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TASK FORCE ON

Resilience Framework, Methods, and Metrics for the Electricity Sector

This white paper results from a collaborative effort between the U.S. Department of Energy and IEEE PES, led by the IEEE PES Industry Technical Support Leadership Committee that established the Task Force to develop this white paper.

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LIST OF ACRONYMS AND INITIALIZATIONS

ADMS	advanced distribution management system
AGC	automatic generation control
BA	balancing authority
BES	bulk electric system
CAIDI	Customer Average Interruption Duration Index
CI	customer interruptions
CIP	Critical Infrastructure Protection (NERC)
Con Edison	Consolidated Edison
CPS	cyber-physical system
DBT	design basis threat
DER	distributed energy resource
DG	distributed generation
DHS	U.S. Department of Homeland Security
DMS	distribution management system
DOE	U.S. Department of Energy
DoS	denial of service
DR	demand response
DSO	distribution system operator
EMS	energy management system
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
FPL	Florida Power & Light Company
GIS	geographic information system
GMD	geomagnetic disturbance
GMLC	Grid Modernization Laboratory Consortium (US DOE)
GMP	gross municipal product
GPS	global positioning system
GRP	gross regional product
GSD	gray sky day
HEMP	high-altitude electromagnetic pulse
HILF	high impact, low frequency (event)
IBR	inverter-based resource
ICE	Interruption Cost Estimate Calculator
ICS	Incident Command System
ICT	information and communication technology
IED	intelligent electronic device
IEEE	Institute of Electrical and Electronics Engineers
IOU	investor-owned utility
IT	information technology
ITSLC	Industry Technical Support Leadership Committee
LOLE	loss-of-load expectation
LOLP	loss-of-load probability
MAIFI	Momentary Average Interruption Frequency Index
MCDA	multi-criteria decision analysis
MW	megawatt(s)
MWh	megawatt-hours
NARUC	National Association of Regulatory Utility Commissions
NATF	North America Transmission Forum
NERC	North American Electric Reliability Corporation
NESC	National Electric Safety Code
NIMS	National Incident Management System
NOAA	National Oceanic and Atmospheric Administration
PG&E	Pacific Gas and Electric
PES	(IEEE) Power & Energy Society
PPD-8	Presidential Policy Directive 8
PRA	probabilistic risk analysis
PSC	Public Service Commission
PV	photovoltaic(s)
RC	reliability coordinator
RI	resilience index
SDG&E	San Diego Gas & Electric
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	supervisory control and data acquisition
SHINES	Sustainable and Holistic Integration of Energy Storage and Solar Photovoltaics
SLR	sea-level rise
SCE	Southern California Edison
T&D	transmission and distribution
TSO	transmission system operator
TT&Ms	technologies, tools, and methods
UFLS	under-frequency load shedding

EXECUTIVE SUMMARY

In today's modern society, our livelihoods are inextricably linked with the critical infrastructure sectors, which are considered so vital to our wellbeing that their incapacitation or destruction would have a debilitating effect on the global economy, national security, and public health and safety. Of the 16 critical infrastructures, the Energy Sector is uniquely critical because it provides an "enabling function" across all critical infrastructure sectors.[1]

The electric grid is the greatest engineering achievement of the 20th Century and has fueled the economic engine that brought prosperity and improved quality of life to billions of people worldwide. This system, however, is being tested increasingly by a combination of physical and cyber-related threats, where terrestrial and space weather events are an example of potential physical threats. The terrestrial weather events are exacerbated by evolving climate change that brings extreme weather conditions with greater frequency and intensity. Other human-made threats range from physical to cyber-attacks. This aging electric grid infrastructure may not be adequate to accommodate the transformational technological changes like renewable resources, energy storage, and electrification. The intermittency of renewable resources, increased electrification, and extreme weather require a comprehensive assessment of grid modernization and resilience investments. Furthermore, the electric grid's resilience is a foundational building block for our decarbonized clean energy future, **which requires renewable resources, energy storage, and electrification—the optimal deployment of which depends on investments in a resilient, modern grid.**

While the concept of resiliency is not new, its application to the electric grid is not as straightforward due to the lack of a consistent definition of resilience or a mature set of metrics by which resilience or its application can be measured. This document provides an overview of resilience definitions, including its relationship with reliability, the existing frameworks for holistically defining resilience planning and implementation process, and the metrics to evaluate and benchmark resilience. It provides recommendations on using those frameworks and metrics and evaluates technologies, tools, and methods to improve electrical system resilience. This task force concluded that the complexity of defining resilience highlights the need for a more simplistic approach to establish a set of metrics that can be more robustly and consistently applied across various stakeholder groups. Ultimately, the value of metrics lies in their ability to be benchmarked and compared across industry participants and to facilitate continuous improvements. However, another conclusion is that there is no "one-size-fits-all" solution for resilience metrics and investments as they are dependent on various factors—regional, functional, regulatory, and business. **Therefore, it is not possible to have simple, industry-accepted resilience metrics addressing all possible events. The proposed approach is to identify individual parameters/events and associated system-dependent metrics, which are then applied based on pre-defined priority weights/factors and by using the appropriate framework to facilitate the investment decision process.**

To identify the appropriate framework, the task force has concluded that it must consider all potential hazards that are likely to impact the electric grid's critical functions. These hazards are very broad, with many of them unpreventable and difficult to predict or control in terms of magnitude and intensity. An effective resilience framework should strive to minimize the likelihood and impacts of a disruptive event and provide the right guidance and resources to respond and recover effectively and efficiently when an incident happens. It should also have a feedback loop to foster continuous improvement. This can be accomplished by applying the **all-hazards framework toward assessing and developing a program with five main focus areas: Prevention, Protection, Mitigation, Response, and Recovery.** The program centralizes, assesses, and prioritizes mitigation projects to address the threats and hazards that pose the greatest risk to critical energy infrastructure. This includes using appropriate tools to evaluate credible scenarios that could affect a grid operator's ability to provide safe and reliable electricity to its customers and the communities it serves. The process starts with identifying critical functions, systems, and resources and the hazards and threats that could impact them. Next, the process determines the appropriate risk mitigation approach by developing prevention, protection, and/or mitigation strategies to reduce those impacts. For those risks and impacts infeasible to mitigate, the operator executes activities to manage the system performance's degradation to recover from those disruptions.

These resilience considerations must also be included as a part of the integrated generation, transmission, and distribution planning and investment prioritization process.

[1] US Presidential Policy Directive 21, February 2013

It is important to highlight the need for investment in resilience improvements. The investment will depend on a good understanding of the consequences of action or inaction. As funds will always be limited and it is not possible to eliminate all impacts on system performance, it is necessary to prioritize actions and corresponding investments to minimize the impact and propagation of the event and assure fast and safe restoration to the original state or a new normal state. New and emerging technologies to address resilience should be considered as part of those investments. This paper describes strategies to evaluate and improve resilience, depending on the type of initiating events with associated consequences that have impacted the system. Some of the best solutions are built on combining the technologies, tools, and methods (TT&Ms) highlighted in Section 5. It is emphasized that IEEE has an important role in identifying best practices and applicable standards.

Furthermore, there need to be more supportive regulatory frameworks and policies that enable utilities to implement appropriate system hardening measures proactively ahead of major events. Such investments will likely increase the cost pressure on electric rates, emphasizing the need for regulators to understand and approve the methodologies used to prioritize and mitigate risks. However, these investments are more cost-effective than attempting to restore or rebuild the system under emergency response conditions—particularly when faced with a shortage of skilled labor and critical resources. They also offer the potential avoidance of untold human suffering and potential loss of lives when critical infrastructures are severely impacted over a prolonged recovery period.

While electric grid operators play a central role in resilience preparations, a comprehensive approach to developing a resilience plan must include the active involvement of diverse stakeholders—starting with regulators and policymakers at the federal and state levels. A resilience plan must also include the full participation and shared responsibilities of emergency response organizations and consumers. There are also benefits of developing processes to support effective system-wide resilience planning across larger regions so that regional planners can co-develop strategies with state/local planners. In summary, this multi-stakeholder collaboration and the acceptance of shared responsibility is a required pre-requisite for a more resilient electric grid.

Finally, to provide a practical perspective to addressing resilience, this white paper includes the progress made by electric grid operators in collaboration with regional authorities to strengthen the resilience posturing. The white paper also includes some of the more common practices and use cases to increase system resilience, enhance broader preparedness, and combat the various external impacts on the electric power grid. Those use cases include Southern California Edison, Con Edison, Entergy, Florida utilities, San Diego Gas & Electric, ComEd, Austin Energy, and transmission and distribution system hardening practices, wild-fire risk mitigation lessons learned from California, and NERC reliability and cyber-security standards.

Section 1 INTRODUCTION

1.1 Importance of Resilience for Electric Grids

Critical infrastructures, including electricity, water, gas, transportation, telecom, and safety, are highly interdependent. Of the 16 critical infrastructures identified by a Presidential Policy Directive[2], the energy sector is uniquely critical because it provides an "enabling function" across all critical infrastructure sectors, especially as it relates to public health and safety. The safe operation of power systems is critical for energy security and the effective functioning of all infrastructures. This paper aims to establish definitions and a framework to organize, clarify, and communicate how different metrics, tools, and methods can be used to support decision-making and investment priorities as it pertains to resilience.

The electric power industry is currently undergoing transformative changes, including integrating renewable energy resources, electrical storage, and electrification. The essential need for the electrical grid to support other infrastructures and help achieve societal goals, such as broad decarbonization, continues to increase. Many critical hazards, such as natural hazards like wildfires, floods, ice storms, and extreme storms, and human-made hazards like cyber and physical attacks, pose a challenge to grid resilience, have been extensively studied. In addition to these sudden disruptions, chronic issues such as aging infrastructure and changing climate stress the grid over longer time periods. These shocks and stresses can create broad consequences across the electrical grid that will cause other challenges in electrical subsystems leading to cascading failures.

As the changing environment requires an improved and flexible response, resilience has received increased public attention. It is becoming an important factor in understanding priorities and investments in modernizing the grid. Many entities have researched this area, including IEEE, U.S. Department of Homeland Security (DHS), U.S. Department of Energy (DOE), Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC), National Association of Regulatory Utility Commissions (NARUC), as well as industry and academia. While reliability definitions and metrics have been standardized and widely adopted, there are no industry standards for grid resilience. **There is a strong need for robust metrics, methods, and associated planning methodologies to quantify risk within an overall framework for grid resilience to weigh resilience improvements against other goals and investments.** A framework for grid resilience must identify regional, functional, regulatory, and business impacts while focusing on common processes and metrics. An example is the impact of weather-related events based on regional conditions (hurricane vs. snowstorm vs. fire events).

The integration of renewable energy and smart-grid technologies are creating both opportunities and challenges for power system resilience. For example, microgrids have demonstrated effective capabilities during critical load restoration; however, sub-transmission and distribution network restoration with highly distributed energy resource (DER) penetration poses a technical, safety, and procedural challenge. Systems with large-scale inverter-based renewable energy resources experience low fault currents and low system inertia, which may negatively affect grid resilience unless design changes are made to strengthen both reliability and resilience.[3]

1.2 Emerging Threats to the Electric Grid

The cyber threat continues to evolve, with malicious actors increasing their desire and attempts to manipulate physical assets across the system. Physical attacks, including the use of electromagnetic pulses, are also of concern. As a result of the increasing impacts of climate change, natural catastrophes such as hurricanes, tornadoes, ice storms, and fires, as well as chronic issues like drought and rain, are becoming more intense and frequent.

None of the electricity supply chain components—generation, transmission, and distribution—are immune to these growing threats and challenges. On the generation side, depending on regional differences, there is a need to address an increasing role of renewables and other variable generation, as well as supply chain issues with an increasing dependence on natural gas and the associated market-side risks on gas supply.

In transmission, long lead times for the delivery of large power transformers or major network infrastructure equipment and the physical security of remote assets remain significant. In addition, the growing reliance on public

[2] Presidential Policy Directive 21
[3] IEEE PES TR68, Impact of Inverter Based Generation on Bulk Power System Dynamics and Short-Circuit Performance, July 2018.

access communication infrastructure for transmission network management poses an increasing number of cyber entry points, creating new vulnerabilities for external attacks.

Distribution systems are evolving rapidly, with the grid edge increasingly moving towards internet-connected devices and DC loads. Behind-the-meter solar and energy storage, along with fast-charging transportation infrastructure, limited situational awareness, and aging infrastructure—especially in dense urban areas—make the distribution system a weak link for system resilience. Although outages at the transmission system level may have greater consequences, the distribution system is frequently the Achilles heel of grid resilience because of its inherently less robust design, as it supplies energy directly to the consumer.

At the overall system level, supply chain issues and limited availability of sensors, communications, and controls make the network more susceptible to severe weather events, coordinated attacks, and other threats.

