FUTURE ELECTRIC
Utility Regulation

UTILITY INVESTMENTS IN RESILIENCE OF ELECTRICITY SYSTEMS

Organization of MISO States
National Rural Electric Cooperative Association
Edison Electric Institute
National Association of State Utility Consumer Advocates

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National Association of State Utility Consumer Advocates

The National Association of State Utility Consumer Advocates (NASUCA) members are designated by the laws of their respective jurisdictions to represent the interests of utility consumers before state and federal regulators and in the courts. NASUCA's comments were developed by a subcommittee of interested members led by Robert Mork, Indiana Consumer Counselors Office, and were approved by the NASUCA Executive Committee. Sheri Givens provided technical assistance. Givens formerly served as the state utility consumer advocate for Texas and a member of NASUCA's Executive Committee. She was president of Givens Consulting LLC when she provided technical assistance. She now is Vice President, U.S. Regulatory & Customer Strategy, National Grid.

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Series Foreword by U.S. Department of Energy

The provision of electricity in the United States is undergoing significant changes for a number of reasons. The implications are unclear.

The current level of discussion and debate surrounding these changes is similar in magnitude to the discussion and debate in the 1990s on the then-major issue of electric industry restructuring, both at the wholesale and retail level. While today's issues are different, the scale of the discussion, the potential for major changes, and the lack of clarity related to implications are similar. The U.S. Department of Energy (DOE) played a useful role by sponsoring a series of in-depth papers on a variety of issues being discussed at that time. Topics and authors were selected to showcase diverse positions on the issues to inform the ongoing discussion and debate, without driving an outcome.

Today's discussions have largely arisen from a range of challenges and opportunities created by new and improved technologies, changing customer and societal expectations and needs, and structural changes in the electric industry. Some technologies are at the wholesale (bulk power) level, some at the retail (distribution) level, and some blur the line between the two. Some technologies are ready for deployment or are already being deployed, while the future availability of others may be uncertain. Other key factors driving current discussions include continued low load growth in many regions and changing state and federal policies and regulations. Issues evolving or outstanding from electric industry changes of the 1990s also are part of the current discussion and debate.

To provide future reliable and affordable electricity, power sector regulatory approaches may require reconsideration and adaptation to change. Historically, major changes in the electricity industry often came with changes in regulation at the local, state or federal levels.

DOE is funding a series of reports, of which this is a part, reflecting different and sometimes opposing positions on issues surrounding the future of regulation of electric utilities. DOE hopes this series of reports will help better inform discussions underway and decisions by public stakeholders, including regulators and policymakers, as well as industry.

The topics for these papers were chosen with the assistance of a group of recognized subject matter experts. This advisory group, which includes state regulators, utilities, stakeholders and academia, works closely with DOE and Lawrence Berkeley National Laboratory (Berkeley Lab) to identify key issues for consideration in discussion and debate.

The views and opinions expressed in this report are solely those of the authors and do not reflect those of the United States Government, or any agency thereof, or The Regents of the University of California.

Introduction

By Lisa Schwartz

While reliability is a foundational attribute for electricity systems, resilience is a related concept that has gained more recent attention. The U.S. Department of Energy included resilience among six core areas for electric infrastructure metrics, envisioning modern grids with greater resilience to hazards of all types.[1] The Grid Modernization Laboratory Consortium published a metrics reference document in 2017, including a set of forward-looking grid resilience metrics and a process for calculating them, designed to:[2]

- Help utilities better plan for and respond to low-probability, high-consequence disruptive events that are not currently addressed in reliability metrics and analyses
- Provide an effective, precise and consistent means for utilities and regulators to communicate about resilience issues

The reference document defined resilience as *the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions, including the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents*. It also recommended adoption of a seven-step process to help specify resilience objectives for utilities (see Figure ES-1).

Figure ES-1. The Resilience Analysis Process[3]

[1] DOE (2015).
[2] Kintner-Meyer et al. (2017).
[3] Source: Kintner-Meyer et al. (2017).

The proposed resilience metrics are consequence-based and fall into two general areas. Following are specific categories and an example for each:

- *Direct*
  - Electrical service (cumulative customer-hours of service)
  - Critical electrical service (cumulative critical customer-hours of service)
  - Restoration (time to recovery)
  - Monetary (loss of utility revenue)
- *Indirect*
  - Community function (hospitals and fire and police stations without power)
  - Monetary (business interruption costs)
  - Other critical assets (key military facilities without power)

Definitions and metrics for resilience are evolving. Whether and how utilities and regulators (or boards or city councils) should distinguish between resilience and reliability — in terms of approaches and decision-making criteria for planning and investments — also are developing areas. Many other entities also are involved in critical infrastructure decisionmaking related to resilience.

This report presents differing viewpoints on several key questions related to utility investments to improve the resilience of electricity systems:

1. What level and scope of resilience do we need and how much are we willing to pay?
2. Who's responsible for resilience, and how should other entities coordinate with utilities when there are mutual benefits?
3. What types of utility investments have the most impact on improving resilience, and how can utilities and regulators tell whether utility investments in resilience are impactful?
4. Should utilities take more proactive approaches to investments in resilience?
5. How can decisionmaking about resilience investments be improved?

Authors representing diverse perspectives provide their responses:

- *State regulators* – Organization of MISO States, with technical support from Lauren Azar (Chapter 1)
- *Utilities*
  - Randolph Elliott, National Rural Electric Cooperative Association (Chapter 2)
  - Scott Aaronson, Edison Electric Institute (Chapter 3)
- *Consumers* – National Association of State Utility Consumer Advocates, with technical support from Sheri Givens (Chapter 4)

All the authors point out lack of a common definition, analytical framework and metrics for resilience, while acknowledging recent efforts by federal entities, including the U.S. Department of Energy; national energy laboratories; and the electric power industry. Other common themes include evolving grid threats as well as state and local responsibilities for improving resilience.

Organization of MISO States (OMS) highlights a variety of approaches state utility regulators are taking to address resilience, including specifically targeted measures, broad initiatives addressing reliability, distribution planning or grid modernization, or other activities under enabling-statute obligations. Some state regulators prefer qualitative over quantitative methods for measuring resilience; others are open to quantitative methods if they are collaboratively developed, voluntary and customizable.

The organization supports a federal role in conversations with utilities and states to respond to electric system needs and potentially planning exercises for high impact, low frequency (HILF) events. The organization also sees potential benefits from improving regional and interregional coordination, including sharing information and best practices. Still, HILF events may affect only one state (or part of a state), and each state evaluates resilience through its own unique lens. Specifically, state utility commission decisions on cost recovery for utility investments are fact-specific and case by case. "Considering the same risks and consequences, some commissions may choose to bolster resilience while others may not," OMS says.

Similarly, the **National Rural Electric Cooperative Association** (NRECA) sees dispersed authority over the electric system "as a feature, not a bug," while acknowledging a growing need for coordination as the power grid and electric industry evolve. The organization supports the Federal Energy Regulatory Commission continuing its inquiry into the resilience of the bulk power system. The coops suggested several principles to guide development of policies to address bulk power system resilience for design of centrally-organized wholesale markets, such as regional flexibility to assess needs and devise solutions, technical ability of the resource to provide resilience services, market-based compensation, and allowing self-supply by load-serving entities. In addition, NRECA sees a potential federal role with respect to developing consensus agreement on resilience definitions, analytical tools and metrics to improve "bottom-up" planning, coordination and decisionmaking at the local level. However, even if resilience was defined, measured and analyzed in a standardized way, NRECA maintains that local variations — such as resource mix, grid topology, topography of the utility's service area, and local weather and earthquake risks — mean that appropriate resilience solutions will vary.

Rural electric coops also stress the need for long-term integrated planning to evaluate resilience risks and alternative measures to address them over the lifetime of potential utility investments, in order to minimize long-term costs and stranded investments. For the near term, the organization finds that hardening distribution systems, pursuing appropriate resource diversity on the generation system, and enhancing cybersecurity appear to offer the best approach in terms of value and minimizing regrets.

Edison Electric Institute (EEI) represents the nation's investor-owned utilities and brings an Electricity Subsector Coordinating Council perspective. The Council is the principal liaison between senior officials of the federal government and the electric power industry for coordinating efforts to prepare for, and respond to, national-level incidents or threats to critical infrastructure. The Council also helps government and private-sector partners deepen relationships with other, interdependent critical sectors, including financial services, communications, water, natural gas and transportation.

In its essay, EEI describes the role of electric companies both in enabling resilience and providing a platform for resilient energy services that support customers and national security. As EEI points out, it is impossible to defend against all threats. So resilience planning must consider how to proactively prepare for and respond to threats. The most impactful resilience investments are those that defend against multiple hazards, according to EEI. Further, a focus on managing potential consequences, rather than prevention alone, means “electric companies avoid chasing the latest defensive measure against always evolving threats and, instead, prepare to respond to all hazards.” Given limited resources and evolving threats, prioritizing investments and focusing on consequence management are key components to improving resilience. Finally, EEI acknowledges that addressing questions about costs and benefits, especially when making investments to address high-risk, low-probability events or investments based on evolving research and new data, requires robust information-sharing and collaboration.

The **National Association of State Utility Consumers Advocates** (NASUCA) notes that few power outages are caused by generation issues and calls for greater attention to investment in resilience measures for distribution and transmission. NASUCA supports development of resilience frameworks that consider the probability of an event and its impacts on the grid, while requiring each utility to conduct cost-benefit analysis of major resilience investments. Specifically, for any proposed investment, potential costs should be fully delineated and just and reasonable, information provided should be transparent, investments should be made prudently and, if approved, utilities should be held accountable to staying within their proposed costs.

According to NASUCA, “The role of consumer advocates is to ensure that utilities and state commissions apply a rigorous cost-benefit analysis, prudence review, and consideration of affordability to evaluate all resilience measures.” Consumer advocates also support distinguishing resilience needs between different consumers in the same customer class (e.g., higher priority for hospitals and emergency services), prioritizing post-event recovery among them, and considering different needs when determining who pays for resilience investments.

1. State Regulator Perspectives on Utility Investments in Resilience

By Organization of MISO States[4]

Introduction

The Organization of MISO States (OMS) is a nonprofit, self-governing organization of representatives from each of the 17 regulatory bodies with retail jurisdiction over entities participating in the Midcontinent Independent System Operator, Inc. (MISO) and serves as the regional state committee (RSC). The purpose of the OMS is to coordinate regulatory oversight among its members and to make recommendations to MISO and the Federal Energy Regulatory Commission (FERC) and other relevant government entities and state commissions as appropriate. Most OMS members have jurisdiction over vertically integrated electric utilities.[5]

Caveats

As regulators of utilities,[6] the OMS members avoid making statements or decisions outside of their regulatory processes or that would presuppose or be perceived to presuppose a future decision on an issue that may be presented. Accordingly, the statements or positions taken in this paper are not decisions by OMS members, nor do they presuppose any current or future decision by any OMS member. In addition, any statements or positions taken in this essay are not attributable to any single regulator or group of regulators, and not all viewpoints or examples from OMS members are captured in this report. Statements and positions herein reflect a range of preliminary ideas and actions from Regulators and are intended to be general and conceptual unless attributed to a particular Regulator. Moreover, regulators' positions may change in the future, particularly as circumstances change.

This essay addresses concepts of electric system resilience in general and does not respond to the U.S. Department of Energy's (DOE) Notice of Proposed Rulemaking issued in 2017 related to resilience or comment on the FERC proceedings that followed.[7] The OMS submitted comments in those DOE and FERC proceedings,[8] which are separate from the concepts and activities discussed herein.

As stated in its comments to FERC, the OMS continues to believe that resilience should mainly be focused on the distribution system, which falls under state jurisdiction. Nothing in this essay is intended to suggest any impact on or cessation of state and local regulatory jurisdiction. The federal government's resilience efforts should remain focused on the bulk power system (BPS). The activities described herein relating to components outside of the BPS are and should remain subject only to state and local jurisdiction.

[4] This essay was developed with technical support from Lauren Azar of Azar Law, LLC. While there are 17 bodies in OMS, the following join in the essay, in whole or in part: Arkansas Public Service Commission, Illinois Commerce Commission only as the essay relates to broad initiatives, Indiana Utility Regulatory Commission, Iowa Utilities Board, Kentucky Public Service Commission, Michigan Public Service Commission, Minnesota Public Utilities Commission, Missouri Public Service Commission, Montana Public Service Commission, North Dakota Public Service Commission, South Dakota Public Utilities Commission, and Public Service Commission of Wisconsin, **herein referred to as "Regulators."** The Public Utility Commission of Texas abstained. The Council of the City of New Orleans, Louisiana Public Service Commission, and Mississippi Public Service Commission voted not to participate in the essay.

[5] Hereafter, reference to "OMS" pertains to the RSC.

[6] For ease of reference we use the term "utility" to apply to investor-owned utilities, publicly-owned utilities and cooperatively-owned utilities.

[7] FERC (2017); FERC (2018a) — except for specific statements related to baseload generation attributed to individual regulators.

[8] OMS (2017); OMS (2018a); OMS (2018b).

Distinguishing Resilience and Reliability for the Electric System

Currently, there is no industry-wide definition of resilience (that includes the distribution system) and, as will be discussed later, some Regulators question whether resilience and reliability merit distinct definitions. Historically "reliability" was a catchall phrase for whether electricity could be consistently delivered to customers. Over time, industry began unbundling the attributes of reliability and created metrics for the BPS[9] and distribution system.[10] The unbundled attributes allowed industry to evaluate with specificity how individual components of the electric system[11] could withstand more frequent events with smaller and better-known impacts.

Three developments during the past two decades provide context for this discussion:

1. Our society's reliance on high-quality, dependable electrical service has increased.
2. The United States has experienced several high-impact, low-frequency events (HILF events) with serious impacts to the electric system.[12]
3. New threats are emerging that could have devastating effects on the nation's electric system (e.g., cyberterrorism[13] and the potential for geomagnetic disturbances (GMDs)).

In response, industry and Regulators have begun to evaluate the electric system in light of the potential for HILF events. Some have begun using the term "resilience" to refer to how the electric system would fare. When used in this way, one of the main differentiators between resilience and reliability, therefore, is the frequency and magnitude of the event.[14]

One could imagine the frequency and magnitude of events on a continuum with common reliability events on one end of the continuum and so called "Black Sky Events" on the other end (see Figure 1-1). The Energy Infrastructure Security Council defines a black sky hazard as "a catastrophic event that severely disrupts the normal functioning of our critical infrastructures in multiple regions for long durations."[15] Black Sky Events would be the most catastrophic, causing a regional electric outage lasting for months[16] and could include a coordinated cyber and physical terrorist attack, electromagnetic pulse (EMP) event, GMD, a widespread earthquake or a widespread extreme storm.

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[9] Reliability metrics for the BPS include NERC TPL-001-4 (which replaced the N-1 contingency) and loss of load expectation (LOLE).

[10] Reliability metrics for the distribution system include System Average Interruption Frequency Index (SAIFI); System Average Interruption Duration Index (SAIDI); and Customer Average Interruption Duration Index (CAIDI).

[11] For purposes of this paper, "electric system" includes generation, transmission, distribution and customer premises.

[12] Hurricane Katrina (2005), Hurricane Ike (2008), the Derecho Storm (2012), Superstorm Sandy (2012), and Hurricanes Harvey, Irma and Maria (2017). Though these extreme weather events may become more frequent, for purposes of this paper, they are considered HILF events when the magnitude of their consequences is large.

[13] "Hackers working for Russia claimed 'hundreds of victims' last year in a giant and long-running campaign that put them inside the control rooms of U.S. electric utilities where they could have caused blackouts, federal officials said." Smith (2018).

[14] OMS (2018a) at § II, B. 1; OMS (2018c) at Q1.

[15] Electricity Infrastructure Security Council. Black Sky Hazards. No date. https://www.eiscouncil.org/blacksky.aspx

[16] National Association for Regulatory Utility Commissioners (NARUC) (2014) at 4-5.

Figure 1-1. Spectrum of Reliability and Resilience Events

In contrast to Black Sky Events, reliability events are common — e.g., trees contacting a distribution circuit causing a circuit outage for a few hours. Major Outage Events or Major Events Days (MEDs) are somewhere in between the ends of the spectrum; they are less catastrophic than a Black Sky Event and would include events like damaging hurricanes and regional flooding. "Major Outage Event" is a generic phrase applying to the electric system. The Institute for Electrical and Electronics Engineers (IEEE) has proposed a definition for MEDs on the distribution system. They occur when the daily System Average Interruption Duration Index (SAIDI) exceeds a threshold based on historical outage data in the state.[17]

While it is clear which events fall on the far left and the far right of this spectrum, the point of demarcation in the middle between reliability and resilience is blurred: A Major Outage Event or MED could be categorized as a failure of either system reliability or resilience. For purposes of this paper, Major Outage Events and MEDs are considered HILF events.

A. The definition of resilience is developing.

To date, no consensus has been reached on the definition of resilience. For purposes of FERC's inquiry into what, if any, additional measures should be implemented to address resilience of the BPS, the OMS accepted FERC's resilience definition for the BPS as a qualitative concept.[18] This paper, which is primarily focused outside of the BPS, nevertheless uses a definition for resilience that is similar to FERC's. Specifically, for purposes of this paper, "resilience" is defined as follows:

- Before a HILF event, the ability to prevent or minimize impacts.
- During a HILF event, the ability to respond and adapt to impacts.
- After a HILF event, the ability to restore functionality of electric service.[19]

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[17] Warren (2005).
[18] The FERC definition is as follows: "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event." FERC (2018a) at ¶23; OMS (2018b) at 2; OMS (2018c) at Q1.
[19] OMS (2018c) at Q1.

Just as the term "reliability" was initially a catchall phrase whose components became more refined over time, the definition of "resilience" is developing. Some Regulators believe its definition and attributes will be refined through efforts like this essay and by the industry as a whole. However, other Regulators believe that resilience is subsumed within reliability and need not be differentiated.[20]

B. Planning for resilience may or may not differ from reliability.

While utilities are responsible for resilience and reliability planning, Regulators evaluate the work of utilities through regulator-led initiatives, rate cases or other requests for cost recovery. Regulators' approaches to resilience planning can be broadly placed in two categories: those that address resilience separately from reliability and others that combine the two. As will be discussed below, regardless of the method, Regulators are addressing resilience of the electric systems that are under their jurisdiction.[21]

i. In some states, planning for resilience is distinct from conventional reliability planning.

For those Regulators who differentiate between resilience and reliability, this section describes how planning for each could differ.

The consequences of HILF events are varying and sometimes unpredictable. Due to the number of independent variables, resilience planning usually includes a risk analysis for a specific HILF event or set of HILF events. Evaluating for specific events is necessary because "the resilience of a system to one threat will likely be different from resilience to other threats."[22] Therefore, the resilience of an electric system is usually framed in relation to a specific event or events, like a 100-year flood. For example, an electric system may be designed to be resilient against a blizzard, but those same designs would not render the system resilient against a 100-year flood. Also, resilience is usually measured in degrees, not simply assessed as "resilient" or "not resilient."

Risk assessments for resilience would likely include the following:

- Identifying critical infrastructure and key resources (CIKR)
- Assessing the vulnerabilities of those CIKR during a HILF event or set of HILF events
- Evaluating the consequences of losing vulnerable CIKR and the probability of those consequences
- Evaluating the degree to which improvements could reduce the probability or magnitude of consequences
- Analyzing the cost and benefits for those improvements[23]

[20] Examples of both models are provided in Section 1.C.
[21] OMS (2018a) at § II.B.1.
[22] Unel and Zevin (2018) at 10.
[23] OMS (2018a) at § II, B. 4; OMS (2018c) at Q3.

The consequences of concern in a resilience risk analysis are not limited to the electric system itself but also to corollary impacts: how losing vulnerable electric-system components impacts and ripples through other sectors of the economy and the community. State emergency planning can provide an in-depth review of risks to all sectors from HILF events. This can inform preparation for HILF events as well as identify the necessary multisector investments[24] that would facilitate recovery following an event.

Moreover, resilience planning includes not only the performance of the physical infrastructure but also the ability to respond and adapt to a HILF event and to restore electric service.[25] Evaluating improvements to bolster resilience, therefore, includes evaluating physical, policy and procedural changes. Examples of potential policy changes include allowing solar photovoltaic (PV) system owners to island from the grid or allowing the use of stored natural gas reserves during a disruption. Procedural changes could include such things as dispatching workers to manually control substations when facing a cyber event, developing credentialing protocols for electrical workers[26] or communication protocols, and turning off equipment in advance of a storm. In all instances, resilience planning is complex because it is multivariate and probabilistic.

Resilience and reliability planning have some commonalities:

- Both may use probability and/or deterministic methodologies during different stages.
- Both may apply a cost-benefit analysis in evaluating which investments to make — i.e., both have processes by which utilities and regulators determine the kind and degree of investments they are willing to pay for.[27]
- Both address how quickly electric service is restored. While reliability planning uses measurements of past restoration performance (such as SAIDI and CAIDI), resilience planning for restoration encompasses a broader array of actions including policies and practices.

In contrast to resilience planning, reliability planning that is conducted separate and apart from resilience concerns is often event-agnostic because it addresses frequent events with common consequences. The consequences considered in reliability planning all pertain to the electric system itself and not the ramifications on other sectors or the community.

[24] Example sectors are telecommunications, natural gas, water, sewer, fuel-dispensary and transportation.
[25] OMS (2018c) at Q1.
[26] An example is creating protocols that ensure electrical workers can be credentialed as first responders and defining who can be credentialed as an electrical worker.
[27] A cost-benefit analysis may not be necessary if an investment is required to comply with a legal standard.

ii. In other states, planning for resilience is embedded in planning for reliability.

Some Regulators do not distinguish between planning for resilience and reliability but, instead, incorporate measures designed to address outage events (including possible HILF events) in their reliability planning. These Regulators may rely on risk analyses that focus on component failures or review consequences of specific events.[28]

C. Typically, improvements that bolster reliability also bolster resilience, and vice versa.

Infrastructure recommended to improve reliability will also improve resilience.[29] If, under normal conditions, a distribution system is unreliable or not robust, that system will have more difficulty withstanding and adapting to a HILF event, and it will likely take longer to restore service. The same could be said for the bulk power system. If a bulk power system cannot withstand a single contingency under normal conditions, it may have more difficulty withstanding and adapting to multiple contingencies (a HILF event) and restoration may take longer.

The reverse is also true: In many circumstances, resilience planning would recommend improvements that would also bolster the reliability of the distribution system. For example, resilience planning for a hurricane could recommend stronger poles that would also make the system more reliable against common wind storms.

However, sometimes planning for resilience may recommend improvements that would not be identified during reliability planning. For example, if a commission or its utility decides to protect against a 500-year flood, it would identify CIKR that would be submerged by a 500-year flood and may choose to elevate or move those components. Reliability planning, exclusive of a resilience component, may not address this question and, therefore, would not likely result in the same recommendation.

Also, since resilience includes response and restoration, including human practices and impacts on other sectors, only resilience planning — not reliability planning — will include response and restoration activities. For example, chains-of-command in communication during a disaster and credentialing protocols would not usually be considered when planning for BPS reliability standards or distribution performance metrics such as SAIDI and CAIFI.

Because of these considerations, some Regulators are focusing primarily on investments that improve both resilience and reliability.

[28] For example, see Section 1.C.

[29] For example, prior to Hurricane Maria, the electric system on the Puerto Rican mainland was weak and had some reliability problems. *The Economist* (October 19, 2017); National Public Radio (May 2, 2018). While even a more reliable system would likely have been damaged by this devastating hurricane, it probably would not have been decimated. DOE (2018).

1. What level and scope of resilience do we need and how much are we willing to pay?

A. States, regulators and communities select resilience measures that are tailor-made to their circumstances.

The states/provinces within the MISO footprint range from Texas to Manitoba and Indiana to Montana (Figure 1-2).

Figure 1-2. Map of MISO footprint

Source: https://www.misoenergy.org/about/

While some HILF events could occur across the entire MISO region, others may affect one state, part of a state or a handful of states. Therefore, each Regulator and its utilities, along with other state and community agencies involved in emergency preparedness and response, will evaluate resilience through its own unique lens. Accordingly, there can be no single answer to how much resilience is desirable, and there is no right answer. Considering the same risks and consequences, some commissions may choose to bolster resilience while others may not.

B. Regulators in the MISO region consider a wide variety of HILF events.

Regulators identified the following as examples of HILF events that could occur in the MISO footprint:

- Cyberattacks
- A regional earthquake along the New Madrid Seismic zone
- Regional flooding
- Hurricanes and tropical depressions
- Interruption of out-of-state natural gas line supply

- Extreme heat or cold over a long period of time
- Droughts, ice storms or blizzards
- An event at a nuclear power station
- Pandemics
- Physical terrorist attacks
- GMDs

Those Regulators that consider resilience and reliability together also include tornados and vegetation management on the list of events to consider in resilience planning.[30] (All Regulators consider vegetation management as an important component of reliability.) The events listed above are just some of the many threats that are considered in planning across the MISO footprint.

