and there is concern that the present decision making is too fragmented to guarantee the needed robustness of the future grid.

It is difficult enough to include all of the control and protection that is part of the grid today, but the use of distributed generation, demand response, and storage will require much more control and protection. Moreover, the rapid deployment of better measurement (advanced metering infrastructure, distribution management systems, and phasor measurement units) and communication (fiber optics) technologies are enabling a new class of control and protection that are not yet embedded into commercial-grade simulation packages.

Architectural Strategies to Reduce the Criticality of Components

A reliable system includes reliable components and a system architecture design that reduces the criticality of individual components needed to maintain grid functionality. A redundant and diverse architecture can enhance resilience of the system by reducing the dependencies on single components and how they contribute to the overall system objectives. Considerations of cascading failures, fault tolerant and secure system design, and mutual dependencies are important to develop resilient architectures. While many design characteristics of the modern power grid employ these concepts, it is important to improve resilient architecture design principles to enhance the capability of the system and to have a high degree of operational autonomy under off-normal conditions.

Historically, one of the primary means of achieving system resilience in the event of accidental component failure is through redundancy. This approach has been adopted by the electricity industry since its inception and has served the customers well. For particularly important components or subsystems, this redundancy can also include diversity of design so as to prevent common mode failures or deliberate attacks from compromising both the primary and secondary components. Both redundancy and diversity in design are often employed in communication networks.

In addition, there is a need to design systems with insights provided by simulation of cascading failure sequences, so that technical or procedural countermeasures to thwart cascading failure scenarios can be applied. This preemptive analysis (and configuring the system to avoid conditions where cascading failure is a credible outcome) is particularly important because the speed of cascading failure sequences can often exceed the capability of automatic control responses, especially when the wide-area nature of the grid, and inherent communication delays, are taken into account.

One approach of resilient system design is to install controls that respond appropriately to limit the consequences or even stop a cascading failure sequence, regardless of the specific scenario that initiated the event. Thus, the system remains resilient even if events occur that are not envisioned or beyond the design basis of the system. Under-frequency load shedding is a notable example of this type of control. It operates when the system is in distress, and the resulting action of this control serves to help bring the system back into equilibrium. This design is elegant in that it is always appropriate to shed load when the system is experiencing a prolonged low frequency condition and that these controls can be autonomous and isolated, making them very secure and robust. Therefore, the presence of this type of control helps to enhance resilience, independent of the specific scenario or sequence of events that led up to its activation. Future implementation of under-frequency load shedding schemes will need to take into account the number of DERs on distribution feeders. These schemes may need to rely on intelligent load shedding instead of disconnecting entire distribution feeders.

Intelligent Load Shedding

Automatic under-frequency load shedding is a common strategy designed into systems, which maintains the stability of the grid when there is an unanticipated loss of generation. Load shedding events typically impact entire circuits, with all customers on the circuit losing power (NERC, 2015). However, with increasing deployment of advanced metering infrastructure (AMI) and sectionalizing switches on distribution systems, opportunities exist to significantly improve the precision and reduce unwanted outages associated with load shedding events. In the near future, it may be possible for utilities to disconnect specific meters on a distribution circuit as opposed to disconnecting the entire circuit at the substation. Some AMI provide greater granularity in control, allowing fractional supply as opposed to only full or no supply. Load shedding could be made even more selective with the installation of "smart" circuit breakers within customer facilities that would disconnect specific circuits within a residence or facility, based on providing appropriate financial incentives to customers. This could be done automatically, as a function of parameters like frequency, or it could be done under a systems optimization controller, but these different levels of functionality have differing levels of communication requirements.

> **Recommendation 4.5:** The Department of Energy, working with the utility industry, should develop use cases and perform research on strategies for intelligent load shedding based on advanced metering infrastructure and customer technologies like smart circuit breakers. These strategies should be supported by appropriate system studies, laboratory testing with local measurements, and field trials to demonstrate efficacy.

Adaptive Islanding

The process of “islanding” the grid—that is, where the interconnection breaks up or separates into smaller, potentially asynchronous portions—can result in significant outages if the islanding is the result of an uncontrolled cascading failure. However, there are opportunities to pre-plan and manage the islanding process such that outages impact significantly fewer customers. Adaptive islanding can preserve the benefits of large-scale interconnected system operations during normal conditions while reducing the risk of failures propagating across the grid during abnormal or emergency conditions.

Under normal system conditions, the track record of system protection is excellent. But performance during off-normal conditions is less predictable. When a cascading failure progresses through a power system, the individual tripping of transmission lines will often result in the formation of islands. The stability of an island post-disturbance depends predominantly on the balance of generation and load within the area and the ability to maintain that balance during the sequence of events leading up to, during, and after island formation. Generator protection might act to trip unit(s) to prevent damaging transients. The nature of these transients and their severity, and the ability of the remaining generation to match the load within the island, will determine whether the island will be stable. Other emergency controls, such as automatic under-frequency load shedding, are useful to help preserve the stability of an island as it is being formed. The goal of under-frequency load shedding is preventing the loss of generation from under-speed protection. Losing generation due to over-speed protection is less consequential because high frequency is the result of too much generation in the first place. Usually, one good indicator of whether an island will survive or fail is whether that region of the system was a net exporter or a net importer of power prior to the disturbance. It is easier for generation to throttle down than to throttle up, although under-frequency load shedding schemes can also be used to maintain stability within the island.

Wide-area protection schemes have been developed to limit the consequences of an uncontrolled cascading failure (NERC, 2013). These remedial action schemes provide fast-acting control to preserve system stability in response to predefined contingencies. One such scheme deliberately separates the western power system into two islands by remotely disconnecting lines in the eastern portion of the system if key transmission paths in the western portion of the system become de-energized.

Adaptive islanding is an idea that has been under development for several years (You et al., 2004). The concept is predefining how to break apart the system in response to system events, by matching clusters of load and generation. The goal is to reduce the size of power system blackouts, and minimizing generation loss is a key element of this strategy. This can be accomplished through more aggressive use of fast-acting demand response to preserve the generation-load balance in each of the islands. The technology has progressed to the point where this is becoming a viable approach.

Finding: The electricity system, and associated supporting infrastructure, is susceptible to widespread uncontrolled cascading failure, based on the interconnected and interdependent nature of the networks.

Recommendation 4.6: The Department of Energy should initiate and support ongoing research programs to develop and demonstrate techniques for degraded operation of electricity infrastructure, including supporting infrastructure and cyber monitoring and control systems, where key subsystems are designed and operated to sustain critical functionality. This includes fault-tolerant control system architectures, cyber resilience approaches, distribution system interface with distributed energy resources, supply chain survivability, intelligent load shedding, and adaptive islanding schemes.

Vulnerability due to Interdependent Infrastructures

A reliable electric grid is crucial to modern society in part because it is crucial to so many other critical infrastructures, as described in Chapter 2. However, the dependency goes both ways, as the reliable operation of the grid depends on the performance of multiple supporting infrastructures. Outages can be caused by disruptions to natural gas production and delivery, commercial communications infrastructure, and transportation systems, among other critical infrastructures (Figure 4.5) (Rinaldi et al., 2001).

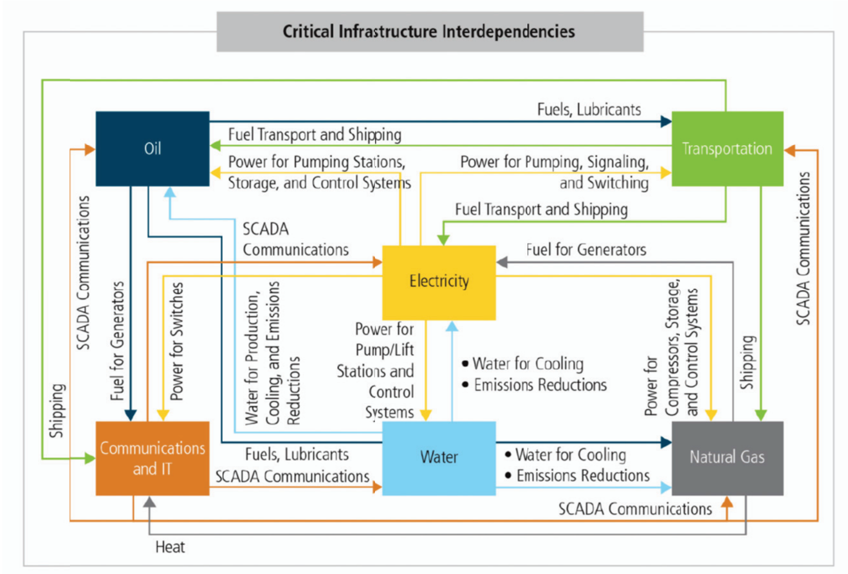

FIGURE 4.5 Disruption of any material or service that the electricity system relies on can result in loss of electric service and make restoration more challenging. NOTE: SCADA, supervisory control and data acquisition. SOURCE: DOE (2017).

Natural Gas Infrastructure

As described in Chapter 2, the fraction of generation provided by natural gas—both large central generating plants and small customer-owned generators powered by internal combustion motors or microturbines—has grown substantially over the past few years. This not only exposes the industry to potential price volatility and supply chain vulnerability, but also raises the question of how utilities could restore electricity service if a major disruption to natural gas delivery occurred (e.g., one or more critical pipelines are destroyed). To date, no such outage has resulted in large electricity outages, and the minor events that have occurred fall on the scale of reliability operations that were handled relatively easily by the industry. The January 2014 Polar Vortex and the natural gas leak and subsequent closing of Aliso Canyon natural gas storage facility have already impacted utility planning and system design to be more cognizant of this critical interdependency (Box 4.2). These studies suggest that resilience can be enhanced through a diverse fuel portfolio, where a single interruption is less likely to impact a significant number of generators that cannot be overcome by reserve assets.

BOX 4.2
Examples of Electric System Vulnerability to Disruptions in Natural Gas Infrastructure

February 2011 Texas Freeze

Abnormally cold temperatures across Texas and the southwestern United States caused many natural gas well heads to freeze, which in turn resulted in curtailment of natural gas deliveries to end use customers and, to a lesser extent, natural gas fired power plants. The cold weather caused 193 power plants (with cumulative load of nearly 30,000 MW) in ERCOT to fail to start or to be de-rated because of frozen equipment, blade icing, and low temperature cutoff limits. At the worst point in the event, one-third of the total ERCOT generator fleet was unavailable. System operators resorted to shedding load and instituted rolling blackouts to prevent an ERCOT-wide uncontrolled blackout. Although electricity-natural gas interdependency was not the primary cause of lost electric load or curtailed natural gas deliveries, the growing interdependency did contribute to the problem (NERC, 2011).

January 2014 Polar Vortex

In January 2014, a mass of cold air moved south across much of the country, plunging the midwest, northeast, and southeast into temperatures 20º to 35º colder than average. The cold snap resulted in above average demand for electricity and natural gas for home heating. Many natural gas power plants were unable to operate as natural gas deliveries were curtailed, and grid operators had to resort to shedding interruptible load to maintain service. Less than 50 MW of firm load was shed over several days, and the event was handled effectively in part because of training and preparation. However, the event focused attention on the vulnerability associated with increasing reliance on natural gas for electricity restoration. Following the 2014 Polar Vortex, NERC made a number of recommendations for operators to increase awareness and coordination with natural gas suppliers, markets, and regulators (NERC, 2014b).

October 2015 Aliso Canyon Storage Facility Closure

A major gas leak was detected in the Aliso Canyon natural gas storage facility in October 2015, resulting in the facility's closing in early 2016. As the second largest natural gas storage facility in the United States, Aliso Canyon supplied gas to 18 power plants in the Los Angeles area with a total generation capacity near 10,000 MW (NERC, 2016b). Analysis suggests that closure of the facility may have significant electricity system reliability impacts, as well as curtailment of gas deliveries, in both summer and winter (CEC, 2016). In combination with the 2014 Polar Vortex, the Aliso Canyon blowout prompted the industry to undertake additional planning and risk mitigation strategies to reduce the likelihood that outages will result from natural gas system constraints.

Finding: Constraints in natural gas infrastructure have resulted in shedding of electric load, and the growing interdependency of the two systems poses a vulnerability that could lead to a large-area, long-duration blackout.

Recommendation 4.7: The Federal Energy Regulatory Commission and the North American Energy Standards Board, in conjunction with industry stakeholders, should further prioritize their efforts to improve awareness, communications, coordination, and planning between the natural gas and electric industries. Such efforts should be extended to consider explicitly what recovery strategies should be employed in the case of failed interdependent infrastructure. Fuel diversity, dual fuel capability, and local storage should be explicitly addressed as part of these resilience strategies.

Commercial Communications Infrastructure

Another example of coupled infrastructure is telecommunications. While many utilities utilize their own dedicated telecommunication assets to support critical communication and automation functions, there is a substantial dependency on communications and internet-based technologies that facilitate the daily operation of the modern electricity system, including coordination among personnel, managing markets, and financial structures, as well as supporting automation and control technology. With growing deployment of smart grid technologies and automated controls, this dependency may continue to increase. In the event of loss of external communications networks, many utility operations may be compromised, requiring greater reliance on manual operation and assessment of the state of damage. As an example, with the failure of multiple communications systems, it may difficult to coordinate the activities of repair crews in the field with operational decisions, thus attenuating the hazards for workers and slowing the restoration.

Design for Cyber Resilience

The electric power system has become increasingly reliant on its cyber infrastructure, including computers, communication networks, other control system electronics, smart meters, and other distribution-side cyber assets, in order to achieve its purpose of delivering electricity to the consumer. A compromise of the power grid control system or other portions of the grid cyber infrastructure itself can have serious consequences ranging from a simple disruption of service to permanent damage to hardware that can have long lasting effects on the performance of the system. Any consideration of improved power grid resilience requires a consideration of improving the resilience of the grid's cyber infrastructure.

Over the last decade, much attention has rightly been placed on grid cyber security, but much less has been placed on grid cyber resilience. In particular, there has been significant research and investment in technologies and practices to prevent cyber attacks. Some of the many methods include the following: (1) identifying and apprehending cyber criminals, (2) defending the perimeter of a network with firewalls and "white listing" and "black listing" certain communications sources, (3) practicing good cyber "hygiene" (e.g., protecting passwords and using two-factor authentication), (4) searching for and removing suspect pernicious code continuously, and (5) designing control systems with safer architecture—for example, segmenting systems to slow or prevent the spread of malware. The sources of guidance on protection as a mechanism to achieve grid cyber security are numerous (DOE, 2015); one good source of reference materials specific to industrial control systems can be found at the Department of Homeland Security's Industrial Control System Cyber Emergency Response Team website.[6] Another good source of information is the Energy Sector Control Systems Working Group's *Roadmap to Achieve Energy Delivery Systems Cyber Security* (ESCSWG, 2011). Furthermore, strategies to achieve power grid cyber security are documented in NISTIR 7628 *Guidelines for Smart Grid Cyber Security* (NISTIR, 2010). A good source of basic information is *Security and Privacy Controls for Federal Information Systems and Organizations* (NIST, 2013), which, although nominally applying to federal systems IT systems, has some guidance that can be useful in protecting grid cyber infrastructure.

It is now, however, becoming apparent that protection alone as a mechanism to achieve cybersecurity is insufficient and can never be made perfect. Cyber criminals are difficult to apprehend, and there are nearly 81,000 vulnerabilities in the National Institute of Standards and Technology (NIST) National Vulnerability Database, making it challenging to use safe code (NVD, 2016). An experiment conducted by the National Rural Electric Cooperative Association and N-Dimension in April 2014 determined that a typical small utility is probed or attacked every 3 seconds around the clock. Given the relentless attacks and the challenges of prevention, successful cyber penetrations are inevitable, and there is evidence of increases in the rate of penetration in the past year, particularly ransomware attacks.

Fortunately, the successful attacks to date have largely been concentrated on utility business systems as opposed to monitoring and control systems (termed operational technology [OT] systems), in part because there are fewer attack surfaces, fewer users with more limited privileges, greater use of encryption, and more use of analog technology. However, there is a substantial and growing risk of a successful breach of OT systems, and the potential impacts of such a breach could be significant. Serious risks are posed by further integration of OT systems with utility business systems, despite the potential for significant value and increased efficiency. Furthermore, the lure of the power of Internet protocols and cloud-based services threatens some of the practices that have historically protected the grid. Cloud-based services provides the potential for better reliability, resilience, and security versus on-premises computing, particularly for smaller utilities. For example, major commercial clouds, like the Amazon cloud, have a very high level of around-the-clock monitoring by a well-provisioned security operations center, better than that operated by some utilities. The cloud does, however, present another attack surface. Utilities that choose to use the cloud must explicitly consider the security of the cloud and how to secure the communications bi-directionally.

Given that protection cannot be made perfect, and the risk is growing, cyber resilience, in addition to more classical cyber protection approaches, is critically important. Cyber resilience aims to protect, using established cybersecurity techniques, the best one can but acknowledges that that protection

[6] The website for the Industrial Control System Cyber Emergency Response Team is https://ics-cert.us-cert.gov/Standards-and-References, accessed July 4, 2017.

can never be perfect and requires monitoring, detection, and response to provide continuous delivery of electrical service. While some work done under the cybersecurity nomenclature can support cyber resilience (e.g., intrusion detection and response), the majority of the work to date has been focused on preventing the occurrence of successful attacks, rather than detecting and responding to partially successful attacks that occur.

Cyber resilience has a strong operational component (mechanisms must be provided to monitor, detect, and respond to attacks that occur), but it also has important design-time considerations. In particular, architectures that are resilient to cyber attacks are needed to support cyber resilience. Work during the last decade has resulted in “cybersecurity architectures” for the power grid cyber infrastructure, such as those described by NIST (2015), but there has been much less work done to define “cyber resilience architectures.” Some preliminary discussion of such an architecture can be can be found in MITRE’s *Cyber Resiliency Engineering Framework* (Bodeau and Graubart, 2011) and in NISTR’s *Guidelines for Smart Grid Cyber Security* (NISTIR, 2010), among other places.

Generally speaking, a cyber resilience architecture should implement a strategy for tolerating cyber attacks and other impairments by monitoring the system and dynamically responding to perceived impairments to achieve resilience goals. The resilience goals for the cyber infrastructure require a clear understanding of the interaction between the cyber and physical portions of the power grid as well as how impairments on either (cyber or physical) side could impact the other side. By their nature, such goals are inherently system-specific but should balance the desire to minimize the amount of time a system is compromised and maximize the services provided by the system. Often, instead of taking the system offline once an attack is detected, a cyber resilience architecture attempts to heal the system while providing critical cyber and physical services. Based on the resilience goals, cyber resilience architectures typically employ sensors to monitor the state of the system on all levels of abstraction. The data from multiple levels are then fused to create higher-level views of the system. Those views aid in detecting attacks and other cyber and physical impairments, as well as in identifying failure to deliver critical services. A response engine, often with human input, determines the best course of action. The goal, after perhaps multiple responses, is complete recovery (i.e., restoring the cyber system to a fully operational state).

Further work to define such cyber resilience architectures that protect, detect, respond, and recover from cyber attacks that occur is critically needed. Equally important, but just as challenging, is work to validate that proposed cyber resilience architectures achieve cyber resilience and cybersecurity requirements (See Recommendation 4.10).

Regulatory and Institutional Opportunities

As described in Chapter 2, utilities seek and regularly receive regulatory approval for routine preventative maintenance activities such as vegetation management and hardening investments. While FERC regulates generation and interstate transmission, individual states are responsible for approving investments in local transmission and the distribution system. There is wide variety in public utility commission (PUC) approval of utility investment across the United States and between geographically similar Gulf states (Carey, 2014). States along the hurricane-prone southeastern coast are more likely to allow alternative mechanisms to finance such investments, including the addition of "riders" to customer bills, securitization and issuance of bonds, and creation of reserve accounts that utilities can use as a form of self-insurance (EEI, 2014).

In addition to approving investments in hardening and preventative strategies, several states, such as California, Florida, and Connecticut, require utilities to regularly submit and update emergency preparedness plans, which often require input and coordination from city and county officials. Others provide performance-based incentives or penalties—for example, based on improvements to reliability measures such as SAIDI and SAIFI (although most reporting standards do not include large-area, long-duration outages when calculating these metrics)—to encourage best practices in the absence of standards on distribution systems. Other states impose penalties for inadequate levels of service or performance during storm events and recovery. Funding of grid modernization investments likewise varies across states, with some regulator commissions such as California and Massachusetts researching and investing significantly in advanced communications and automation technologies. In the absence of regulatory approval, there is a critical opportunity for continuing federal grants (e.g., the Smart Grid Investment Grant provided to Chattanooga Electric Power Board) to further demonstrate the viability of such technologies and promote wider adoption across states.

In response to large outages such as those that resulted from Superstorm Sandy and other high profile storms, state PUCs and, to a lesser extent, state legislatures across the country have considered investments in system hardening and implementing assorted grid modernization strategies with the goal of preventing or mitigating the impact of future large outages (Box 4.3).[7] Historically, such crises often provide the opportunity to focus attention and resources on costly robustness and resilience enhancements in a system that may be optimized economically without systematic consideration of the value of avoiding or responding quickly to these extreme events. Nonetheless, regulators' and the industry's efforts are more often reactive than proactive, and a focus on near-term cost-benefit optimization may not have

[7] A more complete review of state regulatory actions related to robustness and resilience is provided by EEI (2014).

resulted in investments that provide cost-effective benefits from a more resilient power grid. Thus, the committee expects that successfully funding cost-effective investments in resilience will require novel approaches, as described in Chapter 7, and proper metrics, as described in Recommendation 2.1.

BOX 4.3
Select Regulatory Actions Supporting Hardening, Modernization, and Other Preventative Investments

Florida Storm Hardening
Given the recurring high risk of hurricane damage to electricity infrastructure in Florida, state regulators have long considered how to improve reliability and resilience to large storms. In a series of rulemakings in the mid-2000s, the Public Service Commission required that investor-owned utilities provide annual hurricane preparedness briefings, file and update storm hardening plans, increase coordination with local governments, and invest in research with Florida universities to improve robustness and recovery.

Energy Strong New Jersey
Following Superstorm Sandy and the extensive damage done to regional distribution systems and substations, the New Jersey Board of Public Utilities approved more than $1 billion for hardening and modernizing Public Service Enterprise Group (PSEG) electric and gas infrastructure. Approximately $600 million of this will go to elevating 29 substations damaged during Sandy to 1-2 feet above Federal Emergency Management Agency flood levels. An additional $125 million will be used to install more sectionalizing switches in the distribution network, allowing PSEG to reconfigure the distribution systems and maintain service to the maximum number of customers during outage events.

Connecticut Act Enhancing Emergency Preparedness and Response
Passed following Hurricane Irene and major winter storms in 2011, this Act requires utilities to file emergency preparedness plans every 2 years with the state regulatory commission. Additionally, the Act provided grant funding for construction of microgrid projects at critical facilities around the state, and to date more than $30 million has been invested in nearly 20 projects.

Illinois Energy Infrastructure Modernization Act
Passed by the state legislature in 2012, the Act authorizes Commonwealth Edison and Ameren Illinois to invest $2.6 billion and $625 million, respectively, in hardening, undergrounding, distribution automation, AMI installations, and substation upgrades. The Act sets performance-based rates of return for utilities.

OPERATIONS

Much can be done in the area of real-time electric grid operations to enhance physical and cyber resilience. With the advent of smart grid devices, the electric grid is getting more intelligent with more sensing and embedded controls. While they are certainly beneficial, smart grid devices make the grid more complex. While this automatic control is helpful, any consideration of power system operations needs to recognize that the human operators are still very much “in the loop” and will continue to be so for many years into the future. Therefore, strategies to enhance operational resilience need to include tools to enhance the capabilities of the operators and engineers running the system.

In order to understand operations, it is useful to consider the different power system operating states shown in Figure 4.6. By far the majority of the time is spent in the normal state—that is, ready to handle the N-1 reliability criteria. This is the state in which people have the most experience; hence, many of the tools used in the control center are focused on normal operations. More rarely, the system moves into alert, emergency, and restorative situations. However, such situations are encountered often enough that there is good historical experience; control room personnel train for such situations, and, for the most part, they have adequate tools for dealing with these situations.

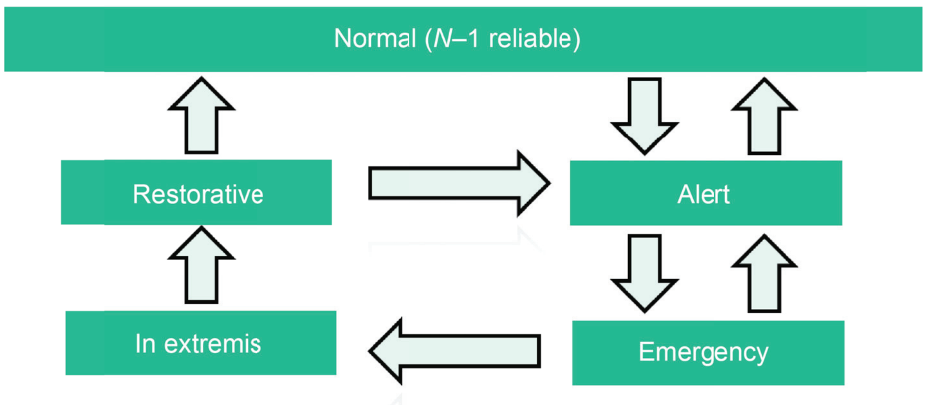

FIGURE 4.6 Power system operating states. SOURCE: © 1978 IEEE. Reprinted, with permission, from IEEE Spectrum Operating under Stress and strain [electrical power systems control under emergency conditions].

Enhancing grid resilience requires that more attention be given to the alert, emergency, in extremis, and restorative stages of these operating states. In these stages, the previously interconnected grid may be broken into a number of electrical islands, and the operation of these islands may need to be performed by entities that are not normally responsible for grid operations (NERC, 2012a).

Sometimes, threats such as hurricanes can be identified with sufficient warning time to allow system operators to preemptively position the system to be more robust and able to respond to emerging conditions. This often involves curtailing any avoidable outages that might be caused by maintenance or other activities, deploying additional reserves to the extent possible, and even powering down certain critical components to minimize potential damage. This strategy is often less expensive than hardening strategies previously discussed. All major events are managed by operators in the control center, and their skills and training, as well as their tools and supporting technologies, are critical factors for how effectively the event will be managed.

Wide-Area Monitoring and Control

As the power grid becomes more complex and is operated closer to reliability limits, the need for greater remote control increases. Fortunately, the technologies needed for such "wide-area control," principally sensors and communications, are becoming cheaper and more powerful. The increasing use of high-speed wide-area measurements, including synchrophasors that measure currents and voltages 30-60 times a second and communicate them to distant computers, allows the design of controls that can use input data from different parts of the system and send control signals to equipment in different locations. The combination of PMUs, distribution automation, dedicated fiber-optic cable communications infrastructure, and affordable computing will likely lead to increasing reliance on artificial intelligence in the power system. Additionally, remedial action schemes[8] are increasingly being deployed to increase the throughput of the grid, while minimizing the risk of cascading failures, by appropriately tripping loads and generators after an event on the system. The measurements for these automatic relays can often be hundreds of miles apart. These automated systems are able to sense and take action in real-time, and can be thought of as a stepping stone to wider application of artificial intelligence and machine learning applied to the power grid..

Although such wide-area controls are appearing all over the world, the design, simulation, on-line testing, and cyber protection of such controls are expensive and time-consuming. Moreover, the architecture of the power grid and its overlaid control system has a direct impact on the design of such controls. For example, how centralized or decentralized a control scheme should be is constrained by where the measurements are, the communication paths to gather these measurements in the controller, and which equipment are available to this controller for control. Such controllers are in their evolutionary stages, so they should be designed for not just economic and reliability benefits, but also for resilience.

Often the term smart grid is used in reference to electronic meters and sensors. However, it also encompasses the wide-area monitoring and control considered here. That is, smart grids could include automatic sectionalizing, smart islanding to prevent cascading failures, the ability to operate these islands in a degraded state, and supercomputing resources to support system operators. For example, during the August 14, 2003, blackout, there was almost an hour of opportunity to intervene before the cascading event initiated (USCPSOTF, 2004). With better operational intelligence, a preventative shedding of approximately 2,000 MW load in the Cleveland area would have prevented the cascading failure that affected over 60 million people.

[8] A scheme designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation, tripping load, or reconfiguring a system (NERC, 2014c).

During a major event such as Hurricane Katrina or Superstorm Sandy, thousands of alarms can overwhelm the system operator. Artificial intelligence could help quickly prioritize these alarms that come in over the supervisory control and data acquisition (SCADA)/energy management systems (EMS) and provide the operator with suggestions for the most important alarms to focus on, the root cause(s) of the event, and the most important actions to prevent further degradation and start restoration. The inherent complexity that power system operators have to face every day used to be addressed through detailed procedures. Today, with the system growing in complexity, the assistance of artificial intelligence and improved man–machine interfaces for system operators is likely to enhance both reliability and resilience. Under this scenario, all historical events and previous operators' experiences could be accumulated by a system such as IBM's Watson to prioritize alarms and suggest appropriate action.

As DERs and smart inverters become more and more common in the distribution system, electricity system operators need to assess whether artificial intelligence combined with closed-loop fiber-optic broadband communication can improve the reliability and resilience for distribution customers. As more DERs are connected with smart inverters, the distribution system can break into smaller microgrids that can island and maintain service to critical load. In addition to distributed generation, demand side resources (customer loads) with inverters and power electronics can improve both reliability and resilience.

The Chattanooga EPB has demonstrated this by installing fiber-optic communication and automatic sectionalizing switches. Its communication system brought fiber optics to every home with smart meters available to determine both billing information and operational data such as Volts, Volt-ampere reactives, and Amps. This alone will not improve resilience, but combined with automated switches and voltage control devices EPB has greatly improved both the reliability and the resilience of its distribution system.

Finding: New automation systems promise to enable better monitoring and control of the grid. The design of such large-scale, wide-area controllers should be done with cyber resilience in mind. Such controllers should tolerate accidental failures and malicious attacks that occur, providing degraded functionality even during recovery from such attacks, and not be a hindrance during catastrophic events or the recovery afterwards. Flexibility of the controller may be achieved with the proper centralized/decentralized design, where the centralized control may provide the best benefits during normal operation. When the grid is broken up after a catastrophic event, however, the decentralized portion may still be able to operate the various parts.

Physical and Cyber Situation Awareness

Bulk electric grids are some of the world's largest and most complex machines, and disturbances (cyber or physical) can rapidly propagate through their systems. Hence, normal operations can quickly change, demanding quick responses by the human operators or preprogrammed automation. Resilient operation requires physical and cyber "situation awareness," defined as "the perception of critical elements in the environment, the comprehension of their meaning, and the projection of their status into the future" (Wickens et al., 2013), so that unfavorable changes of physical or cyber state that occur can be addressed (either by human or automated means) quickly enough to prevent a catastrophic event.

In the power industry, the term "situation awareness" was popularized by the August 14, 2003, *Blackout Final Report* in which "inadequate situational awareness at First Energy" was noted as the second of the four root causes of the event (USCPSOTF, 2004). The importance of system understanding was also highlighted in the first and fourth causes of the event: "FirstEnergy (FE) and ECAR (East Central Area Reliability Council) failed to assess and understand the inadequacies of First Energy's system, particularly with respect to voltage instability and the vulnerability of the Cleveland-Akron area, and FE did not operate its system with appropriate voltage criteria . . . . [T]he interconnected grid's reliability organizations [failed] to provide effective real-time diagnostic support" (USCPSOTF, 2004). If operators were aware of the accurate estimate of the "true state" of the grid, they could have taken appropriate actions, which would have eliminated the propagation of effects that led to the widespread blackout. Thus real-time determination of the combined physical and cyber state of the grid is needed to achieve resilience.

Whether operator action can prevent a blackout depends on the time frame and severity of the event (Overbye and Weber, 2015). Some large-scale blackouts cannot be prevented by operator action; earthquakes are examples of unanticipated events that can cause severe damage within seconds. Cyber attacks also have the potential to spread extremely quickly. Conversely, slow-moving weather systems such as hurricanes or ice storms give operators plenty of time to act, but the blackouts cannot be fully prevented. As an example, an ice storm in January 1998 resulted in the collapse of more than 770 transmission towers, causing a large-scale blackout in Canada (Hauer and Dagle, 1999), and Superstorm Sandy caused 8.5 million customer power outages in 2012 (Abi-Samra et al., 2014). The same might be true of the pandemics that would severely limit human resources for response (NERC, 2010).