With the increase in renewable variable energy resources, real-time balancing of generation and load becomes increasingly complex, with generation becoming less predictable. In addition, advanced control/forecasting systems will be required, along with the deployment of enhanced storage and load control/demand response (DR) functionality. The grid will need to manage voltage and frequency fluctuations, load masking, and power quality issues. Because the grid was originally designed for one-way, predictable power flows, advanced high-speed monitoring and protection and control schemes will be required to detect and isolate a disturbance, as frequency response from traditional central plant generation sources are replaced by asynchronous DER or renewables resources. Increasingly, these resources are weather-dependent, which adds uncertainty in the management of balancing load and demand.

The ongoing COVID-19 pandemic is an extreme case in which a health hazard has imposed a significant burden on power system resilience. Utilities have taken various effective measures to mitigate the pandemic's impact on business continuity, including controllable/dispatchable operational resources, critical operation and construction sites, and supply chain resilience. The scarcity of supply and qualified grid security vendors must also be addressed. The COVID-19 pandemic illustrates that resilience frameworks need to be flexible and rapidly coordinated with unpredicted abruptions.[4] It also shows that the industry has reacted very quickly to the pandemic, with a clear understanding that delivering reliable electric power is essential and that interruptions would greatly impact society. It is remarkable that despite the stresses on the workforce, there have been few major outages reported, and reliability levels have been maintained due to decisive actions and the execution of well thought out plans by major utilities and grid operators.

Section 2 FACTORS IMPACTING ELECTRIC GRID PERFORMANCE

Major events affecting power system resilience can be categorized broadly in the following categories:

- Resilience against natural disasters and pandemic events
- Resilience against human-made cyber and physical attack events
- Resilience against events stemming from system design, aging, and human error

As discussed in the introduction, resilience challenges place stresses on the grid and are described in more detail in the following sections.

2.1 Resilience Against Natural Disaster and Pandemic Events

2.1.1 Natural Disasters

Severe weather events (flooding, drought, strong winds, ice, snowstorms, extreme heat or cold, wildfires, earthquakes, etc.) are the most common disruptions that test modern power systems' resilience because these events can cause severe power system infrastructure damage. They are often predictable to some degree and trackable during the events. The associated forced outages are sometimes mitigable or limited in scope or duration by preventive system planning, system hardening design measures, operational methods using situational awareness, system-wide coordination and dispatch, and system restoration/recovery during and after the events. Regional weather events such as tornadoes are capable of widespread damage to transmission and distribution (T&D) equipment. Predicting the specific location of

[4] A. Paaso (lead), et. al." Sharing Knowledge on Electrical Energy Industry's First Response to COVID-19," IEEE PES Resource Center, May 2020.

these events is often challenging. As the grid transformation continues to occur with greater reliance on common renewable resources such as wind and solar, the prolonged foul-weather condition takes on a different dimension of impacting the adequacy of supply and must also be appropriately addressed.

Preventive resilience planning and system hardening can significantly increase the resilience against natural hazards. Utilities have gained extensive experiences through disaster preparedness and response practices and have developed various natural disaster mitigation strategies through the course of practice. For example, replacing the aging distribution and sub-transmission poles can reduce power line outages during hurricanes; raising the foundations of substations can help withstand high flooding situations observed during the past costly hurricanes. Comprehensive system modeling and earthquake fragility studies of critical transmission and substation assets can identify weak links for targeted system hardening measures to improve resilience during potential large area disruptions such as earthquakes. While system hardening is an effective approach for resilience improvement, it usually requires large capital investment and needs long planning and implementation times.

Operational methods play a key role in mitigating the impact of natural-disaster-caused system outages. They are essential near-term and real-time "front lines" to maintain power system resilience. Adequately predicting and tracking natural hazards enables system operators and utility asset managers to take preventive measures before the disruption materializes. New, more accurate weather forecasting methods will be required to predict weather impacts on daily generation amounts. During the event, situational awareness tools integrated with traditional supervisory control and data acquisition (SCADA) and modern wide-area monitoring technologies help system operators and utility storm duty commanders to make the most effective decisions with big data. Post-event system event analysis is beneficial to review the system responses and provide recommendations for future events.

2.1.2 Space Events

Space-related geomagnetic events can cause transformer saturation, transformer core overheating, and reactive power and harmonic generation. Electromagnetic events such as geomagnetic disturbance (GMD) potential threat to grid stability and reliability. They may further disrupt the global positioning system (GPS), negatively impacting system monitoring and control (e.g., phasor measurement unit [PMU] synchronization). Substantial progress has been made in understanding the potential grid impacts and necessary mitigations to geomagnetic events.[5] [6] However, there are additional opportunities to harden the grid infrastructure further to limit damage from such events. The Congressional Budget Office has observed that "one approach to reducing the economic and social harm that would result from a large-scale disruption of the electric grid would be to deploy new, dedicated systems in space to provide early warning of solar storms by detecting them before they reach Earth. Similar systems exist in space today, but they are aging and were not designed to be the reliable source of data that is needed for uninterrupted forecasting of space weather. The National Oceanic and Atmospheric Administration (NOAA) has formulated a program to deploy new satellites, but lawmakers have yet to commit to fully funding it."[7]

2.2 Resilience for Man-Made Cyber and Physical Attack Events

The physical electric grid and communications infrastructure form a large, complex, and interdependent cyber-physical system (CPS). Disruption of services at the cyber layer can have a major impact on electric grid operations and assets. Denial of service (DoS) and increased latency for measurement and control commands at the cyber system layer can affect the electric grid's observability and controllability. Communication delays in CPSs are crucial for control systems' performance (e.g., power system stabilizers). In the case of large disturbances, the grid can experience instability. Without proper control, such instability can result in a sequence of cascading events and cause a blackout leading to other unintended consequences. Utilities are increasingly building their own private communications networks to isolate them from public networks to reduce some of these issues.

Physical attacks may damage any system equipment, but they are more commonly targeted at large transformers and other critical equipment such as high-voltage circuit breakers. Generation facilities are not as exposed and commonly have higher physical security. Physical security monitoring systems integrate people, procedures, and equipment to

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[5] See EPRI Report on Geomagnetic Disturbances (GMD) Grid Resiliency: Furthering the Research of GMD Impacts on the Bulk Power System, https://www.epri.com/research/products/000000003002011467

[6] https://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

[7] See Congressional Budget Office Report CBO Report https://www.cbo.gov/publication/56083

protect assets or facilities against theft, sabotage, or other malicious human attacks. Currently, substations' physical security focuses almost exclusively on fenceline detection and substation control rooms using video cameras. These systems can be disrupted with a loss of power, preventing the detection of intruders. FERC, NERC, system operators, and utilities have addressed our electrical grid's vulnerability to physical attacks on critical substations. It is important not to succumb to "doomsday scenario" thinking. Instead, it is important to continue developing plans to address vulnerabilities. As serious as the physical attack on Pacific Gas and Electric's Metcalf substation in 2013 was, there were no resulting customer outages.[8] As the industry response to COVID-19 has shown, the grid is resilient if immediate actions are taken. Disabling many substation locations would be difficult and, even in such a case, plans are in place to restore power to electricity users.

Another physical attack threat is the high-altitude electromagnetic pulse, a near-instantaneous electromagnetic energy field produced in the atmosphere by the power and radiation of a nuclear explosion. It is damaging to electronic equipment over a wide area, depending on the intensity of the nuclear device, position of electronic equipment's cabling, and altitude of the burst.

2.3 Resilience Against Events Stemming from System Design and Human Error

The electric grid configuration is a key factor in its resilience. The systems need to be planned and designed in a way that they can avoid blackouts. Power system blackouts result in the complete interruption of electricity supply to all consumers in a large area.[9] This is particularly important in systems with large penetrations of renewable energy resources and storage. Such inverter-based resources (IBRs) result in reduced system inertia and low fault-current levels.[10] As more IBRs are integrated into the system, it is necessary to follow NERC requirements to assure system resilience.[11] While it may be possible to trace a blackout's origin to a single incident (e.g., a transmission line sagging into a tree, a relay misoperations after a local event, etc.), these blackouts almost always result from a series of cascading outages, usually caused by multiple low-probability events occurring in an unanticipated or unintended sequence. The likelihood of power system disturbances escalating into a large-scale cascading outage increases when the grid is already under stress. Blackouts are the result of how we manage, plan, and design the grid in preparation for various operational scenarios.

Generally, disturbance propagation involves a combination of several phenomena:

- Equipment tripping due to faults or overloads (e.g., transmission lines and transformers). These events may cause other equipment to get overloaded, creating a cascading event contributing to large-scale outages.
- Power system islanding (frequency instability) when the power system separates and generation levels do not equal the load connected. Electrically isolated islands are formed, with an imbalance between generation and load, causing the frequency to deviate from the nominal value, leading to additional equipment tripping.
- Loss of synchronous operation among generators (angular or out-of-step instability) and small-signal instability that may cause self-exciting inter-area oscillations if not damped.
- Voltage instability/collapse problems usually occur when the power transfer is increased, and voltage support is inadequate because remote resources have displaced local resources without properly installing needed transmission lines or voltage support devices in the "proper" locations.

The key to making the grid more resilient is to effectively address preconditions that cause grid stress, such as:

- Congested grid with tight operating margins, including non-optimal planning of renewable energy resources, storage, and electrification and not addressing issues such as system inertia and current levels.
- Insufficient reactive support where and when required to maintain required voltage levels.
- Uncoordinated planning and operations among generation resources and transmission and distribution.
- Lack of system and component knowledge (e.g., system operator not aware of line loading margins).
- Lack of more-advanced longer-term weather forecasts.
- Lack of visibility of the level of DERs on the distribution system and their response to system perturbations.

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[8] G. Lemler, "Hardening Against Vandalism - Metcalf Substation Event," IEEE PES GM, Late Breaking News Session, Vancouver, Canada, July 2013.
[9] D. Novosel, "Transmission Blackouts: Risk, Causes, Mitigation," Encyclopedia of Sustainability Science and Technology, Springer, 2011.
[10] IEEE PES TR68, Impact of Inverter Based Generation on Bulk Power System Dynamics and Short-Circuit Performance
[11] https://www.nerc.com/files/glossary_of_terms.pdf

- Inadequate visibility on system and component constraints and inadequate warning, protection, and control systems.
- Insufficient generation resources to meet the system needs or energy policy driving untimely generation retirements.
- Regulatory uncertainty resulting in an insufficient level of investment to improve aging infrastructure and modernization.
- Human error

Reducing disturbance propagation and enabling faster restoration requires the deployment of monitoring, control, and protection devices, software tools, and telecommunication infrastructure that help better manage the grid. However, such actions do not replace the investment needed in the grid infrastructure through asset management programs.

2.4 Prioritizing Resilience Initiatives

Although all the above threats affecting resilience require attention, **it is of the utmost importance to prioritize initiatives and investments to achieve resilience targets in the most cost-effective way**. As regulators set priorities and approve funding, it is necessary to have a common understanding of priorities informed through robust risk assessments.

In summary, a balanced approach—including the value of the grid for resilience and achieving decarbonization through the integration of renewables and electrification of transportation—needs to be implemented based on clear and measurable metrics. The process by which resilience metrics guide priorities and investments is the proactive approach to respond to events affecting the grid, including their likelihood and potential impacts. **A vulnerability assessment process and tools using advanced data analytics are required for an integrated transmission, distribution, and load response planning process that factors in resilience to develop optimal investment strategies.**

Section 3 RESILIENCE AND RELIABILITY DEFINITIONS AND RELATIONSHIP

3.1 Reliability Definitions

The reliability concept has been well established for decades, and many industry organizations have embarked on providing additional perspectives based on their key roles. Table 1 summarizes some of the more commonly referenced definition of reliability.