C. Regulator and utility actions for increasing resilience range from targeted to broad initiatives.

1. Targeted Initiatives

Some Regulators have established initiatives dedicated to resilience or addressing specific threats — for example:

- The state of Wisconsin, in conjunction with private sector owners of critical infrastructure, has developed a Cyber Disruption Response Strategy to provide a framework to identify cyberattacks, protect against threats, detect threats, and respond to and recover from a significant cyberdisruption in Wisconsin's critical infrastructure.[31]

2. Broad Initiatives

Other, broader initiatives include reliability and resilience, such as the following:

- In response to a 2007 HILF event that "broke all outage records," one Regulator enacted a series of rules that included inspection standards, inspection reporting, grid repairs, vegetation management, reliability monitoring and reliability reporting. Its utilities implemented numerous improvements on both the transmission and distribution systems that bolster resilience and reliability. Examples are mobile substation equipment, undergrounding distribution lines and creating a crisis management department.
- The Illinois Commerce Commission initiated a utility-of-the-future study known as "NextGrid." NextGrid's working groups assessed resources and technological innovations that may be needed to strengthen the reliability and resilience of the grid. They recommended how to improve power quality, reliability and resilience, which

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[30] For example, in 2009, Indiana opened an ongoing docket into the vegetation management practices and policies of all of their utilities. Indiana Utility Regulatory Commission (2009).
[31] Wisconsin Homeland Security Council (2015).

included such things as renewable energy technologies, microgrids, Distribution System Management and leveraging other advanced intelligence technology.[32]

- The Indiana Legislature created the Transmission, Distribution, and Storage System Improvement Charge (TDSIC) statute[33] that covers projects related to safety, reliability, system modernization and economic development. Utilities may submit a TDSIC plan to upgrade infrastructure over a seven-year time period. Examples of electric utility projects include investments in substations, circuits, underground cables and breakers/transformers.
- Michigan utilities are engaged in risk-based distribution planning to harden their networks.[34] This approach prioritizes investments according to an asset's importance to the distribution grid, taking into consideration the number of customers who would be without power and duration of the outage. This approach also examines the age and condition of distribution utility assets, informing ongoing equipment maintenance and replacement.
- The Minnesota Commission initiated an inquiry into grid modernization in 2015 and published a staff report in March 2016 with five guiding principles for grid modernization. The Commission supported distribution system planning as the most reasonable and actionable way for the Commission to assist in the forthcoming grid evolutions. The Commission recently set requirements for integrated distribution planning for Xcel Energy[35] and is in the process of setting requirements for the other three rate-regulated public utilities.[36]
- The Wisconsin Commission has an ongoing grid modernization effort. Some of the components of this initiative most related to the resilience and reliability of electric systems include investments in the distribution system, adoption of advanced customer information systems and advanced metering infrastructure and innovative demand response programs. Wisconsin's energy efficiency programs support adoption of advanced technologies that have demonstrated reductions in energy use and could potentially support demand response and load management programs. Both demand response and load management can serve reliability and resilience functions because of the ability to rapidly interface with certain components of the distribution system.[37]

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[32] Illinois Commerce Commission (2017). Additional information regarding working group draft reports and discussions can be found at www.NextGrid.illinois.gov.
[33] Indiana Code chapter 8-1-39.
[34] For example, see Michigan Public Acts 341 and 342 (2016).
[35] See Order Approving Integrated Distribution Planning Filing Requirements for Xcel Energy in Docket E-002/18-251, August 30, 2018.
[36] See Docket No. E-017/18-253 (Otter Tail Power); Docket No. E-015/18-254 (Minnesota Power); and Docket No. E-111/ 18-255 (Dakota Electric Association).
[37] Wisconsin PSC (2018), 73.

These six initiatives address resilience within a broader context; they were not implemented to address resilience *per se*. Some Regulators have in their enabling statutes the responsibility to provide safe and reliable electric supply (or something similar) and they evaluate resilience under that obligation.

In sum, regardless of whether they are doing it through measures specifically targeted to resilience, broad initiatives addressing reliability, distribution planning or grid modernization, or under their enabling-statute obligations, Regulators are addressing resilience.[38]

D. Several variables are weighed and balanced to evaluate potential investments to bolster resilience.

In evaluating whether to expend ratepayer dollars for increased resilience, utilities and regulators may weigh and balance, among other things, the following three variables:

1. The probability of a specific HILF event (or set of HILF events) occurring.
2. The probability and magnitude of the consequences (including damage costs) from that HILF event(s) based upon the vulnerabilities of infrastructure within a specified geographical area.
3. The costs for various steps that would reduce the probability or minimize the consequences of that HILF event(s), which will not only include infrastructure changes but will also address response, adaptation and recovery.[39]

During this evaluation, avoiding or mitigating certain consequences may be given priority over other consequences. For example, some Regulators underscore the priority of a functioning communication system during a HILF event. Others placed a higher priority on restoring service to critical facilities, including fuel dispensaries, hospitals, nursing homes, police and fire stations, military bases and areas with dense population. Multiple priority lists are likely necessary because the order of priority for critical facilities will depend on the magnitude of the damage. For example, is the goal to restore electricity as quickly as possible to allow citizens to shelter in place, or is the goal to evacuate citizens as quickly as possible and only restore electricity needed for the evacuation? Some Regulators rely on their utilities or other departments of state government to prioritize critical facilities. If a utility commission were to create a priority list, it would normally be done as part of a rulemaking or other proceedings to explore this issue.

In sum, a Regulator's decision to either approve or reject a utility's proposal for an investment or cost recovery is fact-specific and done on a case-by-case basis. Given a specific need, the Regulator evaluates whether the benefits outweigh the costs of the improvement.[40] The benefit-cost ratio will be heavily dependent on the breadth of the analysis and whether only benefits to the utility sector are considered. For example, in calculating benefits of being able to restore service more quickly, would the utility only

[38] NARUC (2013) at 13-14.
[39] OMS (2018c) at Executive Summary and Q3.
[40] Some regulators are required to select the least-cost (most reasonable) option for meeting a certain need while others are able to select among cost-effective options.

consider the increase in utility revenues or would it include the economy-wide benefits? More extensive resilience improvements could be cost-effective if economy-wide benefits are included.

E. Black Sky Events are addressed in collaboration with other sectors and agencies.

When analyzing resilience, the larger the magnitude of the HILF event, the more entities must be involved with that analysis. Federal agencies such as the North American Electric Reliability Corporation (NERC), NERC's Regional Entities,[41] and Federal Emergency Management Agency (FEMA) and state emergency management agencies usually plan the exercises for interstate, intersector and large-scale HILF events, including Black Sky Events. (See the response to question 4, Section B, for an example.) Because of the widespread devastation and improbability of Black Sky Events, some Regulators said that addressing the threat of those events is and should continue to be conducted in concert with the federal entities. Some Regulators doubted whether improvements applicable *only* to Black Sky Events (that are not required by law) would be cost-effective.

F. Beneficiaries of resilience improvements in the utility sector may extend beyond utility ratepayers.

Historically, ratepayers who benefit from a utility improvement help to pay the cost of that improvement. However, accurately charging for resilience costs may be difficult. First, resilience improvements in the utility sector may confer benefits beyond the service territory of the utility making those improvements. For example, with the exception of municipal utilities, utility service territories rarely follow municipal boundaries, while resilience improvements may be made to meet municipality-specific or local needs. Second, resilience planning and improvements likely affect a broad swath of sectors, not just utilities. Utilities may be required to improve certain assets as a complement to another sector's needs. Whether and how beneficiaries that lie outside of the utility footprint or sector should contribute to the cost of resilience improvements may need to be considered by regulators and other governmental entities.

2. Who's responsible for resilience, and how should other entities coordinate with utilities when there are mutual benefits?

When discussing only electric-system components, the responsibility for resilience sits with the FERC, NERC, regional entities, regional transmission operators (RTOs), independent system operators (ISOs), utility regulators, utilities, and if a shared electric-system component sits behind a customer's meter, then also with that customer. When discussing resilience generally, however, the responsibility spans a much larger group.

[41] The Regional Entities are the Florida Reliability Coordinating Council, Midwest Reliability Organization, Northeast Power Coordinating Council, ReliabilityFirst, SERC Reliability Corporation, Texas Reliability Entity, and Western Electricity Coordinating Council.

A. Resilience of Electric-System Components

1. BPS Resilience

The BPS is primarily regulated by the federal government, with some sharing of jurisdiction with the states. Accordingly, the resilience of the BPS is primarily the responsibility of FERC and NERC,[42] as well as the entities they regulate, including Regional Entities, RTOs, ISOs and utilities. Regulators oversee the BPS expenditures of their utilities to ensure a safe and reliable supply of electricity at a reasonable cost.

2. Distribution-System and Customer-Premises Resilience

The distribution system sits squarely within the jurisdiction of the states. Some Regulators rely on their utilities to identify needs, evaluate alternatives for meeting those needs and recommend a course of action. In those cases, the regulator's role is simply to approve or deny the utility's recommendation or cost recovery for related expenses and capital investments.

Other Regulators have set reliability standards or goals for the distribution system. As discussed in our response to question 1, regulators may open dockets to investigate or to define a need and direct the utilities to respond to a stated policy. Regulators may also informally prompt utilities to investigate possible improvements. For example, commissions may ask utilities whether they have determined the elevation of each of their substations in relation to various flooding events — e.g., 100-year, 250-year and 500-year floods.

In our response to question 3 (further below), we provide examples of Regulator-prompted and utility-sponsored activities that bolster resilience on the distribution system and customer premises.

B. Effects of Electric-System Resilience on Other Infrastructure and the Community

The telecommunications, natural gas, water, sewer, fuel-dispensary and transportation sectors are all dependent on the electric sector. The loss of electric service can cause cascading disruptions in these other sectors and can cause negative feedback loops into the electric sector. The responsibility for evaluating the widespread consequences of losing electricity includes FERC, NERC, Regional Entities, RTOs, ISOs, state utility regulators, utilities, customers with shared resources behind-the-meter, U.S. Department of Homeland Security, DOE, Federal Emergency Management Agency, Federal Bureau of Investigation, state departments of homeland security, state departments of emergency management, governors offices, state energy assurance offices, state departments of transportation, national guard units, telecommunication providers, natural gas providers, water providers, sewer providers and business leaders.

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[42] As early as 2009, NERC was investigating resilience of the BPS under HILF events. See NERC (2010) and NERC (2012). In its 2012 report, NERC stated: "The recommendations and suggestions offered throughout this report are intended to prompt BPS entities to develop their own approaches and flexible plans that would be applicable under a wide variety of circumstances. These suggestions are in the form of industry guidelines that describe practices that may be used by individual entities according to local circumstances, as opposed to standards." (NERC 2012 at 2).

C. Coordinated Efforts with Mutual Benefits

1. *Planning Among Sectors*

Given the interdependencies among the sectors noted above, it is valuable for entities responsible for all of these sectors to be involved in resilience planning.[43] States usually designate a party responsible for convening these sectors as part of emergency planning. The following are two examples of intersector planning:

- In North Dakota, the National Guard and Division of Emergency Management have coordinated statewide tabletop emergency preparedness exercises in which the Public Service Commission, utilities and other sectors participate.
- In Wisconsin, the Adjutant General of the Wisconsin National Guard has the primary responsibility for creating and directing an emergency plan and for convening multiple stakeholders.[44]

2. *Utility Mutual Assistance and Shared Inventory Programs*

Mutual assistance agreements and shared inventory programs are mechanisms for mitigating the risk associated with HILF events. Many utilities have enacted such agreements. In cases of emergencies, unaffected utilities agree to provide personnel and equipment to the impacted utility to help restore service. The largest deployment of mutual assistance in the United States occurred during Hurricane Sandy in 2012, when tens of thousands of electrical workers with bucket trucks from over 80 utilities traveled to the East Coast to help with restoration.[45]

In the MISO footprint, many investor-owned utilities participate in one of the following regional mutual assistance groups that, among other things, follow guidelines established by the Edison Electric Institute (EEI):[46]

- Midwest Mutual Assistance Group
- Wisconsin Utilities Association Mutual Assistance Group
- Great Lakes Mutual Assistance Group
- Texas Mutual Assistance Group
- Southeastern Electric Exchange
- Western Region Mutual Assistance Group

Publicly-owned utilities and rural electric cooperatives run their respective mutual aid programs. In the case of the electric cooperatives, statewide organizations operate a mutual aid network. There are electric-cooperative statewide organizations in each of the MISO states. In the case of the American

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[43] One Regulator believes that each sector should conduct its own resilience planning.
[44] Wis. Stat. § 323.13(b).
[45] EEI (2018).
[46] NARUC (2015).

Public Power Association (APPA),[47] the program is split into 10 regions, five of which are within the MISO footprint. The utilities involved with such mutual assistance programs meet periodically to discuss coordination.

Utilities are also enrolling in shared inventory programs. Some HILF events may destroy many large transformers and because of their expense, most utilities do not keep a large number of these transformers in inventory. Three Kentucky utilities, along with several others, founded the Regional Equipment Sharing for Transmission Outage Restoration (RESTORE) in 2016 to identify and share spare transformers and other transmission equipment, which are available for purchase by other RESTORE participants during a major disaster. EEI and Grid Assurance[48] have similar programs.

Mutual assistance programs and shared inventory programs can be a cost-effective way to bolster resilience.

3. What types of utility investments have the most impact on resilience, and how can utilities and regulators tell whether utility investments in resilience are impactful?

A. Because most sustained outages arise in the distribution system, the most cost-effective investments to bolster resilience will likely be related to the distribution system.[49]

The MISO footprint is large and the threats are varied. While some distribution system improvements would bolster resilience for all types of threats, other improvements may address specific threats. It would be expected that the cost-effectiveness of an improvement would likely increase as the number of events covered by an improvement increases.

1. Physical Improvements on the Distribution System

The following are examples of physical improvements that could be made to the distribution system that are event agnostic — i.e., they may help bolster resilience against most, if not all, threats:

- Installing automated distribution system components (e.g., smart meters, intelligent switching) that improve the ability to detect problems and collect accurate information about an outage
- Installing protections for key communication systems that improve the ability to communicate during a disaster
- Installing so-called self-healing grid components

[47] American Public Power Association (No date).
[48] Grid Assurance is a private subscription service for access to an inventory of critical long lead-time spare transformers, circuit breakers and related transmission equipment, securely stored in domestic warehouses in strategic locations with pre-planned transportation and logistics support for delivery.
[49] The North Dakota Public Service Commission (ND PSC) believes that transmission improvements provide the most impact on bolstering resilience because they facilitate access to a diverse portfolio of baseload plants.

- Constructing microgrids — creating areas with their own generation and storage sources that can island from the grid to allow critical facilities to remain operational even during outages
- Replacing aging infrastructure
- Purchasing mobile substation equipment, which could include entire substations or just components such as switchgear and transformers
- Participating in shared inventory programs
- Installing distributed energy resources that could reduce load during a crisis
- Deploying energy efficiency to maintain more livable conditions for longer periods (compared to inefficient buildings) and reduce the amount of capacity required for recovery after outages
- Improving vegetation management

The following are example improvements that may bolster resilience only for certain threats.

Potential Improvements	Applicable Threats
Undergrounding distribution lines	Ice storms, hurricanes, high winds and lightning
Reinforcing poles	Ice storms, hurricanes and high winds
Installing guy wires	Ice storms, hurricanes and high winds
Installing pole-and-line designs and configurations that are hardened	Ice storms, hurricanes and high winds
Coating lines to prevent ice buildup	Ice storms
Elevating substations	Flooding
Using advanced weather-prediction models	Weather-related HILF events
Increasing physical barriers to substations	Terrorism

2. *Policies and Practices Related to the Distribution System*

Because resilience entails the ability to adapt and respond during an event and to restore service after the event, resilience includes more than just physical improvements. The following are examples of policies and practices that may improve resilience regardless of the threat:

- Implementing protocols for cybersecurity[50]
- Developing response protocols in advance of a disaster — e.g., credentialing protocols
- Developing protocols for communications during an event

[50] FERC recently ordered NERC to develop standards that increase the scope of what constitutes a reportable cyber incident "including incidents that might facilitate subsequent efforts to harm the reliable operation" of the BES. FERC (2018b).

- Participating in shared inventory programs and mutual assistance programs
- Developing business continuity and emergency action plans for utilities
- Enabling solar PV systems and electric vehicles to island from the grid during power outages, which will also require some hardware improvements
- Creating demand response programs such as interruptible tariffs or mass media-appeal programs
- Testing of backup generators on a regular basis
- Utilizing drones for damage inspections
- Obtaining regular security briefings on emerging threats
- Identifying/inventorying/mapping CIKR (with confidentiality measures)

It is noteworthy that initiatives related to response, adaptation and recovery are applicable to all types of events.

3. Tracking the Performance of the Distribution System in Response to HILF events

Some regulators require their utilities to track the performance of their electric systems and provide reports on that performance to evaluate investments made to bolster resilience.[51] Most use SAIDI, SAIFI and CAIDI metrics. Some Regulators formally compare the performance results before and after system improvements. Other Regulators make those comparisons on an anecdotal level. For example, one anecdote in the MISO footprint is that outages were reduced dramatically by a legislative mandate for hardening. Before the hardening mandate, certain weather events would have caused outages of 70,000–80,000 customers, but after hardening those same events only affected 5,000 customers.

B. Enhancing the resilience of generation and transmission is underway.

Some Regulators already have implemented a number of resilience improvements for the distribution system, as identified above in sections 1 and 3. These commissions and their utilities have also bolstered resilience in their respective state's generation[52] and transmission portfolios, examples of which are provided below:

- Participating in regional and interregional transmission planning, which helps to bolster resilience
- Creating local planning criteria to supplement NERC's mandatory planning criteria[53]

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[51] Example reporting requirements include Indiana 170 IAC 4-1-23(e) and Wisconsin Administrative Code, ch. PSC 113.

[52] The North Dakota PSC is concerned about whether operating resilience is being compromised by the ongoing shift away from thermal baseload generation in the resource mix and how that may affect the BPS's ability to resist frequency change when load and generation become out of balance. See ND PSC (2018).

[53] MISO Tariff Attachment FF and Business Practice Manual 20 4.2.2. Transmission owners' local planning criteria can be found at https://www.misoenergy.org/planning/transmission-studies-and-reports/ - nt=%2Freport-study-analysistype%3ATO Planning Criteria&t=-1&p=0&s=FileName&sd=asc; See NERC TPL 001 4.

- Operating the transmission grid across MISO, allowing for the redirection of supply in cases of a contingency
- Exploring collaborative improvements to the MISO-Southwest Power Pool (SPP) seam between the OMS and the SPP RSC
- Increasing the geographic diversity of generators and transmission lines, reducing the likelihood of multiple component failures to a single event
- Installing phasor measurement units on the transmission grid[54]
- Considering fuel diversity (e.g., fuel type, unit size and location) in state resource planning processes

Not all of these attributes were implemented for purposes of resilience *per se*, but instead were by-products of other initiatives.[55]

C. Regulators have varying opinions on whether it would be helpful for industry to develop quantitative methods for measuring resilience.

To date, methods for measuring resilience, as well as for comparing and contrasting resilience investments, have not been widely adopted by industry.[56] Many organizations have developed competing quantitative methods that include measuring impacts not only to the electric system but also to other sectors and the community at large.[57]

Some Regulators prefer a qualitative approach reflecting the diversity of distribution systems over quantitative methods for measuring resilience. Other Regulators are open to considering quantitative methods for measuring resilience as long as those methods are developed collaboratively with industry, (not dictated by the federal government) and are customizable to the unique circumstances of their states. Until customizable and proven methodologies for measuring resilience are developed, these Regulators likely will continue to apply their existing tools that are used for reliability: risk-based analyses of the benefits and costs for proposed investments. Regardless of their preferred approach, Regulators will be heavily involved in the ongoing debate over whether quantitative versus qualitative methods for measuring resilience are the most useful, or whether both should be used.

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[54] PR Newswire (2013).
[55] OMS (2018c) at Q2.
[56] See Willis and Loa (2015) and Vugrin et al. (2017) at 11.
[57] The following reflect just some of the proposals for measuring resilience and evaluating proposed improvements: National Infrastructure Advisory Council (2009), Argonne National Laboratory (2013), Re:focus Partners (2015), Willis and Loa (2015), EPRI (2016), Larsen (2016), NARUC (2016), Vugrin et al. (2017), Taft (2017), Silverstein et al. (2018) and Unel and Zevin (2018).

4. Should utilities take more proactive approaches to investments in resilience?

A. Utilities are already evaluating, recommending and making investments in resilience.

Unless a regulator opens a docket or some other proceeding, the normal course of business is for utilities to evaluate resilience needs and either bring recommendations to the commission for consideration or make investments and request cost recovery in rate cases. The majority of utility recommendations that address reliability also address resilience.

Utilities have an overarching obligation to provide safe and reliable electric service to their customers. To meet that obligation, they must and do consider the performance of their existing distribution system and whether any improvements are required, which would include resilience. In addition, all utilities are complying with standards for reliability of the transmission grid and cybersecurity, which includes resilience.[58] Moreover, as noted above, utilities in several states are conducting distribution system planning and are modernizing their distribution grid, both of which include considerations of resilience. Utilities also actively participate in emergency planning with states to identify and weigh potential investments in resilience against HILF events.

Additionally, as demonstrated in response to question 1, some Regulators are sponsoring initiatives targeted at resilience or broader initiatives that include resilience. Utilities are participating in all of those initiatives.

B. Utilities and regulators are participating in regional and multisector resilience planning exercises.

States and their utilities participate in regional and multisector resilience planning efforts such as GridEx. According to the NERC Website,[59] GridEx IV:

> …is the biennial exercise designed to simulate a cyber/physical attack on electric and other critical infrastructures across North America, and will involve:

- Electric Utilities;
- Regional (Local, State, Provincial) and Federal Government agencies in law enforcement, first response, and intelligence community functions;
- Critical Infrastructure Cross-Sector partners (ISACs and other utilities), and [;]
- Supply Chain stakeholder organizations.

Regional exercises are a platform to (1) force expanded thinking on what could happen and how parties would react, (2) have discussions about options and best practices, and (3) test existing assumptions

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[58] In a recent filing to FERC, NERC stated "resilience is a component of reliability in relation to an event and thus an implicit feature of NERC's activities." NERC (2018a) at 1-2.

[59] NERC. GridEx. https://www.nerc.com/pa/CI/CIPOutreach/Pages/GridEX.aspx

about current protections/processes and whether they are effective. Some Regulators would welcome more exercises like GridEx because their commissions and utilities have learned valuable lessons. Some states have organized their own in-state multisector resilience exercises with their utilities. These types of exercises can range from smaller-scale “table-top” exercises to larger-scale, hands-on simulations.[60]

5. How can decisionmaking about resilience investments be improved?

The electric industry and its regulators have not reached consensus on the definition of resilience, how to measure it and how to improve it. Similarly, there is no consensus as to whether improvements to resilience decisionmaking are needed and, if so, what they are or how to develop them.

The current debates are similar to early debates on reliability prior to its attributes being unbundled. Is resilience simply an attribute of reliability that needs to be unbundled? Or is there a benefit in creating a stand-alone category with unique processes and indices?

Regulators are both participants in, and beneficiaries of, continued discussion and focus on this issue. In the meantime, Regulators are making decisions about resilience investments — whether standalone or as a component of reliability — that are based on risk analyses conducted by their utilities.

A. Given the changing threats, the regularity of the process may be as important as the process itself.

The threats that electric systems face today may not be the same threats that they face tomorrow. These changing threats are not limited to terrorism. One Regulator noted that the state had several 500-year flood events in the last decade.

As discussed in response to question 4, some Regulators have instituted or are participating in periodic processes to address resilience specifically. Some Regulators and utilities receive regular security briefings where they learn of, among other things, emerging threats. Having a regularly scheduled process ensures that regulators and utilities are cognizant of not only emerging threats but also changes in their electric systems’ vulnerabilities.

Where a utility’s service territory spans more than one state, the regulators of all pertinent states may wish to consider meeting to discuss the resilience of the utility’s electric system because HILF events and electrical disturbances know no political boundaries.

[60] Since 2013, Indiana has periodically convened in an executive session with its utilities and RTOs to discuss their ongoing efforts regarding cybersecurity information, planning and preparedness practices. In 2016, Indiana also conducted a Critical Exercise (Crit-Ex), sponsored by the Indiana Department of Homeland Security, Indiana Office of Technology and the Indiana National Guard. The event brought together two federal agencies, eight state agencies and 15 private sector organizations. The exercise was formulated to explore the intersection between critical infrastructure and cybersecurity. Wisconsin practices a widescale multisector exercise approximately every six months. The latest was the Dark Sky exercise conducted May 15–17, 2018. Wisconsin Department of Military Affairs (2018).

B. Feedback loops are beneficial in measuring the performance of investments.

Currently, regulators receive feedback from utilities on their distribution systems through the reliability metrics of SAIDI, SAIFI and CAIDI. Historically, these metrics only measured normal operations. Data from extended outages were not included in the calculations to avoid skewing the results. However, since the Institute of Electrical and Electronics Engineers (IEEE) developed a definition for MEDs, some Regulators now require their utilities to report reliability indices with and without major events.[61] Data for outages during MEDs could be helpful in measuring the performance of resilience investments.