However, many potential blackouts, including a number of the severe events considered here, do have time frames that could allow for effective operator intervention. North American examples include the August 14, 2003, blackout that affected more than 50 million people, in which more than an hour passed between the system being outside of the normal secure state (remaining stable following the next contingency) and the final uncontrolled cascading failure leading to the blackout (USCPSOTF, 2004); and the September 8, 2011, Western Electricity Coordinating Council blackout that had an 11 minute period between the initiating event and the blackout, and that cited lack of situation awareness as a cause (FERC and NERC, 2012). A primary reason for these time frames is the underlying power system dynamics, including the time constants associated with thermal heating on transmission lines and transformers, the operation of load-tap-changing transformers, protective relaying time constants, and other system limits. Another reason would be the dynamics associated with the initiating event; for a GMD, this might be minutes to hours. Having good power system situation awareness, even during periods of extremely unusual system stress, is crucial for enhancing overall grid resilience.

Furthermore, propagation of disturbances through the grid can potentially be mitigated before a catastrophic event occurs though the use of cyber-resilient, computer-enabled, automated monitoring and state estimation, diagnosis, response and recovery. While humans can only react on time scales that are in seconds-to-minutes, computer-enabled diagnosis, response, and recovery can operate on the time scale of microseconds-to-seconds, effectively halting the propagation of adverse effects before they progress to a stage where they can no longer be mitigated. Hence the development of (1) deep and diverse monitoring mechanisms, (2) computerized monitor data fusion methods, and (3) computerized response selection and actuation methods that themselves are cyber resilient are essential to providing resilience in the face of a wide variety of impairments.

Cyber-Resilient Monitoring of Physical and Cyber States

Regarding monitoring, methods must be developed to determine the amount and diversity of monitoring necessary to gain the cyber and physical situation awareness to effectively respond to particular classes of impairments. Today, monitor selection and deployment is typically a static and off-line process. Methods are also needed to increase the confidence in the monitoring data that are obtained. It is critical that the state estimated from the monitoring data used by a resilience strategy is not influenced by bad data (created either inadvertently or through deliberate attacker action) so as to avoid response decisions that compromise resilience.

Monitor Data Fusion

A key challenge with the effective use of monitor data (whether cyber or physical) is their volume. In order to make sense of this large volume of monitor data, methods are needed to fuse the data into higher level knowledge about the state of the grid, creating actionable situation awareness. Fusion, in this context, is defined as the process to combine information from multiple sources to achieve inferences, which will be more efficient and more accurate than if they were achieved through a single source. A key challenge in the power grid context is that monitoring data concerning both the physical and cyber state of the grid is needed and must be fused together to understand the state of the system to the degree that response actions to preserve correct operation can be taken.

Understanding of the system is complicated by the fact that when a monitor signals a problem, it is unclear whether the problem is with the component or sub-system that is being monitored or with the monitor itself (particularly if malicious actions might cause erroneous monitor data). Monitoring of state of both cyber and physical aspects of the grid is essential and must be sufficiently powerful to diagnose whether the error-condition being observed is due to a cyber and/or physical impairment. While it has been long understood that the monitoring of physical aspects of the grid is needed, understanding of the criticality of the monitoring of the state of the grid's cyber components is less understood.

Human operators will continue to play a key role in grid operations for decades to come, and they can certainly help in the fusion of information. Important goals include minimizing the overhead on human experts and learning from the monitor data to identify important features that can contribute to lack of resilience. It would also be valuable if these techniques are computationally lightweight. This would allow operators to incorporate these techniques in the system to work online.

Response Selection and Actuation

Timely response to detection of undesirable state conditions is critical to maintain the grid's ability to deliver power despite impairments that occur. In order to be effective, determination of response actions must be efficient and scalable. In particular, a resilience response mechanism must respond quickly in a way that limits the cyber or physical impairment (whether accidental or intentional) from propagating to the point that a catastrophic event occurs. Furthermore, resilience response mechanisms must be scalable, in order to account for the unique physical and cyber complexity of the grid and the large volume of monitor data that must be collected, to obtain an accurate estimate of the state of the system.

During the unusual situations associated with severe events, wide-area power system visualization is crucial for providing the operators and engineers with the "big picture" of a grid that may be operating in a physical and/or cyber state they have not previously encountered. There may be multiple electric islands, transmission line flows may be substantially different from normal, and the voltage profile could be quite unusual. Often this wide-area view is provided in a control center using a mapboard, such as the one used by Independent System Operator (ISO) New England's control center, shown in Figure 4.7. As noted by Overbye and Weber (2015), such wide-area visualizations are divided into two main types. The first approach is to draw the display using fairly precise geographic coordinates. An example of this is shown for the synthetic network in Figure 4.4 or in the coupling with the earthquake simulations by Veeramany et al. (2016). Advantages include the ability to overlay power system information with other infrastructures and a familiar context when communicating with non-power engineers. A key disadvantage is that often the locations with a large amount of electrical infrastructure, such as urban areas, have a small geographic footprint. An alternative approach is to use a pseudo-geographic layout in which the position of the power system elements has some relationship with their actual geographic coordinates, but the display is arranged for electrical clarity. This approach was used in the ISO New England control center, which, while covering all of New England, has much of the display devoted to the greater Boston area. Additional visualization techniques, such as color contouring, focus on displaying large amounts of power system information (Weber and Overbye, 2000).

FIGURE 4.7 ISO New England control room. SOURCE: ISONE (2013).

There is also a need to consider the human factors of severe events in the control room context. During such events, there would certainly be a high level of stress, and, while expert operators would be better prepared than less experienced personnel, successful decisions are far from guaranteed. Wickens et al. (2013) explain, “Cues may be uncorrelated, overconfidence may shortchange cognitive monitoring, and rapid pattern-recognition classification may overlook a single outlying cause.” There may also be a “confirmation bias,” which “describes a tendency for people to seek information and cues that confirm the tentatively held hypothesis or seek (or discount) those that support an opposite conclusion or belief” (Wickens et al., 2013). This reinforces the importance of training and drills that provide operators with simulated experience.

Finding: Bulk electric grids are not only some of the world's largest and most complex machines, but they have also been architected in a way that disturbances can, if not mitigated, rapidly propagate through the system. Maintaining physical and cyber situation awareness at all times is key. Lack of situation awareness has been a contributing factor in a number of recent large-scale outages. During severe events, this will be even more of a challenge; therefore, there is a need for work on the development of data analytics and visualization techniques that will allow operators and engineers to maintain cyber and physical situation awareness.

Recommendation 4.8: The Department of Energy and the National Science Foundation should fund research on enhanced power system wide-area monitoring and control and on the application of artificial intelligence to the power system. Such work should include how the human–computer interface and visualization could improve reliability and resilience. In particular, the Department of Energy should develop research programs on enhancing power grid control room cyber and physical situation awareness with a focus on severe event situations.

Monitoring of Grid Cyber System State to Achieve Physical and Cyber Resilience

The proper functioning of the grid's various cyber systems (e.g., computers, communications) directly affects the ability to monitor, operate, and control the power system, thus making it imperative that the cyber system itself also be resilient. Like the physical aspects of the power grid, these cyber systems can be affected by catastrophic events like storms and earthquakes and are directly vulnerable to cyber attacks. These supporting systems are often considered critical and are usually designed with enough redundancy to provide reliability to accidental faults. It is critical to have situation awareness of the state of information systems alongside operations systems, as detailed in the concept of an integrated security operations center (EPRI, 2013).

While existing NERC standards provide some requirements with respect to cybersecurity, no standards or widespread best practices exist for tolerating deliberate cyber attacks. Moreover, monitoring of the system itself has been less stringent than that of the power system, and, unlike the power system, the status of the control system is rarely shared with that of the neighboring power companies. For example, during the 2003 Northeast blackout the neighboring power companies were not aware that several of the monitoring functions like alarm processing and state estimation were not functioning at the Akron, Ohio, control center.

Even less common is the use of architectural approaches to ensure the resilience of the cyber system to accidental failures and malicious attacks. As noted, the operation of an interconnected power grid requires the cooperation of many entities, mostly done through the coordination among dozens of control centers. Thus, the health of the control and communications systems should also be continuously monitored by these control centers. This monitoring data should be used to take actions to maintain the resilience of the cyber system itself to both accidental failures and malicious attacks and be shared with all the others who depend on this coordination.

Unfortunately, data gathering and analysis are often performed separately and differently between neighboring utilities and between T&D sections within the same power company. More coordination between these jurisdictions would be helpful during normal operations; the lack of it severely affects the ability to prevent large-scale catastrophes like a cascading failure or cyber attack. During such an event that impacts several power companies, effective communication of data among utilities can help inform and accelerate decisions that may avoid permanent damage to existing hardware or prevent widespread outages. The main issue in coordinating these various functions has been the lack of standardization of data definitions, databases, and communication protocols. Moreover, data exchange between neighbors also raises some proprietary issues. However, if resilience is to be increased and the ability to recover from catastrophic events is to be accelerated, such coordination between T&D in the same company and between interconnected neighboring companies is necessary. Although the utility industry has a long record of collaboration during large-scale disturbances, this is still done more on an ad-hoc basis; the type of coordination suggested here must be planned, and the tools must be in place long before the catastrophe.

Achieving greater standardization is important and an active research area in Europe, providing opportunities for strong coordination (EDSO, 2015). However, as that occurs, it is important to devote serious attention to cybersecurity lest identical control equipment, with identical vulnerabilities, be used by multiple companies. This could make the system particularly vulnerable to a cyber attack that could be widespread and affect multiple utilities simultaneously.

Finding: The cyber system that monitors, analyzes, and controls the physical components of the power grid is critical to providing efficient and reliable service from the grid. Less attention has been placed on making these cyber systems resilient. Furthermore, the various control systems of an interconnected power grid fall under many different jurisdictions, and close coordination is needed for the design and operation so that information exchange in real time is seamless and timely and response actions are taken in a coordinated way.

Finding: Currently, there is a lack of standardized information sharing between utilities at the T&D levels. In some cases, such as cyber health data, the data requirements have not yet been defined. As greater standardization is achieved, greater attention must also be given to cybersecurity and risks of common-mode failures.

Recommendation 4.9: The Department of Energy should lead and coordinate an effort among the Federal Energy Regulatory Commission, the North American Electric Reliability Council, the National Association of Regulatory Utility Commissioners, and the states to develop standardized data definitions, communication protocols, and industrial control system designs for the sharing of both physical and cyber system health information. The goal of standardizing data definitions and communication protocols would be to improve the awareness of the operating conditions of all interconnected power systems for all involved transmission operators and distribution operators.

Architectures for Providing Cyber and Physical Resilience

A wide range of cyber systems are used to protect and control the grid. In operations, the time requirements for response to maintain resilience range from a few milliseconds (e.g., for protective relays controlling circuit breakers that clear faults), to seconds (e.g., for the automatic generation control that provides real-time dispatch to generators), to several seconds to minutes (e.g., for the software used by the operators for human-in-the-loop control). Much of this architecture, and its enhancement via synchrophasors, is discussed by Bose (2010).

Transmission operators use EMS to monitor and control the grid. Almost all of the real-time measurements input to the EMS come from SCADA systems, which scan the grid every 2 to 4 seconds. An important component of EMS is the monitoring/alarming system that notifies the operator when unusual situations are encountered. This alarm system failed for one transmission operator leading up to the August 14, 2003, blackout, which contributed to its lack of situation awareness (USCPSOTF, 2004). As the name implies, SCADA is used for direct monitoring and control of the grid. A failure of SCADA, such as from a cyber intrusion, would make operations very difficult, requiring personnel to be physically located at key electric substations. Over the last several years, the SCADA data is increasingly being supplemented by PMU data, which uses much faster scan rates of 30 to 60 times per second, allowing direct measurement of the voltage and current phase angles (NASPI, 2015).

In order to run more advanced grid analysis techniques in real time, the imperfect measurements from SCADA (and sometimes PMUs) are input to a process known as state estimation. State estimation is run every few minutes to obtain a best estimate of power system voltages and currents. The output of the state estimator is then fed to applications such as power flow, contingency analysis, security-constrained optimal power flow, and transient stability analysis. State estimation is a maximum likelihood estimator that uses iterative algorithms. In a modern control center, the state estimator might be solving on the order of 250,000 measurements every minute, with convergence rates well over 98 percent of the time (PJM, 2016). However, during unusual situations associated with severe events, convergence of the state estimator itself might be an issue. This was the case during the August 14, 2003, blackout, in which lack of convergence in the Midwest Independent Transmission System Operator state estimator contributed to its inability to provide real-time diagnostic support (USCPSOTF, 2004).

The grid was operated for more than half a century before computers were invented and can still be, in many cases, operated in a degraded way without the advantages of the computerized control system. In fact, the cyber attack on the Ukraine system forced the operators to operate the power grid with reduced levels of service without the automation system, which was badly compromised.

Finding: The control system for the power grid must be designed and operated in a way that allows it to tolerate both accidental faults and malicious attacks. Best practices from the dependable computing community and the emerging cyber resilience community could be employed and extended to make the grid cyber infrastructure itself resilient. Moreover, the interfaces between the cyber control system and the physical aspects of the power grid could be designed in such a way that the power grid can be operated without automation, albeit in a degraded mode. This would require some control functions to be performed manually during catastrophic events, thus requiring personnel to be trained and ready to perform functions that would rarely be needed.

Recommendation 4.10: The Department of Energy should embark upon a research, development, and demonstration program, utilizing the diverse expertise of industry, academia, and national laboratories, that results in a prototypical cyber-physical-social control system architecture for resilient electric power systems. The program would have the following components: (1) A diverse set of sensors (spanning the physical, cyber, and social domains), (2) a method to fuse this sensor data together to provide situation awareness of known high quality, and (3) an ability to generate real-time command and control recommendations for adaptations that should be taken to maintain the resilience of an electric power system. This should include research to develop methods for specifying anomalous operating conditions, so that anomaly detection systems can be deployed widely to aid in the detection of cyber intrusions. In this process, the Department of Energy should coordinate with standards-setting organizations. Analytic arguments should be constructed so that these recommendations do not compromise the safety or availability of the system.

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5

Strategies for Reducing the Harmful Consequences from Loss of Grid Power

INTRODUCTION

Chapter 4 examined planning, design, and operations that can help improve the reliability and resilience of the grid to prevent or reduce the duration of grid outages. Chapter 6 looks at restoration of grid service. But in the middle sits the question of how to design and plan for a society that will be resilient even with the loss of power. This chapter examines current and future responses to that question. As introduced in Chapter 3, the exact form of that planning depends on the causes of grid failure, because those causes may affect which other services are available and the speed and extent of restoration (see Figure 3.2). Full restoration, as explored in Chapter 6, may take a long time—during and after which the effects of lost grid service could continue to reverberate through society.

As in the other sections of this report, the committee does not focus much on small routine disruptions that are inherent to power distribution systems. Those outages, because they are short and familiar, do not create major resilience problems; their effects are usually local, understood, and well within the range of imagination and planning. Indeed, in a typical year there are about 3,200 significant outages on power grids in the United States, with extreme weather and falling trees as leading causes (Eaton, 2016). In a 2015 Harris poll, homeowners self-reported that one out of four had experienced power outages for 12 hours or longer in the last 2 years (Briggs and Stratton, 2015). These are common events that generate large costs to the economy and public welfare—for example, jeopardizing the continued operation of home health care equipment (Ryan et al., 2015) as well as continuity of important public functions and economic activity such as data centers (Vertiv, 2016)—but are within the realm of normal experience and planning.

Instead, the committee focuses on large regional disruptions that last for several days or longer and cover a larger area, such as multiple service territories or even several states. Such long duration outages do occur, as shown in Figure 1.1 and discussed later in this chapter. Such events, which can have profound system-wide effects, require much more attention than they have received to date from policy makers and every segment of society that depends on electric service. Because these effects are outside the realm of normal experience, it is difficult for people and organizations to imagine the possible harmful outcomes on the basis of real-world information about consequences. Reducing these harmful consequences of large-area, long-duration grid failures is a problem of imagination and incentives.

For shorter-duration outages, electricity users have an incentive to make their own preparations for resilience. A wide range of users do exactly that—with different levels of effort and cost depending on what they are willing to pay to avoid loss of vital services. Long-duration outages have much more profound impacts on society and require preparedness that is much more costly. Planning for such outages requires system-wide thinking because so much depends on the power grid, including all 16 critical infrastructure sectors.[1] As the grid becomes even more tightly integrated with other important economic and social activities, the need for this system-wide perspective will grow.

Water supply systems that provide potable water and treat wastewater are one example of critical infrastructure interdependency. Because the pumps are large, sometimes they do not have their own backup generators. Loss of grid power beyond a few hours can lead to depletion of gravity-fed reservoirs and tanks as well as a decline in pressurization of the distribution pipes. Usually the criticality of these pumps is handled through coordination with the electric distribution supplier to give those assets high priority during restoration—an option that may not be available during the kinds of large-area, long-duration outages that are the focus of this report. Similarly, wastewater systems and particularly lift pumps are often critical if left off-line for too long. Sewage treatment often has enough storage to last for several days, but there have been cases where untreated effluent has been released directly to the environment in the aftermath of severe events.

Effective planning will require different strategies for different systems (NRC, 2012). And planning will require engaging actors—from first responders to the operators of critical infrastructures—who often do not work together adequately. Severe events and the corresponding shock, however, have inspired some of these different members of the private and public sector to work together more effectively—for example, during the aftermath of Superstorm Sandy when some parts of the tristate area lacked electric service and other infrastructure for more than a month.

[1] The Department of Homeland Security designates the following 16 sectors to be critical to national security, national economics, or public health/safety: chemical; commercial facilities; communications; critical manufacturing; dams; defense industrial base; emergency services; energy; financial services; food and agriculture; government facilities; healthcare and public health; information technology; nuclear reactors, materials, and waste; transportation; and water and wastewater.

This chapter looks at resilience from three perspectives: (1) incentives for actors to invest in resilience on their own, (2) planning methods that can improve how societies anticipate the effects of long-duration grid outages, and (3) approaches to designing electric power systems so they retain some or all of their function even when the larger grid has failed.

INCENTIVES FOR PREPAREDNESS

By and large, the existing electric power grid has done a remarkable job of providing reliable electric power service. Moreover, existing users of electric power services generally have done a good job of investing where needed to make themselves more resilient when grid service is insufficient. This track record reflects the incentives at work on the actors who are relevant to planning and using grid electricity. Here the committee looks at those incentives because they help reveal places where additional efforts by industry, civil society, and government may be needed to anticipate and plan for large-scale grid outages. Such a perspective helps to expose the areas where failures to prepare are most likely—because the incentives to ensure resilience are weakest—and where additional policy action may be needed.

Surveys of existing electric power users reveal that there are huge variations in the willingness, ability, and need to pay for greater resilience; moreover, desire for resilience depends heavily on the expected duration of grid power outages. Table 5.1 shows results from one review of prior research on interruption costs of different duration and circumstances. The table is complex and busy, demonstrating huge variation (of several orders of magnitude) in the economic harm suffered by different types of customers for different types of outages. For example, the financial losses to large and medium commercial and industrial (C&I) customers are orders of magnitude larger than losses to either residential or small C&I customers. And while much is known about the impact of relatively short duration outages (<16 hours), at present there is essentially no systematic research that provides such information for longer outages—let alone the large-area, long-duration outages that are the main subject of this study. Nonetheless, the existing research suggests that while, on the one hand, there are broader societal needs for more resilient power supply, on the other hand, cost-effective strategies must reflect that not all users need the same levels of resilience. This is particularly true for users and facilities that provide critical services such as hospitals, where using economic measures (e.g., willingness to pay) for resilient service may not be appropriate.

TABLE 5.1 The Significant Variation in Estimated Financial Losses Suffered by Different Customer Classes Operating under Different Ambient Conditions as a Function of Varying Outage Duration

Timing of Interruption	Hours per Year (%)	Losses Based on Interruption Duration ($)					
		Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Medium and Large C&I							
Summer	33	16,172	18,861	21,850	46,546	96,252	186,983
Non-summer	67	11,342	13,431	15,781	35,915	77,998	154,731
Weighted Average		12,952	15,241	17,804	39,458	84,083	165,482
Small C&I							
Summer Morning	8	461	569	692	1,798	4,073	7,409
Summer Afternoon	7	527	645	780	1,954	4,313	7,737
Summer Evening/Night	18	272	349	440	1,357	3,518	6,916
Non-summer Morning	17	549	687	848	2,350	5,592	10,452
Non-summer Afternoon	14	640	794	972	2,590	5,980	10,992
Non-summer Evening/Night	36	298	388	497	1,656	4,577	9,367
Weighted Average		412	520	647	1,880	4,690	9,055
Residential							
Summer Morning/Night	19	6.8	7.5	8.4	14.3	24.0	42.4
Summer Afternoon	7	4.3	4.9	5.5	9.8	17.7	31.1
Summer Evening	7	3.5	4.0	4.6	9.2	17.5	34.1
Non-summer Morning/Night	39	3.9	4.5	5.1	9.8	17.8	33.5
Non-summer Afternoon	14	2.3	2.7	3.1	6.2	12.1	23.7
Non-summer Evening	14	1.5	1.8	2.2	5.0	10.8	23.6
Weighted Average		3.9	4.5	5.1	9.5	17.2	32.4

NOTE: C&I, commercial and industrial customers.
SOURCE: Sullivan et al. (2015).

The incentive to become resilient is evident in the substantial investments that some power users make in obtaining backup supplies. For example, hospitals, data centers, and command posts for first responders all regularly install backup power systems. For smaller users, as well, there is extensive media coverage and advice—along with many vendor firms—that draw attention to the need for on-site power. Diesel generators are the technology of choice for this function; estimates compiled in the late 1990s suggest that the capacity of such generators in the United States was about 100 GW and growing at approximately 2 percent per year (Singh, 2001). Given the vital role of these generators in providing resilience, there has been ongoing attention to possible revision of standards for their reliability and environmental performance (Felder, 2007). There is also a substantial need for ongoing consumer education about the operation and safety of such devices since burns, fires, and especially carbon monoxide poisoning continue to be major problems.

The committee is concerned that, despite substantial investment in standby generators, awareness of the unreliability and other performance attributes of these systems remains highly uneven. According to Huber and Mills (2006), 1 percent of diesel generators at nuclear plants fail to start upon demand, while 15 percent of them fail after 24 hours of continuous operation. Consequently, nuclear sites have multiple redundant sources of backup power, and, in the wake of the Fukushima nuclear accident, the Nuclear Regulatory Commission has required additional investments in on-site power.[2] By contrast, the failure rates at start up of hospital generators—which are much less well maintained in general and have fewer redundancies—are 10 times the rate of those in the nuclear industry (Mills, 2016). Similarly, there is low and uneven awareness of the challenges in obtaining fuel supplies in a long-duration outage, which presents a critical and underanalyzed risk.

> **Finding:** Installing backup power systems alone is insufficient to improve resilience. These systems must be tested (i.e., started, operated) and maintained (e.g., cleaned) regularly so they function reliably during an outage. Relevant industry associations, and policy makers, government agencies, and regulators where appropriate, have an important role in disseminating information about the actual levels of reliability of backup units, as well as challenges obtaining fuel.

> **Recommendation 5.1:** State emergency planning authorities should oversee a more regular and systematic testing of backup power generation equipment at critical facilities, such as hospitals and fire stations, and ensure that public safety officials include information related to electrical safety and responses to long-duration power outages in their public briefings. Those authorities should also periodically assess the costs and benefits of this testing program and use that information to prioritize sites for testing.

In addition to diesel generators—which are often connected to a single vital asset—there has been a steady rise in investment in microgrid systems (Hanna et al., 2017). These systems cover entire office complexes, campuses, and military bases, and, as shown in Figure 5.1, this segment of electricity infrastructure investment is expected to continue with substantial growth, which could have large implications for the resilience of power users. While the logic for installing microgrids at such locations varies, usually the continued service of high-quality electricity even after macrogrid failure is dominant. Microgrids, especially the larger systems, are designed to allow for islanding in the event of macrogrid failure, although in practice very few actually operate or are even tested in that mode. Many microgrids embed renewable power generation systems—notably solar photovoltaics—and the financial case for

[2] Following Fukushima, the Nuclear Regulatory Commission requires backup power for critical systems at nuclear power plants, which will likely cost the industry approximately $4 billion (2016 dollars).

larger microgrids typically hinges on the integration of natural gas-fired small turbines that utilize the waste heat for local heating and cooling. Later in this chapter, the committee will explore how new research and incentives could lead the users of microgrid systems to use this resource to increase resilience.

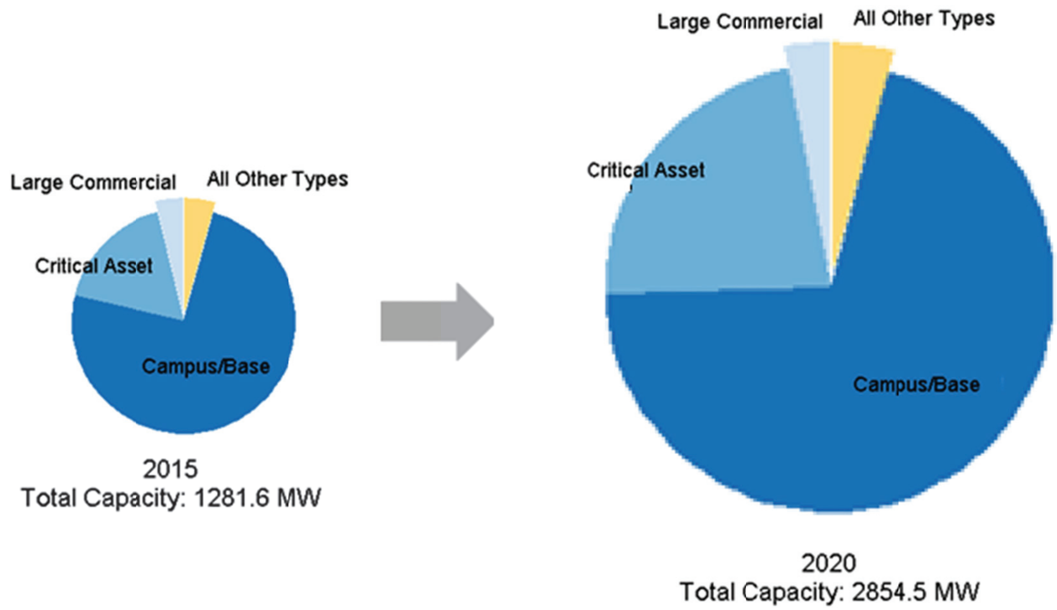

FIGURE 5.1 Installation of microgrids today and expected growth to 2020. NOTE: Total U.S. electricity generation capacity in 2016 was more than 1,000 gigawatts. SOURCE: GTM Research (2015).

Over the last few years, there has also been a surge in installation of "behind the meter" on-site battery storage (see Figure 5.2 and Chapter 2 section entitled "Near-Term Drivers of Change and Associated Challenges and Opportunities for Resilience"). This surge in investment has been driven in part by direct subsidy—notably in California—and in part by fundamental improvements in battery technologies. As with microgrids, these on-site battery systems could in theory lead to higher resilience, but very few of these systems are actually designed for that purpose and none can supply power for periods of several days. Instead, these systems are sized to move small amounts of power—typically a fraction of total load just for an hour or two—from peak to non-peak periods to help C&I customers reduce the charge they pay for peak electricity demand. If technological improvements make it possible to install much larger systems then such batteries could be material to improving resilience to long-duration grid outages.

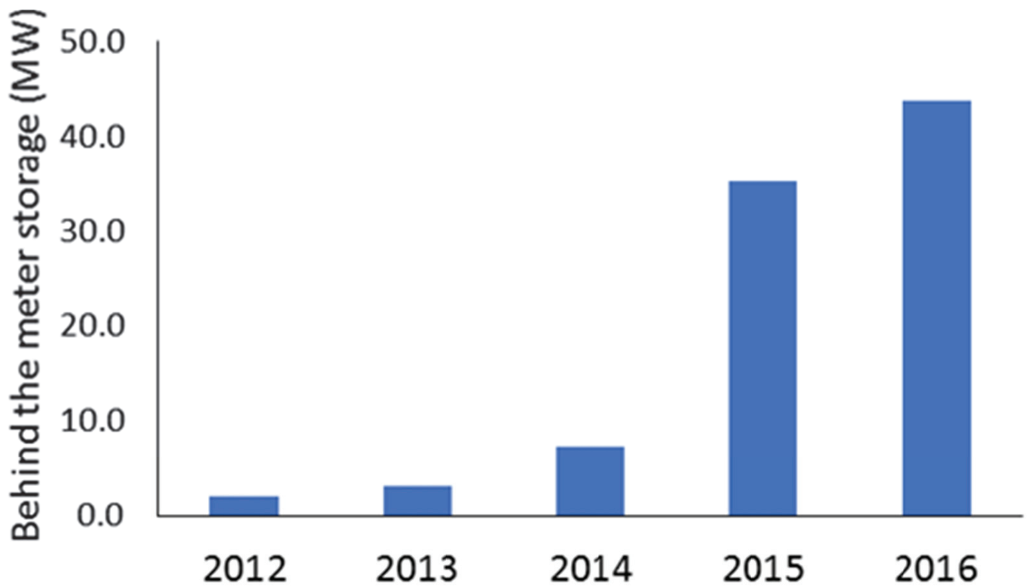

FIGURE 5.2 Installation of "behind the meter" battery storage systems. SOURCE: GTM Research/ESA (2016), "U.S. Energy Storage Monitor."

Where power users have a self-incentive to invest adequately in resilience—and where they have adequate information about the effects of their investments—no further policy incentives may be needed. By contrast, when the market fails—for example, when users are unaware of their exposure to grid failure, unaware of the synergistic consequences of grid failure, or unable themselves to afford or recoup the benefits of actions that could improve resilience if low probability events occur—then there may be a need for policy intervention. These failures are often evident where there are large-scale outages that affect a wide array of vital social services—as revealed, for example, by the long-duration power outage after the January 1998 ice storm described in Box 5.1. In contrast to many events whose intensity was predictable in ways that aided advance preparations, the extent and impact of this storm was largely unexpected. This is a characteristic of such storms since icing conditions depend critically on the vertical temperature profile in the atmosphere; a change of just a few degrees can make the difference between ice, rain, or snow. Such unexpected outcomes are particularly worrisome hazards for the grid since ice storms already account for many long-duration outages. With climate change, the areal extent and possible impacts of such icing events are likely to change although, as noted in Chapter 3, the nature of those changes remains uncertain.

BOX 5.1
Consequences and Civic Response to Damage Caused by the Ice Storm of January 1998

Ice storms are common in eastern Canada, with Ottawa and Montreal receiving freezing precipitation on an average of 12 to 17 days a year, but these events generally last only a few hours at a time. The January 1998 storm brought days of ice to an unexpectedly wide area of eastern Canada and the northeastern states, killing more than 40 people and causing large-scale, long-duration outages of electricity along with many other important impacts on infrastructure (NCEI, 1999).

Montreal was hit particularly hard. On January 9, much of Montreal temporarily lost its water supply after its filtration plant and pumping stations lost power (ICLR, 2013). Three out of the four major transmission lines in the area went off-line. If power had not been partially restored within hours, residents of the city would have been without potable water and firefighters would have had water to put out fires—an outcome that forced officials to consider either evacuating the city or moving residents to facilities like Olympic Stadium, where water could be delivered by truck (Schneider, 1998). Early planning for such an outcome had not been contemplated seriously before—for example, through purchasing of on-site backup power plants—because the city had always been a priority customer of Hydro-Québec and officials thus assumed electricity would always be available (Schneider, 1998).