Table 1 – Summary of Commonly Referenced Reliability Definitions

Organization	Reliability Definitions
NERC	**Adequate Level of Reliability (ALR)**[12] performance is measured against the following objectives: 1) The bulk electric system (BES) does not experience instability, uncontrolled separation, cascading, or voltage collapse under normal operating conditions and when subject to predefined disturbances, 2) BES frequency is maintained within defined parameters under normal operating conditions, and when subject to predefined disturbances, 3) BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances, 4) adverse reliability impacts on the BES following low probability disturbances (e.g., multiple contingencies, unplanned and uncontrolled equipment outages, cyber-security events, and malicious acts) are managed, 5) restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.
	• **Adequacy** is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

[12] https://www.nerc.com/pa/Stand/Resources/Documents/Adequate_Level_of_Reliability_Definition_(Informational_Filing).pdf

Organization	Reliability Definitions
	• **Operating reliability** is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.
US DOE	The ability of the system to deliver expected service through both planned and unplanned events.
	The ability of the system or its components to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components.
IEEE[13]	The probability that a system will perform its intended functions without failure, within design parameters, under specific operating conditions, and for a specific period of time.
NATF	The ability of the system and its components to withstand instability, uncontrolled events, and cascading failures, during normal operation and routine (i.e., reasonably expected) events

Reliability metrics are well defined for both distribution (e.g., SAIDI, SAIFI, CAIDI, MAIFI)[14] and transmission (e.g., N-1, loss-of-load probability [LOLP], loss-of-load expectation [LOLE]).[15] Although there are multiple definitions, the industry has adapted and used them to guide investments. NERC has also developed a series of reliability standards that incorporate resilience by supporting robustness, resourcefulness, rapid recovery, and adaptability. These reliability standards relate to the bulk electric system's capability to withstand disturbances in anticipation of potential events, manage the system after an event, and/or prepare to restore or rebound after an event.[16] [17] [18] [19] [20] [21] [22]

3.2 Resilience Definitions

The standard/dictionary definition of resilience is "the capacity to recover from difficulties: toughness."

The following are some industry definitions of resilience:

- FERC: "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 event."
- DOE: "The ability of a power system and its components to withstand and adapt to disruptions and rapidly recover from them."
- NATF: "The ability of the system and its components (i.e., both the equipment and human components) to minimize damage and improve recovery from non-routine disruptions, including high impact, low frequency (HILF) events, in a reasonable amount of time."
- The IEEE Technical Report PES-TR65 and FERC Docket No. AD18-7-000 defines resilience as "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." (events are described in Section 2)

3.3 Contrasting Reliability versus Resilience

A simplistic approach to summarizing the relationship between reliability and resilience would be to say that reliability is a system performance measure, and resilience is a system characteristic. In many cases, better reliability results in better resilience and vice versa. For example, investing in system hardening against hurricanes will have a positive effect on reliability metrics. However, in some cases, a highly reliable system may have lower resilience and vice versa.

[13] IEEE 100 The Authoritative Dictionary of IEEE Standards Terms, 7th Edition
[14] IEEE1366-2012 IEEE Guide for Electric Power Distribution Reliability Indices
[15] "Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning" NERC, May 2011
[16] Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements)
[17] Reliability Standard EOP-004-3 (Event Reporting): requiring that entities report disturbances and events threatening reliability
[18] Reliability Standard EOP-005-2 (System Restoration from Blackstart Resources)
[19] Reliability Standard EOP-006-2 (System Restoration Coordination):
[20] Reliability Standard EOP-011-1(Emergency Operations): requiring operating plans to mitigate emergencies
[21] Reliability Standard CIP-014-2 (Physical security)
[22] Reliability Standard TPL-007-1 (Transmission System Planned Performance for Geomagnetic Disturbance Events)

For example, reclosing power lines may improve reliability metrics such as the System Average Interruption Duration Index (SAIDI), but during "fire season," it may result in higher fire-ignition risks. Furthermore, while some definitions of resilience vs. reliability focus on resilience addressing "low-probability, high-frequency" events, as conditions under which the electrical system operates are changing much faster than ever before, this definition may be incomplete. For example, as the frequency of weather-related events has increased, those cannot be treated as low-probability events. The same could be applied to cyber and physical threats. This approach translates into a definition of resilience as:

"***The ability to protect against and recover from any event that would significantly impact the grid.***"

Furthermore, the primary difference between reliability and resilience is that resilience encompasses all events (as described in Section 2), including HILF events commonly excluded from reliability calculations.

Resilience quantifies the system's final state (like reliability) and the transition times among the states as described by the resilience trapezoid shown in Figure 1. NERC customized this further to include pre-position of the system before an event occurs if situation awareness is available, time for damage assessment, and recovery into deteriorated, stable, or improved states.[23] Thus, it requires a more detailed characterization of the preparation process before any events occur, the operational process during the event, and the event's response process. It may be measured in the continuity of critical services like transit systems, emergency response, and water/wastewater management. Note that this figure depicts changes in the resilience level involving one event; one would expect an overall improvement in the resilience level over time through continuous learning processes.

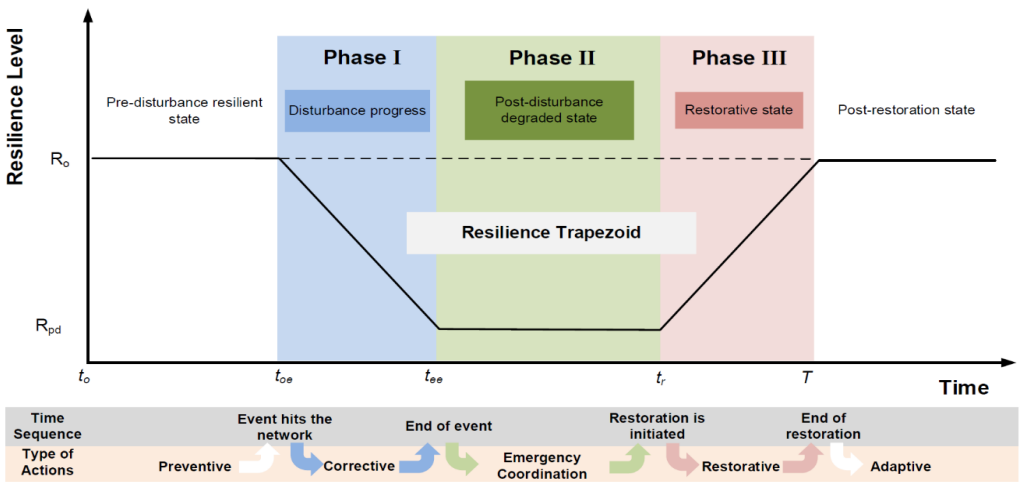

Figure 1 – The resilience trapezoid associated with an event.

There is a social aspect of resilience that cannot be easily quantified but should be considered. It may be termed "community resilience" or "infrastructure preparedness." It is the impact of infrastructure decisions that affect the overall community socio-economic conditions and associated public health, safety, environmental well-being, and livability. Building social and economic resilience begins with a flexible and responsive grid. Resilience may be categorized based on the broad impacts on different systems or end-users. Key indicators representing the holistic view of each performance area should be developed. Those indicators are often system-specific and support a benefit-cost analysis methodology that quantifies the impact that investments and grid modernization have on resilience.

Another distinguishing feature of resilience is that it aims to capture both the effects on the customer (like reliability), effects on the grid operators and staff, and effects on the infrastructure itself (possibly spanning two or more time horizons).[24] **The uncertainty and urgency associated with the planning horizon of interest considered in resilience evaluations, and the likelihood and magnitude of the potential events included in the assessment's scope define the required investments in technology, infrastructure, and processes.** For instance, if it is necessary

[23]https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC%20Resilience%20Report_Approved_RISC_Committee_November_8_2018_Board_Accepted.pdf

[24] The definition and quantification of resilience, IEEE Power and Energy Society, Technical Report PES-TR65, Apr. 2018

to safeguard the system in the very short-term, the pressure to act is high, and uncertainty is relatively low. Conversely, in the long-term, uncertainty is very high, and therefore the pressure to act is lower. These two contexts will lead to competing investment decisions and tradeoffs (shown conceptually in Figure 2).

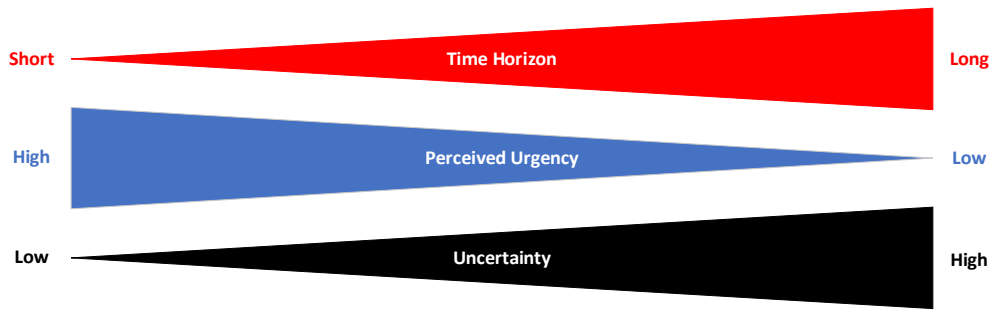

Figure 2 – The resilience investment trinity: time horizon, perceived urgency, and uncertainty.[25]

Resilience is time-dependent and, therefore, resilience planning is a function of the time horizon selected for analysis. An important additional aspect to consider in this decision-making process is that uncertainty levels and urgency will depend on the specific cause being addressed. For instance, although historical data indicate that the frequency of major disasters has increased in the last 50 years,[26] some of these events (e.g., earthquakes) remain very difficult to forecast in advance. Frameworks are emerging that will estimate direct and indirect economic impacts of long-duration power outages and provide important information on the impact of investments in grid resilience. These frameworks also will support the development of the long-term value of resilience.

Section 4 RESILIENCE FRAMEWORKS AND METRICS

4.1 Frameworks for Evaluating Resilience

As resilience has become an important factor in understanding priorities and investments associated with modernizing the grid, there is a need for robust resilience frameworks and metrics. **Those frameworks and metrics would help quantify risks within an overall framework, weigh resilience improvements against other goals, and support investment strategies.** Several frameworks and methods for advancing resilience evaluation have been developed in the last decade. These frameworks can be grouped into two general categories: qualitative and quantitative frameworks.

An example of an existing framework that includes quantitative and qualitative frames is used by NERC to address risks to the BES's resilience.[27] Recognizing that the BES cannot withstand all potential events, an adequate level of reliability must be provided so that the system can be reliably operated even with degradation in reliability due to an event. Further, the system must have the ability to rebound or recover when repairs are made or when system conditions are alleviated. The resulting NERC resilience framework guides how resilience fits into NERC's activities and how additional activities might further support the grid's resilience, underscoring NERC's longstanding focus on resilience and emphasis on re-examining the issue in the face of the changing resource mix. Another example is the risk management framework provided in the U.S. National Infrastructure Protection Plan (NIPP)[28].

4.1.1 Qualitative Frameworks

Qualitative frameworks usually evaluate the power system's resilience, along with other interdependent systems, such as information systems, fuel supply chain, and other such infrastructures. These frameworks evaluate resilience

[25] H. Weise et. al, "Resilience trinity: safeguarding ecosystem functioning and services across three different time horizons and decision contexts", OIKOS, Vol. 129, No. 4, pp. 445-456 https://onlinelibrary.wiley.com/doi/full/10.1111/oik.07213
[26] H. Ritchie, M. Roser, "Our World in Data, Natural Disasters", https://ourworldindata.org/natural-disasters
[27] https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC%20Resilience%20Report_Approved_RISC_Committee_November_8_2018
[28] https://www.dhs.gov/sites/default/files/publications/National-Infrastructure-Protection-Plan-2013-508.pdf

capabilities such as preparedness, mitigation, response, and recovery (e.g., the existence of emergency plans, personnel training, repair crew availability, and other similar measures). Qualitative frameworks are appropriate for long-term planning because they provide a comprehensive and holistic depiction of system resilience. Figure 3 shows typical aspects, capabilities, and methods used in qualitative frameworks.[29]

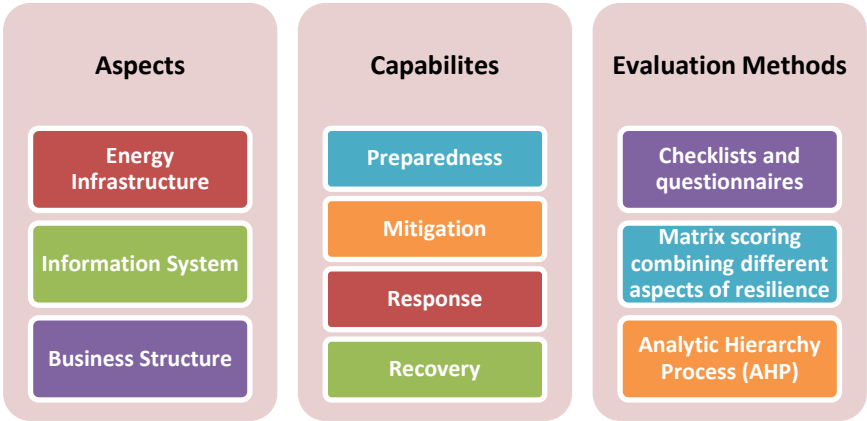

Figure 3 – Qualitative resilience evaluation frameworks.

4.1.2 Quantitative Frameworks

Quantitative frameworks are based on the quantification of system performance. Quantitative metrics are useful when evaluating certain resilience measures' effectiveness or comparing the resilience levels among different systems. Resilience is quantitatively evaluated based on the reduced magnitude and duration of deviations from the targeted or acceptable performance. Quantitative resilience metrics should be: 1) performance-related, 2) event-specific, 3) capable of considering uncertainty, and 4) useful for decision-making. Figure 4 shows the performance-based spiral methodology, which is an example of a quantitative evaluation framework.