C. Interstate and regional data access and planning are important.

FERC, NERC, Regional Entities and MISO have the interstate and regional data necessary to evaluate and bolster the resilience of the BPS. However, the interstate and regional data that are applicable to a state's distribution or generation system can be more diffuse and difficult to obtain.

1. Greater Understanding of Out-of-State Threats and Vulnerabilities Would Be Beneficial for Multisector Resilience Planning

While regulators and utilities have access to data within their state boundaries, gathering information about out-of-state supply chains can be difficult.[62] For example, the ability to transport a large transformer or a portable substation from a shared inventory location or the potential interruption of out-of-state natural gas supplies could be concerns for regulators.

The first step in resolving this challenge may be for regulators and utilities to identify the key out-of-state supply chains necessary for the resilience of in-state electric supply. With that list, utilities can then investigate how best to gather information about the threats and the vulnerabilities of those supply chains and, hopefully, information about the probability for interruptions. Depending on the importance of the commodity and the probability for an interruption, utilities may choose to run a risk analysis on the costs and benefits of finding an alternative supply, a redundant supply or eliminating the need for that commodity.

2. Greater Participation in Regional and Sector Resilience Planning

As noted in response to question 4, states are already actively participating in regional and multisector planning. Regulators find these regional exercises to be beneficial. One Regulator specifically asked for an exercise focused on "identifying the silos that may arise during and after" a HILF event. But while these exercises are useful, another Regulator quoted a well-known prizefighter: "everyone has a plan until they get punched in the mouth."

D. Sharing best practices as they are developed would be helpful.

Distribution system resilience remains undefined and the methods for measuring it elusive. Identification and availability of best practices developed by regulators and industry would be beneficial information as the idea of resilience continues to evolve. These practices could include such things as:

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[61] Minnesota PUC (2018).

[62] Cyberattacks and supply-chain issues were discussed during the NARUC summer meetings in July.

- How utilities are running risk analysis for HILF events
- Reporting requirements for electric system performance that highlight resilience
- Common questions commissioners could ask their utilities about resilience
- Convening more interstate or intrastate exercises

Conclusion

Resilience is an evolving concept. Both regulators and industry are addressing resilience either as a stand-alone concept or under the auspices of reliability. Regulators throughout the MISO region have engaged in significant efforts that may bolster the resilience of the electric systems under their jurisdiction, but there is no single structure or process that dominates regulators' thinking on the best path forward. The additional tools identified in this essay could be helpful as the concept of resilience continues to develop. In the meantime, Regulators will continue to work with their utilities and others in the industry to respond to electric system needs. Other than taking part in such industry conversations, the federal government should not involve itself in resilience outside of the BPS.

2. A Cooperative Perspective on Utility Investments in Resilience

By Randolph Elliott, National Rural Electric Cooperative Association

Introduction

The resilience of the nation's electric power system has become an important public policy issue due to a combination of factors, including natural disasters, intentional attacks, technological and economic changes, and federal government activities.

Natural disasters. In the last decade, several high-profile natural disasters have caused widespread electric outages and infrastructure damage. The list includes Hurricane Katrina (2005), Superstorm Sandy (2012), Hurricane Harvey (2017) and Hurricane Maria (2017), which devastated Puerto Rico's electric grid. The 2011 meltdown of Japan's Fukushima nuclear power plant following an earthquake and tsunami raised concerns about similar vulnerabilities of U.S. nuclear plants.

Intentional attacks. Cyberattacks on electric infrastructure in the United States and abroad — such as the malware that shut down part of Ukraine's electric grid in 2015 — have made cybersecurity a high priority for U.S. electric utilities, regulators and national security officials. The attack on transformers at a high-voltage transmission substation in California in 2013 brought attention to the need for physical security of critical electric infrastructure.

Technological and economic changes. The electrification and digitization of the economy have heightened concerns about the resilience of the electric power system. Customers today expect and depend on reliable, high-quality electric service. Critical sectors of the economy, including water, telecommunications, transportation, health care, and banking and finance depend on reliable electric service. On the flip side, the electric sector's dependence on gas, water, transportation and telecommunications services means these services are also potential vulnerabilities to the resilience of the electric power system. The prolonged shutdown of Aliso Canyon natural gas storage field in California and concern about wintertime fuel security in New England have focused attention on the sector's dependence on natural gas infrastructure. In addition, the nation's generating resource mix is changing with retirements of coal and nuclear generating units, greater reliance on natural gas-fired generation, and rapid growth of wind and solar generation, prompting a discussion of whether the electric power system will have the necessary resources to ensure reliability and resilience of service.

Federal government activities. In September 2017, the U.S. Department of Energy (DOE) proposed that the Federal Energy Regulatory Commission (FERC) adopt a "grid resilience pricing rule" to ensure that generating plants with 90 days of fuel onsite were adequately compensated for their contribution to grid resilience.[63] In January 2018, FERC declined to adopt the proposal but instituted a new proceeding to examine the resilience of the nation's bulk power system (BPS) in regions of the country with regional

[63] Grid Resiliency Pricing Rule, 82 Fed. Reg. 46940 (Oct. 10, 2017) (notice of proposed rulemaking).

transmission organizations (RTOs) and independent system operators (ISOs).[64] DOE is reported to be exploring other authorities it may have to prevent the retirement of fuel-secure generation from affecting national security.[65]

How should electric utilities, regulators and consumers respond to calls to ensure and enhance the resilience of the electric power system? This essay looks at resilience investments for electricity systems by considering the five questions this report addresses from the perspective of rural electric cooperatives.

The National Rural Electric Cooperative Association (NRECA) is the national service organization for America's electric cooperatives. The nation's member-owned, not-for-profit electric co-ops constitute a unique sector of the electric utility industry — and face a unique set of challenges. NRECA represents the interests of the nation's more than 900 rural electric utilities responsible for keeping the lights on for more than 42 million people across 47 states. Electric cooperatives are driven by their purpose to power communities and empower their members to improve their quality of life. Affordable electricity is the lifeblood of the American economy, and for 75 years electric co-ops have been proud to keep the lights on. Because of their critical role in providing affordable, reliable and universally accessible electric service, electric cooperatives are vital to the economic health of the communities they serve.

Overall, the United States has a remarkably resilient electric power system today. Cooperatives and other electric utilities, the North American Electric Reliability Corporation (NERC) and utility regulators have long been dedicated to ensuring not only that the lights remain on, but also that we can recover quickly when the lights go out. The electric power system is undergoing significant changes that make it important for utilities, NERC and utility regulators to reassess and adjust industry practices — and where necessary regulatory requirements and structures — to ensure we are able to maintain reliability and resilience. Although the federal government should continue to guide and assist electric utilities, NERC and state and local regulators in these efforts, no massive federal regulatory intervention appears warranted at this juncture.

Electric utilities such as co-ops should remain the locus for decisionmaking on investments to ensure the resilience of the electric power system. In the end, most resilience issues are local — primarily on the distribution system, requiring local solutions by electric utilities working with their communities. By preserving local control and enabling local planning, policymakers can best ensure cost-effective investments in infrastructure and practices to ensure a reliable and resilient electric system.

Defining resilience

Before turning to these questions, it is important to define the terms being discussed. In particular, what is meant by resilience of an electric power system? How is it different from reliability?

[64] Grid Resiliency Pricing Rule, 162 FERC ¶ 61,012. ("Grid Resilience Order"). FERC (2018a).
[65] See Dlouhy (2018), Plumer (2018), and Whieldon (2018).

A spokesman for a state utility commission recently distinguished reliability and resilience this way: "Reliability is can you take a punch. Resilience is how fast you get up off the canvas after you've been hit hard."[66] That metaphor is not far from how government and industry bodies have tried to define the concepts. Thus, a 2017 report by the National Renewable Energy Laboratory (NREL) defined reliability as "the ability of the grid to resist interruptions," and resilience as "the ability of the grid to respond to and recover from disruptions, minimizing their magnitude and duration."[67]

Reliability is generally understood as "keeping the lights on." As required by the Federal Power Act (FPA) and FERC orders, NERC has developed reliability standards to provide for an "adequate level of reliability" of the BPS.[68] These mandatory, enforceable reliability standards have become accepted and well-understood features of electric utility planning and operations, and they have enabled the industry to achieve high levels of reliability for the BPS.

In addition, FERC has used its FPA authority over interstate transmission and wholesale sales to adopt planning and operating requirements to ensure grid reliability. For example, in Order No. 842, FERC modified the *pro forma* Large Generator Interconnection Agreement and *pro forma* Small Generator Interconnection Agreement to require newly interconnecting generators to be capable of providing primary frequency response as a condition of interconnection to the interstate grid.[69]

No single organization establishes reliability standards for electric distribution systems. But state and local utility regulators often set standards for allowable customer or system outages. Therefore, distribution system reliability is usually measured by statistical indices such as System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Frequency Index (CAIFI) and Customer Average Interruption Duration Index (CAIDI).[70]

Resilience, on the other hand, is not as well defined, and there are no universal, established metrics for electric utilities and regulators to gauge performance or weigh possible investments to enhance resilience.[71] Thus, a 74-page report on performance metrics for RTOs, ISOs and individual electric utilities issued by FERC staff in 2016 and revised in 2017 does not even use the word "resilience."[72] Sue Tierney, former Assistant Secretary for Policy at DOE, commented in 2017 that "in spite of all the lip

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[66] Sisk (2018).
[67] National Renewable Energy Laboratory (2017).
[68] 16 U.S.C. § 824o(c)(1). See Comments of North American Electric Reliability Corporation, *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, FERC Docket No. AD18-7-000 (filed May 9, 2018).
[69] Essential Reliability Services, and the Evolving Bulk-Power System—Primary Frequency Response, Order No. 842, 83 Fed. Reg. 9636 (Mar. 6, 2018), *clarified and reh'g denied*, 164 FERC ¶ 61,135 (Aug. 24, 2018).
[70] See IEEE Standards Association (2018), 8; DOE (2017), 4-4 to 4-6 (Quadrennial Energy Review (QER) 1.2); NAS (2017) 2-26 to 2-28; Vigurin, Castillo, and Silva-Monroy (2017), 7.
[71] DOE (2017), 4-42. See the response to question 1 below.
[72] FERC (Aug. 2016; rev. Aug. 2017).

service paid to resilience, there is no common understanding of what it means, how it can be measured and assessed, who is responsible for assuring it, and how it can be delivered."[73]

Efforts to define and describe resilience are ongoing in government and industry. These efforts, spanning the last decade, reveal a common understanding among many parties of the broad contours of resilience, but have not yielded universal definitions, standards or metrics analogous to BPS reliability standards or customer or system outage indices.

In its January 8, 2018, order rejecting DOE's grid resiliency pricing proposal and instituting a new proceeding on *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, FERC proposed this definition of resilience: "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."[74]

The Commission based this proposed definition on a 2009 National Infrastructure Advisory Council (NIAC) report on resilience of critical infrastructure (not just electric infrastructure).[75] There, NIAC distinguished infrastructure protection — "the ability to prevent or reduce the effect of an adverse effect" — from infrastructure resilience — "the ability to reduce the magnitude, impact, or duration of a disruption. Resilience is the ability to absorb, adapt to, and/or rapidly recover from a potentially disruptive event."[76] In a follow-up 2010 report, NIAC used that definition to develop a "resilience construct" to describe and organize risk-management practices used in the electricity sector.[77] The NIAC resilience construct has four elements, quoted here in full:

- **Robustness** — The ability to keep operating or to stay standing in the face of disaster. In some cases, it translates into designing structures or systems to be strong enough to take a foreseeable punch. In others, robustness requires devising substitute or redundant systems that can be brought to bear should something important break or stop working. Robustness also entails investing in and maintaining elements of critical infrastructure so that they can withstand low-probability but high-consequence events.
- **Resourcefulness** — The ability to skillfully manage a disaster as it unfolds. It includes identifying options, prioritizing what should be done both to control damage and to begin mitigating it, and communicating decisions to the people who will implement them. Resourcefulness depends primarily on people, not technology.
- **Rapid recovery** — The capacity to get things back to normal as quickly as possible after a disaster. Carefully drafted contingency plans, competent emergency

[73] Tierney (2017).
[74] FERC (2018a), 23.
[75] Id., 23, n. 38.
[76] National Infrastructure Advisory Council (NIAC) (Sept. 8, 2009), 8.
[77] NIAC (2010), 16–17.

operations, and the means to get the right people and resources to the right places are crucial.

- **Adaptability** — The means to absorb new lessons that can be drawn from a catastrophe. It involves revising plans, modifying procedures, and introducing new tools and technologies needed to improve robustness, resourcefulness and recovery capabilities before the next crisis.[78]

Roughly speaking, the first three elements of NIAC's construction concern actions before, during and immediately after a disruptive incident. The fourth element relates to post-incident learning that is adapted into the first three elements over time, although lessons presumably may be learned during as well as after an incident and thus be part of "resourcefulness."

The 2017 National Academy of Sciences report, *Enhancing the Resilience of the Nation's Electricity System,* described the NIAC construct and distinguished resilience from reliability:

> 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.[79]

A 2016 report by the Electric Power Research Institute (EPRI), *Electric Power System Resiliency: Challenges and Opportunities*, employed a slightly different formulation for resilience, consisting of three elements:

- Damage prevention: the application of engineering designs and advanced technologies that harden the power system to limit damage
- System recovery: the use of tools and technologies to restore service as soon as practicable
- Survivability: the use of innovative technologies to aid consumers, communities, and institutions in continuing some level of normal function without complete access to their normal power sources[80]

The first two elements of EPRI's formulation resemble the first and third parts of NIAC's resilience construct and refer to actions before and immediately after a disruption. "Survivability," like NIAC's concept of "resourcefulness," refers to actions during a disruption, although NIAC's focus was "primarily on people, not technology."[81] An example of survivability

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[78] NIAC (2010), 16.
[79] NAS (2017), 1–10.
[80] Electric Power Research Institute (2016), 14.
[81] NIAC (2010), 16.

in EPRI's report is using distributed generation to power critical services such as hospitals, mobile phones and traffic lights to ride through an outage until normal service can be restored.[82] Microgrids have the capability to provide greater survivability for communities and critical institutions and services.

For purposes of this essay, NRECA will use a working definition of resilience developed by its staff:

> ***The ability to maintain normal or near-normal service or status of the system through planning, prevention, mitigation, response and recovery efforts.***

This definition embodies concepts from both the NIAC/FERC/NAS and EPRI constructs: robustness (planning, prevention), resourcefulness (mitigation), rapid recovery, adaptability (planning) and survivability (maintaining near-normal service or system status). This definition also has important implications for discussions about resilience and resilience investments.

First, resilience is focused on end-use consumers. The goal is resilient service, not just resilient infrastructure or assets. Decisions about resilience investments should be driven by the consequences for end-use consumers, including cost. For electric cooperatives, this perspective is in keeping with their ultimate purpose of providing safe, affordable and reliable electric service to their consumer-members.

Second, resilience looks not just to the hardening or upgrading of infrastructure and assets but also at investments in people, processes, organization, coordination and emergency response.[83]

Third, resilience is broader than reliability. Reliability remains a keystone objective of every electric utility. Thus, cooperatives' investment and operational decisions will continue to seek to minimize the frequency, duration, and magnitude of system and customer outages. But resilience looks beyond the traditional measures of BPS and distribution-system reliability.[84] The distinction is not always a bright line, but several differences are evident:

- Resilience usually refers to the entire end-to-end electric system, while reliability can also refer to individual components.
- Resilience includes more consideration of what happens after an event causes an outage to occur, including how to minimize and mitigate the economic and human consequences and how to survive the event by maintaining a level of service to provide for high-priority public needs.

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[82] EPRI (2016), 15.
[83] See NIAC (2010), 17. Also see the response to question 3 below.
[84] Silverstein, Gramlich and Goggin argue that considering resilience from the customer perspective means that the frequency, duration, and magnitude of outages should be the measure of resilience and the driver of resilience-related decisions. Silverstein, Gramlich, and Goggin (2018), 56. This analysis properly focuses on service to end-use customers as the key factor, and these measures of service quality are relevant, but they are nonetheless incomplete, since resilience encompasses more than traditional reliability as captured by these measures.

- Resilience focuses more on high-impact, low-frequency events, such as major hurricanes, major earthquakes, massive cyberattacks, or geomagnetic disturbances (sometimes called "black sky" events), while reliability focuses more on recurring contingencies and threats ("blue sky" events).[85]

Reliability and resilience investments nonetheless may overlap: Some threats, such as bad weather or cyberattacks, may affect both reliability and resilience, and some utility investments may improve both reliability and resilience. But resilience investments may have slightly different, broader objectives than improving traditional reliability.[86]

Finally, resilience is all about *local planning* and *local decisionmaking*. From the electric cooperative perspective, this is a key point. As load-serving entities, with a legal obligation to serve their consumer-members (or in the case of a generation and transmission (G&T) co-op, with a contractual obligation to serve their distribution co-op members), cooperatives engage in long-term planning to manage risk and optimize the system to meet their business and regulatory goals. These goals may include safety, affordability, reliability, resilience, regulatory compliance, environmental sustainability, power quality, fuel supply risk, fuel price risk, energy price risk and capacity price risk. Long-term planning enables cooperatives to provide safe, affordable, reliable electric service at stable, reasonable prices to their communities. Resilience planning is a component of a cooperative's overall planning. Facilitating local planning and preserving local decisionmaking will help ensure cost-effective resilience investments for the benefit of consumers. Furthermore, resilience planning involves more than just utility planning and should involve planning and coordination with other entities in the community.[87]

Two recent examples illustrate some of these ideas. Anza Electric Cooperative in the high desert of Southern California recently lost all incoming transmission service to its system when wildfires destroyed portions of the Southern California Edison Company's radial transmission line that connects Anza to the rest of the California electric grid. Restoring transmission service to Anza took over a week, because Edison crews had to rebuild nearly 130 overhead transmission structures in extremely rugged terrain. Anza began working with its wholesale supplier, Arizona Electric Power Cooperative, on emergency plans before the fires reached the Edison transmission line. They brought in a fleet of five trailer-mounted diesel generators to provide power to meet most of Anza's demand on most of its system, although some service rotations were still necessary. According to Anza's CEO, "Keeping some

[85] IEEE Standards Association (2018), 2; Stockton(2014).

[86] NERC has stated that the NIAC and FERC conception of resilience is "an element" of the reliable operation of the bulk power system, and that NERC's reliability standards, reliability assessments and related analytical activities address resilience. See NERC Comments, *Grid Resilience in Regional Transmission Organizations and Independent System Operators* at 4–17. Silverstein, Gramlich and Goggin (2018) agree with this characterization. See Grid Strategies LLC (2018), 9–13. NRECA does not dispute that enhancing reliability can also enhance resilience, and it does not discount the importance of NERC's reliability standards or its growing attention to resilience. But that does not mean electric system resilience is a *subset* of reliability. Resilience addresses a broader set of concerns than either BPS reliability or total electric system reliability.

[87] See the response to question 2 below.

power available allowed our members to provide basic services like pumping water from their wells, keeping electronic devices charged, and maintaining telecommunications service." In its long-term planning, Anza has concluded that building a second transmission line is cost-prohibitive. But the co-op, which already has substantial utility- and customer-owned solar resources on its distribution system, is exploring adding solar capacity plus battery storage to provide a microgrid capability that would enable it to provide critical service in the event of a future loss of the Edison radial transmission line.[88]

The effort to get the lights back on in Puerto Rico after Hurricane Maria illustrates the need to incorporate resilience in long-term planning. A *New York Times* article describes an electric grid one year later that is operating again but far from resilient:

> After spending $3.2 billion, erecting some 52,000 new electrical poles and stringing 6,000 miles of wire from the federal government alone, the Puerto Rico electricity system is not in much better condition now than it was before Maria cut power to every home and business on the island.
>
> Even as some of the last customers are reconnected, many billions of dollars more must still be spent to reconstruct the system and fortify the transmission lines that have been so tattered and poorly maintained that when a mishap occurs, the lights can go out on the entire island.
>
> The new head of the electric utility estimates that up to one-quarter of the work done hurriedly to illuminate Puerto Rico after the storm will have to be redone.
>
> "There are many patches — too many patches — developed just to bring power to the people," said José Ortiz, the new chief executive of the power authority, known as Prepa. "Now we have to redo that thing."
>
> …
>
> Michael Byrne, the federal disaster recovery coordinator for Puerto Rico, said the utility's task now is to design and build a resilient distribution and transmission system that can better withstand problems large and small.
>
> Asked to describe the island's power grid, Mr. Byrne said, "It's stable, but fragile."[89]

A DOE report on *Energy Resilience Solutions for the Puerto Rico Grid* recommends in the near term that "transmission towers installed specifically for temporary emergency restoration should be considered

[88] Holly (2018a,b), Mitnick (2018), 44–46; Post-Technical Conference Comments of the National Rural Electric Cooperative Association, *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, FERC Docket No. RM18-9-000 (June 26, 2018) (Statement of Kevin Short).
[89] Robles (2018).

for prioritized replacement, potentially by monopoles," since "[m]any round monopole structures withstood the storm effectively."[90] In addition, recommended long-term recovery planning goals include "[e]nsuring that investments will result in modern, intelligent infrastructure systems that are affordable, reliable, and resilient …" and "[u]ndertaking the analysis and planning necessary to de-risk those investments and identify an effective mix of centralized and distributed energy resources of different fuel types."[91] Puerto Rico's experience provides important lessons for every utility and regulator to incorporate in resilience planning and investments. Long-term planning is an essential component of ensuring a resilient electric system while controlling costs and maintaining affordable service. With improved planning, utilities and regulators can help ensure that consumers do not have to pay twice for redoing emergency repairs — a particularly harsh blow for Puerto Rico.

1. What level and scope of resilience do we need and how much are we willing to pay?

From the perspective of an electric cooperative, the questions of how much resilience is needed and how much should be invested to enhance resilience will be addressed in the cooperative's long-term planning process. Electric cooperatives are private, independent electric utilities, owned by the members they serve. They are governed by a board of directors elected by and from the membership, which sets policies and procedures that are implemented by the cooperatives' professional staff. Democratic governance ensures that electric cooperatives are anchored in the communities they serve and regulated by their consumers. Resilience-enhancing investments will be part of the cooperative's long-term resource planning and investment decisions, driven by the needs of the cooperative's consumer-members and subject to the cooperative's principles of democratic self-government. This local planning process allows a cooperative to balance reliability, resilience, cost, and many other factors in optimizing its investment decisions and enables cost-effective resilience investments.[92]

The literature generally describes resilience against the consequences of specific risks or threats to electric power systems. There are many potential causes of system failure. These include both known, historical risks (e.g., natural disasters) and emerging risks (e.g., cyberattacks).[93] "Insuring" against these risks is a complicated endeavor because, as the National Academy of Sciences explained in its 2017 report *Enhancing the Resilience of the Nation's Electricity System*, "different causes require different preparation and have different consequences."[94] The consensus recommendation to electric utilities has been to take an "all-hazards" or "multi-hazard" approach to resilience by developing a portfolio of actions to mitigate multiple risks.[95]

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[90] DOE (2018), 42.
[91] Id.
[92] In most states, the cooperative's elected board of directors establishes rates and sets policies governing its services. In a few states, cooperatives' rates and services are regulated by the state public utility commission.
[93] NIAC (2010), 28–32; NAS, 3-1 to 3-27; DOE (2017), 4-25 to 4-37; EPRI (2016), 6–13; Silverstein, Gramlich and Goggins (2018), 23–38.
[94] NAS, 3-3.
[95] See NAS, 1-8; IEEE (2018), 8; Silverstein, Gramlich and Goggins (2018), 54; DOE (2016a).

Following is a list of the major risks and threats that may be considered in planning and decisions on resilience investments by cooperatives and other electric utilities:

- Extreme weather
  - Hurricanes
  - Tornadoes
  - Floods
  - Ice storms
  - Cold snaps
  - Heat waves
  - Droughts and water shortages
- Other natural threats
  - Earthquakes and tsunamis
  - Volcanoes
  - Wildfires
  - Vegetation
  - Wildlife
  - Insects (e.g., bark beetles or emerald ash borers damaging trees near power lines)
  - Space weather, geomagnetic disturbances (GMD)[96]
- Cyberattacks
  - BPS elements (generation facilities, transmission facilities, control centers)
  - Distribution facilities and control systems
  - Customer assets, including distributed energy resources (DERs) and Internet of Things (IoT) devices[97]
- Physical attacks
  - BPS elements (generation facilities, transmission facilities, control centers)[98]
  - Distribution system assets (distribution lines, substations, transformers, control centers)
  - Customer assets
  - Electromagnetic pulse (EMP) attacks[99]
- Operation errors and insider attacks
- Fuel security risks
  - Fuel supply interruptions, curtailments or shortages

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[96] See Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events, Order No. 830, 81 Fed. Reg. 67120 (Sept. 30, 2016) (FERC order approving NERC GMD reliability standard), *reh'g denied*, 158 FERC ¶ 61,041 (2017). See also Geomagnetic Disturbance Reliability Standard, 83 Fed. Reg. 23854 (May 23, 2018) (FERC notice of proposed rulemaking to approve revised GMD reliability standard).
[97] DOE (2017), 4-12 to 4-13 and 4-20 to 4-22.
[98] See Physical Security Reliability Standard, Order No. 802, 79 Fed. Reg. 70069 (Nov. 25, 2014) (FERC order approving NERC physical security reliability standard).
[99] EPRI (2016), 12.