Even after power was restored, disruptions rippled through food supply chains, transportation, communications, and other economic activities. The storm occurred during the depths of winter and was followed by freezing weather and, 2 weeks later, by a snow storm of 8 to16 inches that further slowed restoration (McDonnell, 1998). Along Montreal's south shore—which became known as the "triangle of darkness"—grid power remained out for 2 to 3 weeks following the storm (The Economist, 1998; Dupigny-Giroux, 2012). The commercial sector of Montreal was shut down for a week from January 9 through16 to remove the debris and allow electrical crews to repair or rebuild the power grid in the island city (Dupigny-Giroux, 2012). Grocery stores across the area were unable to open or ran out of basic necessities, gas stations ran out of (or were unable to pump) fuel, and basic transport services were erratic—all leading to reports of a general feeling of vulnerability (Leslie, 1999; CBC, 2017; Murphy, 2009; Dupigny-Giroux, 2012; The Ottawa Citizen, 2016). All told, around 600,000 people moved out of their homes for the event, with 100,000 of them moving into temporary shelters to escape the cold (RMS, 2008). Restoration of grid services required assistance from utility crews drawn from across North America. The event prompted the largest peace time deployment of Canadian armed forces in history, with almost 16,000 troops assigned in the relief effort to help with cleanup, restoration, and evacuation.

The questions surrounding when and how policy makers intervene to encourage additional planning and investment around responses to grid failure raise many fundamental questions about the proper role of government. If government stands ready to provide support in the case of a long-duration grid failure, then the well-known "moral hazard" problems could undermine the incentive for users of electric power to make those investments themselves. While communities are largely left to make their own decisions about their willingness to plan for and invest in resilience, there may be broader social implications and possible unintended consequences from the totality of all these local choices made with reference to local interests.[3] Such societal concerns may create the need for policies to better harmonize or at least take these externalities into consideration. Indeed, better documentation and awareness of the metrics for grid reliability and resilience, discussed in earlier chapters, could make it much easier for market forces to function properly—for users of power services to become more fully aware of their exposures to risk and thus more capable of obtaining the right level of resilience on their own.

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[3] The issue of "moral hazard" arises if a community underinvests in protection for rare major events and then expects the broader society to cover its costs when such an event occurs.

Even once the right incentives are in place to invest in resilience, there may be organizational and cognitive barriers to action—especially for events that have never occurred or been imagined before. The committee believes that the largest challenges in creating resilience against the full effects of large-area, long-duration grid failures may lie with the system-wide consequences and interactions. Such problems are extremely difficult for organizations to anticipate and respond to effectively. Typically, organizations are structured to meet core missions and can be blind to, or find it very hard to address, threats that arise in unexpected ways. Creating resilience against adverse system-wide effects requires that many different organizations coordinate and adopt solutions that might be far outside the normal scope of each organization individually. Where organizations do not have regular interaction and high levels of trust, collective action may be impossible.

The development of a coherent response that best serves the national interest requires laying a foundation for understanding the social value in resilience. Only then is it possible to evaluate whether the incentives of relevant actors will lead them to invest adequately in resilience. Only after establishing the social value in resilience is it possible to debate the degree of policy intervention needed to address the larger systemic impacts of large-area, long-duration outages.

> **Finding:** The existing systems of incentives have generally been successful in encouraging proper levels of investment to address shorter-duration and limited-area outages. However, incentives for individuals and organizations to take steps to increase resilience against large-area, long-duration outages are a different matter. Developing national, regional, and local strategies to improve resilience against such outages requires two things: an assessment of the likelihood that disruptions will occur and a judgment about how much the various actors in society are prepared to invest in actions that lower the consequences of disruptions. At present, many communities, regulators, and grid operators do not have the information and/or incentives needed to make reasoned policy and operational decisions.

Knowing much more about what individuals and society are willing to pay to avoid the consequences of large grid failures of long duration is an important input to deciding whether and how to upgrade systems that can reduce impacts of a grid outage. Much of this knowledge is anecdotal from looking backward at such failures, such as from Hurricane Katrina, Superstorm Sandy, or the northeastern blackout of 2003. Most prior quantitative studies have only examined outages of much shorter duration. If these studies are to provide meaningful results, they will need to use state-of-the art social science methods. Because different strategies may provide different insights, it would be prudent to have separate independent groups undertake more than one study. Results from this work can be used to inform national, regional, and local decision making about resilience investment.

While individuals' willingness to pay is an important input to such decision making, considerations of broader social disruptions and of equity are also important. Some private actors may be willing to pay considerable amounts to assure their continued provision of electric power during events (or parts of them), but these actors typically lack incentive to make investments beyond their own needs. Others may be uninformed about the potential systemic consequences of long-duration outages. It is the role of government to assure the continued provision of critical social services and to provide access to basic power-dependent services to vulnerable groups such as disadvantaged communities or others that lack the financial mechanisms to assure their own resilience.

Recommendation 5.2: The National Association of Regulatory Utility Commissioners should work in coordination with the Department of Homeland Security, the Department of Energy, and the states to develop model guidance on how state regulators, utilities, and broader communities (where appropriate) might consider the equity and social implications of choices in the level and allocation of investments. These include investments in advanced control technologies capable of enabling continued supply to particular feeders or critical users that could mitigate the impacts of large-area, long-duration outages.

PLANNING FOR GRID FAILURE

The remainder of this chapter examines how U.S. communities and the country as a whole can understand and implement an appropriate level of resilience in the event of a large outage of long duration. First, this section introduces planning for grid failure—so that consequences can be anticipated and responses organized. The following section discusses the design of infrastructures so that they themselves are more resilient to long-duration full or partial loss of grid services.

Planning requires information on the potential length and scope of large grid outages. That information can be gleaned partly by looking at past system outages and their coverage, summarized in Appendix E. These experiences suggest the magnitude of possible future outages. History in other countries is also helpful to consider because most modern grids reveal similar points of vulnerability. For example, the downtown area of Auckland, New Zealand, lost nearly all grid service for 5 weeks in the summer of 1998 when the four main cables serving the area failed in rapid succession. While each failure had its own individual causes, the events correlated and cascaded into a national crisis (Rennie, 1998). Systems that should have been redundant instead were the source of additional stress—something that often happens in complex systems where all the interacting failure points are difficult to imagine in advance.

However, the past may be an inadequate guide because long-duration outages are rare events and the underlying structure, operation, and policies governing the grid might expose this vital infrastructure to even larger and longer outages than observed historically. It is important to do more to identify events that are "unthinkable" on the basis of historical experience but could occur with coordinated system-wide attacks on the grid and the many systems that it supports. While there are some public safety professionals and organizations that practice and train for such dark and disturbing work, these practices are not widespread nor comprehensive enough to substantially improve the nation's resilience to large-scale outages. Good imagination and planning begins with understanding the full range of possible outcomes for grid failure. The committee's focus here is on planning for continuation of vital services in areas affected by a large-scale, long-duration outage, but it also notes that one important element of planning includes evacuation—in effect deciding that it may be more feasible to move populations in some areas than to provide emergency provisions.

While characterizing the real risks of grid failure will be difficult, an even more complex planning task involves understanding how prolonged full or partial failures of grid service could have compounding effects on other important public infrastructures and private services. Much of modern life depends on grid electricity, which is why the National Academy of Engineering named electricity as the single most important engineering achievement of the 20th century (NAE, 2017).

At present, planning for all types of hazards to public infrastructure is a disorganized and decentralized activity. Even in federal programs focused explicitly on increasing grid resilience, planning and implementation of research and policy responses are fragmented across federal agencies (GAO, 2017). It is impossible to describe all of the relevant efforts succinctly. Here the committee focuses on the role of the federal government and its National Preparedness System (NPS), whose broad aims are to prevent and then speed recovery from a wide range of hazards that affect the security and resilience of the United States.[4] The NPS is organized by the Federal Emergency Management Agency (FEMA)—an arm of the Department of Homeland Security—to assess and plan for hazards to 12 vital emergency support functions, including energy, for which the Department of Energy (DOE) is responsible for primary agency support (FEMA, 2008). Table 5.2 shows the matrix of vital functions and the relevant federal agencies. It is an intrinsically complex, messy, and organizationally stovepiped activity.

[4] Presidential Policy Directive 8: National Preparedness. See https://www.dhs.gov/presidential-policy-directive-8-national-preparedness

TABLE 5.2 FEMA's Matrix Concept Illustrates the High Amount of Interagency and Interdepartmental Coordination Required for Assessing and Responding to Threats to the Nation's Vital Infrastructures

	Vital Emergency Support Functions											
Department or Agency	Transportation	Communications	Public Works and Engineering	Fire Fighting	Information and Planning	Mass Care	Resource Support	Health and Medical Services	USRT	HAZMATs Food	Food	Energy
Dept. of Agriculture	S	S	S	P	S	S	S	S	S	S	P	S
Dept. of Commerce		S	S	S	S		S			S		
Dept. of Defense	S	S	P	S	S	S	S	S	S	S	S	S
Dept. of Education					S							
Dept. of Energy					S		S	S		S		P
Dept. of Health and Human Services			S		S	S		P	S	S	S	
Housing and Urban Development						S						
Dept. of Interior		S	S	S	S					S		S
Dept. of Justice					S			S	S	S		
Dept. of Labor			S				S		S	S		
Dept. of State	S									S		S
Dept. of Transportation	P				S		S	S		S		S
Dept. of Treasury					S		S					
Dept. of Veteran			S			S	S	S				
Agency for International Development								S	S			
Administrative Resource Center					S	P		S			S	
Environmental Protection Agency			S	S	S			S		P	S	
Federal Communications Commission		S										
Federal Emergency Management Agency	S	S		S	P	S	S	S	P		S	
Government Services Agency	S	S			S	S	P	S			S	
Natl. Space and Aeronautics Admin.					S		S		S			
Natl. Clandestine Service		P			S		S	S				S
Nuclear Regulatory Commission					S					S		S
Office of Personnel Management							S					
Small Business Admin.					S							
Tennessee Valley Authority	S		S									S
U.S. Postal Service	S					S		S				

NOTE: P, principal coordinating agency; S, agencies supporting the principal coordinating agency.
SOURCE: FEMA (2008).

Because planning for grid failure is such an intrinsically complex and difficult task, it appears that very little of the FEMA- and DOE-led effort is devoted to imagining and preparing for the full systemic consequences of losing grid power over large areas for long period.. Instead, by design, the framework shown in Table 5.2 is operational and aimed at clarifying which agencies will be focal points for receiving, collating, and distributing information to the rest of the federal government. Under this framework, for example, DOE is tasked with organizing information to produce estimates of restoration times, percentages, and priorities. In its role as the focal point, DOE is also expected to work with legal authorities to resolve matters of jurisdiction and grant waivers to expedite restoration processes, as discussed in Chapter 6. These are, for the most part, operational functions rather than forward-looking research and development or strategic planning. These patterns of stove piping and overlapping layers of jurisdiction extend from the federal to the regional, state, and local levels. Only during emergencies—events that politically and organizationally focus minds—does some semblance of more unified and strategic focus emerge, such as through the creation of joint field offices that unify the coordinating structures discussed in more detail in Chapter 6.

Because planning for the system-wide consequences of grid failure is such a daunting task, it is not surprising that the jurisdictions that seem to be doing a better job are those that have experienced such failures in the past. The tristate area of New York, New Jersey, and Connecticut in the aftermath of Superstorm Sandy is a good example, as shown in Box 5.2. Electricity outage disaster preparedness and response exercises such as "Clear Path 4" (DOE, 2016) are critical opportunities to gain experience and have great potential to be expanded. Experience transforms the unimaginable and seemingly impossible into a tangible reality. However, often the result is that planning efforts focus excessively on avoiding the same calamitous outcome rather than planning for a broader range of possible future events.

BOX 5.2
Superstorm Sandy: Preparation, Emergency Response, and Restoration of Services

On October 29, 2012, Superstorm Sandy made landfall, leaving approximately 3.5 million of the 8.5 million homes and businesses in the tristate area without electricity. For 4 days prior to landfall, members of the Northeastern Mutual Assistance Group[a] were coordinating closely to reduce impacts and plan for restoration activities—and to reach out to other regions, such as the Midwest, to draw resources such as line crews and call center operators (EEI, 2013). Simultaneously, DOE worked to remove the red tape required for these outside crews to work in the impacted areas, as envisioned in the FEMA emergency preparedness process that had been established for the country just a year earlier (FEMA, 2013). A presidential state of emergency was declared a day before landfall, an action that further activated federal resources—such as the National Response Coordination Center (NRCC) that prepared 5 staging areas to preposition crews, vehicles, and 183 generators of various sizes. After landfall, as the extent of the damage became known, the NRCC also guided the Department of Defense to provide additional resources—such as airlifting 229 power-restoration vehicles and approximately 500 personnel to aid the region while the Army Corps of Engineers was tasked with pumping operations to facilitate restoration in flooded areas (FEMA, 2013). Within 2 days after landfall, 70,000 utility crewmen from around the country were working to restore the grid—by FEMA estimates, those workers replaced 4,500 poles, 2,100 transformers, 44 substations, and over 400 miles of lines over the next 3 days (FEMA, 2013). With so many different federal agencies providing support, FEMA established the Energy Restoration Task Force on October 31 to help coordinate the federal effort—among many other functions, it coordinated the supply of 9.3 million gallons of fuel to New York and New Jersey for use by first responders and the continued operation of emergency generators (FEMA, 2013).

Since Superstorm Sandy, there have been extensive efforts by regulators and utilities to improve reliability of the grid and resilience of society—some of these efforts were triggered originally by Hurricane Irene, which hit the region the year before Sandy (FEMA, 2013). Concerning reliability, regulator orders and utility actions have identified critical power delivery systems that need hardening—such as raising the elevation of transformers at substations, adding supervisory control and data acquisition to substations, and installing equipment that will allow operators to isolate faulted areas and close circuits remotely that can keep more customers online. In the natural gas network, a massive effort has begun to replace cast iron mains and upgrade distribution systems. Public Service Electric and Gas—the largest utility in New Jersey, which saw 2 million of its 2.2 million customers lose power after Sandy—is in the midst of a regulator-approved $1.2 billion “Energy Strong” program to protect its gas and electricity network. All told, in New Jersey alone, regulators have approved almost $2 billion worth of investments in mitigation measures to guard against catastrophic storms and, more generally, upgrade the resilience of electric and gas systems.

Responses in New York were similar. In that state, 2.2 million customers lost power, and the two largest utilities (Consolidated Edison and Long Island Power Authority) spent $1.2 billion to restore service while spending another $1.7 billion after Sandy to harden their electricity, gas, and steam infrastructures.[b] In Connecticut, where the damage was much less relative to New York and New Jersey, relatively little federal help flowed—about 1 percent of the total federal funds spent after Sandy went to the state—and efforts focused less on recovery and hardening of infrastructure and more on helping homeowners dislocated by the storm (Radelat, 2014).

Policy makers have also focused massive resources on improving resilience in the face of future power outages, although that task has required more complex coordination because few of the critical tasks for resilience map neatly onto existing policy structures. In New Jersey, the state’s Board of Public Utilities in conjunction with the New Jersey Office of Emergency Management authored a Petroleum Fuel Task Force Plan. The New Jersey Board of Public Utilities is the lead agency for administering this new plan, which is intended to address fuel shortages or disruptions to the fuel distribution system in times of an emergency. Over 125 gas stations throughout the state have been equipped with emergency generators or electrical connections to accept a portable generator.

[a] Every region of the country has such mutual assistance groups.
[b] For regulatory action after Sandy, see, e.g., Cases 13-E-0030, 13-G-0031, and 13-S=0032 of the New York Department of Public Service.

From the Sandy experience, the Canadian ice storm, and many others, it is clear that long-duration failures in grid power will occur. Even with a concerted effort in design and investment for continuity of some electric services—a topic discussed in the next section—much of the country is unprepared for long-duration outages. To the extent appropriate, resilience must begin with individual households and businesses preparing themselves for long-duration outages with adequate essential supplies—such as of food, water, medicine—to cover, at least, multi-day outages.

Finding: Existing planning systems are, by design, ill-suited for anticipating and considering the wide range of interactions between loss of grid power and other vital infrastructures and services for long-duration outages. These are intrinsically difficult tasks to perform both conceptually and organizationally. They require imagination and planning for interactions among multiple stresses on infrastructures and services that are rarely observed in the world.

For example, in the aftermath of a large regional storm, loss of grid power often leads to loss of reliable traffic control as well as obstruction of many roadways. These impede normal traffic flow and make it difficult for first responders to perform their tasks. The difficulties with first response, in turn, magnify the humanitarian crises that result from the original storm event. Those difficulties compound into additional stresses on hospitals and public safety that consume their resources and make it more difficult to restore normal commercial operations. But even in such settings, it can be extremely difficult to anticipate how interactions among infrastructures lead to yet further interactions and harmful consequences that multiply as a grid outage event extends in time.

State and local emergency management organizations may not have sufficient understanding of electric power systems, which can slow down emergency power provision to critical facilities. In some states, such as California, organizations such as the California State Utility Emergency Association act as a liaison between critical infrastructure utilities and emergency management organizations. While several other states have similar programs, the practice is not widespread.

Finding: In every state, the governor is the ultimate authority responsible for overseeing disaster recovery and the mobilization of federal assistance. However, the states vary widely in the extent to which they are ready to perform these functions for long-duration grid outages. State and regional authorities would benefit from extending existing efforts to help identify common challenges and extend best practices. For example, the National Association of State Energy Officials efforts to improve awareness and preparedness for large-scale disruptions to energy infrastructure (e.g., by holding events to share best practices and experiences managing fuel shortages that often accompany grid outages and other infrastructure failures (NASEO, 2016).

The technology of distribution system operations increasingly allows power system operators, in the face of limited grid or local power supply, to select which distribution feeders to energize. Those feeders typically serve loads with very different levels of social criticality, such as hospitals or water treatment plants. Advanced control will make it possible to selectively supply and/or restore power to individual meters on a feeder, with subsequent or sequenced restoration of service to others on that feeder. It will also be possible to change the allocation of which meters to supply over time as circumstances and needs evolve. While presently there are relatively few demonstration projects and microgrids with these functionalities, there is significant potential to improve resilience through their wider adoption.

Finding: Technologies that allow for intelligent, adaptive islanding of the distribution system create new needs for planners to envision which feeders and users should be energized under different circumstances. Yet, that type of planning has been minimal, and little effort has been dedicated to anticipating how energizing feeders and select users might be adapted over the lifetime of the outage.

> **Recommendation 5.3:** We recommend that the Department of Homeland Security, and the Department of Energy, as the energy sector-specific agency, develop and oversee a process to help regional and local planners envision potential system-wide effects of long-duration loss of grid power. While orchestrated at the federal level, success of this effort will require sustained engagement by regional and local authorities. Federal seed funding could support several such local or regional assessments.

Officials in regions that have experienced long-duration outages will likely be more motivated (see Box 5.2). In other regions, the Department of Homeland Security and others will need to mobilize support for taking these "imagine the unimaginable" activities seriously. The regulatory community's role in these efforts will be crucial. Public utility regulators in particular often have oversight over many infrastructures and determine whether electric utilities may recover the costs associated with planning for the effects of long-duration outages of grid power.

> **Recommendation 5.4:** The National Association of Regulatory Utility Commissioners, in consultation with the Department of Energy, the Department of Homeland Security, and the states, should develop guidance to state regulators and utilities on the following: (1) selective restoration options as they become available, (2) the factors that should be considered in making choices of which loads to serve, and (3) model recommendations that states and utilities can build upon and adapt to local circumstances. In developing these recommendations, attention should be paid to how the use of these new technical capabilities to energize particular feeders or grid-connected users might create evidence to justify wider deployment of such control and metering technologies.

Examples of factors that such guidance might consider include the power needs of first responder and other critical infrastructure systems, service to selected fuel and food suppliers, availability (or lack thereof) of privately supplied backup generation or other means to assure continued availability of electricity, and ability of specific populations to access basic services during prolonged outages.

The industry has done extraordinarily well at improving how the country responds to existing grid failures, a topic explored in more detail in Chapter 6. That said, a great deal of the effort needed to imagine and plan for the effects of long-duration outages sits outside the power industry in other organizations—such as the operators of water supply and treatment facilities and first responders. But industry, led by the North American Electric Reliability Corporation (NERC), should take a fresh look at whether the existing system of reliability standards adequately envisions cascading effects that could lead to long-duration outages. And the industry's central strategic organizations—notably the Edison Electric

Institute, the American Public Power Institute, the National Rural Electric Cooperative Association, and NERC—should draw more attention to the need for society to plan for long-duration outages. This is important, even though such tasks may be uncomfortable for these organizations because they represent, to some degree, an awareness that the grid itself is more fragile than widely thought. At the same time, such self-driven industry efforts should improve awareness of the many ways that the grid system can be designed to allow more resilience, which is an area where there are highly varied experiences across existing U.S. utilities and other system operators.

Finally, much more attention is needed to engage the public in understanding the potential severity of large-area, long-duration blackouts and to improve public awareness and preparedness. The American Red Cross (2016) offers general guidance on how to prepare for power outages—with supplies adequate for 3 days (assuming evacuation from home) or up to 2 weeks (assuming that homeowners stay at home). The Centers for Disease Control offer detailed guidance on food safety, noting that hazards to refrigerated food begin as early at 4 hours into a prolonged power outage; they also offer rudimentary strategies for disinfecting water (CDC, 2014). Many states also offer their own guidance tailored to local hazards—for example, Florida's advice focuses on the need for 3 days of supplies to ride through outages caused by hurricanes (Harrison, 2016). It is unclear how households around the nation respond to this advice, or what factors may drive households to achieve appropriate levels of preparedness. FEMA assesses individual preparedness on a regular basis, and the results suggest that preparedness is low and not improving rapidly (FEMA, 2016). Similarly, many households and businesses obtain equipment—such as portable generators—yet are unaware of how to operate these devices safely, how to procure fuel during extended outages, and how low the real levels of reliability of these devices are in practice.

DESIGN

With better understanding of what society might be willing to pay to avoid or reduce the consequences of grid failure and equipped with better planning for how grid failure could affect other critical infrastructures, planners could then be possible to design systems so they are more resilient when grid power is lost. The committee looks at design from two related perspectives: (1) designing and deploying standby power systems, and (2) designing local power systems to provider higher customer resilience.

Designing and Deploying Standby Power Systems

Many methods already exist to establish on-site power systems—often using components that are patched together in ad hoc ways—that can provide local service in the event of grid failure. These existing approaches should be practiced and improved. Most backup power systems rely on small gasoline, natural gas, and diesel-fired generators that are relatively easy to operate. Nonetheless, experience operating these systems is highly uneven around the country. Areas in which loss of grid power is more frequent are, as a general rule, better at imagining the impacts and thus better prepared.

These self-supplied systems may be ineffective in case of long-duration, large-scale interruptions because backup systems are generally designed to run reliably for a few days at most; after that point, maintenance and fueling may be essential. However, during a large event that affects many interconnected public infrastructures, such services may be very challenging to obtain. During such outages, households and other non-expert users often devise their own ad hoc solutions that can lead to adverse side effects—for example, carbon monoxide poisoning from small generators run with inadequate ventilation. Better information and oversight are needed to improve the availability, safety, and use of these power systems.

Many (if not most) of the emergency generators are not physical assets owned by government or even utilities. Instead, the government maintains contracts with the private sector to deliver equipment as needed. For example, the federal government maintains a small stockpile of portable generators at locations around the country, as well as much larger contracts for additional procurements that can be deployed during a major outage. It is poorly understood whether many of the contracts for provision of generators, fuel, and maintenance would prove to be robust under conditions that lead to sustained loss of grid power—conditions that might include natural disasters and cascading interactions between infrastructures under stress. For example, where delivery of these assets is envisioned by air, supporting facilities (e.g., airports, ground crews, and air traffic control) may be unavailable and roads may be impassable.

In addition to the contracts and stockpiles of mobile generators maintained by the federal government, there is potential to repurpose assets not traditionally used for power supply. Civilian and navy ships could provide a few tens of megawatts of emergency power to loads in coastal cities (Scott, 2006). Likewise, when they are equipped with appropriate interfaces or conversion kits, diesel electric locomotives can also be used to power communities located near railroad tracks. For example, Canada National Railway delivered multiple locomotives off-track to towns without power during the 1998 ice storm (Figure 5.3).

Permission pending

FIGURE 5.3 A Canada National locomotive in the town of Boucherville, Québec, after being used to provide temporary emergency power to municipal buildings following the 1998 ice storm. SOURCE: Abley (1998).

There are several other anecdotes of locomotives being used to supply power to critical loads during emergencies, and many train operators maintain conversion kits used to produce 60 Hz alternating current power from locomotives. However, the availability of such conversion kits is likely limited, and it remains unclear how much load such non-traditional sources of emergency power could serve during actual blackout conditions (NRC, 2012). Nonetheless, such resources can augment federal emergency power operations that rely on conventional mobile generators.

Finding: The federal government maintains a small stockpile of portable generators and fuel, as well as contracts for additional procurements that can be deployed during a major outage. However, the quantity available in the event of a large outage is inadequate, probably by a large margin, and likely to remain that way. Furthermore, there is a lack of knowledge regarding the existence, load characteristics, and emergency power requirements of many critical facilities. During emergency operations, this can impede procurement, delivery, and installation of the proper equipment at the site. Also unknown is the ability to reliably obtain non-traditional sources of emergency power such as from train locomotives and ships.

Recommendation 5.5: The Department of Energy and the Department of Homeland Security should evaluate and recommend the best approach for getting critical facility managers to pre-register information about emergency power needs and available resources. Collecting this information in a centralized, accessible database will expedite provision of emergency power to critical facilities and help set priorities for allocating resources. The Emergency Power Facility Assessment Tool managed by the U.S. Army Corps of Engineers—a tool already in use but whose adequacy the committee was unable to assess completely—may prove to be a suitable platform. Once these informational resources are in place, periodic stress testing and evaluation are needed to ensure that they continue to provide reliable information.

It is crucial to increase community assessments of what will and will not work in the event of large outages of varying duration (including availability of liquid fuel and generators; power to refineries, gas stations, communication networks, and hospitals; local and regional availability of natural gas; workforce). These should be integrated with tabletop emergency planning exercises at the community, county, and state levels. FEMA provides some funding for state and local exercises. However, resilience to large-area, long-duration outages may not be adequately prioritized in existing state/local exercises, and greater emphasis could produce good models for systematic planning and operational assessments.

Designing Local Power Systems to Provide Higher Customer Resilience

Beyond customer-owned sources of backup power, the power infrastructure, and distribution systems in particular, could be designed to operate more effectively when the bulk transmission parts of the grid fail. Many utilities are already installing self-healing and self-correcting distribution systems. These have ubiquitous sensors that can identify and isolate faults and use automated or remotely controlled switching to assure continuity of power to as many users as possible. For purposes of this chapter, what is important about these systems is that they blur the lines between reliability and resilience. When they work effectively, these automated distribution systems improve reliability of traditional grid service. But it is a small step to extend that logic to integration of electric infrastructure that is located on a customer's premises—for example, an intelligent microgrid that can island from or reconnect to the larger system as conditions require. Other examples include on-site battery storage at customers' residences, which combined with photovoltaics (PVs) could provide continuity of service in the event of grid failure (i.e., reliability) and also offer local support for the grid that can help avoid outages or expedite restoration (i.e., resilience). In terms of grid design and decentralization, these activities at the "edge" of the traditional grid are important technological and behavioral frontiers for the future power system. At present, most of the capabilities—such as automated islanding and intelligent integration of local resources into utility distribution systems—are theoretical in nature and have not been tested at scale.

A particularly promising set of options related to improving resilience rest with various types of microgrids. It is crucial to understand how microgrids can enhance resilience by operating in self-islanding mode during long periods of grid failure. In that context, there are various classes of microgrids:

- *Building scale.* Nanogrids are small-scale microgrids feeding residential or commercial end users. During an outage, the nanogrid typically isolates from the distribution system, and individual energy resources (e.g., a rooftop PV system with battery energy storage, a local diesel generator, or a fuel cell) are used to power the local loads. At present, most of these small self-supply systems serve the purposes of improving reliability and saving customers' money through self-generation. Most of these systems are not designed to provide reliability for long-duration outages of the macrogrid, and many of these systems (e.g., at the residential level) are not designed to operate in islanded mode at all. Technically, however, many more of these systems could be designed with those capabilities.

- *Campus scale*. Microgrids are emerging as solutions for whole collections of buildings (e.g., college campuses or military facilities). All of these systems are designed with the capability of seamlessly connecting and disconnecting (i.e., islanding) from the macrogrid. Maintaining power at these locations–oases during emergency situations may be critical for safely riding through a catastrophic event. This is the fastest growth segment of microgrids in part because there are some customers willing to pay heavily for reliability (e.g., military bases) and in part because large-scale energy users can take advantage of combined heat and power efficiencies from burning natural gas in micro turbines (Hanna et al., 2017). For these latter users, dependence on natural gas supplies—which themselves may be compromised during events that lead to outage of the macrogrid—may be an extra source of vulnerability. Earthquakes that affect the power grid can also disrupt natural gas supplies. Extreme cold associated with ice storms can spike other demands for gas, such as heating, and leave less gas for power generation. Such systems, in many cases, are designed for islanding within the microgrids—so that critical services such as hospitals and sensitive scientific equipment are kept online even as the rest of the microgrid suffers graceful degradation in service.

- *Community scale*. Community-centric microgrids can be established by sharing individual end users' distributed energy resources (DERs)—a capability that exists in principle but, so far, is rarely observed in reality. This functionality remains socially and technically challenging, as there are issues with safety, protection, controls, and metering.

Finding: There is enormous technical potential to using microgrids to make electric service more resilient in the face of loss of bulk grid power. This field of research and application is evolving quickly with new control systems, sensors, and distributed energy resources. This rapid evolution of the frontier of technical capabilities is opening a potentially wide gulf between the technical capabilities of microgrid systems and the real-world systems that are operational.

It is difficult to test microgrids and self-islanding distribution systems in real failure modes, especially if real-world events that lead to grid failure create many other forces that could erode the capabilities of self-islanded or microgrid systems. Variations in power quality could damage sensitive equipment needed for operation of these systems, as could physical stresses (e.g., trees, water, wind) that are correlated with the larger events that caused macrogrid failure in the first place. Too little is known about whether decentralization of the power grid will improve or degrade resilience of service under varying conditions. A highly decentralized and automated grid system that is still controlled by central authorities could prove to be a highly effective means of assuring resilient energy services even in the face of macrogrid failure. Or decentralization could actually amplify vulnerabilities in the grid system. Control systems may be unable to provide stability in the face of large numbers of local decisions made without the benefit of centralized authorities. Those systems might also fail in coordinated ways—for example, in case of cyber attack on the power infrastructure.

Finding: Many microgrids have been designed with continuous grid integration in mind, and users are hesitant to operate them in abnormal modes (e.g., islanded, or back-feeding power to the local utility) that could cause harm. Too little is known about whether decentralization of the power grid will improve or degrade resilience of service under varying conditions. A highly decentralized and automated grid system that is still controlled by central authorities could prove to be a highly effective means of assuring resilient energy services even in the face of macro-grid failure. Or, decentralization could actually amplify the vulnerabilities in the grid system.

Recommendation 5.6: The Department of Energy should support demonstration and a training facility (or facilities) for future microgrids that will allow utility engineers and non-utility microgrid operators to gain hands-on experience with islanding, operating, and restoring feeders (including microgrids). While the full need for training and experience—as well as possible adjustment in microgrid standards, notably those developed by consensus under the Institute of Electrical and Electronics Engineers (e.g., 1547.4 and the 2030 family of standards, which are, at this writing, under revision)—is large, the committee envisions a small Department of Energy-backed program to establish best practices that could spread more widely across industry and the regulatory community.

As discussed in Chapter 2, today, in most states, regulatory and legal restrictions limit the ability of a microgrid to sell power to other entities or to move power across public thoroughfare unless it is operated by a traditional electric utility. At smaller scale, privately owned microgrids could offer significant advantages, even with existing rate structures that typically do not acknowledge the value such a system can provide to the grid (King and Morgan, 2007).