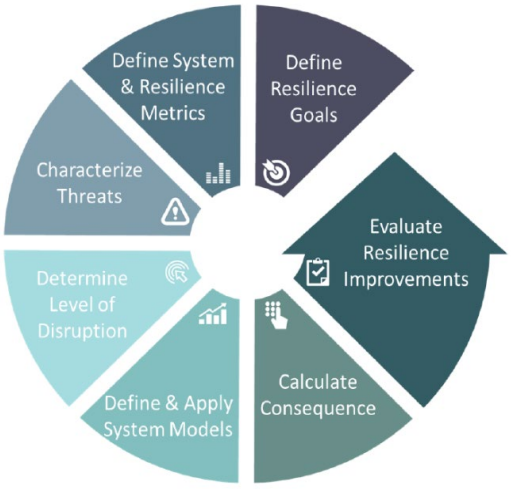

Figure 4 – Performance-based spiral.[30]

4.1.3 All-Hazards Framework for Enhancing Resilience

In 2011, Presidential Policy Directive 8 (PPD-8): National Preparedness was signed. The directive defines how the nation should prepare for and respond to a wide range of natural hazards such as earthquakes, wildfires, severe weather

[29] Z. Bie et. al, Battling the Extreme: A Study on the Power System Resilience, Proceedings of the IEEE, Vol. 105, No. 7, July 2017
[30] J.P. Watson et. al, Conceptual Framework for Developing Resilience Metrics for the Electricity, Oil, and Gas Sectors in the United States, Sandia Report SAND2014-18019, Sep. 2015 https://www.energy.gov/sites/prod/files/2015/09/f26/EnergyResilienceReport_(Final)_SAND2015-18019.pdf

conditions, environmental changes, and human-made or technical hazards such as physical intrusions, cyber-attacks, and sabotage. There are common themes among the preparation of addressing these potential risks, such as managing the plans, equipment, training, and exercise programs required to build and sustain the capabilities outlined in this directive's National Planning Framework.

An effective resiliency strategy should strive to minimize the likelihood and impacts of a disruptive event from occurring. It should also provide the right guidance and resources to respond and recover effectively and efficiently when an incident happens. This resiliency concept is based on Presidential Policy Directive (PPD-8)[31] shown in Figure 5 and the National Preparedness Goal. The directive aims to strengthen the United States' security and resiliency through systematic preparation for threats, including acts of terrorism, cyber-attacks, pandemics, and catastrophic natural disasters. This act prompted developing a series of integrated national planning frameworks covering intertwined prevention, protection, mitigation, response, and recovery. The All Hazards Assessment and Mitigation Program is becoming a common practice among major grid operators. The program centralizes, assesses, and prioritizes mitigation projects to address the threats and hazards posing the greatest risk to the critical infrastructure and business functions. This includes evaluating scenarios that could affect the grid operator's ability to provide safe and reliable electricity to its customers and the communities it serves. A centralized approach improves the prioritization of the limited resources to address the various risks that could potentially impact the electric grid and the operator's ability to provide continuity of safe electric service to its customers.

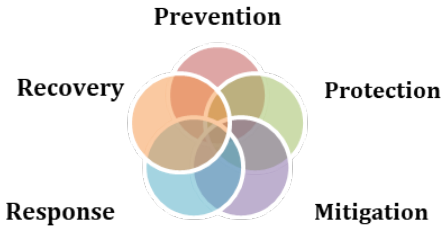

Figure 5 – The interdependencies of the five core mission areas of the National Preparedness Goal.

4.2 Resilience Metrics

The electric power and energy industry has developed several metrics, and some of them will be addressed in this section. Next, we will review the current state of knowledge to identify how to use metrics while focusing on a common framework and metrics' importance.

4.2.1 IEEE Metrics

The IEEE PES Distribution Resilience Working Group[32] under the Transmission and Distribution Committee has designed two draft metrics that will be aggregated into one overall resilience metric:

1. Storm resilience that focuses on the speed of recovery during the first 12 hours of a storm from customers losing power and
2. Non-storm (gray sky) resilience that focuses on robustness and the ability to withstand most weather events.

Storm resilience metric: This metric focuses on the speed of system recovery and is designed to capture the reduction of the number of customers without power for more than 12 hours from the time the customer loses power during a storm event. The metric will consider the instances of customer service interruptions that have been restored automatically without requiring human intervention to capture the value of technology solutions such as distribution automation, advanced distribution management system (ADMS), or microgrids, that minimize customer impacts. It will measure the number of reportable storms where recovery is favorable to threshold values divided by the total number of reportable storms. This metric is calculated as follows:

[31] https://www.dhs.gov/presidential-policy-directive-8-national-preparedness
[32] https://sagroups.ieee.org/distreswg/

1. For each storm in a calendar year, calculate the ratio of customers without power for more than 12 hours and total customer interruptions (CI) including customers automatically restored (avoided customer interruptions) through technology solutions (measured in % of storm event):

$$Storm\ event\ X = \frac{Sum\ of\ customers\ without\ power\ for\ more\ than\ 12\ hr}{Sustained\ Customer\ Interruptions + Avoided\ Customer\ Interruptions}$$

2. Based on the number of interruptions (storm outages), categorize each storm event as significant, large, medium, or small
3. Determine if X is greater than or equal to the threshold value (Y) for the category.
4. If X < Y, the storm met expectations. If X ≥ Y, the storm did not meet expectations

Clearly defining the basis for threshold value (Y) is required for proper baselining. Furthermore, as major climate events and regular storms are becoming more common, baselining the threshold value using historical data needs to be scrutinized to avoid misrepresenting the metrics.

Non-Storm Resilience Metric: This metric focuses on robustness and the ability to withstand events. It is designed to capture the total number of gray sky days (GSD) in a calendar year with no more than the threshold value of customer interruptions. The metric is measured in a percentage of GSDs that does not exceed the threshold value. The threshold value varies by utility size and is defined as the percentage of customer interruptions over the total customer base (e.g., 0.375% of the total number of customers). GSD excludes any calendar day with at least one reportable storm-related outage. The gray sky definition may vary by utility, but it includes certain weather criteria during any calendar day that meets any one of the following weather criteria:

1. ≥ average precipitation across the service territory (e.g., 1" of rain)
2. ≥ average maximum temperature across the service territory (e.g., 90 °F maximum temperatures)
3. ≤ average minimum temperature across the service territory (e.g., 0 °F minimum temperatures)
4. ≥ average maximum wind speed across the service territory (e.g., 25 mi/h sustained wind speeds)

4.2.2 DOE Metrics

DOE's Grid Modernization Laboratory Consortium (GMLC) has developed metrics and a framework for evaluating power system resilience as part of its Foundational Metrics Analysis project. DOE's proposal includes two main categories of metrics:[33]

- Multi-criteria decision analysis (MCDA)-based metrics: MCDA metrics generally try to answer the question, "what is the current state of the electric system's resilience, and what enhances its resilience over time?" These metrics can be used to assess the system's baseline resilience relative to other systems. They typically include categories of system properties beneficial to resilience, such as robustness, resourcefulness, adaptivity, and recoverability. The application of these metrics requires following a process to review to what degree these properties are present within the system under analysis. This usually involves collecting data through surveys, developing weighting factors, and performing calculations to obtain numerical scores. MCDA metrics are used to calculate a resilience index (RI) that accounts for about 1,200 attributes grouped in 350 categories to characterize system resilience.
- Performance-based metrics: performance-based metrics (also known as consequence-based metrics) are generally quantitative approaches for answering the question, "How resilient is my system?" These metrics, shown in Table 2, interpret quantitative data that describe infrastructure performance during disruptive events. The required data can be collected from historical events, subject matter estimates, and computational infrastructure models. These metrics are suitable for benefit-cost and planning analyses because they measure the potential benefits and costs associated with proposed resilience improvements and investments. Resilience metrics need to include a measure of consequences and the relevant statistical probability from the probability distribution of those consequences.

[33] https://gmlc.doe.gov/resources/grid-modernization-metrics-analysis-gmlc1.1-resilience

Table 2 – Performance-Based Metrics

Impact	Consequence Category	Resilience Metrics
DIRECT	Electric Service	Cumulative customer-hours of outages
		Cumulative customer energy demand not served
		Average number (or %) of customers experiencing an outage during a specified time
	Critical Electrical Service	Cumulative critical customer-hours of outages
		Critical customer energy demand not served
		Average number (or %) of critical loads that experience an outage
	Restoration	Time to recovery
		Cost of recovery
	Monetary	Loss of utility revenue
		Cost of grid damages (e.g., repair or replace lines, transformers)
		Cost of recovery
		Avoided outage cost
INDIRECT	Community Function	Critical services without power (e.g., hospitals, fire stations, police stations)
	Monetary	Loss of assets and perishables
		Business interruption costs
		Impact on the gross municipal product (GMP) or gross regional product (GRP)
	Other Critical Assets	Key production facilities without power
		Key military facilities without power

4.3 Risk Management Framework

When planning for power system investment, resilience can be incorporated by including the risk of various consequences within a modified probabilistic risk analysis (PRA) framework. The risk due to events where the probability is well-characterized can be quantified as the combination of probability and consequence – in other words, the outcome of disruptive events and the likelihood of those events. On the other hand, many of the evolving disruptive events, such as cyberattacks, are not well-characterized. Therefore, a modification to the PRA framework is suggested whereby design basis threats (DBTs) are used for the threats that are difficult to characterize. The ability to combine the PRA framework with a DBT-based approach is currently an active area of research. In the power industry, the term "risk" is perceived differently by different organizations. For example, NERC sees risks as the potential consequences to grid reliability (more details are provided in Section 6.11).

Risk management generally addresses acute problems that have been well characterized and documented, but not the longer-term structural challenges, which are much harder to quantify. Because they occur in the future, they are often discounted. Risk assessment has been a common practice to ensure grid reliability and to protect grid assets. As the risk environment evolves due to technological advancement and changes in market paradigms and policies, there is an increasing need for risk management to secure critical infrastructure against emerging threats. The assessment must inform risk management of vulnerabilities, threats, and consequences to the grid infrastructure. The interdependencies between the grid and other critical infrastructure must also be considered. To integrate the risk framework within existing planning techniques, metrics that define system performance during extreme events are necessary. These metrics make up the "consequence" dimension within PRA and may also measure consequence within the DBT approach.

4.3.1 Value of Resilience

Another growing area of interest for the industry is determining the value of the benefits that resilience may provide and using this information to analyze and justify investments. The two methods used to calculate resilience's value can be broadly categorized as bottoms-up approaches and economy-wide approaches. These two methods are defined as

follows:[34]

1. Bottom-up approaches: These include a) stated preference methods, which use surveys and interviews to ask customers about their intended or actual behavior during interruptions, and b) revealed preference methods, which use real-world data to estimate a valuation of non-market goods.
2. Economy-wide approaches analyze the effects of power interruptions on regional economies using economic output and employment indicators, including a) input-output models, b) computational general equilibrium models, c) macro-econometric models, and d) production function approaches.

Calculating the value of resilience is a complex activity and remains an ongoing research area for the industry. **There is no widely accepted or standardized method or publicly available solution that can be used to perform benefit-cost analyses involving improvements to system resilience.** Current approaches[35] in the resilience valuation have limitations as they do not appropriately capture the potentially devastating consequences of not having adequate resilience. For example, prolonged outages lasting weeks is no longer just a mere inconvenience but results in significant pain and suffering or even deaths that are not straight forward to assign a monetary valuation.

The Critical Consumer Issues Forum recently issued a paper, developed with state utility regulators, consumer advocates, and industry participants, "The Path to a More Resilient Energy Grid."[36] The paper noted:

> "There is no 'one-size-fits-all' solution for resilience investment, as circumstances in both states and energy company service territories vary widely (e.g., different high-impact events, critical infrastructure, priorities, regulatory structures, and community needs or interests). However, state commissions, consumer advocates, energy companies, and stakeholders should endeavor to establish methods for gathering lessons learned and sharing solutions that have proven effective over a range of situations… [This includes] collaborative development of independent and credible tools to guide proactive investment in resilience."

4.4 Dependencies Among Electric Power System and Other Critical Infrastructure

As introduced earlier, there are many interdependencies between the electric power sector and other critical infrastructures such as water, oil and gas, telecommunications, and transportation. Those interdependencies are depicted in Figure 6.