- Fuel transportation (pipeline, truck, rail, barge, tanker) or storage interruptions or operational constraints
- Pandemics (may affect the utility workforce)

In making decisions on investments to ensure the safety and reliability of its system, an electric cooperative or other utility will be guided in the first instance by the need to comply with NERC reliability standards and other federal, state and local regulatory requirements. For example, a utility can use traditional measures of distribution service reliability using historical data, such as SAIDI, to determine how much reliability it needs and how much it is willing to pay for it through investments in new infrastructure or technology or improved operations or processes. A utility can use tools such as the "Interruption Cost Estimation" (ICE) Calculator developed for DOE by Lawrence Berkeley National Laboratory and Nexant.[100] These reliability investment decisions may be complex, but they are the traditional domain of utility planning.

By contrast, there are no clear standards or measures of resilience to govern utility investment decisions. In 2010, the National Infrastructure Advisory Council concluded that "[w]ith no universal definition of resilience, the electricity sector has not developed sector-wide outcome-based resilience goals."[101] In 2017, the National Academy of Sciences, in its report *Enhancing the Resilience of the Nation's Electricity System*, reached the same conclusion and noted the relative paucity of data to inform resilience investment decisions: "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)."[102]

Established measures of reliability based on historical outage data like SAIFI and SAIDI are of limited usefulness for measuring resilience, as the IEEE Standards Association explains:

> Although classic reliability indices include the effects of routine weather, they exclude so-called black sky conditions, which represent catastrophic storms and other low-frequency or unusual events that can have a high impact on the functioning of the grid. As a result, reliability measurements do not give us statistical insights on how power systems or networks perform during major outage events.[103]

In a recent order directing ISO New England to address regional fuel security concerns, FERC observed that there are no established standards for fuel security: "We note that fuel security analyses do not

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[100] See the ICE Calculator home page at https://icecalculator.com/home. See also Sullivan et al. (2018).
[101] NIAC (2010), 16.
[102] NAS (2017), 2-28. See also DOE (2017), 4-43 ("There is no established method for quantifying the benefits of investments, which depend on the occurrence of some events with low probabilities.").
[103] IEEE (2018), 2. In the second installment of the QER, DOE concluded that the problem with these indices is inconsistency, because "utilities have historically reported SAIDI, SAIFI, and CAIDI statistics in inconsistent ways; for example, some utilities include data associated with 'major events' … and others do not. Utilities also take inconsistent ways to defining 'major events.'" DOE (2017), 4-6.

currently have an established methodological framework and that there are no industry standards or best practices for conducting such an analysis."[104]

Because we have no common understanding of resilience and no established resilience standards, centrally organized wholesale electricity markets have not evolved very far in offering resilience products, services or price signals to guide electric utilities in determining how much resilience "insurance" they should be buying (either in the form of purchased products or services or in the form of self-insurance by their own resilience investments).[105]

Efforts are underway to formalize the utility decision process for resilience investments. These efforts often employ variations on the familiar model of cost-benefit analysis.[106] The end goal would be to identify the resilience benefits produced by potential investments, or portfolios of investments, and to quantify the present value — in dollars — of these benefits, so that the optimal amounts and types of investment can be determined. One of the challenges in applying traditional cost-benefit analysis to resilience investments is the absence of universal definitions and measures of resilience, as already noted. A further challenge in valuing the benefits is the substantial uncertainty inherent in the high-impact, low-frequency events that drive much of the concern with resilience. Nonetheless, as EPRI notes, "[a] flexible framework for cost-benefit analysis can help evaluate and prioritize investments to improve power system resiliency, and to weigh their value relative to other uses of scarce capital."[107] A long-term planning horizon enables a utility to evaluate resilience risks and potential solutions not only at a particular time, but over the lifetime of the potential investments, minimizing long-term costs and the risks of investments becoming stranded costs in the future.

Cooperatives are well-positioned to use system and consumer-member data to drive investment decisions on the distribution grid, whether in the technical architecture of the grid or in DERs or other devices on the grid. Cooperatives have in fact built a tool to harness some of those data to provide input to such decisions — a dynamic tool called the Open Modeling Framework (OMF) that performs time-series analyses of the distribution grid to assess the reliability and economics of different investments on distribution feeder systems. This tool is increasingly being adopted by electric cooperatives and the industry to analyze grids with time-varying generation and loads, such as variable renewable energy resources and demand response.

As noted above, from the cooperative perspective, decisions about resilience investments should be driven by the consequences for end-use consumers, including cost. An electric cooperative will seek to provide resilient service to all of its member-consumers. This may present some difficult questions of cost allocation and rate design. Some resilience investments will benefit the entire cooperative and are appropriate for recovery from all member-consumers. Yet some member-consumers, such as industrial

[104] ISO New England Inc., 164 FERC ¶ 61,003, at p. 52 (2018).
[105] The issue of market compensation for resilience attributes of generation resources, which was raised by DOE's grid resilience pricing proposal, is discussed in the response to question 5 below.
[106] For example, see EPRI (2016), 45–46; Vigurin, Castillo, and Silva-Monroy (2017); and Unel and Zevin (2018).
[107] EPRI (2016), 45.

facilities, may be willing to pay more for enhanced reliability or resilience measures, beyond those provided to ordinary residential consumers. It may be appropriate to segregate some resilience investment costs and design rates to allocate those costs to the member-consumers who benefit from the investment.

In sum, cooperative and other electric utilities must remain the locus of deciding how much resilience we need and how much we will spend to enhance it. Through the long-term planning process, electric utilities can identify the relevant resilience risks, assess the benefits and costs of alternative measures to address these resilience risks, and incorporate this analysis into the utility's overall investment decisionmaking.

2. Who's responsible for resilience, and how should other entities coordinate with utilities when there are mutual benefits?

Responsibility for the resilience of the electric power system in the United States is widely dispersed among many private and public entities. This is due to several factors, including the many different kinds of risks and threats to grid resilience described above: the electric sector's market structure, which includes 3,000 traditional electric utilities and a growing number of non-utility market participants, and the sector's decentralized, multilevel regulatory regime under our federal system of government. As DOE observed in its second installment of the Quadrennial Energy Review (QER), "the responsibility for maintaining and improving grid resilience lies with multiple entities and jurisdictions, including Federal and state agencies and regulatory bodies, as well as multiple utilities."[108]

Below is a list of entities with some share of the responsibility for the resilience of electric power systems in the United States:

- Electric utilities
    - Investor-owned utilities
    - Electric cooperatives (distribution cooperatives and G&T cooperatives)
    - Public power utilities (including joint-action agencies)
    - Federal utilities (Tennessee Valley Authority and the Power Marketing Administrations)
- Other electric power industry entities
    - RTOs and ISOs
    - Generating companies
    - Transmission companies
    - Distribution System Operators (DSOs) (proposed)
    - DER owners, operators, aggregators
    - Demand response (DR) providers and aggregators
    - Energy efficiency (EE) providers and aggregators

[108] DOE (2017), 4-42.

    - End-use customers (as owners of DERs and IoT devices)
    - Utility supply chain vendors (e.g., transformers, IT assets, OT, cyberassets)
- State and local utility regulators
    - State public utility commissions
    - City councils or local utility boards or commissions
    - Electric cooperative boards of directors
- Other state and local authorities
    - Public safety agencies
    - Emergency response and emergency preparedness agencies
    - Transportation agencies
    - State energy offices
- Federal agencies
    - FERC (transmission, wholesale markets, BPS reliability including physical and cybersecurity)
    - Nuclear Regulatory Commission (nuclear safety, facility security, emergency preparedness)
    - Federal Communications Commission (telecommunications, pole attachments)
    - Pipeline and Hazardous Materials Safety Administration (gas pipeline safety)
    - Department of Transportation - Transportation Security Administration (gas pipeline security)
    - Rural Utilities Service (electric cooperative facility standards and finances)
    - DOE (cybersecurity, emergency grid authority under FPA)
    - Department of Homeland Security (DHS)
        - Federal Emergency Management Agency (emergency planning and response)
        - DHS cybersecurity offices — e.g., National Risk Management Center[109]
        - U.S. Coast Guard
    - Federal Bureau of Investigation
    - Department of Defense
    - Department of Commerce - National Institute of Standards and Technology
- Other electric power industry bodies
    - NERC[110]
        - BPS reliability standards and enforcement
        - Reliability assessments
        - Event analysis
        - Electricity Information Sharing and Analysis Center (E-ISAC)

[109] See America's Electric Cooperatives (2018).
[110] See Comments of North American Electric Reliability Corporation, *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, FERC Docket No. AD18-7-000 (filed May 9, 2018).

- Electricity Subsector Coordinating Council (ESCC) (senior-level liaison between federal government and electric power sector)
  - IEEE Standards Association (National Electric Safety Code® — NESC®)[111]
  - EPRI (electric power industry research)
- Interdependent sectors
  - Natural gas production, transportation, distribution
  - Other fuel production and transportation
  - Telecommunications (landline, cellular, radio, satellite)
  - Water utilities

With so many different entities involved, and no clear lines of authority and coordination between these entities, no single entity is responsible for the whole picture. As Sue Tierney recently observed:

> At present, there is neither a legal framework nor an institutional structure that can fully assure the existence of a resilient grid that operates both across state lines and depends upon fuel-delivery and fuel-supply systems with the same high standards for reliability and cybersecurity that exist for the electric system.[112]

Given this dispersion of authority over matters that may affect the resilience of the electric power system, it is important that matters do not fall through the cracks. However, the fact that multiple entities share responsibilities for resilience does not mean that there is chaos and some massive federal intervention and oversight over all aspects of resilience are needed. Indeed, this dispersed authority can be viewed as a feature, not a bug. The current framework enables electric utilities and other entities to exercise authority within their respective domains and harness their knowledge and expertise to benefit the overall public interest in a resilient electric power system. This approach can be fairly described as "strength through diversity." Thus, as FERC noted in its January 2018 Grid Resilience Order, FERC has already taken multiple actions aimed at ensuring BPS resilience even without using that express term.[113] Importantly, this shared authority over the resilience of the electric power system allows for local planning and local decisionmaking by co-ops and other electric utilities, working with their local communities and regulators, over most resilience investments.

It is important that other entities coordinate with electric utilities in planning, emergency response and other activities to enhance resilience. For example, electric utilities and local public safety and transportation authorities need to coordinate on matters such as who is responsible for clearing

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[111] The IEEE Standards Association states that the purpose of the NESC® is "the practical safeguarding of persons and utility facilities during the installation, operation, and maintenance of electric supply and communication facilities, under specified conditions." It does not directly address reliability or resiliency. But it "provides a foundational level of structural robustness that, in turn, makes a positive contribution to overall system reliability and resiliency." IEEE (2018), 2.
[112] Tierney (2017).
[113] FERC (2018a), 12.

downed trees or other debris on the public road to a power plant, control center, or other critical electric facility to which access may be needed during an event.

As the list above shows, a large amount of coordination is required, among multiple entities, and not just between electric utilities and other entities. Some examples of ongoing coordination include:

- Emergency preparedness exercises such as Grid-Ex
- Local or regional emergency preparedness planning and drills with electric utilities and other entities
- Information sharing through E-ISAC and ESCC
- Mutual aid arrangements between electric utilities
    - Physical mutual assistance — an area where cooperatives excel: "A key aspect of effective mutual aid agreements is a shared set of operational and construction standards such as with RUS (the Rural Utilities Service) that many co-op utilities adhere to."[114]
    - Cyber mutual assistance[115]
- Sharing of spare parts inventories and equipment[116]
- Long-term research on resilience through DOE and EPRI
- Stakeholder processes in RTOs and ISOs or other regional markets such as the Western Energy Imbalance Market to develop new market rules to support regional grid resilience[117]

The comments by RTOs, ISOs and the public in FERC's ongoing proceeding on BPS resilience document that some resilience challenges, such as ensuring winter fuel security in New England, are regional in scope.[118] Regional study and coordination of measures to address such risks will be essential.

The need for coordination with electric utilities is growing with the evolution of the electric power grid and the electric industry. Cooperatives and other electric utilities need visibility concerning energy technologies integrated into distribution systems by other entities that could affect safety, reliability, resilience and security of distribution systems. Integrating and optimizing the operations of DERs such as solar and storage resources holds great promise to benefit the reliability and resilience of distribution systems. Distribution utilities can maximize these benefits by investing in infrastructure such as communications, sensors and new distribution equipment to leverage the capabilities of DERs.

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[114] IEEE (2018), 6, n.13.
[115] See Electricity Subsector Coordinating Council. Cyber Mutual Assistance. http://www.electricitysubsector.org/CMA/
[116] See Jurisdictional Regional Equipment Sharing for Transmission Outage Restoration Participants, 163 FERC 61,005 (2018) (approving RESTORE Agreement).
[117] See the RTO and ISO comments submitted on May 9, 2018, Grid Resilience in Regional Transmission Organizations and Independent System Operators, FERC Docket No. AD18-7-000.
[118] See the comments submitted by ISO New England on May 9, 2018, in Grid Resilience in Regional Transmission Organizations and Independent System Operators, FERC Docket No. AD18-7-000.

Investment in people and processes will also be important, because the list of entities with whom the local utility must coordinate now includes customers and other owners and operators of DERs.

Recent actions and a pending proposal by FERC — if not amended — could greatly complicate if not defeat this needed coordination between distribution utilities, their state and local regulators, and DER owners and operators. In 2016 FERC proposed to direct RTOs and ISOs to remove barriers in their wholesale market rules to participation by electric storage resources — including distributed storage and customer-owned behind-the-meter storage — and by aggregations of any DERs, including but not limited to distributed generation and storage.[119] In Order No. 841, FERC approved this proposal with respect to electric storage resources.[120] The DER aggregation proposal remains pending as of this writing. In comments on the DER aggregation proposal, NRECA has shown (among other things) that DER aggregations responding to wholesale market signals or RTO dispatch instructions could pose serious safety, operational, reliability, and economic consequences on distribution utilities and their customers.[121] Accordingly, NRECA has argued that FERC should require RTOs and ISOs to allow DER aggregations to participate in wholesale markets only with the assent of the relevant electric retail regulatory authority, which can be a state public utility commission, a city council or a board of directors of a cooperative, depending on state law.[122] This is the procedure FERC follows for aggregations of retail customers seeking to participate as DR resources in RTO/ISO energy markets.[123] But Order No. 841 omits this procedure, as does FERC's pending proposal for DER aggregations. A consistent adherence to this procedure not only would respect state and local jurisdiction over retail and distribution service, but it would also enable — rather than preempt — coordination between distribution utilities, their state and local regulators, the RTOs and ISOs, and DER owners, operators and aggregators, with the goal of maintaining safe, affordable, reliable and resilient electric service.

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119 Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 81 Fed. Reg. 86522 (Nov. 30, 2016) (notice of proposed rulemaking).

120 Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 841, 83 Fed. Reg. 9580 (Mar. 6, 2018), *reh'g pending.* NRECA has requested rehearing of Order No. 841.

121 Post Technical Conference Comments of National Rural Electric Cooperative Association, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, FERC Docket No. RM18-9-000 (filed June 26, 2018), https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14682523.

122 NRECA has made this same argument in its request for rehearing of FERC's Order No. 841. See Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 81 Fed. Reg. 86522 (Nov. 30, 2016) (notice of proposed rulemaking).

123 18 C.F.R. § 35.28(g)(1)(iii) (2018). See Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 64100 (Oct. 28, 2008), *order on reh'g,* Order No. 719-A, 74 Fed. Reg. 37775 (July 29, 2009), *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

3. What types of utility investments have the most impact on improving resilience, and how can utilities and regulators tell whether utility investments in resilience are impactful?

As already noted, resilience means resilience of service to end-use consumers and refers to the performance of the entire electric power system. In this context, deciding on utility investments to enhance the resilience of service over the electric power system is like three-dimensional chess:

- On one dimension, investments to enhance the resilience of the electric power system may span the system from end to end, including investments at the generation, transmission, distribution and (today) customer levels. For example, the EPRI 2016 report *Electric Power System Resiliency* describes actions that can be taken now at each of these levels with present technology, as well as innovative new technologies being developed that may enhance resilience.[124]
- A second dimension of resilience investments characterizes them by how they enhance resilience, using the underlying elements of resilience described earlier. Thus, investments can improve robustness, resourcefulness or survivability, rapid recovery, or adaptability.
- A third dimension of resilience investments refers to the general nature of the investment, which can be divided into two basic categories: investments in infrastructure and assets, and investments in people, processes, organization, coordination and emergency response.[125]

This simple visualization yields 32 (4x4x2) potential baskets into which resilience-investment dollars might be placed. If one considers the myriad different risks and threats to resilience, from earthquakes to cybersecurity, many of which require different responses, then the possible alternative investments are greatly multiplied. It is natural to think that a utility should not put all its eggs in one basket, so to speak. But how might a utility reasonably allocate scarce capital resources among the possible categories of investment?

For reasons already discussed, this is not a simple task. There are no established measures of resilience and no established ways of exploring the relative benefits of, or the trade-offs between, investing in, say, hardened generation assets or more cybersecurity protection for the distribution system.[126] There is no top-down solution; no "one-size-fits-all" formula for co-ops and other electric utilities to use.

[124] EPRI (2016), 18–44.
[125] Appendix B to NIAC (2010) has a lengthy list of selected resilience practices in the electricity sector, broken down by robustness, resourcefulness, rapid recovery and adaptability, and for each category lists practices involving infrastructure and assets separately from those involving people and processes.
[126] NRECA's response to question 5 in this essay discusses some ways this decision process could be improved by developing common reliance definitions and metrics.

Moreover, even if there were standardized resilience measures and standardized resilience analytical methods, many resilience risks and threats are local and require local solutions. Determining the appropriate resilience investments for a particular utility will depend on such matters as its resource mix, the topology of the regional transmission grid and local distribution grid, the topography of the utility's service area, local weather risks, local earthquake risks and the like. In other words, even though the decision process and the decision criteria might be standardized in some respects, the outcomes will not be. From the perspective of electric cooperatives, it is important to keep the decisions at the local level, where the cooperative's long-term planning process can consider the benefits and costs of investment alternatives in light of the needs and the situation of the individual cooperative's member-consumers.

In sum, it is difficult to make broad, definitive statements that the resilience of the nation's electric power system would be best enhanced by certain types of investments and not others. The appropriate investments will be different for different regions and different electric utilities.

But this is not to say that some general conclusions cannot be drawn from the available historical data and utility experience about some types of resilience-enhancing investments.

First, upgrading and maintaining distribution systems to reduce their vulnerability to weather-related failures is likely to be a cost-effective way to enhance resilience. The second installment of DOE's QER concluded that most power outages occur because of problems at the distribution level and not the BPS level.[127] Moreover, DOE reported that extreme weather conditions, such as hurricanes, blizzards, thunderstorms and heat waves, were the leading causes of power outages, especially widespread outages.[128] The IEEE Standards Association concluded that the data from industry studies "strongly suggests that effective pole maintenance and vegetation management programs are likely to produce a positive cost-benefit ratio."[129] Thus, hardening distribution systems and improving operational procedures may cost-effectively reduce the risks and consequences of extended outages and thus improve resilience.[130]

Second, even though most interruptions occur at the distribution level, there appears to be real value in pursuing a balanced portfolio of generating resources, both at the BPS level and at the distribution level. The changing BPS generation resource mix has focused attention on the value of "essential reliability services," such as voltage support and frequency response.[131] In response to this trend, as noted earlier,

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[127] See DOE (2017), 4-5. "Based on a reliability measure of average total duration of the interruptions experienced by a customer, more than 90% of the minutes lost by consumers annually are attributable to distribution events." EPRI (2016), 35.
[128] DOE (2017), 4-28. Indeed, all 12 of the largest outages in 2015 (measured by number of customers affected) were weather related. Id. Also see Larsen et al. (2015).
[129] IEEE (2018), 10.
[130] See Silverstein, Gramlich and Goggin (2018), 13–23.
[131] See Comments of NERC, *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, FERC Docket No. AD18-7-000, 17–18; See Comments of North American Electric Reliability Corporation in

FERC has required newly interconnecting generators to be able to provide primary frequency response as a condition for interconnection to the grid.[132] "No single type of generating technology provides all of the essential reliability services, and all technologies provide some of them."[133] Accordingly, resilience may be enhanced by utility investment in a balanced portfolio of resources that is capable of providing the needed quantities of essential reliability services to support reliability and resilient operations at the BPS level.

Although the issue is less discussed, the same may be said at the distribution level. With the evolution of the distribution grid to enable two-way power flows and a mix of utility- and customer-owned DERs, there may be a similar need for electric utilities to invest in DERs with the capability of providing essential reliability services like voltage support or frequency response on the local distribution system. An electric cooperative can make these decisions to optimize the entire system to maximize the benefit of these changes for all of its member-consumers.

Moreover, a balanced resource portfolio also mitigates fuel security risks. NERC has concluded that in addition to essential reliability services, "fuel assurance and diversity are critical elements of a reliable and resilient system."[134] With the growing share of natural gas-fired generation in the resource mix, NERC has noted the possibility of "common mode outages" affecting multiple gas-fired generation resources.[135] Investments in resource diversity measures, including DERs, may be warranted to ensure resilience against these emerging risks. As Sue Tierney recently observed:

> A resilient electric system, for example, needs a varied set of generating resources with diverse attributes: ones that are able to begin the process of energizing a system that has been completely blacked out; ones that can produce power quickly without having to warm up gradually over time; ones with sustained access to fuel supply; ones that are close to customers and don't require major restoration of downed power lines; ones that can be dispatched up as electric lines and customers are reconnected to the system; and many other important features and capabilities.[136]

In other words, investments in a properly balanced portfolio of resources may have a significant positive impact on the resilience of the electric power system.

Third, cybersecurity measures to protect against the adverse consequences of a massive cyberattack are likely to be a matter for ongoing investment given the rapid evolution of the threats themselves as well

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Response to Grid Reliability and Resilience Notice of Proposed Rulemaking, FERC Docket No. RM18-1-000 (filed Oct. 23, 2017).

132 Essential Reliability Services, and the Evolving Bulk-Power System—Primary Frequency Response, Order No. 842, 83 Fed. Reg. 9636 (Mar. 6, 2018), *clarified and reh'g denied*, 164 FERC ¶ 61,135 (Aug. 24, 2018).

133 Tierney (2017).

134 Comments of NERC, *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, FERC Docket No. AD18-7-000, 18.

135 Id.

136 Tierney (2017).

as the evolution of the electric grid and related communications technologies, which are introducing more points for cyber-intrusion into the electric power system.

Ex ante evaluation of possible resilient investments is difficult for the reasons already described. But what about ex post evaluation of whether utility investments intended to enhance resilience have in fact done so? Unfortunately, that too is difficult, for some of the same reasons. To the extent a resilience investment is made to mitigate a high-impact, low-frequency risk, the real-world test of the success of that investment may not happen for many years, if at all. Even comparisons with similar investments by other electric utilities may be difficult. The National Academy of Sciences concluded in 2017 that one reason why we do not have established resilience metrics today is that "there is not a long history of large-area, long-duration outages that can be analyzed to guide future investments …."[137] The very nature of resilience makes it challenging to develop tools for regulators to use in judging the impact of resilience investments. With more experience and with conscious work by industry and regulators, better evaluative tools may be developed in the years ahead.[138]

Despite the shortcomings in the data and tools now available to utilities and regulators, undertaking resilience-enhancing investments in the broad areas described above — hardening distribution systems, pursuing appropriate resource diversity, and enhancing cybersecurity — appears to offer the best "bang-for-the-buck" and "no-regrets" approach for the near term. Indeed, investments in these three areas are consistent with and will help buttress a longer-term, broader strategy of grid modernization by utilities and regulators.

4. Should utilities take more proactive approaches to investments in resilience?

From the perspective of electric cooperatives, the answer is a resounding yes: Electric utilities should take more proactive approaches because they are usually in the best position to make critical decisions on investments to enhance the resilience of the electric power system.

The threats to resilience listed in our response to question 1 are not going away. Many resilience risks are local, and therefore local solutions are needed. The dispersion of responsibility for resilience described in our response to question 2 enables electric utilities — working with their regulators and communities — to be the key decisionmakers on most investments in resilience. As described in our response to question 5, utility decisionmaking will be assisted over time by better data, metrics and decision tools, perhaps including better market price signals. But there appears to be no superior way to make these investment decisions than through the traditional process of long-term integrated resource planning by electric utilities, subject to oversight by the appropriate state and local regulators. Resilience can and should become a component of all utility investment decision-making processes.

[137] NAS, 2-28.

[138] An example of an ex ante and ex post cost-benefit analysis of undergrounding transmission and distribution lines is Larsen (2016).

Electric cooperatives are especially well-positioned to make these investment decisions, given their close relationship with the communities they serve. Cooperatives are able to focus on maximizing consumer value by integrating resilience investments with their overall investments in new resources and new technologies. The key for cooperatives' investment decisionmaking is long-term integrated resource planning. This planning involves the cooperative understanding and listening to its consumer-members and the community it serves. In doing so, cooperatives will be doing what they do best — serving as an efficient integrator and optimizer of generation, transmission, distribution, and consumer resources and loads, and as a provider of safe, affordable, reliable, sustainable and resilient electric service to their communities.