DISTRIBUTION SYSTEM INNOVATIONS THAT COULD ENHANCE RESILIENCE

Today when the power goes out, individual customers are essentially on their own until service is restored. Homes and commercial facilities that are equipped with standby generators can disconnect from the grid and continue to operate with full or partial power. Users with microgrids—such as some campuses and military bases—can island from the grid and continue operations. Everyone else, even those customers with grid-connected PV systems, finds themselves in the dark. There are ways to enhance local resilience, such as by making PV inverters more visible and controllable, by facilitating development of small private microgrids, and by enabling utilities to operate islanded feeders.

Increasing the Capabilities of Distributed Energy Resource Inverters

End-users and utilities are investing in a wide array of DERs (e.g., PV arrays, wind turbines, battery storage), many of which are located on or near customers' premises. These resources could be used, in theory, to provide power to local loads even when the grid is unavailable. Typically, these local resources are interconnected with the grid through power electronic devices called inverters that convert the direct current output from many of these devices into alternating current. Integrating these resources into the grid has presented regulatory and technical challenges. Currently, these devices are required to automatically disconnect when the voltage and/or frequency at their terminals deviates outside of a normal range, indicating the presence of a fault somewhere on the grid. There are several reasons for this requirement, including safety of the line crews in the field and protection of equipment. However, because of the way inverters and their control systems are now implemented, this also results in cutting off the supply of power to the DER owner as well as to the grid. Given the rapidly increasing penetration of DERs, it may often be desirable to keep these resources online during abnormal situations. Motivated by concerns related to the stability of the bulk power system, FERC has modified its small generator interconnection regulations to require that DERs have the ability to "ride through" momentary fluctuations of frequency or voltage.[5] In addition, the Institute for Electrical and Electronics Engineers is in the process of revising DER interconnection standards (IEEE, 2014), including guidelines for the intentional formation and operation of microgrids. These developments could have a positive impact on resilience during large-scale outages.

While it is not yet deployed at significant scale, technology is readily available to allow inverters to power local loads following automatic grid disconnection, making limited local power available to run refrigerators, freezers, and other critical loads.[6] In addition to increasing resilience and reliability for end-use customers, ongoing advances in inverter technology and modifications to interconnection regulations can be beneficial for keeping local loads at least partially energized during large-area, long-duration outages. Such advances can also be beneficial for utilities during restoration (see Chapter 6). With proper design and operating standards, DERs and advanced inverters could actively contribute to the stability and reliability of microgrids to power local loads without jeopardizing equipment or human safety. Nevertheless, individual states are in various stages of policy development related to inverter performance and interconnection of DERs

> **Recommendation 5.7:** Utility regulators and operating utilities that have not adopted standards similar to the Federal Energy Regulatory Commission's ride-through capability requirements for small generators should assess their current interconnection standards as applicable to distributed energy resources, consider the costs of requiring new installations to use enhanced inverters, and determine the appropriate policy for promoting islanding and other related capabilities.

Encouraging Private Microgrids

As explained in Chapter 2, in most states today, regulatory arrangements and laws granting distribution utilities exclusive service territories preclude private entities from constructing and operating microgrids if done in a manner that supplies power to an entity other than the owner of the microgrid or if that power is moved across a public thoroughfare. However, because many distributed generation (DG) systems display economies of scale (King, 2006), there may be sound economic justifications for customers to want to operate some privately owned microgrids at a scale that serves several customers. Indeed, the military does this on many bases, at times with reliability benefits for non-military users as well. Microgrids have several advantages for the electricity grid; for example, they can provide electricity

[5] FERC Order No. 828, 81, Fed. Reg. 50,290, 156 FERC ¶ 61,062 (2016).
[6] See, for example, the Outback FX 2.5kW 120VAC 24VDC 55A Sealed Inverter/Charger GTFX2524 from CivicSolar: https://www.civicsolar.com/product/outback-gtfx2524-sealed-grid-tie-24v-25kw-inverter.

during peak-usage hours and therefore forestall the need for expensive upgrades in central generation, transmission, and distribution systems. They can also be used to improve power quality and reliability for local consumers (Neville, 2008). Finally, with proper arrangements they can serve local customers during power outages, consequently increasing the resilience of the grid. A potential advantage of facilitating the development of privately owned and operated microgrids is that this could considerably speed the pace of innovation (in much the way innovation was spurred after deregulation in the telecom industry).

> **Recommendation 5.8:** The Department of Energy should work with the National Association of Regulatory Utility Commissioners and state regulators to undertake studies of the technical, economic, and regulatory changes necessary to allow development and operation of privately owned microgrids that serve multiple parties and/or cross public rights-of-way. These studies should also consider the potential consequences of such changes.

> **Recommendation 5.9:** State legislatures and public utility commissions should explore economic, ratemaking, and other regulatory options for facilitating the development of private microgrids that provide resilience benefits. Rate structures can be developed to cover the costs of upgrading and maintaining grid assets while also recognizing and rewarding the benefits that distributed energy resources provide to the grid.

Facilitating Utility-Operated Islanded Feeders

Traditional radial distribution feeders are designed only to move power from substations out to customers in one direction. More modern distribution systems that include distribution automation and intelligent bi-directional sectionalizing switches,[7] and other advanced distribution technologies, such as smart meters and micro-phasor measurement units, can reconfigure distribution system topology and feed distribution circuits from more than one location (Grijalva and Tariq, 2011; Grijalva et al., 2011). As the amount of utility and privately operated DG[8] on distribution systems grows, there is no technical reason why, during an extended outage, an intact distribution feeder could not be operated as an islanded micro-grid, supplying customers with limited critical electric service (Narayanan and Morgan, 2012). However, progress will be needed on a variety of technical and regulatory fronts. For example, as DG resources grow in size, simple "plug and play" arrangements are no longer feasible because issues of stability, as well as frequency and voltage control, become critical (Nazari et al., 2012; Nazari et al., 2013).

[7] See, for example, the IntelliRupter® PulseCloser® Fault Interrupter from the S&C Electric Company: http://www.sandc.com/en/products--services/products/intellirupter-pulsecloser-fault-interrupter/http://www.sandc.com/en/products--services/products/intellirupter-pulsecloser-fault-interrupter/.

[8] DG is a subset of DERs. DERs can include storage and non-generation resources.

Distribution systems with smart meters can drop customers before reconfiguring as an island, but issues of synchronizing DG resources and assuring adequate stability also need to be addressed (Nazari and Ilic, 2014). In most cases, it is unlikely that the amount of power available to an islanded feeder would be sufficient to meet all local loads. That means that methods would need to be developed to limit the load imposed by individual customers and perhaps to cycle supply among customers over time. Any operation of islanded feeders using DG resources must be planned and executed in a fashion that does not create a safety hazard for residents or utility repair crews.

Today, an inability to observe the details of what is going on (i.e., lack of visibility) in distribution systems is a significant technical barrier to the islanded operation of DGs and microgrids. Generally, this issue is lessened in transmission systems, as transmission systems typically have greater visibility. During a power outage, transmission system operators can often readily and accurately identify most fault(s) and isolate them from the rest of the grid. Thus, the rest of the system can continue its normal operation while line crews work to repair the isolated part of the grid in a safe manner. If utilities undertake a similar approach for distribution systems and implement smart meters and micro-phasor measurement units in distribution systems, or at least at the points of interconnection of DGs/microgrids, they can identify energized lines during outages and isolate them to ensure line crews safety, while serving critical loads.

Recommendation 5.10: Utilities that have already implemented smart meters and advanced distribution systems with sectionalizing switches should explore the feasibility of establishing contractual and billing agreements with private owners of distributed resources and developing the ability to operate intact islanded feeders as islanded microgrids powered by utility- and customer-owned generating resources to supply limited power to critical loads during large grid outages of long duration.

Recommendation 5.11: Utility regulators and non-governmental entities should undertake studies to develop guidance on how best to compensate the owners of distributed generation resources who are prepared to commit a portion of their distributed generation capacity to serve islanded feeders in the event of large outages of long duration. Additionally, the National Association of Regulatory Utility Commissioners should establish a working group to advise members on the issues they will likely have to address as the possibility grows that some utilities or customers may wish to be able to operate islanded feeders during large outages of long duration.

Facilitating Emergency Use of Hybrid and Fuel Cell Vehicles for Backup Power

With appropriate inverters, plug-in hybrid electric vehicles and fuel cell vehicles are effectively mobile generators that customers could use to provide emergency power to critical loads in their homes, and in theory to an islanded feeder, during a major outage. Like other mobile generators, this service depends on continued availability of fuel, whether natural gas, gasoline, or something similar. Battery electric vehicles with no combustion system only store modest amounts of energy (i.e., 80 kWh at the high end), which would likely be exhausted early in the course of a large-area, long-duration outage. Thus, purely electric vehicles do not offer the same level of resilience benefit for homeowners but could be coupled with DG such as PVs. Inverters designed for vehicle-to-home power transfer have not entered the market in the United States, although there are numerous demonstration projects, in part because of technical, economic, and liability questions that must be negotiated among grid operators, home-owners, and vehicle manufacturers.

Recommendation 5.12: The Department of Energy should work with the manufacturers of plug-in hybrid electric and fuel cell vehicles to study how such vehicles might be used as distributed sources of emergency power.

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6

Restoring Grid Function After a Major Disruption

INTRODUCTION

This chapter discusses the post-event system restoration and the learning phases of the resilience model laid out in Figure 1.2. The committee first introduces a general model for electricity system restoration after a large-area, long-duration outage and then discusses restoration for several classes of disruptions based on the type of damage caused. This organization is based on the recognition that restoration activities proceed differently based on different types of outages—following some events, utility operators will have no situational awareness to guide their deployments; whereas other events may leave monitoring systems intact but overwhelm stockpiled resources. The chapter includes recommendations for improving the restoration process and for improving post-incident investigation to better learn from each experience to improve future performance.

GENERAL MODEL FOR ELECTRICITY RESTORATION

Following a large-area, long-duration outage, electricity system operators set priorities and work across organizational boundaries to bring the system back online as quickly as possible through a series of restoration activities. While the exact steps and procedures for restoration vary depending on the nature of the outage and the damage incurred, electricity providers follow four general restoration steps:

1. Assess the extent, locations, and severity of damage to the electricity system;
2. Provide the physical and human resources required for repairs;

3. Prioritize sites/components for repair based on factors including the criticality of the load and the availability of resources to complete the needed repairs; and
4. Implement the needed repairs and reassess system state.

As shown in Figure 6.1, these general processes are carried out simultaneously by different organizations operating at different scales across all elements of the power system. Many of these organizations have their own restoration plans, spanning those from individual distribution cooperatives such as Cuivre River Electric Cooperative in Missouri (CREC, 2016), to large investor-owned utilities such as New York State Electric and Gas Corporation and Rochester Gas and Electric Corporation (NYSEG and RGEC, 2016), to independent system operators such as PJM (2016). Organizations frequently involved in electricity restoration include not only electricity system operators (i.e., distribution, transmission, and generation utilities and independent system operators), but also emergency management officials from city, county, state, and federal organizations, including the Federal Emergency Management Agency (FEMA), the Department of Energy (DOE), state emergency management agencies, the National Guard, and in some cases even the Department of Defense. Depending on the circumstances, organizations that operate far afield of the utility sector may be called on when they offer special capabilities—for example, the deployment of the U.S. Air Force to transport bucket trucks by air from California to New York in response to Superstorm Sandy. Effective restoration rests on the collaboration and cooperation of myriad organizations and individuals of different skills. Various mutual assistance agreements provide additional resources to extend the reach of the restoration across geographic and organizational boundaries. The restoration work itself is dependent on the skills and resources of the line and electrician crews deployed by the local utilities.

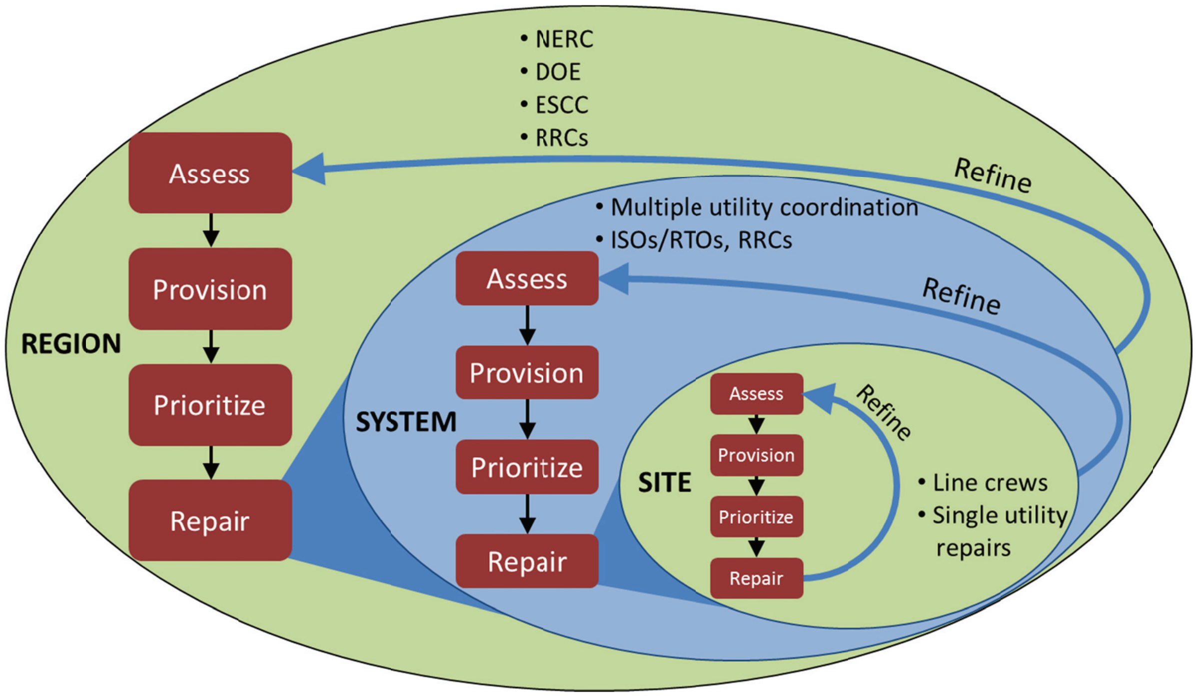

FIGURE 6.1 Illustration of the general processes of restoration that occur on multiple levels by different institutions with responsibility for electricity restoration.
NOTE: NERC, North American Electric Reliability Corporation; DOE, Department of Energy; ESCC, Electricity Subsector Coordinating Council; RRC, Regional reliability coordinator; ISO, Independent system operator; RTO, Regional transmission operator.

Coordination and communication among these groups is challenging, in part because each group has different responsibilities and boundaries within which it operates. Knowledge of local conditions and needs is greatest at the site level and diminishes with increasing scale, whereas understanding of systemic risks and critical needs may be greater at the regional scale. Thus, information must flow in both directions, and while prior agreements can help considerably, communication channels specific to the actors and hazards involved are often established in an ad hoc manner. These communications must be agile and flexible, evolving in response to changing conditions and the shifting composition of the restoration team. Communication is partly a technical issue and partly an organizational issue—for example, determining who should have access to information. In recent storms such as Superstorm Sandy, coordinating the dispatch and routing of crews through damaged and flooded areas was a challenge, and crews were sometimes delayed because they could not reach affected areas.

Beyond identifying a specific threat to the electricity system, key utility CEOs and federal decision makers meet through the Electricity Subsector Coordinating Council to plan for national-level incidents and maintain open communication channels (ESCC, 2016). This lays a good foundation for restoration activities, but an agile approach is necessary to deal with specific circumstances. Exercises are critical, although exercises alone will not address an actual event in all regards. Nonetheless, practice and associated learning will improve reactions during actual response.

During a major disaster, the states coordinate all first responder and restoration activities. For large incidents, when federal resources are warranted and mobilized, the National Response Framework provides the organizational structure, FEMA coordinates federal assets, and DOE is appointed the energy-sector lead agency (DHS, 2016). In preparation for or response to major outages, DOE will staff local and headquarters operations centers to coordinate federal actions that expedite electricity system restoration, working closely with the electricity organizations involved and other responders. Examples of DOE action include waiving federal transportation regulations on the time trucks can drive continuously so as to bring necessary equipment to the affected area more rapidly.

When a physical disruption of the power system occurs, it is important that utility repair crews be able to gain rapid access to damaged substations and other facilities so they can safely isolate and de-energize hazardous components, retain and gain access to emergency communication equipment and supplies, promptly assess damage, and start the process of restoration. In that context, the issue of working with law enforcement to gain access becomes critical, both for reasons of safety and because supplying power can be a key component of disaster recovery and avoiding further risks and damages.

One possible strategy could be to designate selected utility personnel as “first responders.” While there have been efforts to move in this direction, they have become stalled because doing so could raise potential issues of liability, perhaps placing crews under state control or even requiring crews to divert their efforts away from electricity-related activities. The Edison Electric Institute (EEI) and others have been working at high levels to reach informal agreements about achieving access. One problem with such an informal approach is that, without official credentialing, other first responders on the ground may not be aware of such arrangements and serious delays in access can occur. The situation could become even more complicated in the event of a major terrorist attack on substations or other critical grid facilities that might be designated as “crime scenes.” A similar situation could arise in the wake of a cyber attack where affected systems might be considered evidence.

Finding: When major physical damage occurs in the power grid, it is important that utility repair crews be able to gain rapid access. Due to a lack of standing arrangements with law enforcement and other first responders, this is not always possible; informal high-level agreements about access do not always result in smooth operations among key personnel on the ground.

Recommendation 6.1: The Department of Homeland Security in collaboration with the Department of Energy should redouble efforts to work with utilities and national, state, and local law enforcement to develop formal arrangements (such as designating selected utility personnel as "first responders") that credential selected utility personnel to allow prompt utility access to damaged facilities across jurisdictional boundaries. Such agreements should address issues such as indemnity, liability, and the risk of diverting the mission and assets of utility crews to other non-power system objectives.

Utility Planning for Restoration from Major Disruptions

Utilities are well practiced at recovering from localized damage to the grid and helping to restore the system outside their service areas following large events. From line crews to executives, utilities are familiar with recovery from regional natural hazards; they have developed restoration plans and allocated resources for recovery operations. Some utilities equip bucket trucks with mobile generators and communications equipment that allow line crews to maintain contact and proceed with repairs even when the bulk grid and communications infrastructures are down. When damages to the physical system exceed the hardware or human resources of a single utility, mutual assistance agreements (MAAs) are used widely throughout the industry to expedite sharing of crews and equipment among utilities. For larger events, crews and equipment are often brought in from thousands of miles away to aid restoration efforts in affected areas. Following Superstorm Sandy, the EEI developed a National Response Event framework for coordinating regional MAAs across the United States (EEI, 2016). Although the National Response Event framework has not yet been tested, it is designed to help prioritize and expedite dispatch of line crews and resources on a national scale with a comprehensive understanding of damages and restoration efforts.

Utility restoration plans emphasize advanced planning, communication, training, and continual refinement and improvement. Restoration plans are drilled by utilities and externally reviewed by the North American Electric Reliability Corporation (NERC), the Federal Energy Regulatory Commission (FERC), and regional reliability organizations. One recent voluntary review found that participating organizations maintained system restoration plans that were thorough and highly detailed; however, opportunities for improvement remain (NERC, 2016a). For example, restoration plans may make key assumptions about the availability of certain assets (e.g., that a pre-identified black start transmission corridor is operational) that, depending on the extent of damage, may not hold true.

Depending on the hazard, it may be possible for utilities to strategically deploy assets and for state and federal agencies to be mobilized in advance of the event. For example, utilities operating along the Gulf Coast have a long history of anticipating and recovering from large storms that cause extensive damage, and their restoration plans and activities reflect this history. In the week before Hurricane Katrina, Southern Company and its operating subsidiaries in Mississippi and Alabama spent more than $7 million pre-staging personnel and supplies, including catering and amenities for restoration workers, many of whose families were directly impacted by the storm (Ball, 2006). The arrival of Superstorm Sandy was preceded by a large mobilization of assets by utilities and the federal government (Fugate, 2012; Lacey, 2014). Vermont Electric Power Company's Weather Analytics Center provides highly accurate weather forecasts that the utility uses to pre-position restoration crews and assets (NASEM, 2016). Developing additional technologies and strategies to improve pre-positioning of restoration assets remain an important area for additional effort.

The process of electricity system restoration begins long before a specific event or threat is identified, through extensive planning, training, drilling, and pre-positioning of assets, and continues after all service has been restored, through continual refinement of a utility's restoration plans. Fundamental to all restoration planning is an unresolvable uncertainty: the exact nature of damage cannot be known before an event occurs, and restoration plans must simultaneously be specific and actionable for utility personnel yet general enough to accommodate diverse potential scenarios. Thus there is no uniform, repeatable process for restoration that extends beyond a single event. There are many post-action reports from major outages that describe the event, how it was addressed by whom, and lessons learned. By systematically evaluating previous experiences and more openly sharing information about recovery from major outages, utilities have an opportunity to identify and share best practices. While such analysis is conducted on behalf of transmission utilities at the North American Transmission Forum, these assessments do not cover distribution utilities.

Recommendation 6.2: With support and encouragement from relevant state and federal regulatory agencies, the Department of Energy and utilities should continue to work together to analyze past large-area, long-duration outages to identify common elements and processes for system restoration and define best practices that can be shared broadly throughout the electricity industry. The committee notes that progress has been made with the ongoing efforts of the Electricity Subsector Coordinating Council, which provides a good framework for expanded coordination and sharing of best practices.

Black-Start Recovery Plans

Large generation and transmission operators maintain restoration and recovery plans for energizing the high-voltage transmission system following a large-area, long-duration outage. Most generation facilities require electricity for operation, so if generators have gone off-line, these plans begin by starting selected "black-start" generators that do not require power from the larger grid to function. There are almost always functioning areas of the grid adjacent to the area experiencing an outage, and service can be most effectively restored from the edges of the blacked-out areas. If this is not the case, then black-start generators must first supply power to nuclear plants for safe shutdown before providing power to other generating stations. While black-start plans are difficult or impossible to practice (because doing so would require shutting down the grid), restoration plans provide detailed information on black-start resources in a utility's service area, identify the priority loads and transmission corridors that the utility will bring power to first, and provide operators with key contact information. The priority loads for restoring the electricity system are other non-black-start generation plants—particularly nuclear plants that require external power—as well as natural gas pumping stations that maintain pressure in pipelines and provide fuel for natural gas generators to come online.

As generators and transmission corridors become energized, power is provided to distribution circuits—with priority given to known critical loads such as hospitals and repairs that restore service to the most customers. As restoration progresses, more generators are connected and resynchronized until service is restored to more loads. In some cases, this restoration may involve forming "islands" of electrical service: multiple smaller regions maintain balance of generation and load independent of the remaining grid and are then subsequently synchronized to the remaining system (PJM, 2016). Depending on how quickly generators are restored, some low-priority loads may need to remain off-line as the electricity providers will ration available supply to meet prioritized demand requirements. The time required to complete this process depends significantly on the damage to the infrastructure, the amount of data and information available, and the availability of restoration resources.

The Electric Power Research Institute (EPRI) has developed generic restoration milestones as well as a comprehensive methodology for power system restoration based on these milestones. It is also developing and demonstrating a prototype decision support tool for evaluating system restoration strategies (EPRI, 2010). The Optimal Black-start Capability tool can be used by utilities to evaluate the suitability of available black-start capable units and plan optimal locations and capacity levels for new black-start units.

The restoration process is highly dependent on the topology of the transmission and distribution networks, which determine the sequence of restoration starting from the black-start generators. If in the future the generation resources are more decentralized and placed on the distribution feeders, the topology of the grid, and hence the restoration process, becomes more complex. However, the smaller generation resources closer to the loads can make the generation-load balance easier during restoration, provided that these generators (and even responsive loads) have adequate controllability. With the higher penetrations of distributed energy resources (DERs), the restoration process will need to be rethought.

Opportunities to Include Distributed Energy Resources in Restoration and Black Start

Traditionally, black-start plans have focused entirely on large, centralized utility generation assets. As the grid evolves to include larger amounts of DERs more broadly, it becomes important to consider the role these resources might play in the context of black start. The benefits and impacts of DERs will vary by geographic region because some distribution utilities have a higher penetration of DER assets than other areas. Additionally, some distributed generation and other assets are monitored and controlled by third-party entities other than the utility or grid operator because state policies do not allow these utilities to operate behind the meter. At low levels of penetration, DERs should simply be operated in ways that do not interfere with any needed black-start operations. As noted in Chapter 5, with appropriate system upgrades and institutional arrangements, microgrids and DERs could provide islands of power during outages; they could also provide local generation for utilities to restore from the distribution system outwards by connecting such small islands, as opposed to bringing power in from the bulk power system. While it may be possible to configure such resources to speed the process of supplying power to some priority loads, that would also unburden the primary black-start restoration process. At high levels of penetration, there may be an opportunity to factor DERs into black-start restoration plans. For example, multiple islands in the system formed by microgrids could be connected to form larger islands. Doing that might give the utilities more assets and more flexibility in their black-start planning.

Finding: The presence of a significant amount of DERs could provide a limited amount of local power during outages and could also be factored into black-start and emergency planning if appropriate system upgrades have been made and utility operators have visibility into their operating status and controllability of their performance.

Recommendation 6.3: The Department of Energy and utilities should evaluate the technical and contractual requirements for using distributed energy resources as part of restoration activities, even when these assets are not owned by the utility, to improve restoration and overall resilience. Emergency management and restoration plans should include the owners of distributed energy resource assets, including owners with generation, storage, or load-control capabilities.

Monitoring and Control

The monitoring and control of the power grid is accomplished through the supervisory control and data acquisition (SCADA) system and other supporting technologies, as described in previous chapters. At the control center, software tools aggregate diverse data to provide situational awareness and support operator decision making (e.g., energy management systems [EMS] on the transmission system and distribution management systems [DMS] on the distribution side). These systems gather measurement data from sensors deployed throughout the transmission and distribution systems and send out control signals. Additional sensor technologies exist for monitoring the health of circuits and components during and after restoration, which can confirm to repair crews that damage has been corrected; however, to the committee's knowledge, these have not been licensed or developed as commercial products. SCADA systems utilize robust, low-latency communications and are extremely helpful in assessing the state of damage to the system and identifying the centralized and distributed resources available for restoration. The communication networks enabling this monitoring and control are often dedicated infrastructure under the direct jurisdiction of the operating entity but are sometimes leased or provisioned by third parties.

DERs could also be monitored and controlled using the same SCADA system, in which case it would be easier for the DER to assist with restoration activities. If the DER is dispatched through a different monitoring and control communications infrastructure, it may be more difficult to provide restoration services due to the complications of coordinating among different systems. After a major disturbance, the status of the DERs, as well as the rest of the grid components, can only be known if the sensors and communication networks are not damaged or shut down by the disturbance. Electric power operators must restore power control systems and supporting communications systems concurrently with, and as an integral part of, grid restoration. Restoration of control systems and their associated communications infrastructure must remain an integral part of resilience planning.

Recovery Depends on the Type of Damage

Beyond the generalized description of the recovery process, the details of restoration activities can be very different for different types of events and resulting damage. For example, a cascading blackout can cause a large area to lose power, but recovery may be relatively rapid and straightforward if no significant physical damage has been done to system components. Likewise, restoration—and specifically damage assessment—is considerably easier when the grid's cyber monitoring and control systems are intact and operational, compared to a potential cyber attack that diminishes a utility's situational awareness. In contrast, a strong, slow-moving hurricane can cause destruction and flooding over hundreds of square miles of coastal community, making post-event access very difficult. The following sections describe opportunities to improve recovery to outages with different types of damage, as categorized in Figure 3.2.

DISRUPTIONS THAT INVOLVE ACROSS-THE-BOARD DAMAGE TO THE GRID AND ITS SUPPORTING INFRASTRUCTURE

Perhaps the most difficult disruptions to recover from are those that simultaneously cause damage to the physical components of the electricity system, the cyber monitoring and control systems, and critical supporting infrastructure. Damages of this sort can result from major natural disasters such as hurricanes and tropical storms, floods, winter storms, and earthquakes. Table 6A.1 provides details for each of these hazards in terms of the six stages of the outage lifecycle—plan, prepare, event, assess, restore, and recover. Table 6A.2 lists two additional events, tornado and geomagnetic disturbances (space weather), that can also cause widespread damage.

While all of these events involve physical damage to the power system, there can be considerable variation in the extent of damage to other supporting infrastructures and the community. For example, damage from a major hurricane is typically widespread, inflicted on transportation and other critical infrastructures, and can greatly diminish local electricity consumption. In contrast, as Table 6.A1 notes, the spatial extent of damage from flooding depends significantly on local topology: in some cases much of the community may be unaffected, whereas communities and infrastructure in flat and low-lying terrains may be entirely destroyed. Clearly these two situations result in dramatically different restoration environments. Restoring a system from nearby dry ground that has all facilities intact and working is far easier than operating in an environment where everything for miles around has been submerged. Utilities generally know what sort of circumstance they will face in the event of a disaster and plan accordingly.

In some situations, there is sufficient warning time to assess whether critical system components will be at risk and, when possible, take preventative actions. While utilities strive to maintain electrical service at all times, sometimes taking steps that will speed recovery after an inevitable outage should take precedence over keeping power on as long as possible before an outage. For example, a utility will know which substations are exposed to high flood risk and may preemptively power down certain parts of the system to prevent more substantial damage from flooding energized facilities. There are circumstances in which de-energizing vulnerable components *before* an event occurs could better protect them from damage and make recovery much faster.

Recommendation 6.4: Electric service providers should identify those components and corresponding events for which pre-event de-energizing of selected assets is the lowest risk strategy and develop regulatory, communication (especially with customers), and other plans that allow such protective action to be implemented.

Assessing System Damage

As Figure 6.1 notes, the first step in restoration is to assess the state of the system. Where the monitoring and control system is still operating, it can be used to perform a rapid assessment. More monitoring and control is available at the transmission level, but SCADA at the distribution level is also being deployed, driven in part by the increase in DERs and other advanced technologies. This monitoring is also extending to the customer level with advanced metering infrastructure (AMI) and distribution technologies. Rather than depending on customer phone calls, some outage management systems (OMSs) receive direct telemetry from AMI and other sensors to develop a comprehensive view of customer outages.

Where the communications network supporting the SCADA system or other measurement telemetry is damaged, the traditional strategy is to send crews out to do on-site inspections. At the transmission level, aircraft are often used to locate downed lines, towers, and other damage. Normally aircraft would be operating directly under the jurisdiction of the electricity utility operator, as their assets are also used for routine right-of-way patrols. If necessary, electricity operators are able to acquire additional aircraft through leasing or other arrangements. During large national-level events, other government agencies can provide aerial surveillance capabilities if they are not directly involved in search and rescue operations. The Civil Air Patrol,[1] a civilian auxiliary of the U.S. Air Force, has also been leveraged to provide aerial photographic sorties following disasters.

A new option coming into serious consideration is the use of unmanned aerial vehicles (UAVs), commonly known as drones (Olearczyk, 2013; Miller et al., 2014). Such vehicles can systematically survey damage to a system using both visible light and infrared imagery. Some UAVs have a fixed-wing design, but others are more maneuverable and can hover over problem areas for a long duration. The

[1] The Civil Air Patrol (CAP) is a congressionally chartered, federally supported non-profit corporation that serves as the official civilian auxiliary of the United States Air Force. CAP is a volunteer organization that performs three congressionally assigned key missions: emergency services (e.g., search and rescue and disaster relief operations), aerospace education for youth and the general public, and cadet programs for teenage youth. In addition, CAP has recently been tasked with homeland security and courier service missions. CAP also performs non-auxiliary missions for various governmental and private agencies, such as local law enforcement and the American Red Cross.

results of UAV inspections will be most useful if a utility has previously built a geocoded baseline of its entire system. This allows new imagery to be compared with baseline imagery and combined with asset management tools and workforce management systems to establish and coordinate repair priorities and progress (Miller et al., 2014).