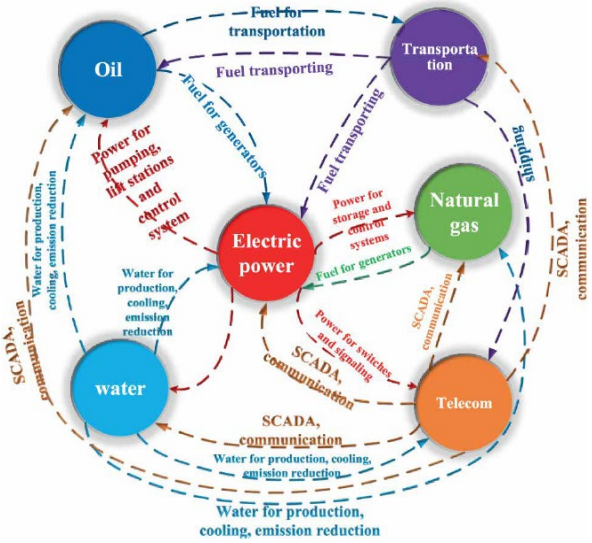

Figure 6 – Interdependencies between the electric power and other critical infrastructure sectors.

[34] National Association of Regulatory Utility Commissioners (NARUC), The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices, April 2019, https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198

[35] Interruption Cost Estimate (ICE) calculator to value the benefits of reliability improvements, https://www.icecalculator.com/home

[36] "Planning for the Electric System of the future. The Path To A More Resilient Energy Grid", Critical Consumer Issues Forum (CCIF), July 2020, http://www.cciforum.com/wp-content/uploads/2020/07/CCIF-Resilience-Report-July-2020-Final.pdf

The complex nature of these interdependencies underscores the importance of collaboration among key stakeholders and jurisdictions. Having a uniform set of metrics that cut across the multi-industry sector is challenging, but it is an important area that needs further development. Addressing system-wide resilience issues will require strategic investments involving the participation of federal, regional, state, and community organizations, as well as their local utilities. The North American Electricity Resilience Model is the U.S. DOE's effort to examine infrastructure interactions and identify actions that might best reduce vulnerabilities. The vulnerabilities associated with the tight coupling of the electricity and natural gas systems can be addressed through structural remedies (e.g., ensuring that natural gas pumping stations have sufficient back-up generation) and improved coordination in planning and operations (e.g., ensuring that natural gas supplies are sufficient to meet electricity needs as a result of extreme weather events).

4.5 Summary

The frameworks and metrics described above demonstrate the challenge in defining industry-accepted resilience metrics. The development of metrics and a framework for evaluating resilience involves a multi-dimensional exercise with high complexity levels across multiple industry sectors, given the interdependencies among the various infrastructure sectors. The core of the issue is that there are numerous parameters or events associated with resilience. The recent COVID-19 impact introduced yet another parameter to be added to the list. Such parameters are dependent on regional, functional, regulatory, and business differences, which further exacerbates the issue. For example, IEEE identifies storm and non-storm metrics. However, as non-storm-metrics are based on weather conditions, events not associated with weather are not addressed. The following dimensions are addressed by resilience:

- Power system performance
- Economic performance
- Societal performance
- National security performance

Each of the above dimensions has associated metrics that could be considered as reliability or resilience metrics. As discussed in Section 3, as reliability and resilience are related, reliability metrics are often used to measure resilience even though the overall objectives may differ. In summary, the complex nature of the metrics and framework highlights the need for a more simplistic approach to establish a set of metrics that can be more easily and consistently applied across the various stakeholder groups. Ultimately, the value of metrics and the resilience framework reside in their ability to be benchmarked and compared across industry participants to facilitate continuous improvements. Furthermore, the potential hazards that are likely to impact the electric grid's critical function are very broad. Many of them are unpreventable and difficult to predict or control in terms of magnitude and intensity.

An effective resiliency framework should strive to minimize the likelihood and impacts of a disruptive event from occurring and provides the right guidance and resources to respond and recover effectively and efficiently when an incident happens. This can be accomplished by applying the framework toward assessing and developing a mitigation program with the five main focus areas: **Prevention, Protection, Mitigation, Response, and Recovery**. The program centralizes, assesses, and prioritizes mitigation projects to address the threats and hazards that pose the greatest risk to the critical energy infrastructure and associated business functions. This includes evaluating credible scenarios that could affect a grid operator's ability to provide safe and reliable electricity to its customers and the communities it serves and using appropriate tools in the process. A centralized approach improves the prioritization of the limited resources to address the various risks that could potentially impact the electric grid and the operator's ability to provide continuity of safe electric service to its customers.

The process starts with identifying the critical functions, systems, and resources as well as the hazards and threats that could impact them. This is then followed by determining the appropriate risk mitigation approach by developing prevention, protection, and/or mitigations strategies to reduce those impacts and, for those risks/impacts that cannot be mitigated, execute preparedness activities to effectively respond and recover from those disruptions. Such a risk assessment would lead to implementating resilience improvement strategies that can be measured for performance by applying program-specific metrics when implemented. Next, the results are measured, and a determination is made regarding whether there is a need for additional mitigation steps or whether to continue monitoring the system's performance.

The proposed approach is to identify individual parameters/events and associated metrics based on the resilience trapezoid shown previously in Figure 1 and the quantitative performance-based spiral framework defined previously in Figure 4. The use case of implementing this approach is explained in more detail in Section 6.3.

It is important not to lose sight of priorities in investing in resilience improvements. The investment will depend on a good understanding of the consequences, which should guide the overall investment. As funds will always be limited and impossible to eliminate all impacts on system performance, it is necessary to prioritize actions and corresponding investments to minimize the event's impact and propagation and ensure fast restoration to a normal state.

Section 5 TECHNOLOGIES, TOOLS, AND METHODS TO EVALUATE AND IMPROVE RESILIENCE

Strategies to evaluate and improve resilience depend on the type of initiating events with associated consequences that have impacted the system. Some of the best solutions are built on combining the technologies, tools, and methods (TT&Ms) highlighted in this section. In addition, IEEE has an important role in identifying best practices and applicable standards.

5.1 Evolution of Technologies, Tools, and Methods to Evaluate and Achieve Resilience

To facilitate the discussion on the maturity of resilience TT&Ms, they are grouped into four stages of evolution, as shown in Figure 7.

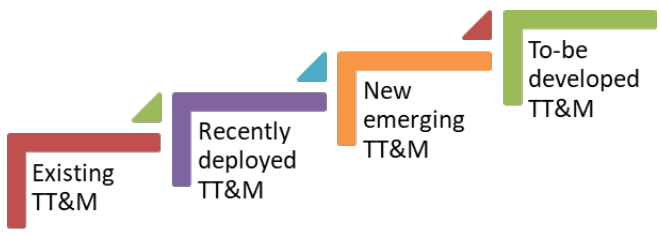

Figure 7 – Evolution of technologies, tools, and methods.

The following subsections will provide a brief overview of the various TT&Ms, focusing on the additional tools to be developed to meet industry needs and cover the gaps.

5.1.1 Existing TT&Ms

Electric utilities have been addressing resilience for several years now and have a wide array of existing TT&Ms that have been extensively used by the industry. A representative set of these long-established TT&Ms are briefly described below.

- Planning scenarios and grid hardening TT&Ms to respond to weather-related events.
- Technologies such as flexible alternating current transmission system devices, automated protection and control, vegetation management, and hardening of the T&D system components.
- Planning and operational tools such as voltage stability analysis, transient stability analysis, small-signal stability analysis, contingency analysis, and extreme events/cascading analysis.
- Use of deterministic and probabilistic methods to analyze the grid more realistically.
- Use of weather radar, detailed weather modeling, and expert weather services.
- Contingency planning and planning for various external and climate scenarios.
- Low-latency, high-bandwidth, resilient communication networks for T&D applications.

5.1.2 Recently Deployed TT&Ms

Several TT&Ms have recently been demonstrated and are being deployed to address the evolving grid, which is transforming to enable high levels of penetration of intermittent IBRs and improve analysis and response to extreme events. Examples include:

- Technologies such as advanced sensors (e.g., synchronized measurements), geomagnetic induced current monitoring systems, system operating procedures, and design objectives, and drones for improved situational awareness and condition assessment.
- DERs, energy efficiency, demand response, smart-meter technologies, and energy storage with more advanced control features, including smart inverters, enable a smooth transition to islanding operation.
- Tools for online analysis of extreme events/cascading analysis and on-line situational awareness, comprised of real-time monitoring and comprehensive visualization systems (power system state, improved weather forecasting, online dynamic security assessment, and other tools of a similar nature).
- Methods that consider interdependencies between electric, gas, and communication systems, including improved power system modeling (e.g., using standard IEEE library of dynamic models vs. user-defined models; composite load model and developing new interdependency models).

5.1.3 New and Emerging TT&Ms

As power systems continue to evolve, and the electric industry is faced with new challenges, ranges of new emerging TT&Ms are being introduced:

- **Integrated generation, transmission, and distribution planning and investment prioritization tools and processes** due to increased inter-relationships between the supply segment and the delivery grids. For example, it is increasingly important to plan the system holistically and prioritize investment with a multi-dimensional approach in today's ever-changing environment. This approach includes DERs, storage, and other non-wires alternatives, as well as electrification of the transportation sector. All of these considerations must also factor in resilience considerations as well.
- **Risk- and probability-based cost-benefit tools** to value resilience-based investments from the consumer perspective. For example, many states and utilities use the DOE Lawrence Berkeley National Laboratory's Interruption Cost Estimate (ICE) Calculator[37] to support resilience investments. The ICE Calculator is a web-based tool that estimates outage impacts on consumers and the value of investments or measures designed to provide resilience while considering the probability of an event's occurrence. Efforts are underway to update the tool and incorporate regional econometric analysis to evaluate the indirect economic impacts of resilience. This best practice should be incorporated into system design and metric development.
- **Real-time tools for monitoring, protection, and control of distribution systems**. With the additional integration of renewables and DERs, the distribution system's operation becomes increasingly complex and needs more sophisticated tools. For example, point-on-wave (or time-tagged oscillography) sensors and synchronized measurements combined with an advanced analytics platform can help identify systemic issues with DERs and IBRs as they react to grid anomalies. Certain types of devices and sensors (e.g., optical sensors) are more immune to natural and human-made adverse events (e.g., electromagnetic pulses). They can help improve the core resilience of the grid. The use of high-bandwidth fiber communications, even within substations, to replace control wires can significantly improve resilience and reduce flood recovery time.
- **Emerging communication technology**. For example, the Black Sky Emergency Communication and Coordination System (BSX™) is designed as an all-hazards emergency communications network providing interoperable cross-sector communications.[38] The system will provide situational awareness and communications capability to enable black sky response and recovery efforts in the absence of connectivity to traditional telecommunications systems.
- **Other technologies**. For example, data analytics, including the use of artificial intelligence for power system analysis and control and novel mitigation technologies against extreme weather events.

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[37] https://www.icecalculator.com/home

[38] EIS Council, "Black Sky Emergency Communication & Coordination System", https://www.eiscouncil.org/App_Data/Upload/50ba2a93-adef-465f-86ef-caef6e6cf8c8.pdf.

5.2 Industry Needs and Gaps

After surveying the available existing, recently-developed, and emerging technologies, the following gaps have been identified, which will require a new generation of TT&Ms to be developed for the following:

- Specifying codes and standards for electricity resilience.
- Consistent climate forecasting and modeling tools.
- Real-time situational awareness after a natural disaster, including outage-reporting smart meters and equipment monitoring systems.
- Improving the restoration-and-recovery stage, including outage management, repair crew optimization, etc.
- Fast and accurate identification of the weak elements in the system, contributing to a major event.
- Better prevention and response to system disturbances.
- Effective data exchange and coordination among multiple energy management system/transmission system operator (EMS/TSO) and distribution management system/distribution system operator (DMS/DSO) systems during extreme events that can cover large areas.

5.2.1 Development of Codes and Standards for Electricity Resilience

Any resilience-based codes or standards developed should recognize the need for regional differences. Different utilities face different threats based on the environment in which they operate. Guidelines for infrastructure specifications should reflect different susceptibility levels, for example, flooding or sustained high winds. Incorporating regional differences, where applicable, into codes and standards will help make them sufficiently flexible to meet all U.S. utilities' needs, despite the various threats they face.

The DBT and resulting planning criteria need not (and in fact, should not) be limited to electric utilities; a consensus-based understanding of the security and extreme weather threats that a region faces can support resilience planning for all critical infrastructure and essential service providers, such as telecommunications providers, water and sewer services, and public safety. With such coordination, critical infrastructure and essential service providers can better promote the resilience of the communities that rely on them. Importantly, states can play a key role in defining the DBT that their critical infrastructure and essential service providers must plan to meet, allowing for the consideration of local preferences and prioritization.