5. How can decisionmaking about resilience investments be improved?

The above discussion has noted the lack of any standard definition of resilience. "Despite growing concern over the critical need for enhanced resiliency," EPRI wrote in 2016, "there is no standardized framework for assessing resiliency levels or evaluating investment options."[139] In 2018, the IEEE Standards Association found no indication that this situation was going to change anytime soon:

> Although efforts to develop resilience metrics are underway across a number of organizations — including the DOE, [FERC] and multiple state public utility commissions — the industry is currently lacking agreed-upon performance criteria for measuring resilience, as well as a formal industry or government initiative to develop consensus agreement.[140]

The lack of recognized definitions and measures of resilience hinders utility planning and decisionmaking about investment. It also hinders the ability of electric utilities to communicate with their regulators and their communities about resilience issues and their investment decisions, which itself is a vital part of the utility planning process. Moreover, the lack of accepted definitions and measures of resilience hinders the evolution and reform of centrally organized wholesale power markets to develop market-based mechanisms to enhance the resilience of the electric power system and provide price signals to guide decisions on resilience investments.

Therefore, it seems clear that decisionmaking about resilience investments would be improved by an industry- or government-led initiative to develop consensus agreement on definitions of resilience and criteria for measuring some dimensions of resilience.[141] The objective should not be to impose "top-down," nationwide resilience standards (analogous to but necessarily broader than NERC reliability standards for the BPS) that displace or preempt the ability of RTOs, ISOs, utilities, and regulators to evaluate and respond to regional or local resilience risks, but rather to provide analytical tools and

139 EPRI (2016), 46.
140 IEEE (2018), 8.
141 An important part of such an initiative would be data collection and analysis of prolonged and widespread outages, their causes and their consequences. Agreements among electric utilities and other entities for the confidential sharing of such utility and customer data for purposes of this analysis would be required.

metrics to facilitate and improve "bottom-up" planning, coordination, and decisionmaking by regional bodies, state and local regulators, utilities and local communities.

An accepted definition of resilience and measurement criteria would enable electric utilities and regulators to use a more formalized, objective framework for cost-benefit analysis of resilience. Such analyses could be used retrospectively to assess resilience in response to a past disruptive event or prospectively to evaluate possible investments to enhance resilience. A 2017 Sandia National Laboratories report, *Resilience Metrics for the Electric Power System: A Performance-Based Approach,* describes how a more formalized analysis with defined, performance-based resilience metrics can be used to quantify baseline resilience and the improvements in resilience from potential investments.[142]

A limitation on such efforts, however, is the availability of data. Quantifying the costs and benefits of resilience investments requires extensive data as well as reliable definitions and metrics. The data needed to perform a complete, rigorous cost-benefit analysis may not be available today. Over time, this situation is likely to improve. Technological improvements, including smart-grid technologies, advanced metering infrastructure, advanced computational modeling, machine learning and artificial intelligence, should facilitate a more sophisticated, data-driven and objective process for decisionmaking about resilience investments at all levels of the electric power system.

At the distribution level, a more rigorous cost-benefit analysis for resilience would improve distribution planning and allow for the optimization of distribution investment by the utility, incorporating resilience into the decision-making process.

At the transmission level, the ability to quantify the costs and benefits of resilience and resilience-enhancing transmission projects and non-transmission alternatives would enable resilience to become an explicit part of regional and interregional transmission planning under FERC Order No. 1000. In fact, if state and local officials adopt resilience requirements for their regulated electric utilities, then Order No. 1000 requires that transmission needs driven by these "public policy requirements" be considered in regional and interregional transmission planning processes.

At the wholesale market level, better resilience definitions and metrics would enable wholesale markets to incorporate resilience into wholesale market products, services and prices. As noted earlier, NERC and other bodies have highlighted the importance of balanced resource portfolios capable of providing essential reliability services and adequate fuel assurance and security. At present, however, wholesale markets have taken only incremental steps toward incorporating resilience attributes into market pricing. Accordingly, many resilience-affecting measures are not incentivized or compensated, including resilience-enhancing attributes of generation resources, such as flexibility and fast ramping capability, or fuel security.[143]

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[142] Vigurin, Castillo, and Silva-Monroy (2017). This approach is applied in Unel and Zevin (2018).
[143] See Tierney (2017).

In its comments on DOE's proposed Grid Resiliency Pricing Rule, NRECA explained that it substantially agreed with the premise of the proposal: The centralized wholesale markets operated by the ISOs and RTOs may not be compensating generating resources for all the grid resilience and reliability services they are providing. NRECA did not support the proposed remedy, however, because it did not compensate resources based on their technical ability to provide resilience services, posed risks of unintended distortions to the centralized wholesale markets, and increased costs to consumers.[144]

When FERC rejected DOE's proposal and commenced an investigation of resilience in RTO and ISO regions, NRECA supported FERC's continued inquiry into the resilience of the BPS.[145] In its comments to FERC, NRECA suggested several principles that should guide FERC's development of wholesale market design policies to address BPS resilience in RTO and ISO regions:

- The RTOs and ISOs should be afforded the flexibility to determine particular regional resilience needs and devise regional solutions, including resource compensation for BPS resilience services. Even though resilience goals may be national, the solutions will be regional and local.
- Resource compensation for BPS resilience services should be based on the technical ability of the resource to provide bulk power system resilience services — not on the resource owner's identity, financial condition, or regulatory status under state or local law.
- Resource compensation for BPS resilience services should be market-based where feasible — provided as always that market competition will result in just and reasonable rates.
- Load-serving entities such as cooperatives should be allowed to self-supply BPS resilience services and should not be required to pay twice for such services (once for their self-supply and also to the RTO or ISO).
- Costs for compensating resources for BPS resilience services should be just and reasonable and should be allocated on a cost-causation basis.
- Commission actions to ensure BPS resilience should preserve the ability of local electric utilities and their state and local regulators to ensure safe, affordable, reliable and resilient electric service. Here, NRECA pointed to FERC's proposal to facilitate the participation of DER aggregations in wholesale markets[146] and noted that DER aggregation should be carefully implemented so that it does not undermine local distribution system reliability and resilience.

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[144] Comments of the National Rural Electric Cooperative Association, *Grid Reliability and Resilience Pricing*, FERC Docket No. RM18-1-000 (filed Oct. 23, 2017). Although still on the drawing board, "transactive energy markets" could further leverage price signals to enhance resilience of local distribution systems.
[145] Comments of the National Rural Electric Cooperative Association, *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, FERC Docket No. AD18-7-000 (filed May 9, 2018).
[146] See Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 81 Fed. Reg. 86522 (Nov. 30, 2016) (notice of proposed rulemaking).

FERC should continue to investigate the concept of BPS resilience in RTO and ISO regions and determine the attributes of generation resources and other BPS elements that contribute to BPS resilience. Essential reliability services, balanced resource portfolios, and fuel security and assurance should be among the issues to be examined. Because resilience risks are different in different regions, FERC should focus on regional and local solutions to resilience risks identified by RTOs and ISOs. It could then apply these lessons to transmission owners and operators in other regions within its jurisdiction and consider proposals for resilience-enhancing wholesale and transmission products and services under its purview.

Conclusions

The U.S. electric power system has achieved remarkable levels of reliability and resilience. Efforts to ensure continued resilience of the system are important as the system continues to adapt and change in important ways. Multiple entities have responsibility for different parts of this task, and it is important for electric utilities and regulators to coordinate their efforts and work in tandem toward the shared objective of ensuring and enhancing the resilience of the electric power system.

From the perspective of electric cooperatives, several principles emerge as critical to this effort.

- Electric utilities such as co-ops should remain the locus for decisionmaking on investments in resilience. By preserving local decisionmaking and enabling local planning, policymakers can best ensure cost-effective investments in infrastructure and practices to ensure a reliable and resilient electric power system.
- Discussions of resilience investments should focus on the consequences for end-use consumers, including costs. The goal is resilient service, not just resilient infrastructure or assets. Thus, resilience investments also include investments in people, processes, organization, coordination and emergency response.
- Efforts are underway to better define resilience and formalize the utility decision process for resilience investments. These efforts often employ variations on the familiar model of cost-benefit analysis. Cooperatives are well-positioned to use system and consumer-member data to drive investment decisions on the distribution grid, whether in the technical architecture of the grid or in DERs or other devices on the grid.
- Responsibility for the resilience of the electric power system in the United States is widely dispersed among many private and public entities. But this does not mean that federal intervention and oversight over all aspects of resilience are needed. Indeed, the current framework enables electric utilities and other entities to exercise authority within their respective domains and harness their knowledge and expertise to benefit the overall public interest in a resilient electric power system. The need for coordination is growing with the evolution of the electric power grid and electric industry.
- Integrating and optimizing the operations of DERs such as solar and storage resources hold great promise to benefit the reliability and resilience of distribution systems. Distribution utilities can maximize these benefits by investing in infrastructure such as communications, sensors and new distribution equipment to leverage the capabilities of

DERs. Therefore, if FERC adopts rules requiring RTOs and ISOs to allow DER aggregations to participate in wholesale markets, the RTOs and ISOs should be required to allow such aggregations only with the assent of the relevant electric retail regulatory authority.

- General statements that the resilience would be enhanced by certain types of investments must recognize that the best investments will be different for different regions and different electric utilities. Nonetheless, some conclusions can be drawn from the available historical data and utility experience.
    - Upgrading and maintaining distribution systems to reduce their vulnerability to weather-related failures is likely to be a cost-effective way to enhance resilience.
    - There appears to be real value in pursuing a balanced portfolio of generating resources, both at the BPS level and at the distribution level.
    - Ongoing investments in measures to protect against the adverse consequences of a massive cyberattack are likely to be warranted given the evolving threats of the evolving electric grid itself.
- There appears to be no superior way to make resilience investment decisions than through the traditional process of long-term integrated resource planning by electric utilities, subject to oversight by their regulators. Resilience can and should become a component of all utility investment decisionmaking processes.
- The lack of recognized definitions and measures of resilience hinders utility planning and decisionmaking about investment; hinders the ability of electric utilities to communicate with their regulators and their communities about resilience issues; and hinders the evolution and reform of centrally-organized wholesale power markets to develop market-based mechanisms to enhance the resilience of the electric power system and provide price signals to guide decisions on resilience investments.
- Decisionmaking about resilience investments would be improved by an industry- or government-led initiative to develop consensus agreement on definitions of resilience and criteria for measuring some dimensions of resilience. The objective should not be to impose nationwide resilience standards, but to provide analytical tools and metrics to facilitate and improve planning, coordination, and decisionmaking by regional bodies, state and local regulators, utilities and local communities.

3. Investor-Owned Electric Company Perspectives on Investments in Resilience

By Scott Aaronson, Vice President, Security and Preparedness, Edison Electric Institute

Introduction

The Edison Electric Institute (EEI) appreciates the opportunity to contribute to the discussion about improving resilience for critical energy infrastructure. EEI's member companies—the nation's investor-owned electric companies—take their responsibility to support national and economic security very seriously. Our members live and work in the communities they serve and understand that the infrastructure they own and operate plays a significant role in the life and safety of their customers.

Our member companies provide electricity for more than 220 million Americans and operate in all 50 states and the District of Columbia.[147] As a whole,[148] the electric power industry supports more than 7 million American jobs and contributes $865 billion annually to U.S. gross domestic product, about 5 percent of the total. EEI's members are committed to the reliability, security and resilience of energy infrastructure.

While improving security and reliability is a priority for our members, providing an energy grid that also is resilient against all hazards is an increasing focus for the sector and policymakers. Acknowledging and understanding how key stakeholders define resilience is valuable, but it is not EEI's intent, nor the purpose of this essay, to further refine the definition. Rather, we aim to illustrate how electric companies are key enablers of resilience and how the energy grid provides a platform for resilient energy services that support customers and national security.

For reference, however, EEI and its member companies have relied on several organizations that have provided definitions of resilience that are useful in any national conversation. These include the National Academy of Sciences, which states that resilience "is the ability to prepare and plan for, absorb, respond, recover from, and more successfully adapt to adverse events."[149]

Other entities have provided similar definitions. The Federal Energy Regulatory Commission (FERC or the Commission) proposed to define resilience as "[t]he ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."[150] The North American Electric Reliability Corporation (NERC) built upon the National Infrastructure Advisory Council's resilience construct to define resilience based on four outcome-focused abilities:

1. Robustness—the ability to absorb shocks and continue operating

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[147] In addition to our U.S. members, EEI has more than 65 international electric companies as International Members, and hundreds of industry suppliers and related organizations as Associate Members.
[148] Including public power utilities and rural electric cooperatives.
[149] National Academy of Sciences, Resilience @ the Academies: http://www.nationalacademies.org/topics/resilience/.
[150] FERC (2018a).

2. Resourcefulness—the ability to detect and manage a crisis as it unfolds
3. Rapid recovery—the ability to get services back as quickly as possible in a coordinated and controlled manner
4. Adaptability—the ability to incorporate lessons learned from past events to improve resilience[151]

While there are various ways to define resilience, it is clear that the concept is based on a holistic approach to address dynamic and impactful risks to electric systems by anticipating, withstanding, recovering, and adapting to a wide variety of human-made or natural threats.

The member companies of EEI are focused on providing a safe, reliable and affordable supply of energy to their customers. The concept of resilience is embedded within these priorities. These companies invest more than $100 billion each year to make the energy grid smarter, stronger, cleaner, more dynamic and more secure. These investments help to increase the integration of renewable resources into the energy grid, power the rapid increase in electric vehicles on the road, harden the grid to better withstand extreme weather events, and facilitate the adoption of a broad array of smart technologies that enhance the energy grid in ways that better serve communities while advancing security and reliability.

However, an inherent challenge with resilience is that risks to the electric system vary across the nation. For example, the filings made by regional transmission organizations (RTOs), independent system operators (ISOs), and individual electric companies at FERC raise different threats, concerns and urgencies in different parts of the country. As a result, coordination at all levels is needed. This includes working locally with customers and state governments to address distribution system needs, regional coordination that acknowledges different threats to different parts of the country, and a national strategy that facilitates investment and looks holistically at the broader energy grid.

Improving resilience requires a strong partnership among policymakers and regulators at the local, state, regional and federal levels; customers; interdependent sectors; and electric companies. This coordination among stakeholders is imperative to ensure alignment on the understanding of resilience and to identify appropriate, cost-effective priorities.

1. What level and scope of resilience do we need, and how much are we willing to pay?

There is no simple answer or one-size-fits-all approach to resilience. The level and scope of resilience investments should be informed by risks and potential consequences to the electric system and those it serves. Risks to the system from cyber and physical attacks, fuel availability and security, and extreme weather are evolving rapidly to varying degrees across the nation. For example, the risk of hurricanes, wildfires and extreme weather vary by region, requiring different resilience measures and levels of

[151] NERC (*2018b). Agenda Member Representatives Committee at Agenda Item 8*.

investment. In addition, the changing energy mix introduces potential new fuel security and reliability risks. As traditional coal and nuclear generation retire, dependence on natural gas and, increasingly, renewable sources require new resilience strategies and investments.

Customer needs and expectations also are changing. Residential, commercial and industrial customers have different needs regarding reliability, outages and recovery. While some customers value greater control over their energy choices and are participating in the active management and even production of the electricity they consume, others are more concerned with a high level of reliability, resilience and power quality. As more distributed energy resources and other new technologies integrate with the energy grid and as new organizations participate in retail and wholesale markets, new vulnerabilities and potential attack surfaces emerge, increasing the need for enhanced security and resilience measures.

It is important to have a national view and federal situational awareness regarding resilience strategy and priorities, particularly as it relates to national security. Again, a one-size-fits-all approach is not the answer. Local, state and regional considerations and solutions are needed, operating in concert and coordination with federal approaches. Electric and natural gas company collaboration with regulators at all levels is essential to manage the evolving system successfully and to keep it reliable, resilient and cost-effective.

Regarding cost-effectiveness and diversity of needs, different customers and regions will require different investments and resilience strategies. Developing a framework for regulators, customers, electric companies, and other stakeholders to support needed infrastructure and to recover costs appropriately will be key. Sharing best practices that can be tailored to various risks will support sound investment decisions. Partnership among electric companies; federal, state, and local regulators; and other organizations focused on customers, policy and technology will be an important part of this effort. Coordination among these stakeholders will help to ensure that the most critical needs are identified and that solutions are developed for specific states, regions, and customers.

While electric companies have always taken their responsibility to ensure reliability seriously, the past two decades have highlighted the important role that other critical infrastructure sectors must play in supporting security and resilience. The Electricity Subsector Coordinating Council (ESCC) is helping government and private-sector partners deepen relationships with other, interdependent critical sectors (i.e., sectors that the electric systems depend on and that depend on the electric sector), including the financial services, communications, water, natural gas and transportation sectors. Planning to defend, mitigate, respond, and recover to and from “black-swan” events requires coordination among all of these sectors.

2. Who's responsible for resilience, and how should other entities coordinate with utilities when there are mutual benefits?

Addressing resilience is a responsibility shared by federal, state and local governments; NERC in its role as the congressionally sanctioned "Electric Reliability Organization;" customers; interdependent sectors; and energy grid asset owners and operators. The diversity of responsibility can be seen just within the federal government with congressional funding related to grid hardening and resilience going to the U.S. Departments of Energy, Homeland Security (DHS) and Defense. This includes research, development, and deployment programs for innovative technologies and strategies that address high-impact/low-probability events, improving security and resilience for defense critical electric infrastructure, and supporting the Federal Energy Management Agency's (FEMA's) partnership with electric companies to respond to and recover from extreme weather events. Each of these departments has a very different role when it comes to interaction with the electric sector, but each is vital to ensuring a holistic approach to energy grid resilience.

From the federal regulatory perspective, FERC's authority over market and bulk electric system reliability can help to address grid hardening and resilience from a national, transmission system perspective, while recognizing, as noted in the response to Question 1, that state and local entities also must have the ability to secure appropriate resources and solutions to ensure and address regionally specific resilience needs. Additionally, the Commission should continue to monitor risks through its non-regulatory offices, like the Office of Energy Infrastructure Security, to ensure they remain well-informed and fully understand the threats stakeholders face and how best to leverage FERC's authorities to improve energy grid security and resilience. Convening events, such as technical conferences, is an important role for the Commission, providing the stakeholder community a valuable venue to address evolving threats.

In addition to developing and enforcing the reliability standards, which include aspects of resilience, NERC conducts assessments to identify potential reliability risks. These risks may be addressed by making modifications to the reliability standards, developing reliability guidelines, or taking other appropriate actions to maintain the reliability of the bulk power system, while improving system resilience. NERC should continue to use its technical resources, including industry expertise, to support future assessments and risk identification. Its biannual GridEx exercises also support resilience, helping to prepare for response and recovery against large-scale cyber and physical security incidents. The fifth GridEx will take place in November 2019 and represents the gold standard for private sector-led exercises, helping to prepare grid operators; emergency responders; federal, state and local officials; the vendor community; and other key stakeholders for potentially catastrophic threats.

Providing state and local regulators with information to understand the value of resilience also is necessary to balance innovation, security and cost-effectiveness within their jurisdictions. Local governments can align their planning and potential investment with electric companies and engage with customers, particularly in planning for incident response. Similarly, electric companies should coordinate with state, local and federal governments, as well as customers and interdependent infrastructure sectors, to align resilience efforts to local expectations.

Electric company resilience programs often are tailored to meet specific threats or needs. In some cases, hardening or resilience benefits will accrue across the customer base (e.g., storm hardening for hurricanes). However, for individual customers that may need a higher level of resilience for a specific threat (e.g., an industrial facility or military base), a cost-sharing approach may be more appropriate. The key is flexibility so that electric companies can tailor their resilience efforts to meet customer needs and expectations.

Electric companies also should continue to invest in grid hardening and resilience, share best practices and participate in technology pilots. As these investments are made, electric companies will need to engage with state, local and federal governments, as well as customers and interdependent infrastructure companies, to balance expectations for grid hardening and resilience.

As the most critical of critical infrastructure sectors, the electric sector often serves as the center of gravity for relevant stakeholders to engage on significant issues. Improving sector and critical infrastructure resilience more broadly is a shared responsibility that requires electric sector leadership and proactive engagement with multiple stakeholders.

Opportunities for coordination on resilience include:

- Electric system planning
- Identifying system risks
- Research and development
- Cross-sector coordination
- Joint emergency preparedness and response exercises
- Information sharing between the private sector and government
- Emergency/critical spare equipment sharing programs
- Mutual assistance to support response and recovery

These coordination efforts should continue to build upon existing industry-government partnerships and programs, such as the ESCC's partnership with the Energy Sector Government Coordinating Council, established cross-sector efforts in collaboration with DHS and respective sector-specific agencies, information sharing and analysis centers, and the states.

3. What types of utility investments have the most impact on improving resilience, and how can utilities and regulators tell whether utility investments in resilience are impactful?

The most impactful resilience investments are those that enhance resilience against a multitude of hazards. By focusing on managing potential consequences, rather than simply prevention, electric companies avoid chasing the latest defensive measure against always evolving threats and, instead, prepare to respond to all hazards. Prioritization of assets and prioritization that accounts for a company's particular risk profile also ensure more efficient resilience investments.

Electric companies and their regulators should work together to determine the right investments to improve the resilience of the energy grid for particular localities or regions. Some specific measures that have shown value include:

- **Undergrounding** – Moving infrastructure underground can have a positive impact on reliability. However, a wholesale move to underground substantial portions of existing distribution facilities is prohibitively expensive and, in areas where there is flooding or inundation risk, could be counterproductive. Instead, a more prudent approach requires looking at each opportunity to underground lines on a case-by-case basis that weighs costs and benefits with customer needs and expectations, as well as engineering considerations and alternative approaches to achieve resilience. This ensures that a variety of cost-effective solutions, including undergrounding, tree wire, or more aggressive vegetation management, are considered depending on the location.

- **Nontraditional Transmission and Distribution Pole Materials** - Considerable improvements have been made in the development of pole materials for transmission and distribution overhead lines. While these new materials have higher upfront costs than traditional wood poles, they often provide greater resistance to weathering, insects, rusting, high winds and even fire, and include materials such as concrete, advanced coatings for steel, high-strength fiberglass, and polyurethane resins. In some cases, these upgrades are more cost-effective long-term than more traditional materials.

- **Smarter Energy Infrastructure** - The energy grid is evolving rapidly, driven by advances in technologies and changing customer expectations. We already have seen substantial improvements driven by smart meters, advanced energy management systems, and enhanced transmission and distribution planning. These breakthroughs increase protection of equipment, enhance situational awareness of grid operations, reduce maintenance costs and improve response times during outages. The grid's evolution has improved Supervisory Control and Data Acquisition (SCADA) systems and network security, provided advanced analytics, deployed more intelligent sensors, improved automation of core functions, enhanced protection of hard-to-replace equipment from protective relays, provided better substation and distribution controls with intelligent end devices, created opportunity with dynamic line ratings, and provided more ubiquitous communications supporting a wide range of grid needs and solutions.

- **Distributed Energy Resources (DERs)** – As the number of DERs grows, new infrastructure and technology are required. Policymakers, regulators, grid operators and others should work together to ensure DER deployment is done in a way that, ideally, enhances overall grid resilience, but at least does not harm the security and reliability of the energy grid. Moreover, stakeholders should engage in discussions to ensure that appropriate actions are taken regarding preparedness efforts for new market entrants, including cybersecurity preparedness, targeted training and drills, and close coordination with other infrastructure sectors and critical stakeholders (e.g., larger customers, first responders, hospitals and public transportation agencies).[152] In addition, the strategic deployment of storage at both the transmission and distribution level could enhance reliability and resilience. For storage to be able to play the most robust role possible, additional research and development is needed to reduce costs and improve performance. In addition, key questions about which entities can own and deploy storage need to be answered.

- **Cybersecurity Protections** – Digital electric infrastructure is advancing rapidly with great benefits. At the same time, associated cybersecurity risks are proliferating. Threats to critical infrastructure are escalating, and attack vectors are changing. These changes create new challenges to protect electric infrastructure. The NERC reliability standards, including the Critical Infrastructure Protection (CIP) Standards, are one of the tools to support security for the bulk power system. However, flexible security measures also are important to ensure the energy grid remains secure and safe while leveraging these new technologies and enhancing the operational efficiency, electric system reliability and overall resilience.

An example of a cost-effective resilience approach that leverages consequence management against rapidly evolving cyber threats is the establishment of the Cyber Mutual Assistance (CMA) program. Developed by the ESCC, the program has grown to a voluntary group of more than 150 electric and natural gas companies from all across North America that are committed to helping each other in the event of a cyber attack. Modeled on traditional mutual assistance, CMA requires very little in the way of upfront resource commitments, but it could have extraordinary benefit for an electric company should the need ever arise.

- **Physical Security Protections** – The NERC CIP Standards focus on protecting substations that are most critical to the reliable operation of the bulk power system. This includes installing physical security systems, such as electronically controlled access, barriers and

[152] Critical Consumer Issues Forum (2018).

video surveillance, to protect critical facilities. In addition to actions taken in response to mandatory standards, electric companies assess facilities by their relative importance to (1) the delivery of electricity; (2) the national defense and impact on the national economy; and (3) customer and employee safety.