The operation of UAVs in the United States is under the jurisdiction of the Federal Aviation Administration (FAA), which has been adopting new rules governing the commercial application of UAVs. However, these regulations have not kept pace with the rapid technological advancement of these systems, and there remains uncertainty surrounding the viability of UAVs for this application. In July 2016, Congress passed the FAA Extension, Safety, and Security Act of 2016.[2] Section 2207 of that law requires FAA, no later than 90 days after enactment, to "publish guidance for application for, and procedures for the processing of, on an emergency basis, exemptions or certificates of authorization or waiver for the use of unmanned aerial systems by civil or public operators in response to a catastrophe, disaster, or other emergency to facilitate emergency response operations, such as firefighting, search and rescue and utility and infrastructure restoration efforts". As of this writing, that guidance has not yet been issued. A system that relies on temporary FAA authorization creates barriers to adopting this technology for electricity service restoration, since the capability to use UAVs for damage assessment needs to be developed, exercised, and refined in advance of a disaster rather than cultivated during the incident.

A continuing problem with the use of UAVs, both for post-disaster assessment as well as for routine surveillance and maintenance of transmission and distribution systems, has been the FAA restriction that such vehicles can only be used within the UAV pilot's line of sight. In the event of a large-scale disaster, such a restriction seriously limits how useful UAVs can be. Several utilities have been experimenting with the use of UAVs and have obtained FAA 333 permits.[3] Some limited use of UAVs for post-disaster surveillance has also occurred under FAA Part 107 waivers following Hurricane Matthew, which aided in damage assessment and expedited recovery. However, both Section 333 and Part 107 permits require pilots to maintain line-of-sight operations, and any operation beyond line of sight requires additional FAA authorization. At the time of this writing, very few waivers for granting operation beyond line of sight have been granted, and these have been primarily to specialized testing and research organizations. While FAA can grant exceptions on an ad hoc basis, this takes time. It would be far better to have standing arrangements for the use of drones in emergency situations.

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[2] Public Law No. 114-190 (2016).

[3] FAA Section 333 "grants the Secretary of Transportation the authority to determine whether an airworthiness certificate is required for a unmanned aircraft system to operate safely in the National Airspace System." As of 2015, the number of FAA 333 exemption permits granted to Duke was 16; San Diego Gas & Electric was 8; Pacific Gas & Electric was 5; Southern Company was 4; and NextEra Energy was 4.

Recommendation 6.5: With convening support by the Department of Energy, the electricity industry should proactively engage the Federal Aviation Administration to ensure that the rules regulating unmanned aerial vehicle operation support the rapid, safe, and effective applications of unmanned aerial vehicle technology in electricity restoration activities, including pre-disaster tests and drills.

Data Fusion to Enhance Restoration Activities

In addition to the OMS that tracks customer outages and correlates these data with geospatial feeder data to determine where repair crews should be sent, other available data from various sources such as weather forecasts and news reports are being used to aid restoration activities (Figure 6.2). An area for research is the use of additional, underutilized information such as social media—Internet resources and social media are widely used to distribute information to consumers during a disaster. It is also possible to make use of information from consumers; however, systems are not generally in place to accomplish this. For example, during and immediately after Superstorm Sandy, many individuals sent images of downed lines, trees, and damaged equipment to utilities. If this information were automatically geotagged and time stamped, it could have provided valuable information to aid in restoration activities. Unfortunately, at the time, utilities struggled to make use of the information as it arrived in high-volumes over non-traditional channels. Additionally, there was a need to ensure that public messaging was consistent, such as continuing to advise the public never to approach downed electrical equipment.

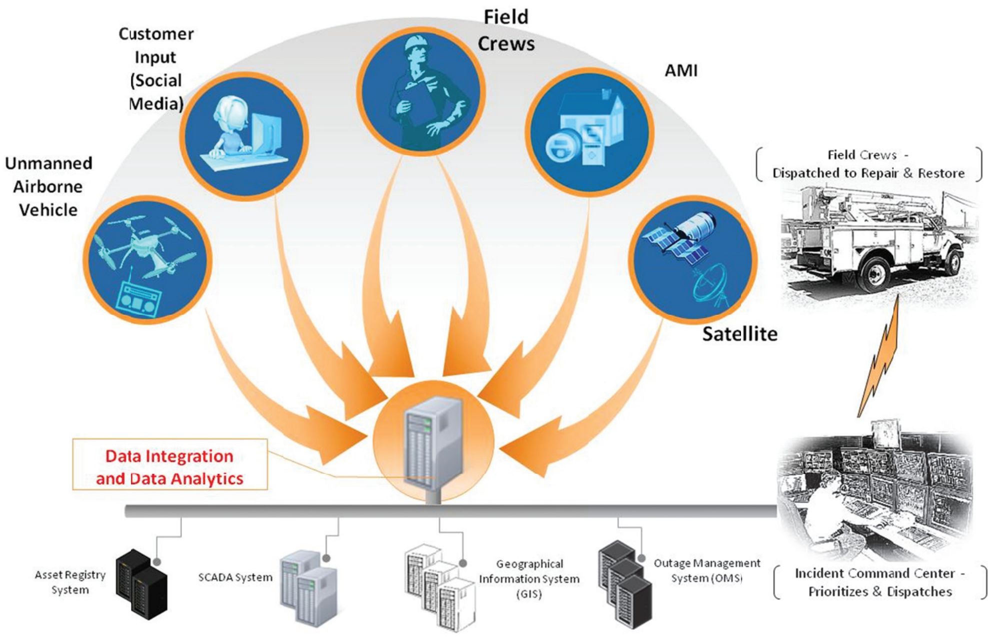


FIGURE 6.2 Example of data integration to support advanced data analytics for improved restoration efforts. The image above is not comprehensive and other technologies—for example, real-time asset health monitoring equipment and manned airborne vehicles—can be used to collect and relay information on the health of transmission and distribution system components.
NOTE: AMI, advanced metering infrastructure. SOURCE: EPRI (2013).

Access to Replacement Parts, Particularly Large Transformers

While line crews are able to repair downed power lines, towers, and poles, and repair or replace low- and medium-voltage distribution transformers, damage to large substation equipment can be much more problematic. These substations contain high-voltage transformers, circuit breakers, and other large equipment that, if damaged, can be difficult and expensive to replace. Extra-high-voltage transformers (i.e., 345 kV and above) are especially problematic. These are large devices that are expensive, have long manufacturing lead times, and are hard to move. In many cases, the electrical properties of high-voltage transformers have been customized to fit the specific locations in which they are installed. It has long been understood that these transformers are an especially vulnerable element of the grid (OTA, 1990; NRC, 2012; DOE, 2015; Parformak, 2014). While spare transformers can become a major issue in outage events that cause broad physical damage, they are especially important in the context of terrorist events where they could become the focal target of intentional attack. Indeed, as far back as 1990, the Office of Technology Assessment concluded that, if a terrorist group wanted to attack the U.S. power system, the obvious target would be a carefully selected set of high-voltage power transformers. *Terrorism and the Electric Power Delivery System* explained the following:

> The large power transformers in generating station switch yards and major substations are vulnerable to terrorist attack and could take months or years to replace. Options for bypassing damaged substations to bring power from remote generating stations to load centers are very limited because the grid is already stressed during peak demand. The result of a coordinated attack on key substations could be rolling blackouts over a wide area until the substations are repaired. Under such conditions, the availability of compact easily transported recovery transformers would be invaluable (NRC, 2012).

The report went on to recommend that the Department of Homeland Security (DHS) cooperate with the DOE to "complete the development and demonstration of high-voltage recovery transformers and develop plans for manufacturer storage and installation of these recovery transformers" (NRC, 2012). In a demonstration program called RecX (for "recovery transformer"), the DHS Science and Technology

Directorate teamed with ABB and the power industry to manufacture three single-phase 345 kV transformers in St. Louis, Missouri, and move them to Houston, Texas, in March 2013 (Figure 6.3), where they were installed and operated in a substation. The entire move and installation was completed in less than a week (DHS, 2014).

FIGURE 6.3 Three ABB single-phase 345 kV compact replacement transformers being moved from St. Louis, Missouri, to a substation in Houston, Texas, under a Department of Homeland Security demonstration project. SOURCE: DHS (2012).

Regulators, policy makers, and utilities recognize the need to stockpile spare equipment, especially large equipment that can be difficult and expensive to replace. As summarized in a recent Congressional Research Service report (Parformak, 2014), the industry has made some progress in constructing a catalogue of spare high-voltage transformers. DOE recently released a request for information to gather input on setting up a national transformer reserve, and eight private energy companies have launched Grid Assurance,™ an independent company that will stockpile transformers and other critical equipment.[4] A central issue with respect to developing a stockpile of replacement transformers is how to cover the cost. The approach taken by Grid Assurance,™ in which participating utilities have helped finance the founding of the company, and in return the company will sell stockpiled equipment to participating utility companies who need them during emergencies, was recently given a boost when FERC allowed participating utilities to recover their costs associated with purchasing sparing service and spare equipment.

Given the inherent challenge to knowing in advance where the need might arise to replace multiple transformers, some argue that building a modest stockpile is a collective national

[4] Grid Assurance™ (www.gridassurance.com) was founded by affiliates of American Electric Power, Berkshire Hathaway Energy, Edison International, Eversource Energy, and Great Plains Energy.

asset that should be covered, or at least partly subsidized, with federal tax dollars. Congress is contemplating the creation of a national strategic transformer reserve (DOE, 2017). However, if federal resources are invested in building such a stockpile, clear policy must be developed to limit its use to well-specified disaster scenarios. Without such policy, there is a risk that industry could become overly reliant on the stockpiled equipment and reduce investment in its own spare equipment stockpiles and programs. Such an outcome could result in negligible net improvement of spare equipment capability for the nation, rather than just shifting from industry-purchased stockpiles to government-purchased stockpiles.

In its 2015 Quadrennial Energy Review (QER), DOE noted that "the use of smaller, less-efficient, temporary replacement transformers may be appropriate for emergency circumstances. In 2006, [EPRI] suggested building compact 'restoration transformers' that would fit on large cargo aircraft and trucks. Since then, DHS's Recovery Transformer Program has developed and tested a flexible transformer that is transportable by truck [see Figure 6.3] and can be installed within several days of an incident. These technologies could help address logistical concerns with moving large transformers in the event of disruptions" (DOE, 2015). The QER concluded that high voltage transformers "represent one of [the grid's] most vulnerable components. Despite expanded efforts by industry and Federal regulators, current programs to address the vulnerability may not be adequate to address the security and reliability concerns associated with simultaneous failures of multiple high-voltage transformers" (DOE, 2015). The 2017 QER also discusses this issue, noting the following:

> 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 . . . 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… 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 [large power transformers] 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 (DOE, 2017).

Over the next two decades, the grid will see increasing use of solid-state transformers and other solid-state power electronics, though penetration at present is nascent. The durability and resilience of this technology will have to be established over time and restoration plans adjusted accordingly. Solid-state power electronics will offer greater operational flexibility than traditional technology, which may be useful when the grid is being operated in non-standard ways. This technology will likely see its first widespread use in lower-power distribution systems. Recently, DOE has been supporting the development of advanced designs for LPTs. Specifically, they have been working to do the following:

> Stimulate innovative designs that promote greater standardization (i.e., commoditize LPTs) to increase grid resilience (i.e., faster recovery) in the event of the loss of one or more LPTs. To this end, new designs must maintain high efficiencies, have variable impedances, accommodate various high-side and low-side voltages, and be cost-effective compared to traditional LPTs. Projects would be expected to involve modeling, analyses, and exploratory research to assess the performance and economics of proposed designs (DOE, 2016). A critical value of [this] research, beyond the development of advanced designs, is increased standardization of components improving agile allocation during disasters (DOE, 2016).

The committee recommends a dual strategy: On the one hand, the nation should push forward to improving the availability of conventional and replacement transformers for use in the event of physical disruption. At the same time, DOE should continue to explore advanced LPT designs that, in the longer term, could lower cost and improve the efficacy of emergency replacements. The vulnerability to grid operation posed by accidental or intentional damage to high-voltage transformers has been understood for decades. While limited progress has been made to reduce this vulnerability, it continues to pose a serious risk to the power system.

Recommendation 6.6: The Department of Homeland Security, the Department of Energy, the U.S. Congress, and the power industry should be more aggressive in finding a way to address the issue of manufacturing and stockpiling flexible, high-voltage replacement transformers as an important component of infrastructure investment initiatives. If federal funds are used to help in doing this, policy will be needed to limit stockpile use to major disasters. Otherwise, utilities might face incentives to reduce their stockpiles for dealing with more routine events.

Finding: Development of innovative approaches for making LPTs with greater operational flexibility (e.g., variable impedances, accommodating multiple voltages) while maintaining high efficiency and cost effectiveness relative to traditional LPTs is promising. If such devices can be developed with standardized components, they could play an important role in expediting restoration of the grid when physical damage has occurred to LPTs.

Recommendation 6.7: The Department of Energy should continue to support research and development of advanced large power transformers, concentrating on moving beyond design studies to conduct several demonstration projects.

DISRUPTIONS THAT INVOLVE DAMAGE TO THE CYBER MONITORING AND CONTROL SYSTEMS

A second restoration case is recovery from damage to the cyber monitoring and control system as a result of a cyber attack that leads to a major service disruption. Restoration from such disruptions is structured around the process shown in Figure 6.4, which contextualizes active restoration within the larger process that begins with planning for cyber restoration in much the same way as utilities plan for physical restoration. Active cyber restoration begins with detecting a breach and follows the same sequence of activities introduced above: assess, provision, prioritize, and repair. This section focuses on the steps that occur to restore power after a cyber detection that has resulted in a major service disruption.

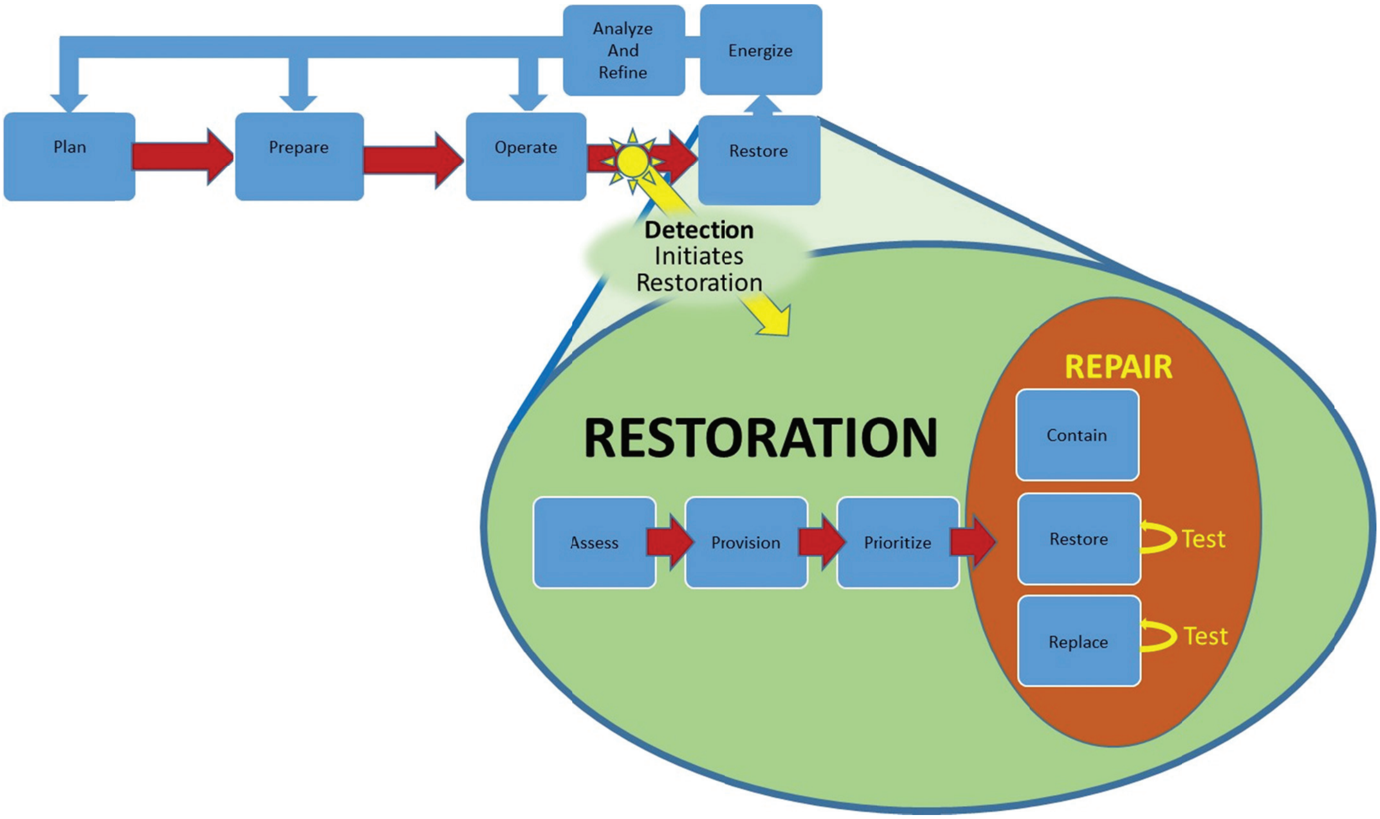


Figure 6.4: Restoration of the industrial control system after a cyber breach.

Detect

One important difference between a cyber failure and a physical disaster is the tightly defined nature of the cyber attack. The impact of a hurricane is expressed in maps as well as in lists of damaged equipment and lines. In the case of a cyber event, the cause is usually more singular than that of a natural disaster. It would be a rare event that would involve the simultaneous breach by two disparate organizations in two different ways, although a well-prepared mal-actor may seek to create exactly this situation. The analysis of a cyber event typically focuses on understanding a specific bit of malware and how it affects communication, and the counter-measures are similarly focused and technical unless the impact extends to the point of requiring replacement of substantial equipment.

A breach of a utility industrial control system (ICS) can be obvious after the system it is controlling malfunctions, but this malfunction may not occur for a long time after the initial breach. For example, in the well-covered breach of the Ukrainian power system, the actual disruption occurred 9 months after the initial breach. Mandiant (2016) reported that the average time from breach-to-detection in a typical information technology system is 140 days. This time delay is important and pernicious as it allows attackers to locate and master critical systems, find valuable or restricted information, and develop a strategy for exploitation. Adversaries lacking detailed knowledge of a system do not know a priori how to inflict damage even if they have accessed the ICS; they need this time to learn how to damage the breached system. The first step in cyber restoration is to detect the breach quickly, so that the adversary does not have time to develop sufficient understanding of the ICS to disrupt operations. Utilities need to develop reliable mechanisms to verify that their systems are running only the expected software and, if this is not the case, to allow remote resetting of systems.

> **Finding:** Breaches of utility industrial control systems may persist for an extended period prior to causing disruptions to operations or service. A breach alone is not sufficient to gain control of a system, to compromise its operation, or to steal or corrupt valuable information. It takes time for attackers to learn about the system they have breached.

The problem of breach detection can be addressed by anomaly detection, although this approach has not been shown to work as well in more general enterprise settings. In part, this is because complex and distributed systems of large enterprise systems are hard to monitor, as the variety of communications is immense (e.g., from e-mail to web site configuration management and integration with multiple systems) and varies over time. However, electric utility ICS systems are different. The boundaries of the system are more clearly defined and slower to change, the network architecture is more consistent, the communications are more structured (i.e., using well-defined protocols), and the values communicated fall into definable ranges and patterns. For example, residential meters typically report every day, hour, or 15 minutes, depending on configuration; they always use a message structure defined by the brand of meter (frequently based on an open standard), and the voltages they report are almost always in the American National Standards Institute band.[5] Using another protocol, reporting a value substantially outside the American National Standards Institute band, issuing a different message type, or reporting too often could indicate that the meter has been compromised or is malfunctioning. Another example of the potential for anomaly detection is reclosers, which control the connection to a lateral power line and do not open or close very often. Too-frequent cycling could indicate an attempt to damage the system.

Beyond these patterns, the electricity system is governed by the physics of its electrical flows. Information from the numerous and diverse sensors must present a coherent model of the state of the conditions on the grid. Reported values which deviate from the physically possible can indicate either a broken sensor or a cyber issue. For these reasons, anomaly detection methods that are not effective in general enterprise systems can work well in utility control systems. Anomalies can be detected based on

[5] American National Standards Institute Standard C84.1 defines the acceptable range of voltage within which a utility can deliver power to customers.

rules derived by various means, including those that are (1) specified by operators, (2) derived from network mapping, (3) derived through machine learning, and (4) based on physical modeling. The first two of these are based on established technology (e.g., The Bro Project[6] and the Essence Project[7]). There is much potential for progress in the latter two. Machine learning could combine support vector machine estimation for classification with neural net methods for training. While good physics models are available (e.g., OpenDSS and GridLab-D for distribution systems), there are challenges in making them fast enough for use in real-time anomaly detection.

> **Finding:** Tools for physics models and ICS network modeling are not well adapted to use in anomaly detection or cyber testing. Any discrepancy between the physics of the grid and the telemetry can indicate a system or component problem or a cyber compromise. The challenge at present is that physics models of power flow are generally too slow for real-time monitoring, and the track record for calibration is spotty.

> **Recommendation 6.8:** The Department of Energy should develop the ability to apply physics-based modeling to anomaly detection. There is enormous value in having real-time or better physics models in deriving optimal power flow and monitoring performance for more accurate state estimation. Such systems should also provide a powerful tool for verifying the integrity of telemetry systems—that is, verifying that observed conditions are consistent with model conditions—and if not, then there is a problem with knowledge of state, presuming the model is accurate.

Assess

Once a breach of the ICS has been detected, the next step is to assess the extent of damage. At this point, power may still be flowing to part or all of the grid; however, the system has failed fundamentally because the ability to determine system state accurately and control component behavior is likely compromised. Work should begin immediately to determine what part of the system (including the ICS, all connected components, and communications in either direction with external systems) has been compromised and how. At the simplest level, this involves examination of all components for indicators of compromise. Examination can include the following:

- *Inspection*. Scanning the memory and storage of each device looking for malware (i.e., “blacklisting”) and checking that only approved software is running (i.e., “whitelisting”);

[6] The website for the Bro Project is https://www.bro.org/, accessed July 11, 2017.
[7] The website for the Essence Project is https://www.controlsystemsroadmap.net/Efforts/Pages/Essence.aspx, accessed July 11, 2017.

- *Challenge*. Exercising devices to verify that they are communicating and operating correctly (e.g., flip a switch electronically to verify that it can be reached, acts as directed, and can confirm its action and state); and
- *Diagnostic Model*. Network and physics-based modeling of the grid to map anomalous behavior, although currently the models that would be used for this are not yet ready to support near-real-time restoration.

The first steps in assessment are to assemble the necessary tools if they are not present, make sure that the tools and their underlying databases are up-to-date, and then systematically and completely examine every software object in the broadly defined system to determine whether and how each has been corrupted. The assessment should be undertaken with a sense of the system connectedness, first emphasizing components that are linked to and dependent on systems known to be compromised, within the same security domain, or accessed in similar ways.

Provide

The provisioning phase of restoration focuses on marshalling human and other resources necessary to bring the ICS back to operation, perhaps in stages. Based on the assessment, the restoration team derives a list of skills and artifacts necessary to restore each component and the integrated system. In instances where replacement is either necessary or more efficient, these lists will include hardware (e.g., servers, smart components). For example, if a server is corrupted, it may be possible to restore it to safe operation, but it may be quicker and easier to build a new server from scratch and return the original sever to inventory at a less hectic time. Restoration may also require software and data: reference disks of software, often termed “gold disks,” are typically required, as are backups of the most current state data. Large transmission organizations are generally scrupulous about maintaining “gold disks,” but this practice has not been promulgated throughout the entire industry. Restoration can be slowed by something as simple as not having license information, not patching backups to current levels, or not having internet access when it is required for activation or download of current patches. The provisioning plan should take all of these activities into consideration. The provisioning plan, overlaid on the assessment, provides a map of what components and subsystems can be restored and with what effort.

Prioritize

Based on the assessment, a plan must be developed to restore the system. The challenge is to coordinate the activities of specialists with the available physical and digital resources in a sequence of steps. Restoration of a specific computer could range from something as simple as running a virus removal tool to something as complex as writing new code for a virus removal tool. It could involve re-flashing a build image, replacing a drive or even a whole computer, or rebuilding a software configuration step-by-step. There may be hundreds of steps, and it may be impossible to determine in detail all of the steps needed in a particular case. Initially, the plan may state only that a network engineer will look at an infected switch and determine what needs to be done to repair it. As the restoration proceeds, knowledge of state and the efficacy of restoration options improve, and the plan becomes more specific.

A critical issue is the affected utility's ability to marshal appropriately skilled resources. The design and documentation of utility ICS systems is insufficiently standardized; outside experts cannot quickly become effective in another organization. They can be tasked with routine tasks like imaging a disk, but their ability to contribute more strategically requires more detailed knowledge of affected systems. Priorities to achieve cyber resilience include establishing a common design and technical lexicon, training and working across organizations, and establishing common practices and formats for supporting artifacts. These need not be accomplished across the nation in a single push; rather, they can develop in groups of related or associated organizations, such as the group of distribution cooperatives supported by the single generation and transmission cooperative North Carolina Electric Membership Corporation. This model should be broadened to include other peer groups, perhaps organized around regional transmission operators and regional reliability coordinators.

Another major barrier is that, to date, organizations have not been transparent about cyber events, in part owing to risk of embarrassment and liability. Furthermore, mechanisms to share resources for cyber restoration and compensate for their use—that is, cyber mutual assistance agreements analogous to traditional MAAs—are nascent. Working with EEI, the Electricity Subsector Coordinating Council is developing such a cyber MAA program (ESCC, 2016); however, the configuration of local systems can differ so substantially across utilities (i.e., when comparing a small cooperative to a major independent system operator/regional transmission operator) that it may be prohibitively difficult for loaned workers to contribute significantly to cyber restoration, even if they are experts. Through a separate program, the Electricity Information Sharing and Analysis Center (E-ISAC) disseminates risk information to utilities; its further development should be encouraged, but the emphasis to date has been on sharing information rather than labor and primarily directed at protection rather than restoration.

One final issue to consider is funding; cyber restoration, like physical restoration, can be costly. Means must be made available for utilities to hire outside assistance when useful and buy new equipment as needed to restore power quickly. A utility may look at its limited resources and plan restoration over a long period, but there may be a social advantage to using resources beyond the utility to restore over a shorter period.

> **Finding:** To date, there have been no large-scale power outages in the United States caused by cyber attacks, but there have been many instances in which components have been compromised. Utilities have experience in fixing these minor cyber problems by rebuilding components and databases. However, cyber restoration is not a routinized process, and different organizations follow different approaches based on the nature of the event.

> **Recommendation 6.9:** The Department of Energy and the Department of Homeland Security should work with the North American Electric Reliability Corporation, independent system operators, and regional transmission operators to develop a model for large-scale cyber restoration. This should be done in collaboration with utilities and leading utility organizations such as the Edison Electric Institute, the National Rural Electric Cooperative Association, the Electric Power Research Institute, and the American Public Power Association.

Repair

Actual repairs are accomplished in three steps: (1) containing the breach, (2) restoring components that can be saved, and (3) replacing those that cannot.

Contain

The first step after detection is to contain the malware by isolating it and preventing its spread to other internal or external systems. Taking an infected component off-line can adversely impact grid operations; thus, expert decisions must be made about how to operate without the impacted components. Operations without compromised or degraded digital control may be possible; if not, a portion of the grid may be operated instead. For example, if the problem impacts voltage control at a particular substation, the feeder may be disconnected from central control and either operated with fixed typical control points or shut down temporarily. In this case, potentially no service will be lost. It is critical to keep safety and the long-term reliability of the grid in mind; operation should not be attempted unless it can be verified that the grid and customers are not put at risk. If digital telemetry is lacking, this may require dispatch of crews to verify switch settings manually, determine voltage and current, or confirm whether a line in energized. Fortunately, protective relays and fuses provide some protection against egregious misoperation.

Another aspect of containment is to communicate with other utilities. Sharing details of the attack—particularly information on the types of components impacted, the IP addresses of the attackers if known, and any identified malware signatures—may help others identify an ongoing attack. The E-ISAC has taken on the role of intermediary in this action; nonetheless, these systems must be strengthened, extended, accelerated, and exercised. The Cybersecurity Risk Information Sharing Program, initiated by DOE with E-ISAC support, is currently monitoring the majority of transmission systems and sharing such information with automated machine-to-machine communication. This has led to substantial improvement in the situational awareness of real-time cybersecurity risks in the electricity industry.

Restore and Replace

With the spread of malware contained to the extent possible, the work shifts to restoring components to a clean state or replacing them if repair is too difficult or time consuming. As practice in cyber restoration moves beyond improvisation, restoration will eventually proceed by following a plan that is developed in advance, updated, and refined for specific circumstances. Implementing the plan requires the following: (1) Executing the outlined steps, (2) Adding detail as necessary and possible, (3) Testing, (4) Monitoring progress and failure, and (5) Providing feedback to update the plan.

At each point in the restoration, the engineer must determine the correct strategy: restore or replace. The trade-offs include cost, time, and the relative risk of a repaired component still hiding malware or being otherwise compromised versus possible errors in the configuration of new components. The choice is specific to the circumstances at hand. For example, the time required for repairs depends critically on whether there is a tested and trusted tool available on hand to remove malware and whether complete and correct backup data are available.

Highly competent staff are key to effective execution of restoration and replacement plans. While a utility may have excellent general support staff, it is unlikely that they will have experience in large-scale cyber restoration. Their skills, experience, and confidence must allow them to innovate and improvise beyond their current skills. Government teams experienced in cyber restoration and similarly skilled staff from other utilities, software vendors, and cybersecurity firms can provide valuable support to the utility teams, although they are still limited by their lack of experience with the particular system being restored.

Finding: There has been a tendency among utilities and other commercial entities not to share information about cyber breaches and to look inward rather than seeking help, which limits potential for collaboration across organizations. Most utilities are not likely to have adequate internal staff directly experienced in large-scale cyber restoration. Furthermore, the ability of outside entities to help a utility with cyber restoration is limited by unfamiliarity with the configuration of the impacted system and by the lack of agreed-upon standards or shared practices. The ICS architecture at one utility may have little in common with the ICS at another utility, independent of the physical differences in the electrical system. This lack of commonality in utility ICS system designs and documentation makes rapid and efficient use of staff from other organizations very challenging, as an engineer at one utility may face a steep learning curve at another utility.

Recommendation 6.10: The Department of Energy and the Department of Homeland Security should work with the Electricity Subsector Coordinating Council and utilities to enhance the sharing of cyber restoration resources (i.e., cyber mutual assistance agreements) including personnel, focusing on peer-to-peer collaboration, as well as engagement with government, industry organizations, and commercial cybersecurity companies. Practices that allow shared personnel to more quickly come up to speed on restoration plans will increase the value of cyber mutual assistance agreements. This should include dissemination of best practices for the backup of utility industrial control systems and operational data.

Finding: Though the basic systems are in place for sharing cyber threat information, practices can be improved with more emphasis on speed. There are organizational systems in place for sharing cyber-information (e.g., E-ISAC), but the lack of a common ontology and design patterns make the shared information more difficult than necessary to put to use.

Recommendation 6.11: The Department of Energy, the Department of Homeland Security, the electricity sector, and representatives of other key affected industries and sectors should continue to strengthen the bidirectional communication between federal cybersecurity programs and commercial software companies.

Effective documentation strategies are also critical for effective cyber restoration. System documentation must be complete, accurate, and up-to-date so that the restoration teams have the information they need to proceed and additional staff can be brought up to speed quickly. Industry experience has shown that the only way to keep documentation up-to-date is to connect it to operational production systems. For example, the network should be mapped periodically and continuously using automated tools, and then the discovered reality can be compared to the documented theory. Documentation should include backup copies of every critical system, including the data and software and all critical keys, passwords, and licenses. Such backup information should be available through a secure system with an expert in the loop.

Finally, cyber restoration workers need the best possible tools to facilitate their collaboration. At a minimum, telephones should be supplemented with shared drives, online screen sharing, and remote disk access. Cloud options should be available to provide backup if local systems are compromised to the extent possible and vice-versa. Such cloud systems must be as secure as possible and potentially open only to utility operators. Furthermore, these teams must practice with either real systems or high-fidelity models. (It is possible to construct virtual systems that would allow training and practice.) Strategies for this sort of simulator are being pursued by DOE, with the National Renewable Energy Laboratory in the lead, and by the National Rural Electric Cooperative Association, with its Simba project.