5.2.2 Longer-Term Climate Forecasting and Modeling Tools

Like the ICE calculator, the industry needs more robust web-based modeling tools on climate-related long-range (multi-decade) forecasts with a common set of assumptions that broad-based stakeholders across multiple industry sectors can use to align on foundational planning assumptions.[39]

5.2.3 Real-Time Situational Awareness After a Natural Disaster

Different natural disasters and human-made attacks result in different types of damage, and the intensity of these disasters will result in a different extent of the damage. Like storms, some disasters can provide prior warning and hence some possibility of preparation. Other disasters, like cyber-attacks or earthquakes, may occur suddenly. A major challenge is to assess the extent of the damage while the event is happening and, more importantly, after the event is over and restoration must commence. The redundancy of equipment, either power or information, and communication technology (ICT), is usually higher in the high-voltage transmission system than in the distribution system; therefore, the situational awareness may be better at the transmission EMS than in the distribution DMS. Determining the distribution system's status is more difficult as the SCADA data are not very comprehensive. The use of smart meter technologies that send a signal back to the utility that the meter has lost power is an excellent tool for quickly understanding the magnitude of the outage disturbance and, conversely, to know when customers have been restored, saving time over verifying this manually.

A major challenge in determining distribution situational awareness is the collateral damage in the neighborhood. If the roads are not navigable because of floods, damage, or obstruction, the manual inspection cannot be performed. Planes and helicopters have been used, but drone technology has been a great help in this area. Furthermore, a rugged

[39] An example of these types of common planning/forecasting tool is the California climate change research efforts, https://cal-adapt.org/.

communications infrastructure with low-power consumption (including back-up power) can play a very key role in fast recovery after a natural disaster.

5.2.4 Technologies Related to Improving Restoration and Recovery Stage

When a very large area is affected by a disaster, a major challenge is the restoration process's sequencing given the available crew. In theory, this can be formulated as an optimization problem, but the many practical issues often require manual decision-making via communications between the distribution operator at the DMS and the field crew. These practical considerations are usually the complex relationships between the various groups responsible for different tasks that impact the electrical system's restoration. Coordination with the first responders (i.e., paramedics, police, fire) is obvious, but also essential is communication with those who remove fallen trees, manage floodwaters, certify electrical safety of buildings, etc. Thus, the simple objective of scheduling the utility crews becomes constrained by these dependencies on many other groups who are being scheduled by other supervisors. Often, the Federal Emergency Management Agency (FEMA) or state emergency agencies are involved, and the utility restoration becomes part of a much bigger operation.

5.2.5 Methods and Tools for Fast and Accurate Identification of the Weak Equipment and System Elements

Fast, accurate identification of weak elements will help identify the event's root causes and assist in the system restoration process. Determining weak elements should be addressed holistically and should consider all of the following analysis perspectives:

- Weak points from a specific equipment-performance perspective. There is a need for higher bandwidth voltage and current sensors to observe higher speed phenomena affecting power equipment (e.g., seeing the impact of micro-second transients from vacuum circuit breakers on power transformers in the field, which results in accelerated aging).
- Weak points from a system-stability perspective: steady-state (based on the "power-phase angle" approach),[40] small-signal stability (based on eigenvalue analysis),[41] transient stability (e.g., Fast Fault Screening),[42] and cascading analysis (e.g., cluster approach).[43]

5.2.6 Methods and Tools to Prevent and Respond to System Disturbances

It is critical to ensure that IBRs, like solar photovoltaics (PV) and battery energy storage systems, can provide essential reliability services to the electric power system. Traditionally, the power grid has relied on the stored mechanical energy in large generators' rotating masses (inertia) and other tools and technologies such as central control coordination to maintain grid stability and balance during moderate disturbances. As more DERs using inverter-based technology without inertia are being deployed, if there is an imbalance between generation and load, frequency declines faster, requiring that under-frequency load shedding schemes need to be reviewed and adjusted. In addition, IEEE interconnection and interoperability standards (e.g., IEEE 1547-18 for distribution and IEEE P2800 for transmission) are required to ensure the desired performance without being prescriptive.

However, the grid's architecture and the associated controls technology can transition to provide similar functionalities even as traditional forms of generation play a smaller role in the electric system. Conventional, synchronous generators have operating reserve margins and "naturally" compensate for the imbalance if they have allocated reserve margin. "Smart" inverters can react immediately and much faster than conventional generation in balancing load and generation. However, smart inverters need to have reserve margins to operate with and need to be controlled at the system level to be effective. Doing this is not as easy as relying on synchronous generation, but it is achievable with present technology.

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[40] M.Y. Vaiman, M.M. Vaiman, "Using Phase Angle for Steady-State Voltage Stability Assessment", PACW Americas Conference 2017.
[41] G. C. Verghese, I. J. Perez-Arriaga, and F. C. Schweppe, "Selective Modal Analysis with Applications to Power Systems, Parts 1 and 2", IEEE Trans., 101, 1982, pp. 3117, 3134.
[42] V. Kolluri *et al.*, "Fast Fault Screening Approach to Assessing Transient Stability in Entergy's Power System", IEEE Proceedings, 2007, pp: 1 – 6.
[43] M. Vaiman *et al.*, "Risk Assessment of Cascading Outages: Methodologies and Challenges", IEEE Trans. on Power Systems, May 2012, Issue 2, pp: 631 – 641.

The answer begins with increased observability so that grid operators and operating systems can react when they need to. This requires advanced sensors connected by a high-speed communications infrastructure to ensure that all data are available and analyzed when needed. The answer continues with flexible resources, such as smart inverters that help ensure system resilience with higher solar PV levels, connected devices like smart thermostats that respond to price signals, energy storage that provides power when clouds are overhead, and microgrids that provide resilient power to communities and facilities. These resources require advanced control capabilities with dynamic load/resource management to use them to their fullest potential. Making loads responsive to system disturbances in real-time can also enhance grid resilience. In Summer 2019, DOE's Building Technology and Solar Energy Technology Offices supported a Building-Grid Pilot project in one large midtown Manhattan office building (more than one million square feet). The project demonstrated the capability to provide instantaneous load response in increasing or decreasing load directions of up to one-third of the building's peak load.[44] Furthermore, electrical energy storage continues to emerge as one of the "non-conventional alternatives" to mitigate the effects of renewable variability, optimize the utilization of existing grid infrastructure, and improve resilience and reliability by providing end-users with the ability to self-supply during outages. As energy storage becomes more cost-effective, using the same energy storage asset for various applications is key to realizing the technology's best economic potential. Another example of methods and tools to address blackouts is in managing a complex voltage stability phenomenon. The interconnected power system needs to maintain appropriate voltages during normal and post-contingency conditions, including both transient and steady-state time frames.

5.2.7 Tools and Technologies for Data Exchange and Coordination among EMS/TSO and DMS/DSO

In North America, the EMSs do not have control over any equipment on the distribution system controlled by the DMS. Thus, the functions of the reliability coordinator (RC), balancing authority (BA), and the transmission system operator (TSO) are performed through a network of dozens of EMSs, either manually by the operator or automatically as with automatic generation control (AGC). The functions on the distribution system like sectionalizing or voltage control are carried out through the DMS either manually by the distribution operator or automatically like with volt-var control. However, the number of generation sources on the distribution system is increasing, and so are active loads/DR resources. Soon, the balancing function and reliability function will no longer be possible by only controlling transmission resources, and the control of distributed generation (DG) and DR will become necessary to meet these fundamentally important reliability functions. The EMS must have access to the information from the DG-DR resources on the distribution side. At the same time, the DMS must know the status of the reliability and balancing functions so that the distribution operator can anticipate these resource needs. Coordination schemes are required to assign the respective roles and responsibilities, including data/information exchange requirements, among all participants involved in the grid operation (e.g., TSO, DSO, DER aggregators, etc.) during normal and contingency situations.

A major growing need is the exchange of information between the EMS and DMS, but there are no standards and/or best practices as of yet. On the transmission side, neighboring EMSs often exchange data with each other. Also, the EMSs of several subsidiary TSOs have to exchange data with the ISO/RC responsible for the ISO region's reliability. Something similar has to be set up between those DMSs that are a subsidiary to an EMS. As usual, the data to be exchanged and the data exchange hierarchy depend on the functions and where those functions are enacted.In addition to the EMS/DMS data exchange, the affected functions have to be extended. For example, suppose the BA needs to send raise/lower signals to the DG and DR in a subsidiary distribution system. In that case, the AGC algorithm could be extended in several ways with more centralized or decentralized controls. The same can be done for voltage control on both transmission and distribution. The ability to do more decentralized control is attractive for resilience purposes when regions or neighborhoods may operate as islands.

As these functionalities mentioned above are stretched because of more DG in the distribution system, causing more two-way power flow, the tools and technologies need to be developed to implement these functions. Several new tools can be envisioned: the automatic sectionalizing of distribution feeders to accommodate two-way flows, automatic adjustment of four-quadrant inverter controls to maintain reasonable voltage, automatic resetting of protection relays, frequency-based local control of generation, etc. The role of aggregators of many small resources is also evolving. Although most of that role is restricted to selling services to the wholesale market, the extension of aggregators' function to provide ancillary services would mean that they will need tools to accept and activate control signals.

[44] V. Cushing, W. Hederman "NYC Pilot: Buildings as Batteries, a Performance Report, IEEE ISGT NA 2020, Feb. 20, 2020

Section 6 UTILITY INDUSTRY PRACTICES AND USE CASES

In this section, we will discuss the progress made by electric grid operators, in collaboration with regional authorities, to strengthen the resilience posturing, including prevention, detection, response, and recovery efforts. We will also discuss some common practices to increase system resilience, enhance broader preparedness, and combat various external impacts on the electric power grid.

6.1 Common Practices in T&D System Hardening to Increase Resilience

Improving the resilience of the T&D system is a critical aspect of achieving an overall power system resilience. In the last 10 years, many utilities have embarked on various measures and investments to harden the "wires" system. The wires system is frequently suffers the most damage and takes the longest to recover and rebuild from the more severe weather events discussed in Section 2. Below are some emerging practices that are becoming more widely adopted by various major utilities and grid operators. This is not an exhaustive list of all the efforts underway, but it should provide the readers with some idea of the practices that are underway:

- **Distribution line construction standards:** The National Electric Safety Code (NESC) specifies three grades of construction for distribution lines that define the strength and load factors to use when performing pole loading and guying calculations. Many of the utilities have adopted a higher grade of construction standards for all new pole installations. These standards lead to installations that are more resistant to damage from wind, ice loading, and adjacent pole failures.
- **Customer segmentation through distribution automation:** Utilities use distribution automation systems equipment to sectionalize their distribution circuit sections into smaller customer groups. This practice improves reliability by limiting customer outages during storms and preventive maintenance and other system work requiring de-energized circuits. During outage situations, the damaged portion of the feeder is isolated automatically or manually by opening the two adjacent reclosers. Power can then be quickly restored to those points (for the undamaged sections) until field crews can make necessary repairs to the damaged section.
- **Tree-resistant overhead conductors:** In heavily wooded areas that are prone to outages, many utilities have used specialized covered conductors or spacer cables. Spacer cable is a pre-engineered electrical distribution system designed for high reliability, low operating costs, and improved right-of-way flexibility. The conductors are covered with two or three layers of polymer designed to allow intermittent contact with ground points (e.g., tree branches) without causing an outage or nuisance tripping. The polymer is resistant to ultraviolet degradation, electrical tracking, and abrasion. The covered conductors are also very effective in preventing potential ignition sources resulting from foreign objects' contact with the traditional bare conductors under high wind conditions. With the spacer cable application method, the conductor is supported by a high-strength messenger that provides mechanical support and a system-neutral and acts as a shield wire against lightning. The conductors are hung loosely beneath the messenger and supported by "spacers." The covering's insulating properties allow the messenger and the conductors to be bundled into a compact area, thereby allowing greater flexibility in solving right-of-way problems.
- **Fiberglass crossarms:** Fiberglass cross-arms are approximately 30 percent stronger than wood cross-arms. Unlike wood cross-arms, they will not rot or succumb to woodpeckers or termites. They also exhibit an extremely high dielectric strength, which prevents the tracking of stray electricity on overhead structures. Because of these benefits, many utilities use only fiberglass cross-arms for dead-end applications (i.e., terminating wire at the end of mainline or crossing). They are increasingly adopting fiberglass cross-arms for use in tangent (i.e., straight-line or slight-angle) applications.
- **Distribution structures:** Many of the power poles used in the distribution system were made from natural wood material and installed many decades ago. It is important to make sure these power poles have not decayed over the years and continue to have a sufficient safety factor rating for various increased loading placed on these structures due to the expansion of telecommunication networks. An emerging best practice is to verify these poles' design safety factors proactively with comprehensive pole loading calculations and replace those with inadequate safety factors. In performing pole loading calculations, one must also incorporate the latest field conditions, including accounting for the additional source of loading placed on the structure and the expected wind speed that the structures are likely to experience during the pole's expected life.
- **Redundant protection systems:** Modern relaying schemes provide for complete redundancy of protection systems at all voltage levels. These systems provide protection from system faults (such as damage from

downed trees and limbs or vehicle pole strikes), allowing isolation of the impacted circuit(s). They also protect against cascading faults, which could extend outages beyond a localized area. Microprocessor relays provide real-time monitoring via SCADA back to the control rooms, improving situational awareness and allowing operators to respond to system disturbances more quickly.