- **Asset Management** – Efforts are underway to leverage the vast amount of data collected around tracking, monitoring, and maintaining assets to improve asset utilization and to identify weaknesses or impending failures predictively. These technology developments and process improvements are leading to fewer unexpected equipment failures and improved maintenance cycles, meaning fewer equipment replacements and saving customers money. These advancements will lead to greater efficiencies and improved asset use, reliability and resilience. The data collection and analysis required are a new cost to some companies, but these costs likely are offset by the improved outcomes and system savings.

- **Vegetation Management** – Vegetation management is key to ensuring that overhead transmission and distribution systems are well-maintained and managed. Without effective and proactive management of utility rights-of-way, both reliability and resilience can be impacted negatively. Electric companies are rethinking vegetation management solutions to better inform their processes through improvements in data analytics, rights-of-way monitoring, consideration of the impacts outside of their rights-of-way, and improved forest management. Federal, state and local government cooperation that reconsiders utility rights-of-way is essential.

- **Advanced Grid Management / Proactive Shutdowns** – Advanced grid management, including programs to deenergize circuits during certain high-risk emergency conditions (e.g., dry and windy conditions that create high fire risk), are beginning to be used and considered, but raise significant legal and policy questions that state and federal regulators have not addressed yet.

- **Extreme Weather Damage Mitigation** – Electric companies in many flood prone areas, such as coastal regions, have experienced increased risks resulting from flooding at substations and other associated electrical equipment. This issue has led these companies to reconsider their design standards and to take proactive measures to raise the elevation of equipment and substations and, where practical, relocate affected equipment to areas less prone to these events. In some cases, the use of mobile substation equipment has provided added resilience and additional capacity in emergency situations.

- **Support for Smart Meter Investments** – Smart meters are one of the most important resilience investments for the distribution system. In addition to providing valuable electricity usage information to customers, these devices provide situational awareness to electric companies, including outage reporting that allows for more timely response. However, recently several state regulatory commissions have rejected proposals to deploy these devices. While each smart meter filing is unique, EEI's member companies would appreciate support in future proceedings that recognizes and enumerates the value of these investments to support distribution system resilience.

- **Support for Greater Visibility into Distribution Systems** – Unlike operations in the bulk power system, which are highly visible, energy companies rarely have equivalent visibility into their distribution systems. Investments made to improve this visibility is increasingly needed as more DERs are added to utility systems, as they inject variability and can complicate electric company operations.

- **Support for State Regulatory Commissions on Cyber Security at the Distribution Level** – State regulatory commissions have jurisdiction over distribution system policies, including cybersecurity. Many of these commissions lack the resources, staff and access to sensitive information that would help them to address these issues. Providing support to these entities through the National Association of Regulatory Utility Commissions would be helpful to promote best practices among the states, especially as the "Internet of Things" and DERs proliferate and add to the "attack surface" of the distribution system.

- **Support for Transmission Investments** – Investments in transmission are challenging given the difficulty of siting these facilities, determining proper cost allocation for these long-term assets, and determining an adequate return on equity for projects. Yet the resilience and reliability attributes of these investments are rarely, if ever, included. Support for quantifying these attributes and investments is important for long-term resilience of the entire energy grid.

- **Support for Advanced Research for Development and Deployment of Transmission Sensor Technology** – Deploying sensor technology on energy infrastructure can provide predictive analytics to make maintenance more efficient. Further, sensors can help detect anomalies on the system and even help to prevent the spread of wildfires. Support for these investments will help increase the resilience of the nation's transmission system, particularly, but not exclusively, in the western United States.

- **Support for Other Critical Infrastructure** – Electric companies in many areas are taking proactive measures to improve reliability and resilience to identified critical customers (e.g., police, fire stations, hospital, military and government facilities) through measures such as redundant infrastructure. While these improvements can be costly, the benefits they provide during major events can outweigh the cost. The issue of resilience also must be looked at holistically since electric companies depend on other sectors, including water to generate steam and cool systems, telecommunications to operate, and transportation or pipelines to move the fuel that generates electricity.

Electric company response and recovery programs and processes also are critical resilience investments because it is difficult to anticipate all threats and may be cost-prohibitive to guarantee protection against all hazards. These programs include:

- Information sharing and analytics
- Mutual assistance networks, including cyber mutual assistance
- Spare equipment sharing programs
- Business continuity programs
- Emergency management structures
- Emergency drills and exercises
- Ability to operate the energy grid in degraded conditions
- Cross-sector information sharing and situational awareness programs
- Lessons learned and best practices sharing
- Use of drones

With respect to prioritization, electric transmission infrastructure is the backbone of the nation's energy grid, and investment in transmission infrastructure will continue to play an important role in electric system resilience. This access to diverse generation and extra capacity enhances system stability and allows for communities to be restored more quickly when an incident occurs. This is the hallmark of a resilient system. However, as with the distribution system, flexibility is needed to address regional differences in transmission planning and development to promote a stronger, more robust system.

4. Should utilities take more proactive approaches to investments in resilience?

Electric companies already are taking a more proactive approach to investments in infrastructure. This includes investing in new and upgraded transmission and distribution infrastructure, using advanced technologies to enhance communications, improving operating efficiency and reliability, and enhancing protection to enable a more secure, flexible and resilient electric system.

We estimate that electric companies have invested more than $285 billion in transmission and distribution since Superstorm Sandy, helping to harden the energy grid and make it more resilient. These investments include advanced monitoring systems, high-temperature low-sag conductors, underground cables, fiber optics, advanced high-capacity composite core conductors, new transmission lines, energy storage devices, enhanced condition-based monitoring, and mobile transformers and substations. These investments support electric company operations and other investments and enhancements in transmission and distribution systems that, among other things, allow for the integration of DERs on the grid in a safe and reliable manner.

The EEI member companies are investing in efforts to harden transmission and distribution system infrastructure to resist storm damage, while also developing new technologies and techniques that allow for faster restoration of transmission service. In the case of Hurricane Irma in 2017, more than 4.4 million customers lost power, and Florida Power and Light was able to restore electricity within 10 days versus the 18 days it took to restore power to 3.2 million customers after a similar storm, Hurricane Wilma, in 2005. The company credits the reduced power outages and improved restoration efforts on infrastructure improvements (e.g., steel and concrete poles and burying power lines) and smart grid technology (e.g., flood monitors and smart meters). These efforts demonstrated improved restoration and recovery and reduced overall costs. In addition to investments in the transmission and distribution system, EEI's members continue to invest in the generation resources and new generation technologies necessary to maintain resource adequacy.

As threats to the reliability of the bulk power system have evolved, the Reliability Standards developed and enforced by NERC and FERC have evolved, too. Although there appropriately is not a resilience standard or requirement, FERC has taken steps directed at elements of resilience, including significant work to address bulk power system reliability through NERC Reliability Standards, assessments and risk identification. Collectively, the Reliability Standards developed by NERC inherently account for resilience by supporting robustness, resourcefulness, rapid recovery and adaptability:

- The CIP Standards address risks from cyber and physical attacks. Many of the CIP requirements provide enhanced protections that help ensure that systems can resist, absorb, and rapidly recover from coordinated physical and cyber attacks.
- The Transmission Planning Standards are designed to ensure that the bulk power system operates reliably through many system conditions and contingencies, including solar events, spare equipment shortages, and generation retirements, assuring affected systems appropriately absorb the impacts of changing conditions and continue to remain reliable throughout.
- The Emergency Preparedness and Operations Standards ensure entities have plans, facilities, and personnel in place that are capable of recovering rapidly from events (e.g., system restoration, loss of control center functionality, geomagnetic disturbance) that could impact the reliable operation of the bulk power system.
- The Protection Control (PRC) Standards include loadability standards that ensure that key elements of the bulk power system will remain in service while absorbing short-duration overload conditions, allowing time for system operators to mitigate the situation without unnecessary loss of load or damage to equipment. The PRC Standards also address stable power swings to ensure bulk power system elements do not trip unnecessarily during system oscillations resulting from large disturbances. That allows the system to absorb and recover without unnecessary loss of load or contributing to events that might result in much larger power disturbances.

In addition to developing and enforcing the Reliability Standards, NERC assesses various risks that may impact the reliability of the bulk power system,[153] including resource adequacy issues that cannot be addressed fully by reliability standards or requirements.[154] However, NERC's reliability assessments and historical operational information can inform discussions between electric companies and state regulators responsible for addressing potential resource adequacy issues. The states and RTOs/ISOs may need to conduct additional analyses to identify issues unique to their local systems,[155] including impacts caused by factors outside of NERC's bulk power system focus, expertise and regulatory authority.[156]

It is impossible to defend against all threats. Therefore, resilience planning also must include consideration of how the industry proactively prepares for and responds to threats. The chief executive officers of 22 electric companies participate in the ESCC, which represents all segments of industry and the full scope of electric generation, transmission and distribution in the United States and Canada. The ESCC is the principal liaison between senior officials of the federal government and the electric power industry for coordinating efforts to prepare for, and respond to, national-level incidents or threats to critical infrastructure. This partnership leverages government and industry strengths to develop and deploy new technologies, share information, conduct drills and exercises such as GridEx, and facilitate cross-sector coordination.

In addition, mutual assistance is the cornerstone of electric company operations during recovery from power outages caused by infrastructure damage. Electric companies affected by significant outages often turn to the mutual assistance network—a voluntary partnership of electric companies from across the United States and Canada—to help speed restoration whenever and wherever assistance is needed when it is safe to do so. When natural disasters cause power outages, electric companies use this partnership to increase their restoration crews and contractors.

Since Superstorm Sandy in 2012, electric companies have enhanced mutual assistance programs[157] to scale to national-level incidents. Members of EEI created the National Response Event framework to support the industry's Regional Mutual Assistance Groups in the event of an incident that has national implications. This effort includes the development of emergency response playbooks and protocols to facilitate situational awareness and information sharing, an online tool to streamline the allocation of restoration resources, and a robust exercise program to prepare company personnel. These enhancements have allowed the industry to support large restoration efforts in recent years.

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[153] See e.g., NERC (2010, 2012, 2015, 2016, and 2017).

[154] Resource adequacy issues may be identified by NERC in assessments, but the Reliability Standards or requirements cannot and should not be the means to require entities to secure resources to address resource adequacy issues. 16 U.S.C. §824(o)(a)(3); FERC (2011).

[155] See e.g., ISO New England (2018).

[156] NERC's authority is limited to the operation of existing bulk power system facilities. 16 U.S.C. §824(o)(a)(3). Threats to other infrastructure sectors that may impact the bulk power system are not within NERC's authority or expertise.

[157] Public power utilities and electric cooperatives have parallel and complementary mutual aid networks to support their members. All three segments of the electricity subsector share information and coordinate mutual assistance efforts through the U.S. Department of Energy's Emergency Support Function #12 and the ESCC.

In addition to the industry's voluntary mutual assistance programs to restore power and respond to cybersecurity threats, electric companies participate in spare-equipment sharing programs to enable rapid recovery from events. For example:

- The Spare Transformer Equipment Program provides a mechanism to share assets when equipment is destroyed deliberately. It is based on binding contracts for access to hard-to-replace transformers.
- SpareConnect is an online tool for transmission asset owners and operators to connect and share transmission and generation step-up transformers and related equipment (e.g., bushings, fans, and auxiliary components) in the event of an emergency or other non-routine failure.
- Grid Assurance is a stand-alone company that focuses on critical transmission equipment procurement, security and strategic equipment warehousing, equipment management, and logistics support to facilitate rapid deployment of critical long-lead time equipment in light of a grid emergency.
- The Regional Equipment Sharing for Transmission Outage Restoration program provides additional sources for obtaining critical transmission equipment following disastrous events.[158]

Investments in the transmission and distribution infrastructure that facilitate the use of clean energy will continue to be important to resilience. Tracking development and proactively planning transmission investment to accommodate electric vehicle charging stations supports resilience. Additional transmission infrastructure is needed to access that energy, to modernize transmission assets to meet growing customer demand for new and innovative services. Such initiatives, with an eye on affordably and reliability, have the capability to reduce the magnitude and duration of disruptive events. Additionally, for more proactive approaches to be successful, policymakers, regulators and customers also must support resilience investments.

5. How can decisionmaking about resilience investments be improved?

More support from stakeholders at the local, state, regional and national levels would help to prioritize risks to resilience and inform investments required to address those risks. While customers, new grid service providers, regulators, policymakers, and other critical sectors all can help inform how best to improve system resilience, energy grid operators play a unique role in enabling resilience for some of the nation's most critical infrastructure.

Given limited resources and an always evolving threat landscape, prioritization of investments and a focus on consequence management will be key components to improving resilience. Moreover, all stakeholders will have to grapple with questions about costs and benefits, especially when making investments to address high-risk, low-probability events or investments based on evolving research and

[158] Recently authorized by the Commission. FERC (2018c).

new data. This will require robust information sharing and collaboration to identify risks and will require protecting sensitive security information. Also, establishing clear criteria to resolve the tension between transparency and security issues raised by resilience planning will be essential. Finally, sharing lessons learned and best practices on resilience investments will help to improve future investments.

As electric companies plan for change and more frequent and extreme weather events amid a changing climate, there will be an increased need for improved data, models, planning and flexible design options. The quality of decisionmaking will be improved with better weather and climate data that can be used when making investments and maintenance decisions within an electric company's service area.

Conclusion

The energy grid is integral to national and economic security and to the life and safety of our customers. This is a responsibility that EEI's members take extremely seriously. While protecting critical infrastructure against all hazards is a top priority, preparing for extraordinary circumstances is imperative. It is this philosophy that has led EEI and its members to focus not only on providing reliable service under normal circumstances, but also working to be resilient in the face of abnormal circumstances in an increasingly dynamic threat environment. Our members are eager to work with key stakeholders to continue enhancing preparedness of the energy grid as we believe electric companies are enablers of resilience, with the energy grid providing a platform for resilient energy services.

4. Consumer Advocates' Perspectives on Utility Investments in Resilience

By National Association of State Utility Consumer Advocates[159]

Introduction

The membership of the National Association of State Utility Consumer Advocates (NASUCA) is composed of more than 55 utility consumer advocate offices in both restructured and vertically integrated jurisdictions in the United States. This chapter of the report represents a general consumer advocate perspective and does not necessarily reflect the views of any particular state office or NASUCA as a whole.[160] Before responding individually to each of the five questions this report addresses regarding resilience, we provide general comments on resilience at the generation and transmission levels in contrast to the distribution level, and on cybersecurity and the definition of resilience.

Generation- and Transmission-Level Resilience Versus Distribution-Level Resilience

The resilience of the electric system is broadly based on types of generation, infrastructure redundancy, transmission planning, and distribution system elements. NASUCA acknowledges that the U.S. Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) are contemplating resilience at the generation and transmission levels. Due to the diversity of NASUCA's membership and varied individual state perspectives on these issues, this paper will not speak directly to generation or transmission resilience issues currently being considered by DOE and FERC.

However, there are several high-level issues involving generation and transmission that NASUCA deems relevant to provide context in any discussion about resilience. First, the generation resource mix on the nation's electric system is changing (e.g., due to market forces, climate change initiatives, retirements and other reasons) and will continue to change over time, which will impact resilience measures taken. Planning for resilience means planning for a future with a different resource mix and an electric system able to meet any challenge that arises. NASUCA recognizes that system planners need to assess the

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[159] NASUCA's comments were developed by a subcommittee of interested NASUCA members and were approved by the NASUCA Executive Committee. Sheri Givens provided technical assistance. Givens formerly served as the state utility consumer advocate for Texas and a member of NASUCA's Executive Committee. She was president of Givens Consulting LLC when she provided technical assistance.

[160] NASUCA is a nonprofit, voluntary organization of 55 consumer advocate offices in 43 states and the District of Columbia, Barbados, Puerto Rico and Jamaica. NASUCA members are designated by the laws of their respective jurisdictions to represent the interests of utility consumers before state and federal regulators and in the courts. Members operate independently from state utility commissions as advocates primarily for residential consumers. Some members may additionally represent small business consumers, and others may represent all utility consumers in their respective state. Some NASUCA member offices are separately established consumer advocate organizations while others are divisions of larger state agencies (e.g., the Attorney General's office). NASUCA's associate and affiliate members also serve utility consumers but are not created by state law or do not have statewide authority. Each individual NASUCA member reserves the right to take positions or advance views that are consistent or inconsistent with this document.

impact of generation departures and the entry of new generation technologies to ensure the electric system is resilient over the long term.

Second, when considering resilience planning and the interaction between generation, transmission and distribution, it is also important to appreciate the differences between vertically integrated and restructured states, and between states with formal regional transmission operator/independent system operator (RTO/ISO) market structures and those without — as well as differences that arise because of regional weather patterns, such as southern versus northern states.[161] While FERC and the North American Electric Reliability Corporation (NERC) will continue to introduce and enforce reliability standards, for resilience planning purposes the communication pathways and jurisdictional authorities differ. For example, a vertically integrated utility may more easily control the type, timing and location of generation on its system, resulting in additional levels of control over the entire resource mix in resilience planning. In contrast, a utility in a restructured state with much less control over the type, timing or location of generation must rely upon, and work closely with, the RTO/ISO when addressing questions of long-term system resilience. In each instance, the challenge for resilience planning is to ensure clear communication between the specific entities with authority and control over each aspect of the electric system.

Third, consideration also must be given to regional transmission constraints. For example, there may be enough generation capacity to serve load, yet there might not be enough transmission to push reserves to load if a plant goes down. It will be necessary to ensure operators have sufficient generation, the appropriate resources, and the necessary transmission capacity as problems arise. For instance, a town may have a radial-only feed damaged by a storm, leaving no way for the system to be restored until the lines are rebuilt. If redundancy is built into the system, or a customer has customer-sited generation that can be called upon, the system may be able to restore itself faster.

Fourth, it is unclear whether energy markets are currently designed to value or incent generation resilience or to appropriately consider the impacts of upstream supply interruption on long-term resilience. RTOs/ISOs are in the process of evaluating the extent to which their current market designs adequately provide for generation resilience. It will be important to ascertain the incremental value versus the cost of any such proposed changes. If market mechanisms are failing to achieve the desired level of resilience, when considering options to preserve or increase resilience through other means, adding new resilience measures may require consumers to pay multiple times to the extent they overlap with existing measures provided or designed for the market.

NASUCA will not address each of these questions in detail in this paper; rather, we will focus primarily on distribution-level investments in resilience. However, many of the issues raised by NASUCA in this report apply broadly to investments across the generation, transmission and distribution spectrum and will ultimately determine whether the electric system is resilient.

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[161] Utilities that serve multiple jurisdictions will face additional complications in appropriately allocating costs when the jurisdictions require different resilience measures.

Cybersecurity

Another significant area of discussion with regard to resilience that is not addressed in this paper is cybersecurity. It is of immense importance, both in the near-term for reliability and as part of any longer-term resilience discussion. However, it is often the case that, due to limited resources, the sensitivity of the material at issue, and a lack of clear responsibility, consumer advocates have not always been included in robust discussions of planning for cybersecurity challenges. The level of involvement of consumer advocates differs state by state; however, as a general statement, NASUCA believes it is important that additional resources and training be made available to consumer advocates to enhance their participation in the review of cybersecurity planning and associated costs. It will also help prepare consumer advocates in communicating clearly with their constituents in the event of a cybersecurity incident or issue.

Definition of Resilience

NASUCA members generally agree that resilience and reliability overlap; however, there are important differences. *Reliability* involves keeping the service on at all times, replacing equipment at the end of its useful lifecycle, ongoing maintenance and other measures. *Resilience* involves measures that will improve utilities' ability to react to and recover from infrequent but potentially catastrophic events, including the inherent ability to resist, recover from or absorb a disturbance.[162] Utilities and regulators should distinguish between planning for resilience and planning for reliability, and this distinction should be clearly acknowledged and considered to avoid costly overinvestment.

As evidenced by the many available definitions of resilience that exist, there is no real consensus or one-size-fits-all approach as to how federal, state or multijurisdictional entities understand or apply the term. Various entities have proffered different definitions for resilience over the past five years.[163] While NASUCA members have not formally adopted any particular definition, many NASUCA members cite elements similar to the Argonne National Laboratory's definition of resilience as the "ability of an entity (e.g., asset, organization, community, region) to anticipate, resist, absorb, respond to, adapt to, and

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[162] NASUCA acknowledges the many threats to grid resilience exist today, including natural events (e.g., wildfires, hurricanes, floods, droughts and earthquakes) and coordinated, extensive physical and cyberattacks, and geomagnetic disturbances. There are numerous high-cost protections in the realm of resilience, but each is typically unique in nature.

[163] For background, NASUCA provides here an overview of several entities' definitions of resilience. A 2013 presidential policy directive, PPD-21, defines resilience as "the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents." FERC proposes that resilience means the "ability to withstand and reduce the magnitude and/or duration of disruptive events, which include the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event." It further acknowledges that resilience "could include a range of attributes, characteristics, and services that allow the grid to withstand, adapt to, and recover from both naturally occurring and man-made disruptive events." See 162 FERC 6,102, Grid Reliability and Resilience Pricing, Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures (Issued Jan. 8, 2018). NERC considers resilience to be part of reliability and uses the National Infrastructure Advisory Council definition: "Infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event." See NERC (2012).

recover from a disturbance."[164] Most NASUCA members also include the ability of an entity to respond to an "unusual" or "unplanned" event in their definition of resilience.

Currently, there are no standardized metrics to measure resilience efforts or to quantify the extent or likelihood of damage created by a catastrophic event.[165] Rather, resilience is addressed on a state-by-state, and oftentimes event-by-event, basis. If different metrics, benchmarks, rewards or incentives are identified and developed for reliability and resilience, there will need to be a way to properly distinguish each, take into account the benefits for each, and differentiate how to separately determine the benefits, rewards and penalties for each. To plan for and make investments to address every possible catastrophic event as part of resilience would result in an overbuilt and costly grid that most electricity consumers would not need or be able to afford.

It is with this general framework that NASUCA responds to the five questions this report addresses.

1. What level and scope of resilience do we need and how much are we willing to pay?

How Much Resilience Is Needed

There is no single, objective answer to these questions. Each location, system configuration, resource mix, and stakeholder process will dictate how much resilience is appropriate. States' approaches to resilience have also been informed by real-world events they have experienced.[166] However, broadly speaking, the majority of electric service outages arise from distribution system disruptions, and to a lesser extent, transmission infrastructure problems. The Second Quadrennial Energy Review (QER 1.2), released in January 2017, states that "[f]ailures on the distribution system are typically responsible for more than 90 percent of electric power interruptions, both in terms of the duration and frequency of outages."[167] (See Figure 4-1.)

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164 Argonne National Laboratory (2016a).

165 DOE (2017). See Key Findings at S-13: "There are no commonly used metrics for measuring grid resilience. Several resilience metrics and measures have been proposed; however, there has been no coordinated industry or government initiative to develop a consensus on or implement standardized resilience metrics." https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

166 For example, following Superstorm Sandy, New Jersey implemented numerous resilience initiatives. New Jersey Board of Public Utilities (NJBPU or Board), *In the Matter of the Board's Establishing a Generic Proceeding to Review the Prudency Costs Incurred by NJ Utility Companies in Response to Major Storm Events in 2011 and 2012*, Docket No. AX13030196 (March 20, 2013). A NJBPU order established a generic proceeding to review the prudency of costs incurred by NJ utility companies in response to major storm events in 2011 and 2012, and the Board ordered the utilities to implement a series of measures to improve preparedness efforts, communications, restoration and response, post event measures and underlying infrastructure issues. In Connecticut, after two major storms in 2011, the state mandated the following: enhanced tree trimming, technological enhancement in field crew vehicles to ensure real-time damage assessment and outage restoration data would be available, improved planning for mutual assistance from other utilities, enhanced outage restoration estimation systems, and improved communications by utilities with state and town officials. PURA Decision, Docket No. 11-09-09, *PURA Investigation of Public Service Companies' Response to 2011 Storms* (Aug. 1, 2012) at 33–35, 115–16.