Energize

Restoration of the ICS culminates with energizing the grid, shown at the top of Figure 6.4. There needs to be rapid iteration and tight integration between the plan and test steps, but ultimately the real-world test in the grid cannot be achieved digitally and virtually. Utility ICSs have switches and other controls that set machines in motion and power flowing. Some of these actions can be dangerous to line crews and could cause damage to utility and customer equipment as well as to other infrastructures. Also, a compromised control system may incorrectly alter limits on a fault protection relay or send signals to a generator that crews on site in the plant know are incorrect, resulting in dangerous system operations.

The scale and importance of utility operations dictate validation in many aspects of cyber restoration. The physics of the grid must be considered in all cyber decisions. Expert judgment is needed to determine when physical contact and observation are needed and when the benefits outweigh the risks. The training of utility personnel ensures a culture of safety.

Analyze and Refine

After the grid is re-energized, the final step is to examine what was accomplished and gather lessons learned. The goal is to refine the process, further moving cyber restoration from an ad hoc exercise to an engineering process.

> **Recommendation 6.12:** The Department of Energy should develop a high-performance utility network simulator for use in cyber configuration and testing. There is, to date, no flexible, peta-scale utility industrial control system simulator that offers sufficient fidelity for testing intrusion detection, anomaly detection, software defined network controls, and other aspects of utility operations. The closest systems to date take a "hardware-in-the-loop" approach. While this offers some apparent advantages in terms of fidelity, it is too

time consuming and expensive to test a wide range of scenarios in such as system. A purely virtual system is necessary.

DISRUPTIONS THAT INVOLVE ONLY PHYSICAL DAMAGE

There are few hazards that cause *only* physical damage to the electricity system. Of principal concern is the threat of a well-coordinated and executed physical attack. This was the subject of a 1990 Office of Technology Assessment report (OTA, 1990) and a more recent National Research Council report, *Terrorism and the Electric Power Delivery System* (NRC, 2012). While distribution and transmission equipment have been the target of attacks internationally, the Metcalf incident (described in Chapter 3) is one of the few cases in the United States, although the event was modest in scale and did not disrupt electricity service.

A terrorist attack on the towers and poles of the transmission infrastructure could disrupt service over a large area. However, utilities are well practiced at rebuilding lines and replacing poles, and it is unlikely that such an outage would be of long duration. The situation is very different for an attack on substations and especially high voltage transformers. As noted in *Terrorism and the Electric Power Delivery System*, a terrorist attack carried out in a carefully planned way by people who knew what they were doing could "deny large regions of the country access to bulk system power for weeks or even months. An event of this magnitude and duration could lead to turmoil, widespread public fear, and an image of helplessness that would play directly into the hands of the terrorists. If such large extended outages were to occur during times of extreme weather, *they could also result in hundreds or even thousands of deaths due to heat stress or extended exposure to extreme cold*" (NRC, 2012).

Table 6.1 revisits the recommendations made by that report and summarizes the present state of affairs. Unfortunately, the ubiquity of grid assets and their inherent vulnerability make it too costly to achieve a comprehensive high level of security. Resources are prioritized on those assets where improved security will yield the greatest improvement. Efforts to improve security at key assets should proceed alongside efforts to stockpile replacement equipment and develop and deploy temporary recovery assets.

TABLE 6.1: Summary of Selected Recommendations Made by the National Research Council in Its 2012 Report *Terrorism and the Electric Power Delivery System*, Together with the Committee's Assessment of Where Things Now Stand

National Research Council Recommendation	Assessment of Present Situation
6.1: The Electric Reliability Organization (ERO) [NERC] should require power companies to re-examine their critical substations to identify service vulnerabilities to	The industry has made progress on this issue.

terrorist attack. Where such vulnerabilities are discovered, physical and cyber protection should be applied. In addition, the design of these substations should be modified with the goal of making them more flexible to allow for efficient reconfiguration in the event of a malicious attack on the power system. The bus configurations in these substations could have a significant impact on maintaining reliability in the event of a malicious attack on the power system. Bus layout or configuration could be a significant factor if a transformer, circuit breaker, instrument transformer, or bus work is blown up, possibly damaging nearby equipment.	
6.2: The ERO and FERC should direct greater attention to vulnerability to multiple outages (e.g., n-2) planned by an intelligent adversary. In cases where major long-term outages are possible, reinforcements should be considered as long as costs are commensurate with the reduction of vulnerability and other possible benefits.	Some progress has been made on these issues, but additional effort is warranted.
7.6: State legislatures should change utility law to explicitly allow microgrids with distributed generation. [Institute of Electrical and Electronics Engineers] should revise its standards to include the appropriate use of islanded distributed generation and microgrid resources for local islanding in emergency recovery operations. Utilities should reexamine and, if necessary, revise their distribution automation plans and capabilities in light of the possible need to selectively serve critical loads during extended restoration efforts. Public utility commissions should consider the potential emergency restoration benefits of distribution automation when they review utility applications involving such investments.	There has been some progress on this. Some states are considering whether and, if so, how to support the development of microgrids as well as the role of the local distribution utilities and other entities in the process of developing such systems. But additional effort is warranted.
8.1: The Department of Homeland security and/or the Department of Energy should initiate and fund several model demonstration assessments each at the level of cities, counties, and states. These assessments should examine systematically the region's vulnerability to extended power outages and develop cost-effective strategies that can be adopted to reduce or, over time, eliminate such vulnerabilities. These model assessments should involve all relevant public and private participants including public and private parties providing law-enforcement: water, gas, sewage, healthcare, communications, transportation, fuel supply, banking, and food supply. These assessments should include a consideration of outages of long duration (≥ several weeks) and large geographic extent (over several states) since such outages could require a response different from those needed to deal with a shorter duration events (hours to a few days).	To the best of the committee's knowledge, no such demonstrations have been undertaken.
8.2: Building on the results of these model assessments, DHS should develop, test, and disseminate guidelines	To the best of the committee's knowledge, no such activity has been undertaken.

and tools to assist cities, counties, states, and regions to conduct their own assessments and develop plans to reduce their vulnerabilities to extended power outages. DHS should also develop guidance for individuals to help them understand steps they can take to better prepare for and reduce their vulnerability in the event of extended blackouts.	
8.3: State and local regions should use the tools provided by DHS as discussed in Recommendation 8.2 to undertake assessments of regional and local vulnerability to long-term outages, develop plans to collaboratively implement key strategies to reduce vulnerability, and assist private sector parties and individuals to identify steps they can take to reduce their vulnerabilities.	While not following the strategy that the committee recommended, some limited progress has been made.
8.4, **8.5,** and **8.6:** Congress, DHS, and the states should provide resources and incentives to cover incremental costs associated with private and public sector risk prevention and mitigation efforts to reduce the societal impact of an extended grid outage. Such incentives could include incremental funding for those aspects of systems that provide a public good but little private benefit, R&D support for new and emerging technology that will enhance the resiliency and restoration of the grid, and the development and implementation of building codes or ordinances that require alternate or backup sources of electric power for key facilities. . . . Federal and state agencies should identify legal barriers to data access, communications, and collaborative planning that could impede appropriate regional and local assessment and contingency planning for handling long-term outages. Political leaders of the jurisdictions involved should analyze the data security and privacy protection laws of their agencies with an eye to easing obstacles to collective planning and to facilitating smooth communication in a national or more localized emergency . . . . DHS should perform, or assist other federal agencies to perform, additional systematic assessment of the vulnerability of national infrastructure such as telecommunications and air traffic control in the face of extended and widespread loss of electric power, and then develop and implement strategies to reduce or eliminate vulnerabilities. Part of this work should include an assessment of the available surge capacity for large mobile generation sources. Such an assessment should include an examination of the feasibility of utilizing alternative sources of temporary power generation to meet emergency generation requirements (as identified by state, territorial, and local governments, the private sector, and nongovernmental organizations) in the event of a large-scale power outage of long duration. Such assessment should also include an examination of equipment availability, sources of power generation (mobile truck-mounted generators, naval and commercial ships, power barges, locomotives, and so on),	Limited progress has been made on selected items.

transportation logistics, and system interconnection. When areas of potential shortages have been identified, plans should be developed and implemented to take corrective action and develop needed resource inventories, stockpiles, and mobilization plans.	
9.1: Complete the development and demonstration of high-voltage recovery transformers and develop plans for the manufacture storage and installation of these recovery transformers.	A demonstration has been successfully conducted. Considerable work is still needed on developing and implementing an adequate program of funding and other support for recovery transformers.
9.2-9.6: Continue the development and demonstration of the advanced computational system currently funded by the Department of Homeland Security and underway at the Electric Power Research Institute. This system is intended to assist in supporting more rapid estimation of the state of the system and broader system analysis . . . . Develop a visualization system for transmission control centers which will support informed operator decision making and reduce vulnerability to human errors. R&D to this end is underway at the Electric Power Research Institute, Department of Energy, Consortium for Electric Reliability Technology Solutions, and Power System Engineering Research Center, but improved integration of these efforts is required . . . . Develop dynamic systems technology in conjunction with response demonstrations now being outlined as part of an energy efficiency initiative being formed by EPRI, the Edison Electric Institute, and DOE. These systems would allow interactive control of consumer loads . . . . Develop multilayer control strategies that include capabilities to island and self-heal the power delivery system. This program should involve close cooperation with the electric power industry, building on work in the Wide Area Management System, the Wide Area Control System, and the Eastern Interconnection Phasor Project . . . . Develop improved energy storage that can be deployed as dispersed systems. The committee thinks that improved lithium-ion batteries have the greatest potential. The development of such batteries, which might become commercially viable through use in plug-in hybrid electric vehicles, should be accelerated.	Limited progress has been made on selected items.

NOTE**:** NRC (2012) was undertaken for the Department of Homeland Security. Progress has been limited on a number of the recommendations that are listed on page 6 of that report. SOURCE: NRC (2012).

Finding: The power system continues to be vulnerable to physical attack by terrorists. Some progress has been made in making the system more resilient in the face of this hazard—for example, through physical security standards such as NERC CIP-014—but much remains to be done. Several strategies (e.g., high-voltage replacement transformers) that reduce vulnerability to terrorist events also reduce the system’s vulnerability to a range of natural hazards.

Recommendation 6.13: Efforts by the Department of Energy and the Department of Homeland Security, in conjunction with the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, and the electric industry, should be redoubled to reduce the vulnerability of the power system to terrorist attacks (paying particular attention to topics in Table 6.1 that have not yet been adequately addressed).

DISRUPTIONS THAT CAUSE BOTH PHYSICAL AND CYBER DAMAGE

Restoration of electric service from a system that has sustained both physical damage (e.g., a damaged transformer) and compromised monitoring and control systems (e.g., SCADA and EMS disrupted) will require greater reliance on manual inspection and operation, which can slow the pace of damage assessment and recovery. Thus, recovery from a coordinated cyber-physical attack may proceed slowly if operators suffer diminished situational awareness and have to dispatch linemen to assess damage. The principal concern across the industry is the potential for a well-informed state actor or terrorist group to execute a coordinated cyber-physical attack, the so-called “structured adversary.” Both cyber and physical attacks can be combined, targeted towards system components that cause the most damage or are most difficult to replace, and carried out repeatedly and perhaps with the explicit intent of hindering restoration.

EPRI has developed scenarios of coordinated cyber-physical attacks targeting generation, transmission, and distribution systems that can be used by operators and asset owners to test their readiness and improve planning and drilling (EPRI, 2012). More recently, NERC coordinated more than 100 participating organizations in the biennial distributed-play exercise GridEx III, which practiced response and recovery from a series of hypothetical cyber and physical attacks (NERC, 2016b). Such planning and drilling exercises are a valuable industry practice; however, the level of sophistication of attacks may continue to grow along with the number of vulnerable cyber and physical targets.

Recommendation 6.14: Utilities, with support from federal and state government, should continue to expand joint cyber-physical recovery exercises. These should emphasize, among other things, the maintenance of cyber protection during the chaotic period of physical restoration. The need to reconfigure electrical systems during a disaster requires changes to the industrial control system. It is frequently necessary to disable elements of the cybersecurity systems while the state of the gird is in flux. Research should be done on how to maintain a higher level of security during this period. This may involve operation in default modes or with analog controls to some extent until cybersecurity can be reestablished.

OPPORTUNITIES TO IMPROVE RESTORATION

Other Technologies and Operations that Improve Restoration

Though many of the technologies discussed in Chapter 4 are intended to reduce the likelihood and extent of outages, many of these technologies also directly aid in the restoration stage. Improvements from advanced sensing, controls, and analytics have reduced outages and quickened restoration. In particular, distribution system automation and adaptive islanding are examples of where these technologies can play a role in improving restoration. Further, while these technologies help in the resilience of the electric system, these technologies also improve the reliability of the system to small, localized outages.

Improving Resilience by Learning from Past Events

The final step in restoration is to reflect on and analyze the experience to improve future restoration efforts. Often restoration from a large-area, long-duration outage is viewed as a unique effort. Nonetheless, it is certain that, even in the midst of a great disaster, another similar outage will follow. In 2005, Katrina seemed a nonpareil event, but Superstorm Sandy followed a mere 7 years later. The industry can and must plan for disaster recovery, but only real disasters stress the plans and expose their gaps and weaknesses. Disasters provide a genuinely unique opportunity to learn.

For most large-area, long-duration outages, there is an after-action report that, for the most part, reads like a historical piece rather than a technical study aimed at process improvement. They accurately describe what occurred and what was done (when, where, and by whom) as well as contain a number of short narratives related to particular successes or failures. While this information is useful, even essential, the idiosyncratic approaches make it difficult to identify more general process improvements across multiple events. Outside of the electricity industry, other sectors have developed sophisticated investigation procedures and even maintain full time, well-trained staff whose only job is to investigate major incidents. The National Transportation Safety Board Investigative Process[8] is solely focused on improving safety and since the Board has no regulatory or enforcement powers, its conclusions cannot be

[8] The National Transportation Safety Board Investigative Process is described at https://www.ntsb.gov/investigations/process/Pages/default.aspx, accessed July 11, 2017.

used in litigation. The committee believes that the electricity sector can improve its own investigations by learning from the National Transportation Safety Board and potentially creating a similar institutional structure.

Part of the problem is the lack of a general restoration model to provide a common framework for learning. A simple, initial framework was proposed earlier in this chapter, and extension and elaboration of that framework could be very useful in structuring the learning process. Two additional problems are as follows: (1) There is no national process or organization to systemize the integration of studies, and (2) there is insufficient rigor to data collection. The following sections describe a general process for collecting information on the failures and shortcomings in disaster restoration.

Step 1: Compile High-Level Facts That Describe the Event

Step 1 is performed by the study team. A summary should be prepared detailing the essential known facts, including a description of the event, high-level summary of known impacts (e.g., where power was lost and for how long), the grid-level drivers of power loss, the organizations involved with restoration and their activities, a timeline of restoration activities, notable successes and failures, and a list of questions raised. From these facts, a series of maps, organization charts, and information flow diagrams should be prepared. This will provide a guide for the research and a common understanding of the event that can be shared among all of the participants in the research.

Step 2: Conduct Interviews

Beginning with the above summary, a series of interviews with a large number of individuals from all organizations involved in the restoration should be undertaken by the study team. The interviews should focus on what the organization did, as well as its inputs and outputs.

Step 3: Perform Synthesis

The synthesis phase is conducted by the study team and supplemented by subject-matter experts as needed. The synthesis phase extends the event summary by using information from the interviews. The results are summarized in a narrative that incorporates a number of graphics. The graphics include an "entity relationship diagram" (ERD); diagrams of material flows, equipment flows, and information flows; and any other charts the study team deems necessary. The ERD is crucial, as it lists all of the entities involved in restoration, from government, utility, and other private sector groups, and documents their interactions through arrows. For example, the governor's office (entity) may direct (relationship) to the National Guard (entity). The actual flows of material, equipment, and information overlay the ERD. The reduction of the narrative to these artifacts ensures rigor in and understandability of the analysis.

Step 4: Conduct Special Engineering Studies

Special engineering studies are conducted by technical teams assembled for each study. Electrical disasters and remediation are, to a large extent, studies in organization, communication, and coordination. They are at root, however, serious exercises in engineering. Much of the process described here is directed at organizational and process improvement, which is important because it underpins the response to all disasters, but it is just as important to learn about the design and operation of the grid. These elements must be part of the learning process. Based on the recommendations of the interviews, special engineering studies should be initiated. An example that is particularly important is in understanding the transmission grid. Despite its immense scale, it is a precision machine that requires careful harmonization. The studies may look at things like cyber and physical black start, the repair of analog versus digital components in flooded substations, repair of underground laterals in flooded areas, structure failure mode and possibly the need for redesign, and a host of other subjects. Special subjects should be defined in the study phase when they are essential to understanding the restoration or when the restoration presents an opportunity to learn about the grid and how to improve it. Superstorm Sandy provided an unparalleled opportunity to study grid physics at a large scale, and Katrina provided may examples of restoration of flooded substations.

Step 5: Review and Distribute Widely

All parties involved in grid restoration should be involved in review and socialization. This includes individuals and organizations not impacted by the disaster or involved in its restoration. The synthesis report should be widely distributed and reviewed at meetings in a process of improvement and refinement. This will likely span several months.

Step 6: Generalize and Integrate

This step is conducted by a team developed specifically for this purpose but should involve a few members of the study team. The purpose of the final step is to take the specific analysis that comes from Step 5 and use it to improve the general restoration model, asking which lessons have value beyond simply understanding what occurred.

Special Studies—Cascading Failures on the Bulk Power System

The reliability of U.S. electric power systems has been high enough that the rare occurrences of major blackouts have been prominent national and even international news items. Often, the circumstances leading up to a major system failure include multiple individual factors, each of which alone would have little or no significant impact but when combined conspire to impact the integrity of the system. In the past, such combinations have resulted through coincident occurrence of unrelated events. For example, during the August 14, 2003, blackout, there were four root causes identified (UCPSOTF, 2004). In the future, events could also be brought together through malevolent synergy. The job of an outage investigation team is to sift through all of the evidence to determine the root causes of the larger system failure and extract lessons for future improvement.

The first step in investigating an incident is to accurately reconstruct the sequence of events. Determining the sequence of events can be a time-consuming process. The first step is gathering all of the data to support the investigation team's evidence-building process (Dagle, 2006). Myriad data sources can provide useful information to support this phase of the investigation. Among the most valuable sources of information are operational logs, records of sequence of events, digital fault recorder output, protective relaying event information, synchrophasor data history, and other similar records of real-time information. The accuracy and precision of these event logs can be critical during cascading events, allowing investigators to sift through the initiating actions and subsequent responses. In the past, significant difficulties have arisen in gathering the data to support the investigation team (Dagle, 2004). The good news is that with the advent of modern power system measurement technology, it is becoming much easier to collect data with microsecond-class measurement accuracy, which is often of ample temporal resolution to be able to accurately determine the sequence of events.

Once the sequence of events is organized, it is valuable to separate it into slower events leading up to the cascading failure and faster events that are occurring during the cascading failure itself.

Normally the role of human operators is only relevant during the slower events, and automatic controls are involved in the faster sequences associated with the later stages of the cascading failure.

Particularly with the automated controls, it is necessary to understand the relationship among the various steps in the sequence of events. Characterizing the reason behind any automatic control action helps to develop a deeper understanding of the sequence of events and the chain of events that led up to the cascading failure sequence. This often involves a detailed assessment of protection and other control devices to determine why they operated as well as how their operation contributed to subsequent actions in the sequence of events.

Finally, after considering the sequence of events, and earlier actions that contributed to later actions, the process of root cause determination can be made. It is important in this process to understand that actions taken in advance of the event could be a key root cause finding. For example, inadequate vegetation management, rather than a ground fault to a tree, might be a root cause.

Another important consideration is the degree to which infrastructure damage will prevent rapid restoration of electricity service. As disruptive as widespread blackouts can be, much worse events are possible. Under several different types of circumstances, electric power systems could be damaged well beyond the level of normal design criteria for maintaining reliability (OTA, 1990). The threats of terrorism, severe storms, and other phenomena, such as geomagnetic disturbances, have increasingly become major concerns to the government and the commercial utility industry. The regulations and policies to mandate how the nation would respond to such an event, or even define who is in charge, are still evolving.

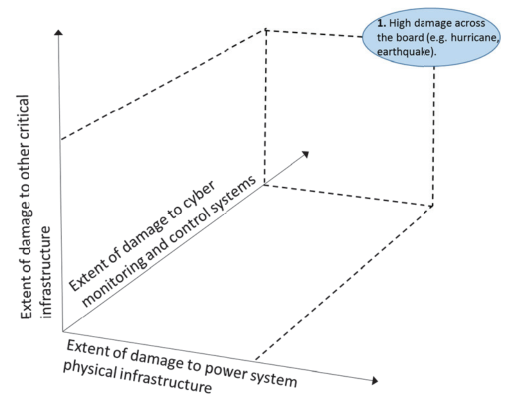
Finding: Analysis of large-area, long-duration outages requires an enormous amount of high-precision data. Provision for the collection of these data could be in place before an event. Fundamentally, it is the responsibility of each organization involved in operating the system to conduct event investigations, gather lessons learned, and apply those lessons to minimize the likelihood of subsequent similar events. NERC has jurisdiction and responsibility to conduct investigations of outages involving the bulk power system. Particularly for events that involve multiple organizations, NERC brings tremendous value to the process by assembling outside expertise that cuts across organizational boundaries.

Recommendation 6.15: The North American Electric Reliability Corporation, the Federal Energy Regulatory Commission, and relevant regional- and state-level organizations should improve the investigation process of large-scale losses of power with the objective of disseminating lessons across geographical and jurisdictional boundaries. Experiences from outside organizations such as the National Transportation Safety Board should inform this work. To further improve the investigation process, the committee recommends that organizations involved in electricity system operation improve restoration through the following:

- Better and more uniform calibration of recording instruments, including precise time synchronization.
- Pre-defined data requirements to support incident investigations using standard data formats.
- Pre-work logistical details (e.g., prior establishment of confidentiality agreements).
- Infrastructure to support centralized blackout investigations.
- Creation of a data warehouse with servers and databases to store and process the incoming data, support the investigation team, and manage data inventory.
- Defined data categories (to readily track and follow-up on data gaps).
- Automated disturbance reporting.
- Routine collection of transmission and generation events.
- Improved mechanics of data formats, exchange protocols, and confidentiality issues that can be worked out and tested on an ongoing basis.
- Blackout data that are collected in a matter of hours rather than a matter of days or weeks.

Annex Tables

TABLE 6A.1: Variation in Restoration Activities Across the Six Stages of the Life Cycle of an Outage Characterized by Damage to Physical Components, Monitoring and Control Systems, and Supporting Infrastructure, As Indicated in the Upper Right Corner of Figure 3.2

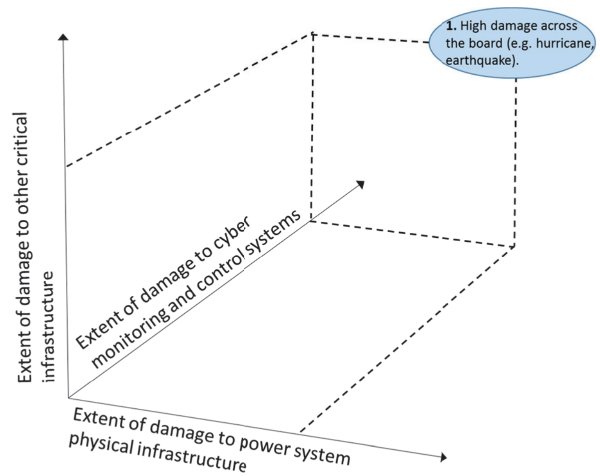


	Hurricanes and Tropical Storms	Floods
	Area Impacted: Typically very large Damage to above ground assets: Poles, towers, substations Damage to customer assets: Extensive Limits to access and mobility: Major blockage Event warning: Days Risk assessment: Can be identified beforehand Rate of propagation: Slow	Area Impacted: Typically very large Damage to above ground assets: Poles, towers, substations Damage to customer assets: Extensive Limits to access and mobility: Major blockage Event warning: Days Risk assessment: Can be identified beforehand Rate of propagation: Slow
Plan	Individual utilities plan for hurricanes and tropical storms based on their experience and historical hurricane tracks, although these tracks may be trending more northerly in the Atlantic, placing the Mid-Atlantic states and New England at greater risk than in the past. Utilities are experts in identifying their specific vulnerable assets. During this phase, utilities should establish and refresh mutual aid agreements, create owned and shared inventory, train crews, conduct exercises, and communicate with customers regarding emergency preparedness.	More than any other disaster, floods are subject to statistical analysis, and utilities plan based on FEMA flood maps. Some adjustment should be made if there has been substantial reduction in forest cover or if there has been substantial development in the impacted watershed. Consideration should also be given to how, in light of climate change, future flood risk may be different from historical risk. To the extent possible, critical assets should not be located in identified flood plains, but there are numerous legacy assets exposed to flood risk. Floods in major river basins tend to be slow rising and slow receding, with lesser hydrostatic force. In contrast, canyon flooding (largely in western mountains) tends to be fast rising with short notice, forceful, and quick to recede. In either case, assets at risk can be identified and measures taken to reduce risk such as elevating them above the flood or building coffer dams. Plans should be made to replace assets in flood plains.
Prepare	Hurricane wind and rain forecasts with high uncertainty are available up to 1 week in advance, which is sufficient time to elevate or downgrade risk. When risk is elevated,	River basin flood forecasts are available 3 to 4 days in advance. Many flash floods occur with effectively no warning; however, if major rain events are

	staffing for the emergency can be refined, and mutual aid agreements can be activated. Flood forecasts are available only 3 to 4 days in advance, and peak flooding frequently follows the event.	forecast for canyon areas, utilities may place crews on standby. When a flood is forecast in a river basin, it is possible to forecast which areas and assets are most likely to be affected. General restoration plans can be made more specific, and mutual aid agreements and emergency operations centers can be activated. Lists of materials, supplies, and equipment can be developed, procured, and staged.
Event	Relatively little can be done on distribution systems during the comparatively short duration of the event. Transmission systems must be adjusted as loads, generators, and transmission lines drop off the grid. Utilities develop an understanding of the extent of damage and customer outages and develop specific plans for remediation, building on the general planning. Government support organizations monitor conditions and establish and exercise lines of communications with utilities and with each other. Limited actions should be taken by utilities only when safety is an issue.	Major river floods are long-duration events that move down a river basin. Restoration can start upstream while the event is still evolving downstream, and some protective measures can be undertaken as water rises. Before restoration begins in an area, the plans can be improved and refined with emphasis on the temporal sequencing. Communications and coordination should be established and exercised.
Endure	The endurance phase is the period from when the storm passes to the start of restoration. Unless there is flooding, restoration can begin immediately. If there is a delay, the time should be spent moving crews into position to the extent that the condition of the roads and safety considerations allow. Effort should also be made to improve the assessment of the state of conditions, to refine plans, and to refine requests for support from and coordination with other organizations, including other utilities and governmental organizations. This involves the high level such as governors' offices, but also the crews on the ground, as per informing police and fire departments about the utility staff who will be working in their area. If specialized equipment is needed, arrangements should be made for acquisition and staging for deployment.	The endurance phase for a flood at one point can be very short in areas where the grade of a river is steeper or long in low-lying flat areas. Work begins in an area as soon as the water recedes, allowing restoration.
Restore	Restoration is the most visible phase of the event. Crews are on the streets working. While this is a difficult and costly phase, it is one that most utilities are familiar with and good at. If there are many trees and other obstacles in the street, they must be cleared to gain access to facilities. Utilities and the linemen know how to clear access, set poles, erect towers, string conductors, and clean and repair substations. The goal of management and support organizations (including governmental) is to ensure that the line crews are used effectively. They must be dispatched to the areas where their work will have the greatest impact, considering what is doable, and placed in a sequence of restoration activities. Management should work the supply chain to be sure that crews have the equipment, parts, and supplies (including fuel) they need to execute the necessary repairs. Crews must be provided with provisions, including food and housing, and amenities, such as electrical and phone service and access to health services for the injuries that are inevitable in this dangerous physical work. Experience has shown that taking care of the families left behind when crews are deployed is an important factor in enabling them to work effectively.	Flood restoration can take a very long time. In the absence of wind, poles and towers are not typically damaged; nonetheless, the ground can be softened and some distribution and transmission failures may occur. Manholes are flooded and must be pumped out. Underground lines and associated gear sometimes survive intact but often are damaged to the point of needing costly and time-consuming replacement. Flooded substations are difficult to restore. Analog equipment can sometimes be cleaned, dried, and returned to service, but digital devices typically need replacement. Underground vaults are problematic as they are difficult to drain and dry, can accumulate deep mud, and are more difficult to move equipment in and out of. All of this, however, is work utilities know and are well equipped to manage. The key, as noted in the discussion of hurricanes, is to provide broad support to the crews.
Recover	Hurricanes damage communities, not just utilities. Utilities must be part of the community restoration, perhaps lasting years. Rebuilding is an opportunity for	Floods damage communities, not just utilities. Utilities must cooperate with other entities in the restoration as, for example, in repairing or replacing civil

	improving.	and safety infrastructure.

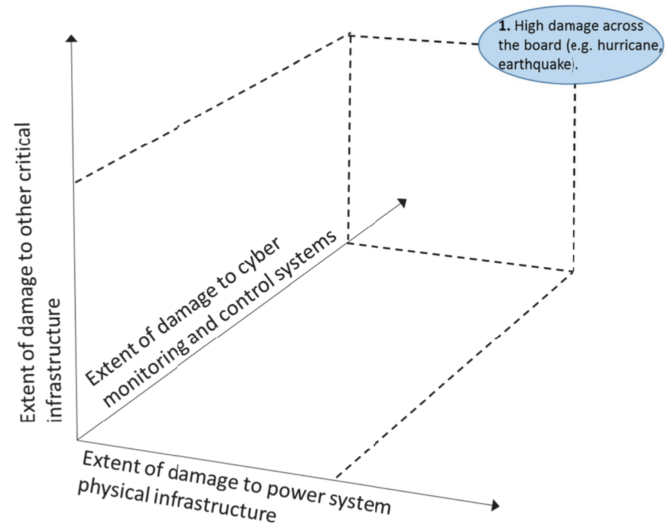
TABLE 6A.1 continued: Variation in Restoration Activities Across the Six Stages of the Life Cycle of an Outage Characterized by Damage to Physical Components, Monitoring and Control Systems, and Supporting Infrastructure, As Indicated in the Upper Right Corner of Figure 3.2



	Earthquakes	Winter Storms
	Area Impacted: Limited to extensive Damage to above ground assets: Poles, towers, substations Damage to customer assets: Limited to extensive Limits to access and mobility: Major blockage Event warning: Seconds to minutes Risk assessment: Difficult Rate of propagation: Fast	Area Impacted: Regional Damage to above ground assets: Lines, poles, towers Damage to customer assets: Limited Limits to access and mobility: Potential blockage Event warning: Days Risk assessment: Straightforward Rate of propagation: Slow
Plan	Earthquake risk is well mapped, and utilities routinely consider earthquake risk in siting and planning processes. Methods for earthquake survivable construction are well researched. Major plants (e.g., North Anna Nuclear Power Station) have survived earthquakes with no damage, though safety considerations have taken them off-line for an extended period. Planning	Utilities operating in regions subject to winter storms often design systems components, such as transmission towers and lines, to be able to withstand greater amounts of precipitation and wind compared to other areas.

	consists of maintaining adequate parts inventories.	
Prepare	There is work on developing a near-term warning capability for earthquakes, but presently most occur with no useful warning.	Winter storm forecasts provide several days' warning that allows for arrangement of mutual aid.
Event	Earthquakes are of short duration. No action during the earthquake is practical.	Some final preparation is possible during the event as outages are mapped. Transmission system operators must rebalance to accommodate failing loads and distribution systems.
Endure	Restoration can begin immediately.	Delay in the start of restoration is possible if the roads are blocked or ice-covered.
Restore	Restoration consists of familiar utility construction but can be severely hampered by damage to supporting infrastructure. Roads and bridges can be blocked or torn away, natural gas pipelines can break, and fuel storage can rupture. Electricity system restoration is executed as part of a broader restoration effort, and coordination among federal, state, and local government, as well as utility decision makers, is essential. Shortages of materials and equipment may result in competition for scarce resources, and availability will vary geographically. Even access to food and water may be a challenge in some remote areas. There is substantial risk that the homes and families of crews may be impacted or imperiled, undermining their ability to commit to utility restoration activities. Mutual aid from unaffected areas is essential.	Restoration following winter storms is standard utility work. Mutual aid is beneficial, and due to the generally smaller geographic extent of such storms, there are fewer issues in supporting the crews or marshalling supplies than are faced during restoration from hurricanes and earthquakes. Cold temperatures do reduce effectiveness of line crews.
Recover	Utility restoration can be completed well in advance of the general commercial and civil infrastructure. Utility capabilities are enablers of recovery.	Winter storms do not typically inflict lasting damage on infrastructure and enablers of economic recovery.