- **Flood protection measures:** Many utilities have established a flood mitigation plan to protect their substations at the greatest risk of flooding. These substations were risk-ranked using flood plain/flood-way information, along with information about the number of customers (including critical customers) that the substations serve. In most cases, utilities will construct a flood wall around the entire substation to protect the infrastructure (i.e., equipment and buildings). The flood wall's minimum height is the base flood elevation (100-year flood level) plus 3 feet. Another common practice is to supply portable pumps and sandbags for deployment in case of flooding. These investments will significantly reduce the likelihood of substation damage due to flooding. In some regions with a higher probability of seasonal adverse weather events, such as hurricanes, utilities are upgrading their substation construction standards to build/position all equipment higher off the ground. They are also using fiber-optic connections to connect intelligent electronic devices (IEDs) (e.g., relays) and primary equipment (e.g., breakers). During intermittent flooding, fiber cable can be quickly and safely disconnected and reconnected to minimize a substation's downtime that experiences temporary flooding.
- **Substation firewalls:** Fire separation and spacing between possible fire hazards at a substation can mitigate damage to assets located within a substation in case of a fire. While rare, fires can occur during high-load system conditions (such as prolonged heat waves), extreme weather events, equipment failure, and system faults when protection schemes fail to operate as intended. Adequate separation and/or spacing can minimize damage to surrounding equipment and buildings that were not part of the initial fire source. Where spatial separation is not feasible, alternative fire protection features such as fire barriers can be deployed to achieve the same result. At a minimum, fire barriers are 3-hour rated for resistance to a fire exposure similar to what is expected. Permanent and precast concrete barriers have been installed around oil-filled equipment to protect the adjacent equipment and control/relay buildings and switchgear buildings. Fire barriers can also be deployed at the perimeter of the substation to protect neighboring structures.
- **Emergency restoration structures:** Utilities have stocked the equipment required to erect temporary structures to support the conductor when a transmission tower is damaged. Some of these temporary structures require guying that extends beyond the right-of-way, in which case temporary wood structures can be deployed.

6.2 Examples of Various Utility Practices to Enhancing Resilience

Facing grid resilience uncertainties induced by natural hazards, utilities have developed innovative engineering methods for identifying system hardening priorities and enterprise strategies to utilize available resources in responses to a variety of threats to grid resilience. Utilizing enterprise resources during emergency response and addressing business continuity and stakeholder collaboration, the all-hazards resilience strategy has effectively dealt with the diverse geography and varying climate regions served by Southern California Edison (SCE), as well as with the variety of natural hazards. In Consolidated Edison's (Con Edison's) adaptive implementation pathway approach, flexible solutions for at-risk infrastructure paths are identified not only based on knowledge from past events but also with trackable "signposts" (i.e., situational awareness data for precise hardening decisions). To achieve a highly cost-effective system hardening investment, Entergy has developed a vulnerability-model-based cost-benefit analysis framework to evaluate the equilibrium point of hardening investment and cost of business interruption. Through the state-wide system-hardening efforts in Florida, utilities have proven that preventive infrastructure enhancement will reduce the outages during natural hazards and improve operation flexibilities and improvements. Innovative technologies are centered on the response of grid resilience enhancement. San Diego Gas & Electric's (SDG&E's) flexible adaptation pathways solution for critical load services integrated cross-disciplinary modeling of sea-level rise and power grid planning for natural hazard uncertainties. Distributed generation and microgrids have proven records in critical load support and system restoration during hazards. ComEd's microgrid pilots are collecting field experiences from both operation and distribution network transformation perspectives.

6.3 Case Study: SCE Applying the All-Hazards Resilience Strategy

To examine an all-hazards approach in practice, this section examines SCE, where they have adopted the nationally-established practices and standards outlined in PPD-8. These concepts, when applied to critical infrastructure, can be defined as shown in Table 3.

In Southern California, earthquakes and fires are the key hazards for which SCE applies the concepts presented in Table 3 to organize its approach. This approach includes hardening its infrastructure, ensuring robust response and recovery plans are in place and a means to communicate if the public communications systems are down, and training its response teams with alternate communications technologies. The process includes business continuity, information technology (IT) disaster recovery, cybersecurity, physical security, critical infrastructure protection, hazard assessments and mitigation (seismic activity, climate change, severe weather, wildfires, etc.), external engagement, crisis communication, emergency management, and employee and family preparedness. An example of a resilience strategy is included in Figure 8.

Table 3 – Definitions of the Five Main Focus Areas in PPD-8 as Applied to Critical Infrastructure

Focus Area	Definition
Protection	Protecting the company from physical, social, cyber, and financial threats through asset hardening, barriers, and specialized equipment to strengthen critical assets.
Prevention	Preventing disruptive events that could negatively impact the company, customers, employees, and/or infrastructure through intelligence and information-sharing that drives tactical decisions to avoid or stop disruptive events.
Mitigation	Mitigating the impacts of an incident by developing strategies that reduce the company's vulnerabilities, risks, and the loss of resources, life, or infrastructure.
Response	Responding to all incidents with a uniform approach, consistent with those used by the emergency management community, public agencies, and first responders.
Recovery	Recovering using established plans and procedures to quickly get the company and the communities it serves back to a state of normalcy while ensuring appropriate corrective actions.

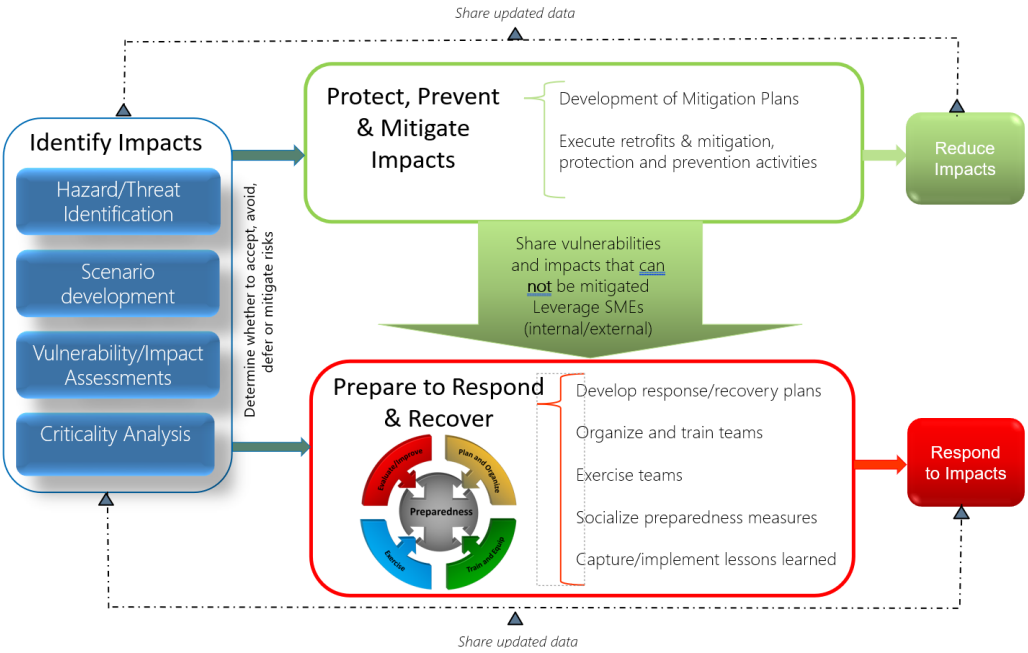

Figure 8 – Resilience strategy graphic: SCE example.

SCE realized about 10 years ago that it had to adapt its emergency management approach using the same systems and protocols as the city, county, state, and federal government. By following nationally accepted emergency management doctrine, SCE ensures consistency in its approach with other utilities and federal, state, and local emergency management organizations. Planning for business disruptions and emergencies is done at multiple levels within the company. It is designed to allow for smaller, more "routine" disruptions to be handled within the line organizations and for more complex, corporate-wide incidents to be identified and managed through SCEs corporate response structures. The organization responsible for changes depends on the scale and complexity of an event. As a result, SCE must be prepared to coordinate with different external bodies such as other utilities (mutual assistance), local agencies (city and county emergency operations centers), state agencies (state operations center and cost recovery), or federal agencies (Joint Field Office and National Response Coordination Center).

These organizing principles are based on the National Incident Management System (NIMS) and the Incident Command System (ICS) and allow the company to use a flexible and scalable systematic approach to manage response and recovery operations, regardless of the emergency type. At any given time, approximately 500 employees across the company are trained in NIMS and ICS, qualified through function exercises, and rostered on corporate Incident Management Team ready to respond to a corporate-level emergency. Building resilience is a shared responsibility. Utilities have a responsibility to build resilience and to communicate with stakeholders in understanding the impacts. The partners at the various jurisdictions levels also have a responsibility to develop solutions and resilience for their respective areas.

6.4 Case Study: Con Edison Climate Change Vulnerability Study

In December 2019, ConEd released a Climate Change Vulnerability Study[45] that the New York Public Service Commission ordered and approved for funding.[46] The Commission directed the study to aid in the ongoing review of the company's design standards and the development of a risk mitigation plan. ConEd explains further that the study will equip the utility with a better understanding of future climate change risks and strengthen its ability to address those risks more proactively. The study used an "integrated approach" to assess risks and review a portfolio of measures to improve climate resilience, establishing an overarching framework that can work to strengthen ConEd's resilience over time.

Using a foundation of internal expertise, this approach started with an initial screening to identify and prioritize at-risk assets. The team then performed detailed analyses for the sensitive assets, including identifying a portfolio of adaptation options and qualitatively considering the financial costs, co-benefits, and resilience of each option. To identify areas of action in the face of irreducible uncertainties in projections of future climate conditions, the team used an adaptive implementation pathway approach to support flexible solutions allowing for effective risk management. This approach relies on a series of "signposts" representing information that will be tracked over time to help ConEd understand how climate, policy, and process conditions change and, in turn, trigger additional action. These detailed analyses inform the development of flexible solutions and the further prioritization of assets and options to increase system-wide resilience.

This method's goal—using a comprehensive set of adaptation strategies—is to build a system that can withstand climate changes, absorb and recover from outage-inducing events, and advance to a better state. ConEd explains that a resilient system should better withstand, absorb, and recover from climate-driven conditions while advancing based on lessons learned. This "withstand" component prepares for both gradual (chronic) and extreme climate risks through resilience actions throughout the lifecycle of assets. "Withstand" investments are not necessarily a one-time event. They may also include changes in the planning, design, and new infrastructure construction; ongoing data collection and monitoring; and eventually investing in the upgrade of existing infrastructure using forward-looking climate information. "Absorb[tion]" includes strategies to reduce the consequences of outage-inducing events, as a company cannot and should not harden its energy systems to try to withstand every possible future low-probability, high-impact extreme weather event. "Recover[y]" aims to increase the rate of recovery and increase customers' ability to cope with impacts after an outage-inducing event, including prioritization of critical services. "Advance[ment]" refers to building back stronger after climate-related outages and updating standards and procedures based on lessons learned and revealed asset vulnerabilities.

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[45] MJB&A Issue Brief, "Key Considerations for Electric Sector Climate Resilience Policy and Investments," December 2019

[46] Consolidated Edison, Climate Change Vulnerability Study, December 2019, https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/climate-change-resilience-plan/climate-change-vulnerability-study.pdf?la=en

6.5 Case Study: Entergy "Building a Resilient Energy Gulf Coast Plan"

Entergy's "Building a Resilient Gulf Coast Plan" develops a new cost-benefit analysis framework that incentivizes forward-looking resilience planning.[47] Entergy's plan focuses on sizing risk based on how extreme (e.g., low, medium, and high) future climate change will be. Based on that assessment, Entergy generates an expected loss scenario that evaluates hazard, value, and vulnerability models for each climate change possibility.

$$\textit{Expected loss per climate change scenario} = \textit{hazard model} \times \textit{value model} \times \textit{vulnerability model}$$

Whereas other cost-benefit models focus on shorter-term planning horizons, Entergy's analysis evaluates potential near-term resilience efforts that will lead to cost savings in the longer term as the frequency and severity of storms increase. The cost-benefit analysis discounts lifecycle costs to capture present value benefits to evaluate potential long-term impact. This type of valuation enables increased near-term investment, which can dampen future loss. Such valuation is critical to resilience planning. As part of this framework, Entergy has valued different asset classes by either their economic value or their ability to diminish business interruption. One critical asset evaluation is the granular assessment of electric and gas utility assets. Entergy's Gulf Coast analysis found that the oil and gas industry sectors contribute to a significant share of the expected annual loss in a 2030 timeframe. Entergy's analysis found that cost-beneficial utility measures, like vegetation management and resilient distribution lines, can avoid $830 million of the projected losses in 2030. Factoring these future losses into cost-benefit analyses could enable longer-term utility resilience projects to pass cost-effectiveness tests and be implemented, ultimately saving utilities and ratepayers money in the long term.