167 DOE (2017), 4-31 to 4-32.

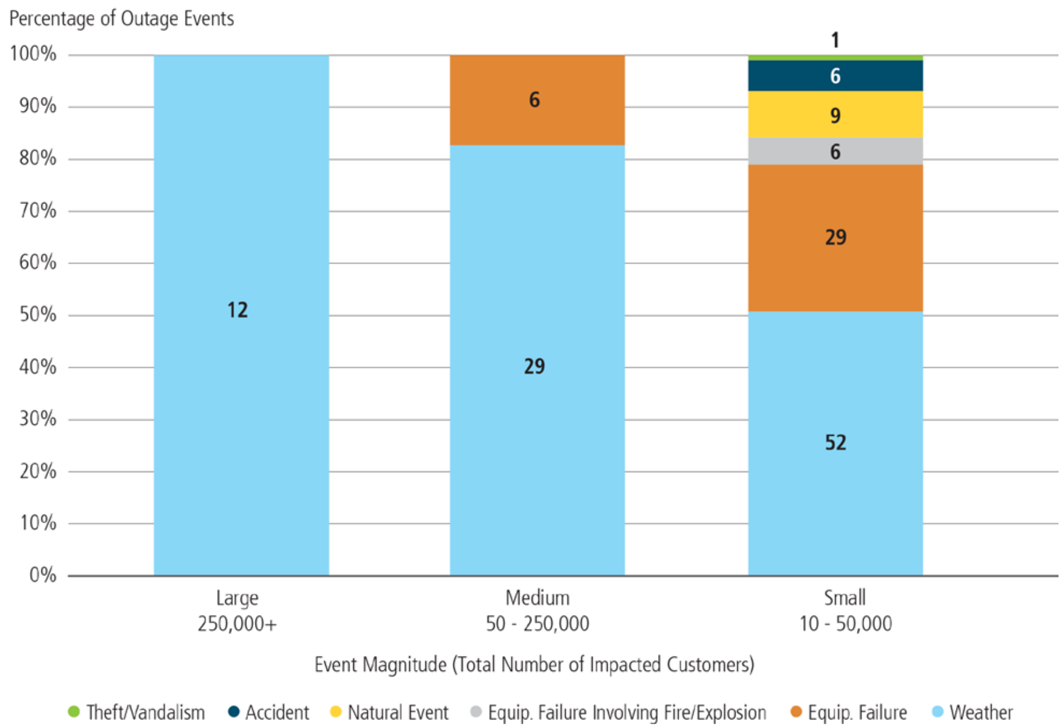

Figure 4-1. U.S. Electric Outage Events by Cause and Magnitude, 2015

Source: DOE, Quadrennial Energy Review: Second Installment (2017), Figure 4-9.[168]

States vary in how they have approached resilience to date. Some states have been active in resilience-related activities due to recent storms and other disasters.[169] (For example, see Figure 4-2.) Other states are just beginning to analyze resilience, how to measure it and which acceptable benchmarks should be utilized.[170] In addition, some states may be addressing resilience-related measures through integrated grid planning and modernization efforts.

[168] Adapted from DOE (2016b).

[169] See New Jersey and Connecticut examples provided earlier. In regards to these "grid modernization" initiatives, among consumer advocates, there are questions as to how much these proceedings and filings overlap, include and address grid resilience measures.

[170] Hawaiian Electric (2018). The filing proposes the path that the utilities seek to plan a "safe, secure, reliable, and resilient grid."

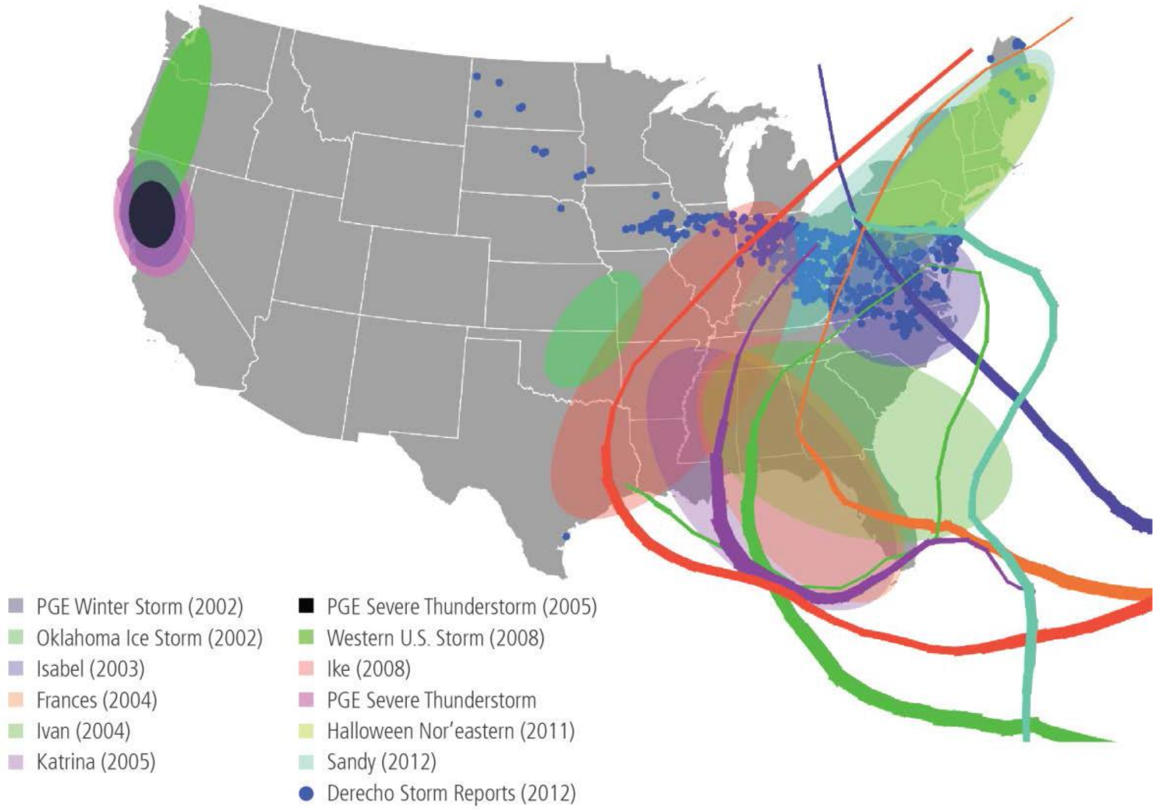

Figure 4-2. Major Weather-Related Outages Requiring a National Response, 2002–2012

Source: DOE, Quadrennial Energy Review: Second Installment (2017), Figure 4-10.[171]

With new technology entering the picture, consumer advocates caution that stakeholders should not get caught up in the "new and shiny."[172] Instead, stakeholders must focus specifically on the details of proposed measures, what the suggested devices will do, the circumstances they will likely help address, and what situations they might additionally improve beyond resilience. Consumer advocates hope to persuade state commissions to focus on these fact-based ideas.

Nationwide, utilities have been offering various proposals encompassing resilience. Generally, neither state commissions nor consumer advocates have formulated comprehensive frameworks for reviewing these proposals; rather, both are typically informed by the events that have occurred most recently.

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[171] Based on analysis by DOE's Office of Energy Policy and Systems Analysis of DOE OE-417, DOE Electric Emergency Incident and Disturbance Report, https://www.oe.netl.doe.gov/oe417.aspx, and NOAA Historical Hurricane Tracks - GIS Map Viewer, https://www.climate.gov/maps-data/dataset/historical-hurricane-tracks-gis-map-viewer.
[172] NASUCA Smart Grid Resolution 2009-03, Smart Grid Principles (2009), https://nasuca.org/nasuca-smart-grid-resolution-2009-03/; see also NASUCA Resolution on Advanced Electric Metering and Advanced Electric Infrastructure Principles 2009-01, http://nasuca.org/nasuca-resolution-on-advanced-electric-metering-and-advanced-electric-metering-infrastructure-principles-2009-01/.

Furthermore, due to budgetary and resource constraints, state commissions and consumer advocates often do not have the in-house expertise or funding necessary to hire outside experts to review emerging utility proposals on resilience.

Proposed Analytical Frameworks for Resilience

Consumer advocates recognize it would be helpful to develop more consistent and comprehensive frameworks when considering the types of utility investments that would improve resilience most cost-effectively. As noted, few consumer advocates have the resources to develop such frameworks on their own; therefore, NASUCA reviewed the work conducted by DOE labs and others and offers the following examples for consideration by state commissions, utilities and interested stakeholder parties when considering resilience measures.

Broadly speaking, consumer advocates support the development of analytical frameworks that evaluate the probability of specific events in conjunction with the impact of an event and the costs to avoid those impacts. Through such a framework, NASUCA and other stakeholders should be able to more objectively discuss and analyze any proposals aimed at increasing resilience of the electric system while remaining sensitive to cost impacts on consumers.

Example A: Argonne Framework

In December 2016, Argonne National Laboratory published its state energy resilience framework.[173] Argonne's five-step framework includes the following:

1. Understanding stakeholders' needs and requirements
2. Determining threat and hazard susceptibilities and vulnerabilities
3. Developing a resilience plan using state energy resilience planning, defining generic options and determining barriers to resilience
4. Implementing resilience enhancement options (e.g., preparing for energy service disruptions, mitigating risks from system hazards, responding to disruptions to energy service, and recovering and restoring energy service)
5. Reviewing and maintaining resilience gaps and resilience enhancement options including developing after-action reports and lessons learned, evaluating and updating resilience options, and revising resilience planning

According to Argonne, criteria for evaluating resilience measures might include "lifecycle costs, longevity, and regulatory concerns" and should have a "measurable aspect so as to maintain consistency when evaluating the different options."[174]

Argonne identified common barriers to resilience enhancement measures as "the lack of actionable predictive modeling for natural hazards and uncertainty regarding terrorist or insider threats;

[173] See Argonne National Laboratory (2016a).
[174] Id., 7.

coordination and collaboration activities between state and local governments, as well as private-sector entities that own the infrastructure; and the uncertainty surrounding what the future operational environment will be due to climate change impacts and political unrest."[175]

Example B: Berkeley Lab Framework

Another model for consideration is Berkeley Lab's Interruption Cost Estimate (ICE) Calculator, a reliability planning tool aimed at assisting electric reliability planners in estimating service interruption costs and benefits associated with reliability improvements in the United States.[176] Perhaps DOE labs could similarly create a resilience cost-benefit analysis model and address common barriers to resilience enhancement measures as identified by Argonne National Laboratory in its proposed resilience framework.

Example C: Prospective Versus Retrospective Framework

A resilient system is built, from generation source to the customer meter, to be ready for a variety of potential sources or causes of disruptions or outages. It is designed to be redundant, diverse, flexible and controllable. The concept of resilience is routinely designed into the bulk electric system through the planning and standards enforcement efforts of NERC, the regional reliability entities, RTOs/ISOs, and individual transmission owners through a well-developed process set out in FERC rules and practices. These planning and risk assessment practices are also frequently used by individual utilities in their Integrated Resource Planning activities. These planning processes rely on prospective measures of the risk of outages and disruptions on the system such as loss of load probability, effective load carrying capability, and expected unserved energy. The planning and assessment of risk in distribution system planning is less robust.

Rather, distribution system planning typically centers on *ex-post* measures of reliability such as System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI), Momentary Interruption Average Frequency Index (MAIFI) and other metrics. Such metrics generally measure the root cause of equipment failures in the distribution system and focus on the size and age of distribution system components, as well as utility maintenance practices. In this context, reliability and resilience are not interchangeable concepts; rather, each is quite distinct from the other. Consumer advocates believe that the distribution planning process used by utilities must evolve to incorporate a forward-looking perspective, much like the one that underpins planning for the bulk electric system.

Just like the bulk electric system, distribution system planning should include design elements to address system redundancy, flexibility, diversity and controllability, not just size and age of equipment. For instance, a distribution system should be designed to include multiple looped substations such that an outage on one transmission path does not cause the substation to be de-energized. Similarly, distribution feeders should be designed so that they are not susceptible to outages at a single

[175] Argonne National Laboratory (2016a), 8.
[176] Berkeley Lab and Nexant. Interruption Cost Estimate (ICE) Calculator. https://icecalculator.com/home.

substation. Such designs allow the utility the flexibility to feed neighborhoods from multiple sources, or to transfer loads among substations as operating conditions warrant.

Consumer advocates, however, do not believe that distribution systems can or should be designed to be fail safe. Prudent planning and design standards account not only for the expected risk of outages on the system but the expected cost of mitigating that risk. For this reason, consumer advocates favor the development of risk metrics, similar to those listed above for the bulk electric system, that evaluate the resilience of the distribution system on a prospective, risk-adjusted basis.

Example D: California Risk Assessment Framework

In California, the Risk Assessment and Mitigation Phase (RAMP) process is utilized in assessing, measuring and addressing risks.[177] Pacific Gas and Electric (PG&E) currently has the most advanced, albeit still nascent, approaches in the RAMP process.

PG&E stated its process provided "initial quantitative, probabilistic views of the Company's top safety risks; identif[ied] the costs associated with controlling these risks; and describ[ed] future mitigation plans based on an alternatives analysis informed by the concept of risk-spend efficiency." While PG&E's initial focus was safety, PG&E also quantified risk consequences in terms of the following: impact to the environment, customer reliability, achieving regulatory compliance, company trust and impact to ratepayers. PG&E's model focused more on mitigating specific risks rather than achieving resilience, yet the general framework of RAMP might be useful to inform decisions on the best types of resilience investments and improve decisionmaking for resilience investments.

The California Office of Ratepayer Advocates (ORA) recommended changes to improve PG&E's RAMP proposal. Specifically, ORA recommended reweighting the different consequence categories used to calculate Multi-Attribute Risk Score and removing "company trust" as a consequence entirely. ORA also recommended that PG&E define an acceptable level of risk and optimize mitigation spending across different risk categories to mitigate overall risk down to an acceptable level. PG&E acknowledged that it had insufficient data for some risks. Thus, although RAMP is a work in progress, it may be a useful starting point to identify and mitigate catastrophic risks.

Example E: NRDC Resilience Measure Evaluation Process Framework

A May 2018 report prepared for the Natural Resources Defense Council (NRDC) and Environmental Defense Fund (EDF) included a discussion on a "resilience measure evaluation process."[178] The report cites to Sandia National Laboratory's resilience analysis process as a "useful starting point" in structuring

[177] In 2013, the California Public Utilities Commission (CPUC) issued a rulemaking to incorporate a risk-based decisionmaking framework into utility Rate Case Plans for their respective General Rate Cases. Such a framework and associated parameters were intended to assist utilities, parties and the CPUC in evaluating how energy utilities assess safety risks, and how they would manage, mitigate and minimize such risks. For specific information on PG&E and ORA filings referenced in this section, see CPUC, D. 16-08-018, PG&E's RAMP Report (Nov. 30, 2017) and ORA's Comments (May 10, 2018).
[178] Grid Strategies LLC (2018), Section 5, 53–62.

a resilience analysis process which will "define resilience goals, articulate system and resilience metrics, characterize threats and their probabilities and consequences, and evaluate the effectiveness of alternative resilience measures for avoiding or mitigating the threats." It recognizes the threats on the end user, not just the physical power system.[179]

The report further offers numerous considerations in evaluating resilience measures, including "a measure's efficacy in reducing outage probabilities, frequency, scale and duration for different customer groups; the costs of the measure and how would the necessary resources be procured; whether the measure is already being performed under current practices, standards or regulatory requirements; how cost-effective the measure might be in terms of dollar cost per reduction in frequency of outages and customer outage-minutes; whether there might be a better way to protect customers against outages than this measure; and whether the measure delivers a substantive incremental reduction in the risk or duration of outage-minutes, or a meaningful improvement in survivability, that customers are not positioned to bear."[180]

NASUCA's Thoughts on a Resilience Framework

While not specifically endorsing any of the above frameworks, consumer advocates support the idea that any resilience measure should include the probability of an event occurring and the projected impacts of that event on the system. After determining the probability and impacts of an event, the framework should consider individual (or collective) resilience measures and the associated costs of those measures to address each event. It should also consider metrics measuring the efficacy of the resilience proposal. Moreover, any resilience proposal must require utilities to perform cost-benefit analyses for major infrastructure investments relating to resilience and to quantify the savings to consumers from such investments.

How Much Are We Willing to Pay and Who Pays?

Regarding how much we are willing to pay, there is no single objective answer to this question. As previously mentioned, having an appropriate analytical framework in place to evaluate resilience measures is an essential first step. Likewise, as further discussed below, defining appropriate key metrics around resilience will assist in the decisionmaking process.

Any investment will depend on the needs of the system and the traditional sensitivities around rate impacts. It is important to understand the electricity needs of consumers and communities served, recognize those needs may not always be the same, and distinguish between different needs among consumers within the same customer classes. As utilities propose to spend money to allow their systems quicker recovery post-event, they should consider making such expenditures on a customer-priority basis, reflecting on whether spending on certain customers and customer classes require a higher

[179] Grid Strategies LLC (2018), 54.
[180] Id., 54–55.

priority.[181] Perhaps utility spending, both how much and for whom, could be analyzed in relation to a "priority stack." Utilities should also consider how customers may be prioritized following an emergency service restoration — e.g., military bases, hospitals, emergency services, state agencies, businesses, residences, child care facilities and educational institutions.

Understanding how much resilience consumers are already paying for, and ensuring they are not being asked to pay more for something that is already received, is essential. Given consumer advocates' experiences, the traditional metrics for distribution spending (i.e., resources must be used and useful, investments must be prudent, and costs must be just and reasonable) are still relevant. It is difficult to analyze whether all of a utility's spending on resilience is ultimately beneficial, as such measures tend to be proposed on a piecemeal basis, and may only be deemed "useful" if there is an event. Thus, it will also be essential to audit detailed financial expenditures and determine whether a resilience proposal is already being addressed under other reliability requirements to ensure consumers are not double-paying for the same measure.

State commissions and grid operators also need to consider whether it is appropriate to separate out a "resilience decision-making process." As a general matter, the decision-making process for potential expenditures of ratepayer funds should be comprehensive, rather than focus on any particular attribute. Resilience, if it is to be viewed as its own attribute at all, is a benefit to be weighed, as with any other benefits, against the costs.

While certain customers may place a higher value on having their service restoration prioritized after a destructive event, it is important to note that this is an example of resilience, not reliability. Reliability is an essential, universal service that should not be prioritized based on customer type, and investment and service planning decisions should be made accordingly. Because bringing customers back online necessitates prioritization, discussion around resilience can possibly differentiate service priorities and costs based on customer need.[182] That approach, however, should apply only to resilience-related decisions, and not reliability decisions.

Another concern of consumer advocates is the increasing tendency for programs, including those proposing resilience measures, to be paid for through state commission-approved trackers.[183] Trackers generally can cause concern for consumer advocates[184] and also may allow for reliability work to be misdesignated as resilience efforts, allowing the utility recovery through a more advantageous cost

[181] For example, in Florida, there is a robust system with county emergency operations centers (EOCs) coordinated within the state. Each county and utility decides priorities in their respective areas as to what to bring on first (e.g., hospitals, emergency services). Most hospitals have generators available when they lose power. The local EOCs decide priorities, and utilities respond to those priorities to harden those facilities first. Each EOC lists facilities it considers priorities.

[182] NASUCA (2018).

[183] NRRI (2009). The abstract provides that a "cost tracker allows a utility to recover its actual costs from customers for a specified function on a periodical basis outside of a rate case."

[184] NASUCA (2005).

recovery mechanism. Any trackers should include a rigorous process for cost evaluation prior to recovery.

Potential-Cost Sharing Opportunities

NASUCA is interested in learning more about potential financial support for proposed utility resilience measures being offered by the private sector; federal, state and local agencies; those entities proposing, requesting or interested in microgrids; the transportation sector; and any other relevant entities.

- **Private Sector.** Some states have experienced a demonstrated need for interagency and private partnership coordination.[185] They are seeing "an increasing interest in leveraging private sector investment and reinsurance tools to offset financial risks and better plan for future events."[186]
- **Federal Agencies.** The Stafford Disaster Relief and Emergency Assistance Act authorizes the Federal Emergency Management Agency (FEMA) to provide federal aid to, among others, municipal, state and rural electric cooperatives.[187] Likewise, federal funding has been made available, in limited circumstances, to investor-owned utilities under the Community Development Block Grant program of the U.S. Department of Housing and Urban Development.[188]
- **State Agencies.** Electric grid resilience planning should not be contemplated in a vacuum apart from the resilience planning done for the state's emergency planning and response efforts. If agencies may, as a matter of public policy, establish certain key parameters or standards relating to resilience planning, the issue of how much funding might come from those entities to help meet those standards and reduce the impact of resilience planning and implementation on consumers' electric utility bills are worthwhile considerations.
- **Local Agencies.** Utilities might find the need to coordinate resilience measures with a county, city, local fire department, local police department or other emergency management entities. In instances like these, all of the costs should not fall on the utility and be spread across its customer base for recovery; rather, these entities could help in planning and funding resilience initiatives. For example, a 9-1-1 fund directed toward public safety might also be utilized to garner additional money for resilience measures and investments. Outlined plans for cost sharing may be an option for states to pursue.[189]

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[185] See the State of Hawaii Resilience and Disaster Management website at https://dashboard.hawaii.gov/stat/goals/5xhf-begg/ezet-axai/nc87-bpmw.
[186] Id.
[187] McCarthy (2011).
[188] 25 Code of Federal Regulations (CFR) Part 570; Title I of the Housing and Community Development Act (HDCA) of 1974, as amended, https://www.hud.gov/sites/documents/DOC_16470.PDF.
[189] After Hurricane Iniki in 1992, a Hawaii state law was introduced to allow the state utility commission to spread the cost for recovery across all of the islands, providing for customers from one utility to help customers from another.

- **Microgrids.** Microgrid proposals are becoming more prevalent as a way to help protect critical facilities, increase safety and preserve quality of life for consumers during outages.[190] There needs to be a robust policy discussion about the public versus private benefit of these proposals, and cost recovery should align with the benefits.[191] Hospitals, military bases and other entities interested in microgrids should partially or wholly fund these projects. State commissions should avoid having the utility first pay for such projects, and then later debate in a general rate case who should pay for the microgrid investments, especially those which may only ultimately benefit a small group of customers.[192]
- **Transportation Sector.** Consideration relating to resilience planning and shared resources should also be given to airports, highways, railways, transit systems and harbors as these may be key infrastructure points in which supplies will be brought into a state after an event, along with how to plan for sufficient support for first responders (e.g., hospitals, police and fire departments).[193] Agencies and entities responsible for

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See http://www.capitol.hawaii.gov/hrscurrent/Vol05_Ch0261-0319/HRS0269/HRS_0269-0016_0003.htm. However, there are no rules or laws requiring state or county agencies to find their own funding instead of relying upon utility customers.

[190] Connecticut, Ohio and New Jersey have application processes in place for microgrid projects delineating what, how and where investments should be made. Connecticut funded microgrids in 2012 through a bonding act such that the funding will come from taxpayers, not utility ratepayers, although a small subsidization from ratepayers arguably occurs through eligibility of some microgrid-connected loads for virtual net metering. See Public Acts 12-148, 12-189, 13-298, Conn. Gen. Stat. §§ 16-243y, 16-244u, 32-80a et seq. Under Connecticut's Microgrid Program, grants can be awarded to any number of recipients to support critical facilities and are generally split between small, medium and large municipalities if possible. Critical facilities, as defined by Public Act 12-148, Section 7 are "any hospital, police station, fire station, water treatment plant, sewage treatment plant, public shelter or correctional facility, any commercial area of a municipality, a municipal center…." More information on Connecticut's microgrid program is available at http://www.ct.gov/DEEP/cwp/view.asp?Q=508780. Ohio has 100 percent individual customer-funded microgrid pilot projects. A majority of microgrid projects in New Jersey were funded through the NJBPU's Clean Energy Program, using funds from the Societal Benefits Charge applied to all ratepayers' bills. See also NJBPU, *In the Matter of the Clean Energy Programs and Budget for Fiscal Year 2018 – 4th Budget Provisions*, Docket No. QO17050465 (May 22, 2018). The Order set the Clean Energy Program budget for 2018–2019, including funding for CHP/fuel cell and microgrid studies; see https://www.nj.gov/bpu/pdf/boardorders/2018/20180522/5-22-18-8D.pdf.

[191] For example, Baltimore Gas & Electric (BGE), a combined gas and electric utility in Maryland, sought Maryland Public Service Commission (MPSC) approval for a pilot project consisting of two public purpose microgrids, with a total estimated cost of approximately $16 million. BGE proposed the project as a pilot to advance public purposed microgrid development as a way to address extended outages in two neighborhoods and grid resilience generally; however, the state commission rejected the proposal, citing a number of deficiencies including BGE's failure to engage in discussions with the community, emergency management officials and local government representatives, site selection deficiencies, and failure to address how public purpose microgrids relate to BGE's long-term distribution plan. MPSC, In the Matter of the Baltimore Gas and Electric Company's Request for Approval of its Public Purpose Microgrid Proposal, Case No. 9416, Order No. 87669 (July 19, 2016).

[192] CPUC Docket A.17-10-007/008, https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1710007.

[193] In New Jersey, much has been done in regards to resilience and cost-sharing. Some customers, like hospitals, pay for their resilience proposals, and funds may be created to help socialize the costs (e.g., backup generation for a hospital). The state's transit system is currently building a microgrid for emergencies. NJBPU, *In the Matter of the Clean Energy Programs and Budget for Fiscal Year 2018 – 4th Budget Provisions*, Docket No. QO17050465 (May 22, 2018). The Order set the Clean Energy Program budget for 2018–2019, including funding for combined heat and

these types of infrastructure may likewise be able to allocate funding to utilities to help ensure quick restoration and recovery after a major event.[194]

2. Who's responsible for resilience, and how should other entities coordinate with utilities when there are mutual benefits?