TABLE 6A.1 Continued: Variation in restoration activities across the six stages of the life-cycle of an outage characterized by damage to physical components, monitoring and control systems, and supporting infrastructure, as indicated in the upper right corner of Figure 3.2.



	Tornadoes	Geomagnetic Disturbances
	Area Impacted: Limited to clustered Damage to above ground assets: Poles, towers, substations Damage to customer assets: Serious but contained Limits to access and mobility: Minor blockage Event warning: Seconds to minutes Risk assessment: Regionally known Rate of propagation: Fast	Area Impacted: Very large Damage to above ground assets: Transformers, substations Damage to customer assets: Limited Limits to access and mobility: None Event warning: Minutes to days Risk assessment: Costly Rate of propagation: Very fast
Plan	Utilities in high-risk areas are aware of the peril and have likely dealt with tornadoes in the past. The focus in planning is on inventory of above-ground assets and mutual assistance. Unlike some other causes, transmission and generation assets are at risk of damage from tornadoes.	Risk assessment is nascent and based on highly uncertain estimates of frequency and intensity, but methods to harden the grid are available. Replacement transformers and other vulnerable components can be stockpiled but may be too expensive to be forward deployed.
Prepare	The incidence of weather conditions likely to spawn tornadoes can be provided 1 day to several hours in advance. There is little time to prepare, except to bring crews to a state of readiness and fully man response centers.	Solar weather warning systems can provide some notice, allowing for minimal preparation, but there is generally insufficient time to move crews.
Event	Events are of such short duration that there is no practical action during the event, except that transmission operators may have to adjust to limit impact.	The building up of current on long lines can trigger operational changes to protection systems, particularly shedding load to desaturate transformers.
Endure	Restoration can generally begin immediately after the event passes.	Restoration can begin immediately.

Restore	Customer property may be destroyed alongside utility assets, which means that there may be no immediate need to restore power to the affected area. Nonetheless, the tornado may damage a transmission corridor or section of the distribution grid essential to providing service to unaffected areas. The work is familiar to utilities and, in the case of tornadoes, the impact is sufficiently localized that there is less difficulty in provisioning and supporting crews. There are likely to be intact facilities within a few miles or tens of miles of the worksite.	There is no precedent for a large-scale geomagnetic disturbance event. If the impact is very large, there may be shortages of major components, particularly large transformers due to the long lead time in building and acquiring these.
Recover	Tornadoes do very serious damage to the impacted community so that the recovery period can be extensive after the immediate restoration is completed. Utilities must participate in planning this recovery.	Recovery is not a factor. Extensive damage beyond the grid is unlikely since long lines are needed to build damaging current level.

TABLE 6A.2 Restoration Activities Across the Six Stages of the Life Cycle of an Outage From a Cyber Attack

Area Impacted	Feeder Level to System Level
Damage to above-ground assets	Cyber assets will certainly be compromised, perhaps beyond restoration. Control actions initiated by the pernicious actor may create a wide range of physical damage up to and including generators. In addition, "smart" components may be compromised in a way that they are no longer controllable. Such damage may be irreversible or compromise trust in the device so that it may not be used safely. This damage to the electronic aspects of a device is functionally equivalent to physical damage.
Damage to customer assets	Limited except, possibly, to smart meters. Meters are owned by the utility but are associated with a specific customer. If the meter includes a local wireless connection for home automation, there are potential attack strategies which may do damage to customer systems, but no such Internet-of-Things attack has been successful.
Limits to access and mobility	None.
Event warning	Potentially months.
Risk assessment	Cyber N-1 and N-2 analyses should become standard practice.
Rate of propagation	Slow from breach to first action, very fast from first action.

Plan	Planning for cyber attack is a routine part of utility operations. It tends to focus, however, on prevention rather than restoration. The emphasis in restoration is on reestablishing the operational capability of sensor, computational, and communications assets; reestablishing state; and gaining confidence in the integrity of the systems and the information they manage. Planning for cyber-restoration should be planned and practiced.
Prepare	Systems must be improved to react more effectively to new threat information. Updated threat information is provided daily, but the systems to move this information into quick action at a utility cannot make immediate use of the information. Much of it must work its way through cybersecurity software and service providers.
Event	A cyber event may last several months. During the period from breach to action, the utility may be able to sever access by malicious actors, preventing damage.
Endure	Restoration can begin immediately on detection.
Restore	Methods for manual operation and restoration systems should be developed in advance. Fast reaction cyber teams should be on call.
Recover	Not applicable.

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7

Conclusions

No single entity is responsible for, or has the authority to implement, a comprehensive approach to assure the resilience of the nation's electricity system. Chapter 2 described the complex structure, asset ownership, and regulatory system of the current electricity system and how the changing nature of the electricity system provides both opportunities and challenges for system resilience. Because most parties are preoccupied dealing with short-term issues, they neither have the time to think systematically about what could happen in the event of a large-area, long-duration blackout, nor do they adequately consider the consequences of large-area, long-duration blackouts in their operational and other planning or in setting research and development priorities. Hence the United States needs a process to help all parties better envision the consequences of low-probability but high impact events precipitated by the causes outlined in Chapter 3 and the system wide effects discussed in Chapter 5. The specific recommendations addressed to particular parties that are provided in the report (especially in Chapters 4 through 6) will incrementally advance the cause of resilience. However, these alone will be insufficient unless the nation is able to adopt a more integrated perspective at the same time. Thus, this chapter provides a series of overarching recommendations that build upon the detailed recommendations contained within this report.

OVERARCHING INSIGHTS AND RECOMMENDATIONS

The first strategy that should be pursued to enhance the resilience of the system is to make sure that things already in place will work when they are needed. One of the best ways to do that is to conduct drills with other critical infrastructure operators through large-scale, multisector exercises. Such exercises can help illuminate areas where improvements in processes and technologies can substantively enhance the resilience of the nation's critical infrastructure.

> **Overarching Recommendation 1:** Operators of the electricity system, including regional transmission organizations, investor-owned utilities, cooperatives, and municipally owned utilities, should work individually and collectively, in cooperation with the Electricity Subsector Coordinating Council, regional and state authorities, the Federal Energy Regulatory Commission, and the North American Electric Reliability Corporation, to conduct more regional emergency preparedness exercises that simulate accidental failures, physical and cyber attacks, and other impairments that result in large-scale loss of power and/or other critical infrastructure sectors—especially communication, water, and natural gas. Counterparts from other critical infrastructure sections should be involved, as well as state, local, and regional emergency management offices.

The challenges that remain to achieving grid resilience are so great that they cannot be achieved by research- or operations-related activities alone. While new technologies and strategies can improve the resilience of the power system, many existing technologies that show promise have yet to be fully adopted or implemented. In addition, more coordination between research and implementation activities is needed, building on the specific recommendations made throughout this report. Immediate action is needed both to implement available technological and operational changes and to continue to support the development of new technologies and strategies.

> **Overarching Recommendation 2:** Operators of the electric system, including regional transmission organizations, investor-owned utilities, cooperatives, and municipals, should work individually and collectively to more rapidly implement resilience-enhancing technical capabilities and operational strategies that are available today and to speed the adoption of new capabilities and strategies as they become available.

The Department of Energy (DOE) is the federal entity with a mission to focus on the *longer-term* issues of developing and promulgating technologies and strategies to increase the resilience and modernization of the electric grid.[1] At present, two offices within DOE have responsibility for issues directly and indirectly related to grid modernization and resilience.

> **Overarching Recommendation 3:** However the Department of Energy chooses to organize its programs going forward, Congress and the Department of Energy leadership should sustain and expand the substantive areas of research, development, and demonstration that are now being undertaken by the Department of Energy's Office of Electricity Delivery and Energy Reliability and Office of Energy Efficiency and Renewable Energy, with respect to grid modernization and systems integration, with the explicit intention of improving the resilience of the U.S. power grid.

[1] The Department of Homeland Security, the Federal Energy Regulatory Commission, and other organizations also provide critical support and have primacy in certain areas.

Field demonstrations of physical and cyber improvements that could subsequently lead to widespread deployment are critically important. The Department of Energy should collaborate with parties in the private sector and in states and localities to jointly plan for and support such demonstrations. Department of Energy efforts should include engagement with key stakeholders in emergency response to build and disseminate best practices across the industry.

The U.S. grid remains vulnerable to natural disasters, physical and cyber attacks, and other accidental failures.

Overarching Recommendation 4: Through public and private means, the United States should substantially increase the resources committed to the physical components needed to ensure that critical electric infrastructure is robust and that society is able to cope when the grid fails. Some of this investment should focus on making the existing infrastructure more resilient and easier to repair, as follows:

- The Department of Energy should launch a program to manufacture and deploy flexible and transportable three-phase recovery transformer sets that can be pre-positioned around the country.[2] These recovery transformers should be easy to install and use temporarily until conventional transformer replacements are available. This effort should produce sufficient numbers (on the order of tens compared to the three produced by the Department of Homeland Security's RecX program) to provide some practical protection in the case of an event that results in the loss of a number of high voltage transformers. This effort should complement ongoing initiatives related to spare transformers and not replace them.
- State and federal regulatory commissions and regional transmission organizations should then evaluate whether grids under their supervision need additional pre-positioned replacements for critical assets that can help accelerate orderly restoration of grid service after failure.
- Public and private parties should expand efforts to improve their ability to maintain and restore critical services—such as power for hospitals, first responders, water supply and sewage systems, and communication systems.[3]
- The Department of Energy, the Department of Homeland Security, the Electricity Subsector Coordinating Council, and other federal organizations, such as the U.S. Army Corps of Engineers, should oversee the development of more reliable inventories of backup power needs and capabilities (e.g., the U.S. Army Corps of Engineers' mobile generator fleet), including fuel supplies. They should also "stress test" existing supply contracts for equipment

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[2] As noted in Chapter 6 and in the next section of this chapter, the DOE Office of Electricity Delivery and Energy Reliability is supporting the development of a new generation of high voltage transformers that will use power electronics to adjust their electrical properties and hence can be deployed in a wider range of settings. The committee's recommendation to manufacture recovery transformers is not intended to replace that longer-term effort. However, the new DOE advanced transformer designs will not be available for some time, and in the meantime the system remains physically vulnerable. While in Chapter 6 the committee notes several government and industry-led transformer-sharing and recovery programs, the committee recognizes that high voltage transformers represent one of the grids most vulnerable components deserving of further efforts.

[3] In addition to treatment, sewage systems often need to pump uphill. A loss of power can quickly lead to sewage backups. Notably, a high percentage of the hospital backup generators in New York City failed during Superstorm Sandy.

and fuel supply that are widely used in place of actual physical assets in order to be certain these arrangements will function in times of major extended outages. Although the federal government cannot provide backup power equipment to everyone affected by a large-scale outage, these resources could make significant contributions at select critical loads.

In addition to providing redundancy of critical assets, transmission and distribution system resilience demands the ability to provide rapid response to events that impair the ability of the power system to perform its function. These events include deliberate attacks on and accidental failures of the infrastructure itself, as well as other causes of grid failure, which are discussed in Chapter 3.

Overarching Recommendation 5: The Department of Energy, together with the Department of Homeland Security, academic research teams, the national laboratories, and companies in the private sector, should carry out a program of research, development, and demonstration activities to improve the security and resilience of cyber monitoring and controls systems, including the following:

- Continuous collection of diverse (cyber and physical) sensor data;
- Fusion of sensor data with other intelligence information to diagnose the cause of the impairment (cyber or physical);
- Visualization techniques needed to allow operators and engineers to maintain situational awareness;
- Analytics (including machine learning, data mining, game theory, and other artificial intelligence-based techniques) to generate real-time recommendations for actions that should be taken in response to the diagnosed attacks, failures, or other impairments;
- Restoration of control system and power delivery functionality and cyber and physical operational data in response to the impairment; and
- Creation of post-event tools for detection, analysis, and restoration to complement event prevention tools.

Because no single entity is in charge of planning the evolution of the grid, there is a risk that society may not adequately anticipate and address many elements of grid reliability and resilience and that the risks of this system-wide failure in preparedness will grow as the structure of the power industry becomes more atomized and complex. There are many opportunities for federal leadership in anticipating potential system vulnerabilities at a national level, but national solutions are then refined in light of local and regional circumstances. Doing this requires a multi-step process, the first of which is to anticipate the myriad ways in which the system might be disrupted and the many social, economic, and other consequences of such disruptions. The second is to envision the range of technological and organizational innovations that are affecting the industry (e.g., distributed generation and storage) and how such developments may affect the system's reliability and resilience. The third is to figure out what upgrades should be made and how to cover their costs. For simplicity, the committee will refer to this as a "visioning process." While the Department of Homeland Security (DHS) has overarching responsibility for infrastructure protection, DOE, as the sector-specific agency for energy infrastructure, has a legal mandate and the deep technical expertise to work on such issues.

> **Overarching Recommendation 6:** The Department of Energy and the Department of Homeland Security should jointly establish and support a "visioning" process with the objective of systematically imagining and assessing plausible large-area, long-duration grid disruptions that could have major economic, social, and other adverse consequences, focusing on those that could have impacts related to U.S. dependence on vital public infrastructures and services provided by the grid.

Because it is inherently difficult to imagine systematically things that have not happened (Fischhoff et al., 1978; Kahneman, 2011), exercises in envisioning benefit from having multiple groups perform such work independently. For example, such a visioning process might be accomplished through the creation of two small national power system resilience assessment groups (possibly at DOE national laboratories and/or other federally funded research and development centers or research universities). However such visioning is accomplished, engagement from staff representing relevant state and federal agencies is essential in helping to frame and inform the work. These efforts should build on the detailed recommendations in this report to identify technical and organizational strategies that increase electricity system resilience in numerous threat scenarios—that is, by preventing and mitigating the extent of large-scale grid failures, sustaining critical services in the instance of failure, and recovering rapidly from major outages—and to assess the costs and financing mechanisms to implement the proposed strategies. Attention is needed not just to the average economy-wide costs and benefits, but also to the distribution of these across different levels of income and vulnerability. It is important that these teams work to identify common elements in terms of hazards and solutions so as to move past a hazard-by-hazard approach to a more systems-oriented strategy. Producing useful insights from this process will require mechanisms to help these groups identify areas of overlap while also characterizing the areas of disagreement. A consensus view could be much less helpful than a mapping of uncertainties that can help other actors—for example, state regulatory commissions and first responders—understand the areas of deeper unknowns.

National labs, other federally funded research and development centers, and research universities do not operate or regulate the power system. At the national level, the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) both have relevant responsibilities and authorities.

Overarching Recommendation 7A: The Federal Energy Regulatory Commission and the North American Electric Reliability Corporation should establish small system resilience groups, informed by the work of the Department of Energy/Department of Homeland Security "visioning" process, to assess and, as needed, to mandate strategies designed to increase the resilience of the U.S. bulk electricity system. By focusing on the crosscutting impacts of hazards on interdependent critical infrastructures, one objective of these groups would be to complement and enhance existing efforts across relevant organizations.

As the discussions throughout this report make clear, many different organizations are involved in planning, operating, and regulating the grid at the local and regional levels. By design and of necessity in our constitutional democracy, making decisions about resilience is an inherently political process. Ultimately the choice of how much resilience our society should and will buy must be a collective social judgment. It is unrealistic to expect firms to make investments voluntarily whose benefits may not accrue to shareholders within the relevant commercial lifetime for evaluating projects. Moreover, much of the benefit from avoiding such events, should they occur, will not accrue to the individual firms that invest in these capabilities. Rather, the benefits are diffused more broadly across multiple industries and society as a whole, and many of the decisions must occur on a state-by-state basis.

Overarching Recommendation 7B: The National Association of Regulatory Utility Commissioners should work with the National Association of State Energy Officials to create a committee to provide guidance to state regulators on how best to respond to identified local and regional power system-related vulnerabilities. The work of this committee should be informed by the national "visioning" process, as well as by the work of other research organizations. The mission of this committee should be to develop guidance for, and provide technical and institutional support to, state commissions to help them to more systematically address broad issues of power system resilience, including decisions as to what upgrades are desirable and how to pay for them. Guidance developed through this process should be shared with appropriate representatives from the American Public Power Association and the National Rural Electric Cooperative Association.

Overarching Recommendation 7C: Each state public utility commission and state energy office, working with the National Association of Regulatory Utility Commissioners, the National Association of State Energy Officials, and state and regional grid operators and emergency preparedness organizations, should establish a standing capability to identify vulnerabilities, identify strategies to reduce local vulnerabilities, develop strategies to cover costs of needed upgrades, and help the public to become better prepared for extended outages. In addition, they should encourage local and regional governments to conduct assessments of their potential vulnerabilities in the event of large-area, long-duration blackouts and to develop strategies to improve their preparedness.

Throughout this report, the committee has laid out a wide range of actions that different parties might undertake to improve the resilience of the United States power system. If the approaches the committee has outlined can be implemented, they will represent a most valuable contribution. At the same time, the committee is aware that the benefits of such a contribution—avoiding large-scale harms that are rarely observed—are easily eclipsed by the more tangible daily challenges, pressures on budgets, public attention, and other scarce resources. Too often in the past, the United States has made progress on issues of resilience by "muddling through" (Lindblom, 1959). Even if the broad systematic approach outlined in this report cannot be fully implemented immediately, it is important that relevant organizations develop analogous strategies so that when a policy window opens in the aftermath of a major disruption, well-conceived solutions are readily available for implementation (Kingdon, 1984).

SUMMARY OF DETAILED RECOMMENDATONS

Underlying the Overarching Recommendations are the numerous, more targeted recommendations presented throughout this report. Here, the committee summarizes and sorts these recommendations by the institutions to which they are directed**.**

Recommendations Directed to the Department of Energy

DOE plays a critical role in enhancing the resilience of the grid through research, development, and demonstration programs as well as convening and engagement activities. Much progress has been made, and DOE should sustain and expand many of these efforts.

Recommendation 1 to DOE: Improve understanding of customer and societal value associated with increased resilience and review and operationalize metrics for resilience by doing the following:

- Developing comprehensive studies to assess the value to customers of improved reliability and resilience (e.g., periodic rotating service) during large-area, long-duration blackouts as a function of key circumstances (e.g., duration, climatic conditions, societal function) and for different customer classes (e.g., residential, commercial, industrial). (Recommendation 2.1)

- Conducting a coordinated assessment of the numerous resilience metrics being proposed for transmission and distribution systems and seeking to operationalize these metrics within the utility setting. In doing the review, engagement with key stakeholders is essential. (Recommendation 2.2)

Recommendation 2 to DOE: Support research, development, and demonstration activities, as well as convening activities, to improve the resilience of power system operations and recovery by reducing barriers to adoption of innovative technologies and operational strategies. These include the following:

- Coordinating with federal and state utility regulators to support a modest grant program that encourages utility investment in innovative solutions that demonstrate resilience enhancement. These projects should be selected to reduce barrier(s) to entry by improving regulator and utility confidence. (Recommendation 4.1)
- Initiating and supporting ongoing research programs focused on the operation of degraded or damaged electricity systems, including supporting infrastructure and cyber monitoring and control systems, where key subsystems are designed and operated to sustain critical functionality. (Recommendation 4.6)
- Convening transmission and distribution system owners and operators to engage the Federal Aviation Administration proactively to ensure that the rules regulating operation of unmanned aerial vehicles support the rapid, safe, and effective applications of unmanned aerial vehicle technology in electricity restoration activities, including pre-disaster tests and drills. (Recommendation 6.5)
- Continuing to support research and development of advanced large power transformers, concentrating on moving beyond design studies to conduct several demonstration projects. (Recommendation 6.7)

Recommendation 3 to DOE: Advance the safe and effective development of distributed energy resources (DERs) and microgrids by doing the following:

- Initiating research, development, and demonstration activities to explore the extent to which DERs could be used to help prevent large-area outages. (Recommendation 4.2)
- Supporting demonstration and a training facility (or facilities) for future microgrids that will allow utility engineers and non-utility microgrid operators to gain hands-on experience with islanding, operating, and restoring feeders (including microgrids). (Recommendation 5.6)
- Engaging the manufacturers of plug-in hybrid electric and fuel cell vehicles to study how such vehicles might be used as distributed sources of emergency power. (Recommendation 5.12)
- Evaluating the technical and contractual requirements for using DERs as part of restoration activities, even when these assets are not owned by the utility, to improve restoration and overall resilience. (Recommendation 6.3)

Recommendation 4 to DOE: Work to improve the ability to use computers, software, and simulation to research, plan, and operate the power system to increase resilience by doing the following:

- Collaborating with other research organizations, including the National Science Foundation, to expand support for interdisciplinary research to simulate events and model grid impacts and mitigation strategies. (Recommendation 4.3)
- Supporting and expanding research and development activities to create synthetic power grid physical and cyber infrastructure models. (Recommendation 4.4)
- Collaborating with other research organizations, including the National Science Foundation, to fund research on enhanced power system wide-area monitoring and control and the application of artificial

intelligence to the power system. Such work should include how the human–computer interface and visualization could improve reliability and resilience. (Recommendation 4.8)

- Leading efforts to develop standardized data definitions, communication protocols, and industrial control system designs for the sharing of both physical and cyber system health information. (Recommendation 4.9)
- Developing a high-performance utility network simulator for use in cyber configuration and testing. (Recommendation 6.12)

Recommendation 5 to DOE: Work to improve the cybersecurity and cyber resilience of the grid by doing the following:

- Embarking on a research, development, and demonstration program that results in a prototypical cyber-physical-social control system architecture for resilient electric power systems. (Recommendation 4.10)
- Developing the ability to apply physics-based modeling to anomaly detection, which provides real-time or better physics models that derive optimal power flow and monitor performance for more accurate state estimation. (Recommendation 6.8)

Recommendations Directed to the Electric Power Sector and the Department of Energy

There are thousands of operating utilities and electricity system asset owners across the United States, with diverse characteristics and institutional structures, including private investor-owned utilities, cooperatives, and publicly owned entities. These organizations, and the people they employ, are the foundation of a reliable and resilient grid, and many promising demonstrations and initiatives are ongoing across the sector. The industry and DOE have benefitted from a strong relationship, and the committee encourages further collaboration on projects to increase the resilience of the grid.

Recommendation 6 to the electric power sector and DOE: The owners and operators of electricity infrastructure should work closely with DOE as follows:

- Develop use cases and perform research on strategies for intelligent load shedding based on advanced metering infrastructure and customer technologies like smart circuit breakers. (Recommendation 4.5)
- Explore the feasibility of establishing contractual and billing agreements with private owners of DERs and developing the ability to operate intact islanded feeders as islanded microgrids powered by utility- and customer-owned generating resources to supply limited power to critical loads during large grid outages of long duration. (Recommendation 5.10)
- Work together to analyze past large-area, long-duration outages to identify common elements and processes for system restoration and define best practices that can be shared broadly throughout the electricity industry. (Recommendation 6.2)

- Identify those components and corresponding events for which pre-event de-energizing of selected assets is the lowest risk strategy and develop regulatory, communication (especially with customers), and other plans that allow such protective action to be implemented. (Recommendation 6.4)
- Expand joint cyber-physical recovery exercises that emphasize, among other things, the maintenance of cyber protection during the chaotic period of physical restoration. (Recommendation 6.14)

Clearly, some of these recommendations will require greater degrees of DOE engagement than others.

Recommendations Directed to the Department of Homeland Security and the Department of Energy

Because emergency response and management is central to power system resilience, the committee makes several recommendations that call for collaboration between DHS and DOE.

Recommendation 7 to DHS and DOE: DHS and DOE should work collaboratively to improve preparation for, emergency response to, and recovery from large-area, long-duration blackouts by doing the following:

- Working with state and local authorities and electricity system operators to undertake an “all hazards” assessment of the natural hazards faced by power systems on a periodic basis (e.g., every 5 years). Local utilities should customize those assessments to their local conditions. (Recommendation 3.2)
- Developing and overseeing a process to help regional and local planners envision potential system-wide effects of long-duration loss of grid power. (Recommendation 5.3)
- Evaluating and recommending the best approach for getting critical facility managers to pre-register information about emergency power needs and available resources. (Recommendation 5.5)
- Renewing efforts to work with utilities and national, state, and local law enforcement to develop formal arrangements (such as designating selected utility personnel as “first responders”) that credential selected utility personnel to allow prompt utility access to damaged facilities across jurisdictional boundaries. (Recommendation 6.1)
- Building off of existing efforts to manufacture and stockpile flexible, high-voltage replacement transformers, in collaboration with electricity system operators and asset owners and with support from the U.S. Congress. (Recommendation 6.6)
- Developing a model for large-scale cyber restoration of electricity infrastructure. (Recommendation 6.9)

Recommendation 8 to DHS and DOE: With growing awareness of the electricity system as a potential target for malicious attacks using both physical and cyber means, DHS and DOE should work closely with operating utilities and other relevant stakeholders to improve physical and cyber security and resilience by doing the following:

- Working with operating utilities to sustain and enhance their monitoring and information-sharing activities to protect the grid from physical and cyber attacks. (Recommendation 3.1)

- Continuing to work with the Electricity Subsector Coordinating Council and operating utilities to enhance the sharing of cyber restoration resources (i.e., cyber mutual assistance agreements), including personnel, focusing on peer-to-peer collaboration as well as engagement with government, industry organizations, and commercial cybersecurity companies. (Recommendation 6.10)
- Working with the electricity sector and representatives of other key affected industries and sectors to continue to strengthen the bidirectional communication between federal cybersecurity programs and commercial software companies. (Recommendation 6.11)
- Redoubling efforts to reduce the vulnerability of the power system to terrorist attacks in close collaboration with FERC, NERC, and other representatives of the electric industry. (Recommendation 6.13)

Recommendations Directed to State Offices and Regulatory Bodies

State offices and elected officials have an important role in increasing the resilience of the nation's electricity system, including through planning and regulatory decisions as well as emergency preparedness and response. Several of the committee's recommendations encourage various actors in state government to take action.

Recommendation 9 to state offices and regulators: Work with local utilities and relevant stakeholders to increase investment in resilience-enhancing strategies, including the following:

- State emergency planning authorities should oversee a more regular and systematic testing of backup power generation equipment at critical facilities, such as hospitals and fire stations, and ensure that public safety officials include information related to electrical safety and responses to long-duration power outages in their public briefings (Recommendation 5.1)
- Utility regulators should work closely with operating utilities to assess their current interconnection standards as applicable to DERs, consider the costs of requiring new installations to use enhanced inverters, and determine the appropriate policy for promoting islanding and other related capabilities. (Recommendation 5.7)
- State legislatures and utility regulatory bodies should explore economic, ratemaking, and other regulatory options for facilitating the development of private microgrids that provide resilience benefits. (Recommendation 5.9)
- Utility regulators and non-governmental entities should undertake studies to develop guidance on how best to compensate the owners of distributed generation resources who are prepared to commit a portion of their distributed generation capacity to serve islanded feeders in the event of large outages of long duration. Additionally, the National Association of Regulatory Utility Commissioners (NARUC) should establish a working group to advise members on the issues they will likely have to address. (Recommendation 5.11)

Recommendations Directed to the National Association of Regulatory Utility Commissioners and Federal Organizations

NARUC is uniquely capable of convening and disseminating information to regulators from diverse states while providing a single point of contact with federal agencies.

Recommendation 10 to NARUC and federal organizations: The committee recommends that NARUC work with DHS and DOE as follows:

- Develop model guidance on how state regulators, utilities, and broader communities (where appropriate) might consider the equity and social implications of choices in the level and allocation of investments. (Recommendation 5.2)
- Develop guidance to state regulators and utilities on (1) selective restoration options as they become available, (2) the factors that should be considered in making choices of which loads to serve, and (3) model recommendations that states and utilities can build upon and adapt to local circumstances. (Recommendation 5.4)
- Undertake studies of the technical, economic, and regulatory changes necessary to allow development and operation of privately owned microgrids that serve multiple parties and/or cross public rights-of-way. (Recommendation 5.8)

Recommendation Directed to the Federal Energy Regulatory Commission and the North American Energy Standards Board

The growing interdependence of natural gas and electricity infrastructures requires systematic study and targeted efforts to improve coordination and planning across the two industries.

Recommendation 11 to FERC and the North American Energy Standards Board: FERC, which has regulatory authority over both natural gas and electricity systems, should address the growing risk of interdependent infrastructure by doing the following:

- Working with the North American Energy Standards Board and industry stakeholders to improve awareness, communications, coordination, and planning between the natural gas and electric industries. (Recommendation 4.7)

Recommendation Directed to the North American Electric Reliability Corporation

Following large-scale outages, detailed investigations are essential to support the learning phase of resilience. NERC, with authority delegated from FERC, has conducted several such investigations.

Recommendation 12 to NERC: Review and improve incident investigation processes to better learn from outages that happen and broadly disseminate findings and best practices by doing the following:

- Engaging relevant regional and state-level organizations to improve the investigation process of large-scale losses of power, drawing lessons from the National Transportation Safety Board and others, with the objective of disseminating lessons across geographical and jurisdictional boundaries. (Recommendation 6.15)

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A

Statement of Task

An ad hoc National Research Council (NRC) committee will address technical, policy and institutional factors that might affect how modern technology can be implemented in the evolution of electric transmission and distribution (T&D) in the United States, and recommend strategies and priorities for how the nation can move to a more reliable and resilient T&D system. The committee will consider how existing and emerging technological options, including greater reliance on distributed power generation, could impact the reliability, robustness, and the ability to recover from disruptions to the electrical T&D system or systems. The study will identify barriers to implementing technology pathways for improving T&D reliability, key priorities and opportunities including, where necessary, those for research, development and demonstration (RD&D), the federal role, and strategies and actions that could lead to a more reliable and resilient T&D system. As part of this study the committee may do the following:

1. Review recent studies and analysis of the current and projected status of the nation's electric T&D system including any that identify significant technological concerns over vulnerability, reliability and resilience;
2. Assess factors affecting future requirements and trends for the nation's T&D infrastructure including such issues as the need for new capacity, replacement needs, siting issues, vulnerability to external threats and the need for security, whether physical or cyber, the alignment of costs and benefits, the effects of interconnectedness among regional networks, and others identified by the committee;
3. Evaluate the role existing and emerging technological options, especially of renewable and distributed generation technologies, can play in creating or addressing concerns identified by the committee and that can lead to enhanced reliability and resilience;
4. Consider how regional differences both in terms of the physical setting and the utility structure may impact solutions to improving resilience;
5. Review federal, state, industry, and academic R&D programs, as well as any demonstration and/or deployment efforts, focused on technologies for the T&D system that are aimed at improving its capacity, reliability, resilience, flexibility and any other attributes aimed at enhancing the robustness of the nation's electric power T&D system;

6. Identify non-technological barriers (including those related to regulatory, ownership, and financial issues) to implementation of new and/or expanded technology to improve the stability, reliability, and resilience of electric T&D;
7. Suggest strategies, key opportunities and priorities, and actions for implementation of the identified technology pathways for the T&D system, which could include RD&D, policies, incentives, standards, and others the committee finds are necessary; and
8. Address the federal role, especially of DOE, in addressing the technical, policy, and institutional issues for a transformation of the T&D system to one with increased robustness and resilience.