Distribution planning is a matter of state, local and utility authority. Each of these stakeholders may have a role in evaluating, coordinating and planning for events that affect the distribution system. Transmission planning falls on utilities, federal (and state, to some extent) regulators, and RTOs/ISOs, yet there may be areas where federal agencies can proffer resilience criteria or funding support, either prior to or following a major event. Following is a list of entities that might be considered when coordinating resilience measures:

- **Utility.** Historically, reliability has been a utility focused-function; however, many states now approach reliability planning in a manner that includes multiple stakeholders.[195] Similarly, resilience may involve entities at the state, local and potentially federal level. Sifting through this distinction can be a challenge, but it is important. Other utility coordination efforts include the Electric Subsector Coordinating Council, which serves as the liaison between the federal government and the electric power sector. Its twofold mission is (1) to coordinate efforts to prepare for and respond to national-level disasters and threats to critical infrastructure, and (2) to focus on tools and technology, information flow, incident response, and utility mutual assistance programs that enable sharing of resources between utilities during storm response and are based on voluntary agreements among utilities within the same region.[196]
- **State Utility Commissions.** Planning for resilience has become a more clearly identified need highlighted after 9/11 and, more recently, by the struggles that the Commonwealth of Puerto Rico experienced after Hurricane Maria. Generally, state commissions have jurisdiction over distribution and stand as the frontline on resilience. Some state commissions are also considering cybersecurity in their analysis of resilience

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power/fuel cell and microgrid studies (on p. 5), https://www.nj.gov/bpu/pdf/boardorders/2018/20180522/5-22-18-8D.pdf.

[194] For example, on May 31, 2018, the Federal Transit Administration announced $277.5 million in Emergency Relief Program allocations for states and territories affected by Hurricanes Harvey, Irma and Maria, with the majority of the funds dedicated to response, recovery and rebuilding projects and a portion going toward "resiliency projects." See https://www.transit.dot.gov/funding/grant-programs/emergency-relief-program/emergency-relief-program.

[195] In California, for example, the California Independent Service Operator, the CPUC and the California Energy Commission are all involved in reliability and reliability planning along with the investor-owned utilities, community choice aggregators, direct access providers and other stakeholders. While all these entities supply oversight or input on reliability standards and resource adequacy, the infrastructure maintenance tasks related to reliability (tree trimming, etc.) are still the purview of the distribution utility. This division of responsibilities is, generally, true of resilience planning as well.

[196] See Electric Subsector Coordinating Council website at http://www.electricitysubsector.org/.

measures, and the National Association of Regulatory Utility Commissioners (NARUC) established a Committee on Critical Infrastructure following the 9/11 attacks.[197]

- **State Legislatures.** Legislatures nationwide are actively introducing and passing legislation as it relates to electric resilience. Many of these laws are directed toward state utility commissions and regulated utilities.[198]
- **Other State Entities**. Other state entities involved in coordination of efforts related to resilience measures may include: (1) a state office of emergency management which may lead emergency response and recovery following a natural disaster or storm;[199] (2) a state department of transportation which may aid in debris clearing or enable transportation of spare equipment to storm-damaged utility areas; (3) a state utility consumer advocate office which might push out updates and messaging through social media or participate in resilience planning proceedings;[200] (4) the state governor's office; (5) the state energy office; or (6) the state environmental agency.
- **Local Emergency Response and Facilities**. Utilities have to do the actual work on resilience efforts, and they should do so collaboratively under the direction of and in coordination with state or local emergency personnel before, during and after a natural disaster.[201] It might be difficult for state utility commission staff and consumer

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[197] NARUC established a Committee on Critical Infrastructure to provide regulators a "forum to analyze solutions to utility infrastructure security and delivery concerns." The committee also provides its members with an online resource repository as "one-stop access to topical critical infrastructure information across a spectrum of public- and private-sector activities aimed at reliability, security and resilience." See http://members.naruc.org/4DCGI/committees/committeeroles.html?Action=naruc&naruc_Activity=CommitteeandRole&CommCode=NARUC109.

[198] Connecticut Public Act 12-148; PURA Decision, Docket No. 12-06-09, *PURA Establishment of Performance Standards for Electric and Gas* Companies (Nov. 1, 2012). In the wake of Tropical Storm Irene and an October 2011 snowstorm that caused widespread outages, legislation was enacted requiring the Connecticut Public Utilities Regulatory Authority (PURA) to develop standards for acceptable performance by an electric distribution company in an emergency in which more than 10 percent of a utility's customers are without service for more than 48 consecutive hours. The agency developed emergency performance standards in the areas of designation: restoration priorities, mutual assistance, communications with state and local officials and other state utilities, exercises and drills, safety and after-action reporting. The standards are available at: http://www.dpuc.state.ct.us/FINALDEC.NSF/0d1e102026cb64d98525644800691cfe/cc9a8844417b0c3f85257aa9006d4f32?OpenDocument&Highlight=0,12-06-09.

[199] Coordination between state commissions and entities such as offices of emergency management may allow for better identification of critical infrastructures or areas where increased resilience may provide the best benefits.

[200] Consumer advocate agencies, in general, do not have a large or direct role in system restoration when a storm or natural disaster occurs; however, after the event, the consumer advocate may be involved in a resilience planning proceeding at the state utility commission, ensuring the restoration measures are reasonable, prudent and in the public or consumer interest. For example, after an event, the California ORA is involved in reviewing the reasonableness of costs incurred with respect to service restoration and costs not recovered through utilities' insurance that are proposed for recovery from ratepayers, such as through the Catastrophic Expense Memorandum Account, designed to allow the utility to recover the direct costs of service restoration after a disaster (e.g., replacing distribution lines and poles), or through proceedings looking specifically at future disaster resilience and restoration programs.

[201] In Connecticut, following two major storms in 2011, the Connecticut Light & Power Company, both voluntarily and through orders issued by the Connecticut PURA, updated its town liaison program for coordination and communication between the utility and town officials. The revisions included: (1) more frequent updating of town

advocates to determine what makes the most sense when it comes to prioritization of resilience efforts for restoration purposes. Emergency management personnel, depending on a state's organization, may have more knowledge on what parts of the grid need to be targeted first for resilience. In some states, the resilience efforts have not been conducted by the utilities.[202] In other states, counties are taking over initiatives regarding resilience and emergency planning exercises, allowing utilities to act more as facilitators, rather than drivers of resilience measures.[203]

- **Federal Entities**. There is a "before and during" aspect to resilience efforts for power restoration purposes, and certain federal entities can offer beneficial input into resilience planning and provide potential funding sources for resilience efforts, including but not limited to NERC,[204] RTOs/ISOs,[205] DOE,[206] FEMA's National Response Coordination Center (NRCC),[207] U.S. Department of Defense (DOD)[208] and U.S. Department of Transportation (DOT).[209]

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restoration priorities, such as hospitals, police and fire stations, senior centers, etc.; (2) real-time information displays that indicated the status of prioritized locations in the town, trouble spots, crew locations and restoration estimates; (3) designation of both a town liaison and a backup for each town to build understanding and relationships in advance of major events; and (4) improved training exercises and drills for town liaisons. Connecticut PURA Decision, Docket No. 11-09-09, *PURA Investigation of Public Service Companies' Response to 2011 Storms,* (Aug. 1, 2012) at 33-35.

[202] NJBPU (2015). The NJBPU's Clean Energy Program paid 38 percent and 73 percent of the respective combined costs of energy efficiency and combined heat and power programs of two supermarket chains, and each supermarket chain paid the balance.

[203] Hawaii's Honolulu County created an Office of Climate Change, Sustainability and Resiliency. The office has initiated some planning exercises. City of and County of Honolulu (2017).

[204] NERC deals more with normal operations, rather than catastrophic events. It also develops reliability standards to protect the grid's critical infrastructure (Critical Infrastructure Protection standards), cyber and physical standards, and mandatory reliability standards. It also oversees the GridEx exercises.

[205] RTOs/ISOs have a role in protecting parts of the system, but most of the damage at the distribution level is local.

[206] DOE has provided funding for research, development and pilot efforts aimed at resilience. For example, in 2013, DOE and New Jersey announced a partnership to develop an advanced microgrid for the state transit system. The state is evaluating the roles of microgrids, distributed generation and smart grid technologies in relation to grid resilience. DOE (2013). Through an agreement, DOE and Sandia National Laboratories agreed to work with New Jersey Transit and NJBPU to "design a dynamic microgrid to power the transit system between Newark and Jersey City and Hoboken as well as critical stations and maintenance facilities."

[207] The NRCC has stepped in during large storm events to ensure communication channels are open and restoration logistics are handled appropriately.

[208] DOD has provided for restoration of staging areas at federal air facilities and airlift crew and equipment (e.g., for Superstorm Sandy).

[209] DOT, in conjunction with the U.S. Department of Homeland Security (DHS) and Canadian Border Services Agency, may help in "expediting the movement of electric utility resources in support of mutual assistance by issuing transportation permits and addressing delays through toll and weigh stations for traveling support crews during restoration efforts." See EEI Comments to DOE (2014), 22.

3. What types of utility investments have the most impact on improving resilience, and how can utilities and regulators tell whether utility investments in resilience are impactful?

Types of Investments

The investments that have the most impact on improving resilience relate to preventing distribution and transmission from going down, maintaining service when distribution and transmission become disabled, and getting service back online as soon as possible when distribution and transmission outages occur. At this time, few power outages are caused by generation issues; therefore, investment in generation resilience measures generally is not as cost-effective as investment in distribution and transmission resilience measures.[210] Resilience planning will differ by state, type and need of customers, and the particular risks which are most at issue in the area. Examples of such investments include:

- Vegetation management
- Mutual assistance or aid programs and personnel
- System redundancies, IT system backup and backup generators
- Moving, raising or sealing at-risk facilities or flood-prone facilities
- Emergency response drills, training, planning and coordinating communications between responders
- Targeted investments in next-generation communication networks, including broadband fiber
- Mobile incident management and command centers
- Standby or spare equipment for transmission and distribution inventory[211]
- Cyber and physical security measures
- Real-time system intelligence improvements
- Tools for more precise targeting of utility restoration efforts
- Planning tools to provide data to evaluate risks
- Flood and wind protection
- Enhanced pole surveys
- Storm hardening, strengthening, retrofitting or undergrounding lines
- Overhead distribution reinforcement
- Microgrids
- Improved fault detection and location equipment
- Workforce development, including training and cybersecurity awareness

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[210] Hawaii may be an exception to this statement as it has had issues with both reliability and resilience affected by generation.

[211] Examples include the Spare Transformer Equipment Program and the SpareConnect program, which communicates equipment needs in the event of an emergency or other nonroutine failure to connect interested utilities with shared transmission and generation step-up transformers and related equipment. Hardening against a Category 5 hurricane may not reasonable, but standing up the electric elements following such a major event is.

- Other, yet to be seen or determined, technologies, programs or services

Consumer advocates do not necessarily support every one of these potential resilience enhancement measures. A cost-benefit analysis for any proposal, accompanied by an analytical framework as previously described, will be necessary in contemplating whether investment in such measures is worthwhile.

Importance of Vegetation Management

Vegetation management, or tree trimming, is one of the most impactful, low cost and effective types of utility resilience measures. Per a 2013 Electric Power Research Institute (EPRI) report, "tree trimming is a fundamental practice for mitigating local distribution outages. Recently, utilities have found it effective to use the results of storm damage and subsequent restoration as an element to assess their vegetation management and tree trimming programs. In particular, this application of storm data allows a critical review of damage and clearance standards and trim specifications, and it facilitates regulatory enforcement of tree trimming rights."[212]

After customers experience extended outages, opposition to tree trimming generally decreases, as awareness that vegetation management may prevent such outages from happening again becomes more obvious. NASUCA members support robust tree trimming programs in accordance with industry standards, including detailed annual goals and activities, followed up by detailed reporting to the state utility commission.[213] NASUCA members recommend utilities and commissions should consider assessing how and if resilience is affected if vegetation management standards are enhanced. NASUCA members also recommend that utilities, commissions, and state legislatures examine how vegetation

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[212] EPRI (2013). Also, as cited in the EPRI report, according to a 2008 Edison Electric Institute (EEI) Reliability Report, 67 percent of electrical outage minutes were weather related … typically due to wind, ice or snow either directly affecting distribution assets or bringing vegetation into contact with utility lines, poles and transformers. On average, U.S. electricity consumers can expect to lose power for more than 100 minutes annually due to outages from major storms.

[213] In October 2012, Superstorm Sandy caused large-scale flooding and wind damage in the Mid-Atlantic and Northeast, as well as blizzard conditions in the central and southern Appalachians. In New Jersey, since the occurrence of Superstorm Sandy, fewer customers have objected to or complained about tree trimming, and utilities have been required to be more proactive in getting problematic trees trimmed. For example, one utility claimed that trees on private property that could fall onto the right-of-way could not be trimmed; however, when asked if the utility had approached the customer, knocked on their door and offered to trim the tree to avoid this problem, they indicated that they had not. The utility then did so and found that many customers accepted the offer as they now understand the importance of the task post-Sandy. NJBPU, N.J.A.C. 14:5-9, Electric Utility Line Vegetation Management. In Maryland, after a series of severe storms hit the District of Columbia's suburbs in 2010, the state commission investigated the utility's performance and found that its vegetation management plans and performance had been lacking. Order No. 84564, Maryland Public Service Commission, Case No. 9240 (2011). The Maryland General Assembly passed a law requiring the Commission to adopt regulations implementing service quality and reliability standards for electric distribution service. Maryland Public Utilities Article, §7-13. The state commission adopted regulations that include SAIDI and SAIFI standards for all electric utilities in the state. COMAR 20.50.12.02. The regulations also establish standards for the restoration of 92 percent of customers within 8 hours during normal weather conditions and 95 percent of customers within 50 hours during a major outage. COMAR 20-50.12.06. Additionally, the regulations require the annual reporting of data.

management should be addressed when private land owners prohibit utility access to perform vegetation management.

Utility vegetation management budgets have increased in the years following the Northeast blackout of August 2003, when vegetation management was identified as one of the root causes of outages.[214] Reliability rules provide for the inspection, maintenance, repair and replacement of utility transmission and distribution system facilities (e.g., circuits and equipment), including vegetation management along rights of way.[215]

Standard, regular reporting measures should be mandated to ensure the state commissions have insight on what is being done in regards to tree trimming and distribution line maintenance. In those states with such requirements, consumer advocates believe these standards have made a difference.[216]

Determining Impact – Defining Metrics and Establishing an Analytical Framework

As indicated earlier, consumer advocates are keenly interested in the development of both metrics and an analytical framework[217] to evaluate proposed resilience measures; however, to date, little has been done to develop a uniform or "best practice" framework, or metrics to evaluate the effectiveness of resilience proposals.[218]

As metrics are formulated state by state, it will be essential to properly frame the type and amount of investments required to meet resilience needs. Metrics for measuring the value of proposed resilience measures and related documentation may include, but not be limited to, SAIDI, SAIFI, CAIDI and MAIFI (although these metrics are utilized primarily for determining reliability, they may be useful in the context of resilience as well);[219] outage impacts; mandatory utility report filings; lifecycle costs and longevity;[220] and annual reporting of service quality standards and performance. Other examples of potential resilience metrics may be found in the previously referenced frameworks. These include metrics measuring the efficacy in reducing outage probabilities, frequency, scale and duration for different customer groups; whether the measure delivers a substantive incremental reduction in the risk

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214 See EPRI (2013).

215 U.S. - Canada Power System Outage Task Force (2004); Rule 4901:1-10-27 O.A.C.

216 For example, Maryland experienced a series of severe storms in 2011, with outages mainly due to trees near power lines coming down. The state utility commission adopted tree trimming protocols on a more regular cycle. See Order No. 84564, Maryland Public Service Commission, Case No. 9240 (2011).

217 See NASUCA response to question 1, NASUCA's Thoughts on a Resilience Framework.

218 As mentioned in NASUCA's response to question 1, DOE labs and other groups are working toward providing an analytical framework to analyze resilience measures.

219 States typically have reliability metrics on outage duration, which utilities are expected to meet and typically exclude outages associated with major events (including storm damage), transmission failures and momentary outages. NASUCA offers that some of these metrics could be partially expanded to include major events.

220 See Argonne National Laboratory (2016a), 7. Argonne provides that criteria for evaluating resilience measures might include "lifecycle costs, longevity, and regulatory concerns" and should have a "measurable aspect so as to maintain consistency when evaluating the different options."

or duration of outage-minutes; whether there is a meaningful improvement in survivability that customers are not positioned to bear; and addressing lifecycle costs, longevity and regulatory concerns.

Defining key metrics for resilience measures will assist in the decisionmaking process as it relates to a number of key questions (e.g., where to make resilience investments, how much to invest, who should be making the investments, and when those investments should occur).[221] Informing the metrics and benchmarks should be:

- Policy determinations about what to prioritize
- The desired resilience levels for the various aspects of a state's operations (and economy)
- Balancing the costs against the benefits
- Recognizing that different resilience needs will likely exist for different customers (e.g., government, private, industrial, residential)
- How to fund those planning efforts and investments

4. Should utilities take more proactive approaches to investments in resilience?

The obvious answer to this question is yes. Utilities and stakeholders should always be proactive in planning for grid resilience. Consumer advocates generally do not want utilities to wait for the next disaster or catastrophic event to happen to determine what resilience planning should have occurred.[222] Utilities can take measures to minimize impacts; however, they can never anticipate every potential scenario. Moreover, it would be imprudent for a utility to make every infrastructure investment to mitigate against all possible, but perhaps improbable, events. That said, there will always be a degree to which a utility must be reactive.

By its very nature, resilience planning is proactive in that it attempts to anticipate and evaluate probabilities and risks on an ongoing basis. The role of consumer advocates is to ensure that utilities and state commissions apply a rigorous cost-benefit analysis, prudence review, and consideration of affordability to evaluate all resilience measures.

To strike a responsible balance of proactive and reactive measures in their approach, state commissions and grid operators should:

[221] See NASUCA response to question 3.

[222] Electric utilities in Hawaii agree with and are willing to participate in the state's interest in improving resilience planning. As part of Hawaii's efforts to transition to 100 percent renewable energy, utilities hope to incorporate resilience planning as part of the investment that will be needed to accommodate more renewable resources; thus, it is expected that a more proactive approach will be applied rather than a reactive approach. Due to the geographic isolation of Hawaii, waiting for an event, then hoping that supplies can be delivered from the mainland to address the assessed supply needs (e.g., poles, conductors), will likely lead to longer restoration times and a less resilient grid.

- require that the available information relevant to a proposed resilience measure supports a reasonable level of certainty in the net benefit before investing ratepayer dollars in the measure, and
- conduct post-event reviews of major outages and near-outage incidents and revise planning assumptions based on relevant insights gleaned from these analyses.

In considering other potential vulnerabilities, like workforce turnover, utilities may need to be more proactive in providing training to maintain institutional knowledge, recruiting new employees, and incentivizing younger generation employees to remain with their companies.[223] Training of new personnel requires long lead times and is challenging in light of high turnover rates and decreasing numbers of experienced workers, either due to retirements or employees leaving due to lack of incentives to stay.[224]

Another threat to resilience is the potential impact from supply chain interruptions.[225] Fossil-fuel power plants depend on transportation networks to bring fuel and other materials to their facilities. Some plants also rely upon water for cooling. Substations and advanced meter technologies may depend on telecommunications systems for monitoring and measuring the grid and for end-user smart meters. The same few critical component equipment suppliers might provide parts for multiple industries and utilities, and after a major event, this could lead to supply shortages. As a result, significant disruption of other types of utility, network and supply-chain services may also have a significant impact on a utility's ability to rebound from a major outage. Thus, a resilience framework should identify and provide for means to address disruptions in these interconnected services to address the resilience of the overall grid.

5. How can decisionmaking about resilience investments be improved?

Many states have not yet incorporated resilience planning as part of their general planning efforts. There are many ways to improve in this area, including enhancing coordinated communications, involving more stakeholders in distribution system planning, developing an appropriate analytical framework for analysis of proposed resilience investments, and establishing suitable metrics for determining the potential success of such proposals.

It is crucial to improve outreach and communications between the utility planners and relevant state, county and local agencies responsible for responding to natural disasters or catastrophic events. Improved understanding of the requirements of these key agencies will better inform the utility planner's decisions relating to the design of grid resources to best meet customer needs during recovery and restoration.

[223] Argonne National Laboratory (2016b), B-11 to B-12.
[224] NASUCA recognizes the importance of workforce development. Any investment in related initiatives should be done through base rates, not trackers, as these types of investments address reliability.
[225] See Argonne National Laboratory (November 2016b).

Increasing state commission attention to distribution system planning could provide for increased cost efficiency, planning process transparency, and better incorporation of technology like distributed energy resources (DERs).[226] State commissions may wish to explore developing tools and predictive models to gain more insight into what currently exists at the distribution level to better understand the best resilience options for preventing or mitigating potential risk and threat scenarios.

Generally, NASUCA members promote coordinating resilience measures with local entities, considering cost-effective resilience solutions, and identifying an analytical framework and metrics for reviewing the internal utility processes underlying resilience proposals. NASUCA members further agree that states, federal agencies (when jurisdiction-appropriate) and utilities should conduct a detailed cost-benefit analysis, through an evidentiary proceeding, and should only go forward with a proposal if the benefits outweigh the costs.[227] Also, if there are cost savings, those savings should be netted against the full price tag and given back to consumers.

Conclusions

NASUCA provides the following recommendations:

- **Define Resilience.** NASUCA supports stakeholders in each state having a common definition of resilience and supports generally the concepts presented in Argonne National Laboratory's definition of resilience as the "ability of an entity (e.g., asset, organization, community, region) to anticipate, resist, absorb, respond to, adapt to, and recover from a disturbance," adding that such a "disturbance" be defined as an unusual or unplanned event.
- **Establish an Analytical Framework and Evaluation Metrics.** NASUCA supports efforts to develop a comprehensive and consistent resilience analysis framework, and appropriate evaluation metrics, to be used in decisionmaking processes regarding the investment of ratepayer funds for resilience proposals. Further, DOE and its national laboratories are encouraged to work with NASUCA and its members on any proposed analytical frameworks for analysis of resilience enhancement measures.
- **Consider Focusing Attention on the Grid.** At this time, few power outages are caused by generation issues; therefore, investment in generation resilience measures generally is not as cost-effective as investment in transmission and distribution resilience measures.

[226] For example, with the adoption of Maryland's electric restructuring law in 2000, and the subsequent sale or transfer of utility generating facilities, the state commission continues to produce annual 10-year plans as required by state law, but there is no requirement for public review of utility-specific distribution system planning, including plans to integrate DERs. The state commission has indicated that it may explore distribution system planning in the future, noting that it may hold promise to improve reliability and cost-effectiveness of the utilities' distribution systems, to seamlessly incorporate DERs into such systems, support reliability and increase transparency into the planning processes of the utilities. See *In the Matter of Transforming Maryland's Electric Distribution Systems to Ensure that Electric Service is Customer-Centered, Affordable, Reliable and Environmentally Sustainable in Maryland, PC44,* Notice issued Jan. 31, 2017, 13-14.

[227] NASUCA Smart Grid Resolution 2009-03, Smart Grid Principles (June 30, 2009), https://nasuca.org/nasuca-smart-grid-resolution-2009-03/.

- **Assess Vegetation Management Practices.** NASUCA members recommend that utilities and commissions consider assessment of how and if resilience changes will occur if vegetation management standards are enhanced.
- **Ensure Comprehensive Financial Audits.** For any proposed utility resilience investments, such potential costs should be fully delineated, information provided should be transparent, costs should be just and reasonable, investments should be made prudently and, if approved, utilities should be held accountable to staying within their proposed costs.
- **Understand and Distinguish Among Consumer Needs.** When determining who pays, it is important to understand the electricity needs of the consumers and communities served. Those needs may not always be the same, so it is important to distinguish between different needs among consumers within the same customer classes and between classes. The traditional metrics for distribution spending (i.e., resources must be used and useful and costs must be just and reasonable) remain relevant and important.
- **Investigate Cost-Sharing Opportunities for Resilience Measures and Ensure Consumers Are Not "Double-Paying."** Resilience and reliability are related and should be developed in coordination to ensure customers do not double-pay for resilience initiatives that may be duplicative of reliability efforts that are already being made (or have already been paid for). All funding sources should be appropriately examined prior to, or concurrent with, a utility seeking reimbursement from its ratepayers for its proposed resilience measures. Related investments should be demonstrated to be cost-effective before being passed on to customers.
- **Avoid Trackers for Resilience Investments.** Cost recovery by utilities for prudently incurred expenses associated with resilience planning and measures should be included within base rates, and not through separate trackers or surcharges.
- **Understand the Types of Resilience Measures Along With Respective Costs and Benefits and Regional Differences.** NASUCA and its members welcome the opportunity to work with DOE and its national laboratories on training and technical assistance relating to reviewing the costs and benefits of grid resilience measures and in making allowances for the risk differential and needs of different states and regions.
- **Improve Communications and Coordination of Resilience Planning.** Increased coordination by state commissions and utilities with local agencies and communities is essential to improving the grid resilience planning process.
- **Provide for Appropriate Sharing of Cybersecurity Information With Consumer Advocates.** State commissions, RTOs/ISOs, utilities, federal agencies and other informed

organizations should include consumer advocates in cyber and physical security training and discussions.[228]

[228] State commissions and consumer advocates have a long and successful record of being able to address the need to safeguard confidential information through mechanisms already built into state disclosure statutes and other provisions.

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