B

Committee Biographies

M. GRANGER MORGAN, *Chair,* is Hamerschlag University Professor of Engineering; professor, Department of Engineering and Public Policy (where he served for 38 years as the founding department head) and Electrical and Computer Engineering at Carnegie Mellon University. He also holds an appointment in the H. John Heinz III College of Public Policy and Management. He is a fellow of the Institute of Electrical and Electronics Engineers (IEEE), the American Association for the Advancement of Science and the Society for Risk Analysis. His research addresses problems in science, technology, and public policy with a particular focus on energy, environmental systems, climate change, and risk analysis. Much of his work has involved the development and demonstration of methods to characterize and treat uncertainty in quantitative policy analysis. At Carnegie Mellon, he co-directs (with Inês Azevedo) the Center for Climate and Energy Decision Making and (with Jay Apt) the Electricity Industry Center. He is a member of the National Academy of Sciences, serves on several committees for the National Academies of Sciences, Engineering, and Medicine, and is a member of several domestic and international advisory committees for organizations addressing issues involving electric power, other energy issues, and the management of risks to health safety and the environment. He holds a B.A. from Harvard College (1963) where he concentrated in physics, an M.S. in astronomy and space science from Cornell University (1965) and a Ph.D. from the Department of Applied Physics and Information Sciences at the University of California, San Diego (1969).

DIONYSIOS ALIPRANTIS is an associate professor of electrical and computer engineering at Purdue University. Dionysios obtained his Ph.D. from Purdue University in 2003 and his Diploma in electrical and computer engineering from the National Technical University of Athens, Greece, in 1999. Prior to joining Purdue, he was an assistant professor of electrical and computer engineering at Iowa State University. His research interests include electromagnetic energy conversion and electric machinery, power electronics, and power systems analysis. More recently, his work has focused on technologies that enable the integration of renewable energy sources in the electric power system and the electrification of transportation. He is currently serving as an associate editor for the *IEEE Transactions on Energy Conversion*.

ANJAN BOSE is Regents Professor and Distinguished Professor of Electric Power Engineering at Washington State University. He has 50 years of experience in industry, academia, and government, as an engineer, educator, and administrator. He is also the site director of the National Science Foundation (NSF)-sponsored Power System Engineering Research Center. He served as the dean of the College of Engineering and Architecture (1998-2005) and as the director of the School of Electrical Engineering and Computer Science (1993-1998). Prior to Washington State University, he taught at Arizona State University (1981-1993) and worked in the Energy Management Systems Division of Control Data Corporation (now Siemens), where he developed power grid control software. He is a member of the U.S. National Academy of Engineering and the Indian National Academy of Engineering. A fellow of the IEEE, he was the recipient of the Outstanding Power Engineering Educator Award (1994), the Third

Millennium Medal (2000), and the IEEE's Herman Halperin Electric Transmission and Distribution Award (2006). He has been recognized as a distinguished alumnus of the Indian Institute of Technology, Kharagpur (2005) and the College of Engineering at Iowa State University (1993). During 2011-2013, Prof. Bose served as senior advisor to the Department of Energy (DOE) coordinating priorities for the next-generation grid.

TERRY BOSTON is the former chief executive officer of PJM Interconnection, the largest power grid in North America and the largest electricity market in the world. Mr. Boston is past president of the Association of Edison Illuminating Companies and past president of GO 15, the association of the world's largest power grid operators. He also served as a U.S. vice president of the International Council of Large Electric Systems and is a past chair of the North American Transmission Forum. He also was one of the eight industry experts selected to direct the North American Electric Reliability Corporation investigation of the August 2003 Northeast blackout. In 2011, Mr. Boston was honored with the Leadership in Power award from the IEEE Power and Energy Society. He also was chosen by *Intelligent Utilities* as one of the Top 11 Industry Movers and Shakers, and led PJM to win Platts Global Energy Awards in Industry Leadership in 2010, Excellence in Electricity in 2012, and Lifetime Achievement Award in 2015. Mr. Boston is a member of the National Academy of Engineering. He received a B.S. in engineering from the Tennessee Technological University and an M.S. in engineering administration from the University of Tennessee.

ALLISON CLEMENTS is the president of goodgrid, LLC, based in Salt Lake City, Utah. She is the former director of the Sustainable Federal Energy Regulatory Commission (FERC) Project at Natural Resources Defense Council (NRDC). The Project represents a coalition of clean energy-focused advocacy organizations at FERC and at the independent system operator/regional transmission organization level in pursuit of a clean, reliable, and affordable electric system. Prior to joining the FERC Project, Clements spent 3 years as NRDC's corporate counsel while maintaining a policy practice in renewable energy deployment. Before joining NRDC, she worked as a project finance attorney at Chadbourne & Parke, LLP, as well as an energy regulatory attorney at Troutman Sanders, LLP. Clements is a 2015 Presidio Institute Cross-Sector Leadership Fellow, co-directed the Yale Law School and School of Forestry Environmental Protection Clinic (2013-2014), acted as co-chair of the Bipartisan Policy Center's Electric Grid Initiative (2011-2013) and served as a director and treasurer of the Healthy Building Network (2008-2014). She holds a B.S. in environmental policy from the University of Michigan and a J.D., with honors, from the George Washington University Law School.

JEFFERY DAGLE has been an electrical engineer at the Pacific Northwest National Laboratory since 1989. He currently manages several projects in the areas of transmission reliability and security, including the North American SynchroPhasor Initiative and cybersecurity reviews for the DOE Smart Grid Investment Grants and Smart Grid Demonstration Projects. He is a senior member of the IEEE and the National Society of Professional Engineers. He received the 2001 Tri-City Engineer of the Year award by the Washington Society of Professional Engineers, led the data requests and management task for the U.S.-Canada Power System Outage Task Force investigation of the August 14, 2003, blackout, supported the DOE Infrastructure Security and Energy Restoration Division with on-site assessments in New Orleans following Hurricane Katrina in fall 2005, and is the recipient of multiple patents including a Federal Laboratory Consortium Award in 2007 and an R&D 100 Award in 2008 for the Grid Friendly™ Appliance Controller technology. Mr. Dagle was a member of a National Infrastructure Advisory Council study group formed in 2010 to establish critical infrastructure resilience goals. He received B.S. and M.S. degrees in electrical engineering from Washington State University in 1989 and 1994, respectively.

PAUL DE MARTINI is the managing director at Newport Consulting. He has more than 35 years of experience in the power industry. He is a thought leader and expert in the global electricity industry, providing guidance to utilities, policy makers, and new entrants. Previously, Mr. De Martini held several executive positions focused on strategy, policy, and technology development, including chief technology and strategy officer for Cisco's Energy Networks Business and vice president of Advanced Technology at

Southern California Edison. Mr. De Martini has an M.B.A. from the University of Southern California and a B.S. in applied economics from the University of San Francisco. He is a visiting scholar at the California Institute of Technology.

JEANNE FOX is an adjunct professor at Columbia University's School of International and Public Affairs and at Rutgers University School of Arts and Sciences. She served as a commissioner of the New Jersey Board of Public Utilities from January 2002 until September 2014 and was its president and a member of the Governor's cabinet from January 2002 to January 2010. The New Jersey Board of Public Utilities has regulatory jurisdiction over telephone, electric, gas, water, wastewater, and cable television companies and works to ensure that consumers have proper service at reasonable rates. Commissioner Fox is currently a member of the National Petroleum Council and its Emergency Preparedness Committee, Carnegie Mellon University's Advisory Board for its Center for Climate Energy Decision Making, Rutgers University's Energy Institute Advisory Board, and GRID Alternatives Tri-State Board of Directors. Ms. Fox was active with the National Association of Regulatory Utility Commissioners as a member of the Board of Directors (2003-2014), Subcommittee on Education and Research, Subcommittee on Utility Market Access, Committee on Energy Resources and Environment (chair, vice chair), and Committee on Critical Infrastructure (vice chair). She is currently a member of the National Association of Regulatory Utility Commissioners' Emeritus. Fox served as Region 2 administrator of the United States Environmental Protection Agency (1994-2001) and as commissioner and deputy commissioner of the New Jersey Department of Environmental Protection and Energy (1991-1994). Starting at the Board of Public Utilities in 1981 as a regulatory officer, she was promoted to Solid Waste Division deputy director (1985), Water Division director (1987) and chief of staff (1990-1991). In 2001, Ms. Fox was a visiting distinguished lecturer at Rutgers University's Bloustein School of Planning and Public Policy and at Princeton University's Woodrow Wilson School of Public and International Affairs (2001-2002, 2016-2017). Ms. Fox is currently president of the associate alumnae of Douglass College and a Rutgers University trustee emerita. She is a member of the Rutgers Hall of Distinguished Alumni Award (1997) and the Douglass Society (1993) and a recipient of the Rutgers Alumni Federation Alumni Meritorious Service Award (1991) and the Loyal Sons and Daughters of Rutgers Award (2012). Fox graduated cum laude from Douglass College, Rutgers University, and received a J.D. from the Rutgers University School of Law, Camden.

ELSA GARMIRE is the former Sydney E. Junkins Professor at Thayer School of Engineering, Dartmouth College. She received her A.B. at Harvard and her Ph.D. at M.I.T., both in physics. After post-doctoral work at Caltech, she spent 20 years at the University of Southern California, where she was eventually named William Hogue Professor of Electrical Engineering and director of the Center for Laser Studies. She came to Dartmouth in 1995 as dean of Thayer School of Engineering. In her technical field of quantum electronics, lasers, and optics, she has authored over 250 journal papers, obtained nine patents, and been on the editorial board of five technical journals. She has supervised 30 Ph.D. theses and 14 M.S. theses. Garmire is a member of the National Academy of Engineering, on whose Governing Council she has served, and the American Academy of Arts and Sciences. She is a fellow of IEEE, the American Physical Society, and the Optical Society of America, of which she was president in 1993. In 1994, she received the Society of Women Engineers Achievement Award. Garmire has been a Fulbright senior lecturer in fiber optics and a visiting faculty member in Japan, Australia, Germany, and China. She chaired the NSF Advisory Committee on Emerging Technology and served on both the NSF Advisory Committee on Engineering and the Air Force Science Advisory Board. With her electrical engineering background and fiber optics expertise, she has followed the growing challenges to the nation's energy infrastructure, with particular interest in the electric grid.

RONALD E. KEYS, an independent consultant, retired from the Air Force in November 2007 after completing a career of over 40 years. His last assignment was as Commander, Air Combat Command, the Air Force's largest major command, consisting of more than 1,200 aircraft, 27 wings, 17 bases, and 200 operating locations worldwide with 105,000 personnel. General Keys holds a B.S. from Kansas State

University and an M.B.A. from Golden Gate University. General Keys is a command pilot with more than 4,000 flying hours in fighter aircraft, including more than 300 hours of combat time. No stranger to energy challenges, General Keys first faced them operationally as a young Air Force Captain, piloting F-4s during the fuel embargo of the 1970s. Later, as director of operations for European Command, fuel and logistic supply provisioning were critical decisions during humanitarian, rescue, and combat operations across European Command’s area of responsibility including the Balkans and deep into Africa. As Commander of Allied Air Forces Southern Europe and Commander of the U.S. 16th Air Force, similar hard choices had to be made in supporting OPERATION NORTHERN WATCH in Iraq as well as for combat air patrols and resupply in the Balkans. Later, as the director of all Air Force Air, Space, and Cyber mission areas as well as operational requirements in the early 2000s, he saw the impact of energy choices on budget planning and execution as well as in training and supporting operational plans in Iraq and Afghanistan. Finally, at Air Combat Command, he faced the total challenge of organizing, training, and equipping forces at home and deployed to balance mission effectiveness with crucial energy efficiency, security, and resilience. Continuing after retirement, he has advised the U.S. Air Force on energy security strategy planning and acted as a subject matter expert during analysis of energy impacts and trade-offs in “futures” war games. As a Bipartisan Center senior advisor, he served as a technical advisor on the “Cyber Shockwave” exercise based on cyber and physical grid and internet attacks. He is a member of The Center for Climate and Security's Advisory Board as well as their Climate and Security Working Group focused on developing policy options and encouraging dialogue and education. As chairman of the CNA Military Advisory Board on Department of Defense Energy Security and Climate Change, he is intimately familiar with the relationship of energy, military, economic, and national security and has contributed to a number of energy and climate reports, most recently concerning the vulnerability and resilience of the electric grid.

MARK MCGRANAGHAN is vice president of distribution and energy utilization for the Electric Power Research Institute (EPRI). This research area is leading the development of the next generation integrated grid while continuing to develop new innovations for designing, maintaining, and improving the existing grid. This includes research to define and develop the information and communication infrastructure that will support the integrated grid. He has been involved in resiliency research at EPRI at both the transmission and distribution levels. McGranaghan has over 35 years of experience in the industry. He has authored more than 70 technical papers and articles on topics ranging from power quality to insulation coordination of extra high voltage systems. He is an IEEE fellow and, in 2014, received the Charles Proteus Steinmetz award for his expertise and dedication to power engineering standards development. He has recently been one of the industry leaders developing the standards and platforms to support the next-generation smart grid for integration of widespread distributed resources. He is a member of the executive committee of the CIGRE U.S. National Committee, vice chairman of the CIRED U.S. National Committee, and a member of the International Electrotechnical Commission Advisory Committee on Electricity Transmission and Distribution. McGranaghan has taught courses and seminars around the world to help support collaboration in the power industry. He is a co-author of the book *Electrical Power Systems Quality*, now in its third edition. McGranaghan has a B.S.E.E. from the University of Toledo and an M.B.A. from the University of Pittsburgh. In 2015, he received the Outstanding Alumni Award from the University of Toledo College of Engineering and Computer Science.

CRAIG MILLER currently serves full time as the National Rural Electric Cooperative Association’s chief scientist. Dr. Miller is a technologist with extensive background in the physical sciences, information technology, and systems engineering. He has developed new technology and cutting-edge systems for more than 30 years, within and for both start-up and established corporations. His particular strength is the conceptualization, tuning, and positioning of new technology products. More than 2,000 companies in the United States use systems or technology he has architected or developed. Dr. Miller’s many accomplishments deserve mention: participating in seven start-ups; serving as SAIC’s chief scientist (during which time he was granted the “Heroic Achievement in Information Technology” award from the Smithsonian Institution); and a wide experience in technical and financial media as a key investor relations expert, technologist, inventor, and analyst on behalf of diverse companies such as Proxicom, GridPoint, DiData, and Aguru Images, a high-end digital imaging company that he started. More recently, Dr. Miller has achieved a national reputation in the advanced smart grid and cybersecurity arenas.

THOMAS J. OVERBYE is a Texas A & M Engineering Experiment Station Distinguished Research Professor in the Electrical and Computer Engineering Department at Texas A&M University. Formerly, he was the Fox Family Professor of Electrical and Computer Engineering at the University of Illinois,Urbana-Champaign, where he has taught since 1991. He received his B.S., M.S., and Ph.D. in electrical engineering from the University of Wisconsin, Madison and is a member of the National Academy of Engineering. His current research interests include electric power system analysis, visualization, dynamics, cybersecurity, and modeling of power system geomagnetic disturbances. Prof. Overbye is the original developer of the PowerWorld Simulator, an innovative computer program for power system analysis, education, and visualization; a co-founder of PowerWorld Corporation; and an author of *Power System Analysis and Design*. He was the recipient of the IEEE/Power and Energy Society Walter Fee Outstanding Young Engineer Award in 1993 and the IEEE/ Power and Energy Society Outstanding Power Engineering Educator Award in 2011, and he participated in the 2003 DOE/ North American Electric Reliability Corporation Blackout investigation.

WILLIAM H. SANDERS is Donald Biggar Willett Professor of Engineering and the head of the Department of Electrical and Computer Engineering at the University of Illinois, Urbana-Champaign. Dr. Sanders's research interests include secure and dependable computing and security and dependability metrics and evaluation, with a focus on critical infrastructures. He has published more than 270 technical papers in those areas. He served as the director and principal investigator of the DOE/Department of Homeland Security Trustworthy Cyber Infrastructure for the Power Grid Center, which is at the forefront of national efforts to make the U.S. power grid smart and resilient. He is also co-developer of three tools for assessing computer-based systems: METASAN, UltraSAN, and Möbius. Möbius and UltraSAN have been distributed widely to industry and academia; more than 1,700 licenses for the tools have been issued to universities, companies, and NASA for evaluating the performance, dependability, and security of a variety of systems. He is also a co-developer of the Network Access Policy Tool for assessing the security of networked systems; it is available commercially under the name NP-View from the start-up company Network Perception, which was cofounded by Dr. Sanders.

RICHARD E. SCHULER is professor of economics (College of Arts and Sciences) and professor of civil and environmental engineering (College of Engineering), emeritus, and a graduate school professor at Cornell University. Professor Schuler served on the executive committee of the NSF-supported, multi-university Institute for Civil Infrastructure Systems. Previous administrative positions at Cornell have included director of the Waste Management Institute and the New York State Solid Waste Combustion Institutes (1987-1993), as associate director of the Center for the Environment (1989-1993) and director of Cornell's Institute for Public Affairs (1995-2001), a university-wide multidisciplinary program offering the M.P.A degree. He has served on the Board of Trustees of Cornell University (1993-1997). Professor Schuler's industrial and government experience include engineer and manager with the Pennsylvania Power and Light Company (1959-1968), energy economist with Battelle Memorial Institute (1968-1969), and public service commissioner and deputy chairman for New York State (1981-1983). He has been a consultant to numerous government agencies and industries on pricing, management, and environmental issues and to the World Bank on energy and infrastructure investment programs. From its inception in 1999 until April 2012, he was a founding board member of the New York Independent System Operator that is responsible for operating the electric transmission grid reliably in New York while overseeing an efficient power market. During his tenure he chaired the New York Independent System Operator board's market performance, reliability and markets, and its governance committees, and from 2008-2010 he was the board's lead director. Professor Schuler's degrees include a B.E. in electrical engineering, Yale, 1959; an M.B.A., Lehigh, 1969; and a Ph.D. in economics, Brown, 1972. He has been a registered professional engineer in Pennsylvania since 1963.

SUSAN TIERNEY is a senior advisor at Analysis Group and is an expert on energy economics, regulation, and policy, particularly in the electric and gas industries. She has consulted to businesses, governments, tribes, non-profit organizations, foundations, and other organizations on energy markets, economic and environmental regulation and strategy, and energy policy. She has participated as an expert in civil litigation cases, in regulatory proceedings before state and federal agencies, on a variety of boards and commissions, and on National Academies' committees. Previously, she served as the assistant secretary for policy at the DOE. She was the secretary for environmental affairs in Massachusetts, commissioner at the Massachusetts Department of Public Utilities, chairman of the Board of the Massachusetts Water Resources Authority, and executive director of the Massachusetts Energy Facilities Siting Council. She chairs the DOE's Electricity Advisory Committee as well as the External Advisory Board of the National Renewable Energy Laboratory, and she previously served on the secretary of Energy Advisory Board. She is a director of the World Resources Institute, Resources for the Future, and other boards. She has published widely, frequently speaks at industry conferences, and has lectured at many leading universities. Dr. Tierney received her Ph.D. and M.A. in regional planning from Cornell University.

DAVID G. VICTOR is director of the Laboratory on International Law and Regulation and a professor at the School of Global Policy and Strategy at University of California, San Diego, where he also co-leads the university's Deep Decarbonization Initiative. His research focuses on how regulatory law affects the environment, technology choices, industrial structure, and the operation of major energy markets. Prior to joining the University of California, San Diego, Victor served as director of the Program on Energy and Sustainable Development at Stanford University where he was also a professor at the law school. He is a member of the Board of Directors of EPRI, on the advisory council for the Institute of Nuclear Power Plant Operators, and chairman of the Community Engagement Panel that is helping to guide the decommissioning of Units 2 and 3 at the San Onofre Nuclear Generating Station. He has contributed to numerous publications on topics such as energy market innovations and electric power market reform.

C

Disclosure of Conflicts of Interest

The conflict-of-interest policy of the National Academies of Sciences, Engineering, and Medicine (www.nationalacademies.org/coi) prohibits the appointment of an individual to a committee like the one that authored this Consensus Study Report if the individual has a conflict of interest that is relevant to the task to be performed. An exception to this prohibition is permitted only if the National Academies determine that the conflict is unavoidable and the conflict is promptly and publicly disclosed.

When the committee that authored this report was established, a determination of whether there was a conflict of interest was made for each committee member given the individual's circumstances and the task being undertaken by the committee. A determination that an individual has a conflict of interest is not an assessment of that individual's actual behavior, character, or ability to act objectively despite the conflicting interest.

Mr. Paul De Martini was determined to have a conflict of interest because he is the managing director at Newport Consulting. Dr. Susan Tierney was determined to have a conflict of interest because she is the senior advisor at Analysis Group and also performs consulting work.

In each case, the National Academies determined that the experience and expertise of the individual was needed for the committee to accomplish the task for which it was established. The National Academies could not find another available individual with the equivalent experience and expertise who did not have a conflict of interest. Therefore, the National Academies concluded that the conflict was unavoidable and publicly disclosed it through the National Academies' Current Projects System (www8.nationalacademies.org/cp).

D

Presentations and Committee Meetings

FIRST COMMITTEE MEETING
March 2-3, 2016
Washington, D.C.

FERC Activities in the Office of Electric Reliability
Michael Bardee, Federal Energy Regulatory Commission, Office of Electric Reliability

EPRI Activities in Electricity Sector Modernization
Mark McGranaghan, Electric Power Research Institute

NERC and APPA Activities in Critical Infrastructure Protection
Nathan Mitchell, American Public Power Association

DOE Office of Electricity Perspective on NAS Committee Task
Patricia Hoffman, Department of Energy, Office of Electricity Delivery and Energy Reliability

SECOND COMMITTEE MEETING
May 11-12, 2016
Washington, D.C.

Overview of Relevant DOE Activities and Needs
Gilbert Bindewald, Department of Energy, Office of Electricity Delivery and Energy Reliability

Improving Resilience of Transformers
Richard Boyd, Siemens
James McIver, Siemens

Resilience Through Relays, Sensors, and Components
Gregory Zweigle, Schweitzer Engineering Laboratories

Resilience through Automation and Trade-offs with Cybersecurity
Steven Kunsman, ABB

Cybersecurity and Activities in NERC and E-ISAC
Tim Roxey, Electricity Information Sharing and Analysis Center

THIRD COMMITTEE MEETING
July 11-12, 2016
Washington, D.C.

Panel on State Regulatory Commissions and Resilience
Paul Centolella, Paul Centolella and Associates
David Littell, Regulatory Assistance Project
Kris Mayes, Utility of the Future Center
Audrey Zibelman, New York State Public Service Commission

Extreme Weather Events
Tom Karl, National Oceanic and Atmospheric Administration's National Centers for Environmental Information
Jim Kossin, National Oceanic and Atmospheric Administration's National Centers for Environmental Information
Ken Kunkel, National Oceanic and Atmospheric Administration's National Centers for Environmental Information
Mike Squires, National Oceanic and Atmospheric Administration's National Centers for Environmental Information

Trends in Battery Storage
Jay Whitacre, Carnegie Mellon University

FOURTH COMMITTEE MEETING
September 29-30, 2016
Washington, D.C.

Utility Perspectives on Resilience
Joe Svachula, Commonwealth Edison
Ralph LaRossa, Public Service Enterprise Group
William Ball, Southern Company
Erik Takayesu, Southern California Edison

Distribution Resilience with High Automation
Jim Glass, Chattanooga Electric Power Board

Briefing on RAND Resilience Report
Henry Willis, RAND Corporation

Industry-wide Trends in Resilience
David Owens, Edison Electric Institute

FIFTH COMMITTEE MEETING
November 2-3, 2016
Washington, D.C.

No open session presentations were held at this meeting.

SIXTH COMMITTEE MEETING
February 15-16, 2017
Washington, D.C.

No open session presentations were held at this meeting.

E

Examples of Large Outages

NORTHEAST BLACKOUT AFFECTING UNITED STATES AND SOUTHEAST CANADA (AUGUST 13, 2003)

Pre-Event

Due to the minimal amount of warning time before this event, no significant preparations were taken.

Event

High electricity demand in central Ohio combined with scheduled maintenance of several generators resulted in low voltage around the Cleveland-Akron area. Computer and alarm systems failed to warn operators due to software bugs in both the power company's and regulating authority's computer systems. Three 345 kV lines feeding central Ohio tripped due to contact with trees. Cascading failures resulted throughout the region as lower voltage lines attempted and failed to take on the redistributed load from tripped lines. The blackout affected at least 50,000,000 customers, caused a loss of 70,000 MW, cost $4-10 billion, and contributed to 11 deaths.

Recovery

Most areas were restored to full power within hours, but some areas in the United States were without power for 4 days. Parts of Ontario experienced rotating blackouts for up to 2 weeks. Physical damage was limited, making recovery much faster than other types of events.

Lessons Learned

Improvements in system protection to slow or limit cascading failures should be made. Improvements in operator training, emergency response plans, communication between reliability coordinators and utilities, and sensor usage should also be made. Managing and pruning of vegetation and vegetation-caused bulk incidents should be reported to the North American Electric Reliability Corporation (NERC) and regional reliability coordinators (NERC, 2004).

WEST COAST BLACKOUT
(AUGUST 10, 1996)

Pre-Event

Due to the minimal amount of warning time before this event, no significant preparations were taken.

Event

Heavy loading on 500 kV transmission lines and the western interconnect system was caused by good hydro conditions in the northwest region and high demand in California resulting from high summer temperatures. The 500 kV Big Eddy-Ostrander line arced to a tree, followed by four more 500 kV lines over 100 minutes. Several smaller lines also arced and closed. Systems protections removed 1,180 MW of generation from the system, creating an unstable power oscillation and ultimately causing islanding of the Western Electricity Coordinating Council into four distinct islands: Island 1, Alberta, Canada; Island 2, Colorado to British Colombia; Island 3, Central to Northern California; and Island 4, Southern California to New Mexico to Northern Mexico. The outage affected approximately 7,500,000 customers and caused a loss of 33,024 MW.

Recovery

Physical damage was limited, making recovery much faster than other types of events. Islands 1 and 2 had power restored within 2 hours. Island 3 was restored within 9 hours. Island 4 was restored within 6 hours.

Lessons Learned

Limiting certain high-voltage lines would prevent cascading failures. Insuring coordination between power producers and transmission operators is imperative (NERC, 2002).

GEOMAGNETIC DISTURBANCE AFFECTING EASTERN CANADA (MARCH 13, 1989)

Pre-Event

Due to the small amount of warning time before this event, no significant preparations were taken. However, forecasts for solar storm events may enable preparation in the future.

Event

At 2:45 a.m., a solar magnetic storm resulting from a solar flare tripped five lines in Eastern Canada by inducing a quasi-direct current. The land surrounding the Hudson Bay rests on an igneous rock shield, making the region more susceptible to ground-induced currents that result from solar storms. Higher latitudes also determine a location's magnetic storm vulnerability. The outage affected approximately 6,000,000 customers and caused a loss of 19,400 MW.

Recovery

Forty-eight percent of power was restored after 5 hours. Eighty-three percent of power was restored after 9 hours. Some strategic equipment and two major step-up transformers were damaged and required repair due to overvoltage.

Lessons Learned

NERC urged the National Oceanic and Atmospheric Administration for the capabilities and coordination for at least 1 hour of notice of solar storms. Forecasting remains less precise compared to meteorological events but still has potential to give minutes to hours of warning to grid operators for the approach of strong solar storms. Current standards require systems to withstand benchmark geomagnetic disturbance events, particularly to prevent high-voltage transformers from overheating (NERC, 1989).

ICE STORM AFFECTING SOUTHERN CANADA AND THE NORTHEAST UNITED STATES (JANUARY 10, 1998)

Pre-Event

The severity of the ice storm was poorly predicted since icing conditions depend critically on the vertical atmospheric temperature profile. As a result, officials did not make any significant preparations for this event.

Event

During a series of severe ice storms beginning on January 5, heavy ice and snow loads caused the destruction of trees and high-voltage towers. 30,000 wooden utility poles collapsed, leaving millions without power. Two major generating stations were disconnected from the rest of the grid due to line tripping, causing the area to blackout. The bulk transmission grid remained mostly intact, keeping the outage from spreading too far outside of the Québec area. The outage affected 2,800,000 customers and caused a loss of 18,500 MW.

Recovery

Hundreds of utility crews from outside the area were brought in, along with 16,000 Canadian military personnel, making this the largest deployment of Canadian military since the Korean War. American military also assisted in recovery efforts. Northern New York and New England had their power returned within 3 weeks. Québec had its power back online within 4 weeks.

Lessons Learned

Disruptions of telephone, cellular, and fiber optic cables made communication difficult. The most reliable means of communications were found to be the utility-owned and operated microwave and mobile radio systems. More accurate temperature profiling and precautions around temperatures where ice storms are possible would be beneficial for preparing for any outage that results from these types of storms. Building towers and lines to withstand greater weights from icing would also result in greater resilience (NERC, 2001).

HURRICANE SANDY AFFECTING THE NORTHEAST UNITED STATES (OCTOBER 29, 2012)

Pre-Event

Unlike unexpected cascading failures or solar storms, hurricanes typically offer days of warning before outages occur. In the days leading up to landfall, extensive communication was made between utilities and generating facilities to prepare for abnormal operation, including preparing black start units with enough fuel for emergency use. Additional field operation crews were made available for response. Sandbags and other barriers were put around vulnerable substations. In the minutes and hours leading up to outages, flood-prone areas were de-energized.

Event

Superstorm Sandy made landfall over New Jersey, New York, and the northern mid-Atlantic with wind speeds of about 80 mph at landfall and a storm surge that flooded low-lying assets, causing more than 260 transmission trips and loss of roughly 20,000 MW of generation capacity. High winds and flooding were the major causes of outages, with some snow and icing contributing as well. More than 5,770,000 customers were affected.

Recovery

Ninety-five percent of customers' power was restored between November 1, 2012, and November 9, 2012.

Lessons Learned

Pre-staging equipment for recovery and de-energizing facilities in flood-prone areas can mitigate losses and hasten recovery. Implementing flood-protected facilities that include water-tight doors and barricades would prevent some stations from tripping (NERC, 2014).

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F

Acronyms

AC	alternating current
AGC	automatic generation control
AMI	advanced metering infrastructure
APS	Arizona Public Services
BPA	Bonneville Power Administration
C&I	commercial and industrial
CAISO	California Independent System Operator
CAP	Civil Air Patrol
CHP	combined heat and power
CIP	critical infrastructure protection
DC	direct current
DER	distributed energy resource
DES	distributed energy storage
DG	distributed generation
DHS	Department of Homeland Security
DMS	distribution management system
DOD	Department of Defense
DOE	Department of Energy
DR	demand response
DSO	distribution system operator
E-ISAC	Electricity Information Sharing and Analysis Center
EEI	Edison Electric Institute
EIA	Energy Information Administration
EIM	Energy Imbalance Market
EMP	electromagnetic pulse
EMS	energy management system
EPAct	Energy Policy Act
EPB	Electric Power Board
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERD	entity relationship diagram

ESSC	Electricity Subsector Coordinating Council
FAA	Federal Aviation Administration
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GMD	geomagnetic disturbance
GMLC	Grid Modernization Laboratory Consortium
GPS	global positioning satellites
GW	gigawatt
ICC	Illinois Commerce Commission
ICS	industrial control system
IEEE	Institute of Electrical and Electronics Engineers
IPCC	Intergovernmental Panel on Climate Change
ISO	independent system operator
IT	information technology
JCESR	Joint Center for Energy Storage
LOLP	loss of load probability
LPT	large power transformer
MAA	mutual assistance agreement
MW	megawatt
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Council
NIST	National Institute of Standards and Technology
NOAA	National Oceanic and Atmospheric Administration
NPS	National Preparedness System
NRC	National Research Council
NRCC	National Response Coordination Center
NRDC	National Resources Defense Council
NSF	National Science Foundation
OMS	outage management system
OT	operational technology
PMU	phasor measurement unit
PSEG	Public Service Enterprise Group
PUC	public utility commission
PURPA	Public Utility Regulation Policy Act
PV	photovoltaic

QER	Quadrennial Energy Review
R&D	research and development
RAS	Remedial Action Scheme
RTO	regional transmission operator
RTU	remote terminal unit
RUS	Rural Utility Service
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCADA	supervisory control and data acquisition
SoCo	Southern Company
T&D	transmission and distribution
UAV	unmanned aerial vehicle

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