6.6 Case Study: Florida Utilities System Hardening

Florida is expected to experience a wide range of climate change risks. One increasing risk is hurricanes and tropical storms, which can be some of the largest natural disasters nationwide regarding economic disruption and damages. Over the past decade, the state has taken action to harden utility systems to respond to these storms. The Florida Public Service Commission (PSC) and its regulated utilities have a long history of developing storm preparedness policies. For example, starting in 1992, the PSC developed its first storm-cost-risk mitigation plan for utilities. Since then, the PSC has provided several recommendations that have enabled utilities to incorporate up-to-date projections and data into their infrastructure hardening efforts.

In 2006, spurred by significant hurricane seasons in 2004 and 2005, the PSC required investor-owned utilities (IOUs) to document the effectiveness of their investments in storm hardening technology by collecting and monitoring outage data during storms in addition to other storm preparedness initiatives, including the following: 1) developing a 6-year transmission structure inspection program, 2) hardening existing transmission structures, 3) developing T&D geographic information systems (GIS), 4) collecting post-storm data and forensic analysis, 5) collecting a detailed outage data differentiating between reliability performance of overhead and underground systems, 6) collaborating on research on the effects of hurricane winds and storm surge, and 7) developing a natural disaster preparedness and recovery program plan.

In November 2017, the PSC asked IOUs to review their hurricane preparedness and restoration actions by assessing their damage assessment process, restoration workload, and staffing needs, as well as storm impact on hardened/non-hardened infrastructure after the 2017 hurricane season.[48] The PSC held a workshop on this topic in May of 2018 and issued a summary document that highlighted the following key takeaways from the meeting: 1) data collected during and after a 2017 storm show Florida's aggressive hardening programs work, 2) hardened overhead facilities had substantially lower failure rates, 3) underground facilities had minimal failure rates, 4) the three largest utilities currently have 37.6 percent of distribution lines underground, and 5) public expectations for a lower number of outages and restoration times is rising, indicating resilience and restoration need to improve.[49]

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[47] *Building a Resilient Energy Gulf Coast: Executive Report*, Entergy, 2010, https://www.entergy.com/userfiles/content/our_community/environment/GulfCoastAdaptation/Building_a_Resilient_Gulf_Coast.pdf.

[48] Document No. 09780-2017, Issued 11/14/2017, in Docket No. PSC- PSC-20170215-EU, Review of Electric Utility Hurricane Preparedness and Restoration Actions. http://www.floridapsc.com/library/filings/2017/09780-2017/09780-2017.pdf

[49] Document No. 04236-2018, Issues 6/14/2018, in Docket No. PSC-20170215-EU, Review of Electric Utility Hurricane Preparedness and Restoration Actions. http://www.floridapsc.com/library/filings/2018/04236-2018/04236-2018.pdf

In requiring data collection and projections, the PSC enabled IOUs throughout Florida to better understand the impacts of hardening infrastructure on storm preparedness, which encouraged increased investment from IOUs within the region. For example, since 2004, Duke Energy has invested more than $2 billion to harden its electrical system in Florida. It plans to invest $3.4 billion over the next 10 years to further modernize the grid, including advanced self-healing technology, hardening and resilience, advanced metering infrastructure, and targeted undergrounding. Since the 2004–2005 hurricanes, Florida Power & Light Company (FPL) has invested $4 billion in grid resilience, including strengthening transmission lines, replacing poles, and clearing vegetation from more than 150,000 miles of power lines.

Furthermore, when the PSC asked IOUs to compare their responsiveness to storms before and after increased storm hardening efforts, several noted decreased outages and restoration times. FPL found dramatic differences in restoration time after implementing storm hardening projects when it compared Category 5 hurricanes from 2005 and 2017. For example, FPL took 1 day to restore power to 50 percent of its customers during Hurricane Irma in 2017. In contrast, it took 5 days to restore power to 50% of its customers during Hurricane Wilma in 2005. TECO Energy in Tampa and other IOUs also noted similar reductions.

6.7 Case Study: SDG&E Flexible Adaptation Pathways

SDG&E, as part of California's 2013 rulemaking,[50] conducted a detailed analysis evaluating how its existing infrastructure will be impacted given different sea-level rise (SLR) projections. In addition to assessing risks to their service territory, SDG&E evaluated community-wide risks—looking at the potential costs to underserved communities in addition to costs to critical customers—such as naval yards, hospitals, and port and sewage stations within its service territory. This analysis was conducted using impact scenarios that varied in SLR impacts and conditions. For example, Impact Scenario 1 assumed future periodic tidal inundation and lower SLR, while Impact Scenario 3 assumed extreme future storm coastal wave flooding under a 100-year storm and higher SLR. These scenarios were designed to address further the potential key interdependencies between the electric system and other critical infrastructure.

As part of this modeling exercise, SDG&E developed a series of flexible adaptation pathways to determine which actions to take to create a more resilient electrical system. The pathways are designed to be adjusted over time as new information or circumstances emerge. SDG&E developed several policy actions that fit into its pathways methodology. These actions included short-term actions, such as enhancing coastal storm prediction and response, and long-term actions such as asset and site relocation. Each of these actions is mapped into a suite of forward-looking actions that create a more resilient system for SDG&E. In developing a framework and series of adjustable metrics, SDG&E has a plan to move forward and has the flexibility to adjust the plan as new information is gathered, ultimately making its resilience planning process more proactive and beneficial for long-term performance.

6.8 Case Study: ComEd's Resilience Approach and Bronzeville Community Microgrid

Many of the technologies used to enhance resiliency also help utilities enable communities to have higher power reliability levels while also meeting their sustainability goals. ComEd has developed a coordinated strategy that leverages a wide range of technologies to meet these shared goals. Developing a resilient, modern grid begins with prioritizing the challenges impacting resilience. This includes efforts to enhance resilience, such as preparing for the disruptive events associated with climate change, assessing health pandemics' effects, and identifying other challenges, such as aging infrastructure.

In addition, ComEd emphasized investments to enhance grid flexibility by optimizing substation and feeder capacity by increasing the emergency margin on feeders and implementing adaptive protection capabilities. To fully meet its needs, ComEd also enhanced its telecommunications infrastructure to enable real-time monitoring and control. These technologies support broader goals of technology integration, such as enabling the integration and management of DER like solar PV, energy storage and electric vehicles, and the deployment of microgrid technology to enhance reliability, resilience, and sustainability. The holistic investment strategy approach to achieve a resilient grid is shown in Figure 9.

The Bronzeville Community Microgrid (BCM) is the culmination of a flexible and adaptable grid that provides resiliency to the community and the infrastructure. Once finished, the BCM will be the first utility-operated microgrid cluster, leveraging DERs, including solar PV and battery energy storage, to serve approximately a thousand residences, businesses, and public institutions with approximately 7 MW of load. The BCM enables a green, resilient, sustainable

[50] CA PUC Rulemaking 13-11-006

neighborhood for consumers. The project serves an urban area of more than 1,000 homes and businesses. These homes and businesses include 11 facilities providing critical services, such as the Chicago Public Safety Headquarters, the De La Salle Institute and the Math and Science Academy, a library, public works buildings, restaurants, health clinics, public transportation, educational facilities, and churches.

ComEd developed a holistic, data-driven methodology to determine which portion of the service territory would most benefit from the resilience enabled by a microgrid. The approach considered factors related to the grid's operation and the social assets available in each area, including customers that could provide critical public services. The approach divided the service territory into 1-mile by 1-mile sections outside Chicago and into half-mile by half-mile sections inside the city. ComEd chose this location in part because it could serve as an oasis, where first responders could deploy medications and fresh food during a disruptive event, supporting the broader region. In the selection process, ComEd leveraged its partnerships with governmental emergency response organizations.

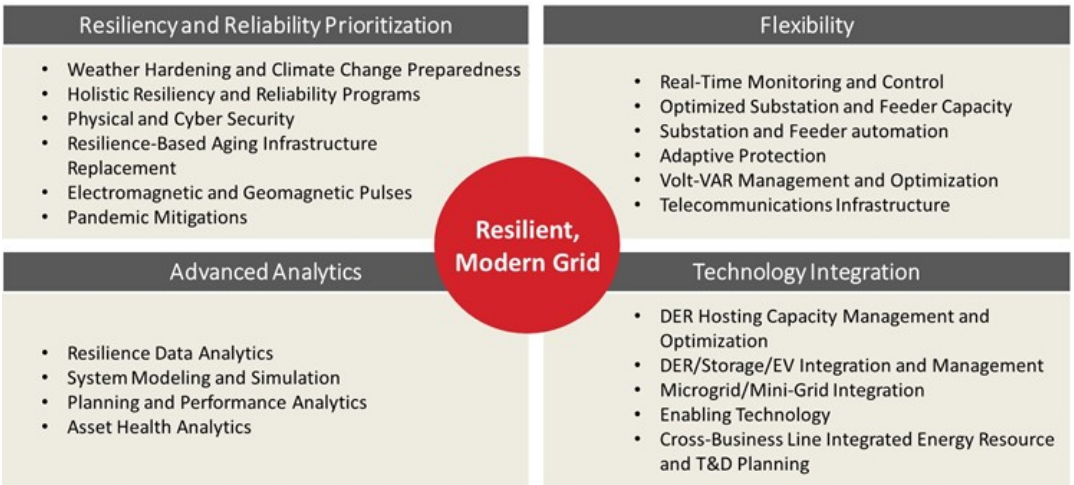

Figure 9 – ComEd investment strategy approach.

To demonstrate the resilience provided by the BCM, performance metrics were developed in the three following areas: energy systems resilience, critical infrastructure resilience, and community resilience. For each area, ComEd identified key indicators representing a holistic view of each performance area. These indicators quantify the impact that this project has on resilience. By tracking these metrics and enhancing the impacts of the BCM, ComEd is creating a model for a more resilient grid. The DOE supports the project under a SHINES (Sustainable and Holistic Integration of Energy Storage and Solar Photovoltaics) funding opportunity.[51]

6.9 Use Case: Austin Energy SHINES

The Austin SHINES project explores new ways to build grid resilience by incorporating new and emerging technologies. This project recognizes that emerging DER assets such as solar and energy storage are part of an integrated, interconnected grid system. The benefits of these resources are maximized only when they are holistically coordinated with other grid assets. Austin SHINES integrates solar power, energy storage, smart inverters, forecasting tools, market signals, advanced communications, and a software optimization platform.

This project has been implemented in the service area of Austin Energy in the Austin, Texas, region. Final reports have been developed and are publicly available on-line.[52] The SHINES project includes a 1.5-MW/3-MWh lithium-ion battery that is co-located with the La Loma community solar array. Additionally, a 1.5-MW/3.2-MWh lithium-ion battery is paired to the Mueller neighborhood in east Austin, which contains 2 MW of rooftop solar. Residential and commercial properties also have battery storage paired with solar arrays. Funding for Austin SHINES project has included government partnerships with the U.S. Department of Energy Solar Energy Technology Office[53] and the Texas Commission on Environmental Quality, as well as many others working with Austin Energy on the project.

[51] https://www.energy.gov/eere/solar/project-profile-commonwealth-edison-company-shines
[52] https://austinenergy.com/ae/green-power/austin-shines/final-deliverable-reports
[53] https://www.energy.gov/eere/solar/project-profile-austin-energy-shines

6.10 Case Study: Wildfire Risk Mitigation – Lessons Learned from California

Wildfires bring about devastating consequences to the impacted communities and lead to prolonged power outages due to the potentially significant damages of the infrastructure damaged by the fires. Although wildfires happen for several reasons, utilities have an important role in wildfire risk reduction efforts. Greater investments in wildfire-related safety enhancements to electric systems are crucial to providing greater system resilience. California has experienced ever-increasing wildfire risk in recent years due to evolving climate change and other factors like the growing wildland-urban interface and significant build-up of fuel, including on federal and state forest lands.[54]

Lessons from the devastating impacts of the wildfires have led California's utilities to comprehensively review its already robust fire mitigation strategies and develop enhanced comprehensive measures for areas where there are elevated wildfire risks. These efforts are focused on wildfire prevention (reducing potential ignitions) and supporting suppression (i.e., more rapid identification and assessment of wildfires), as well as enhancing system resilience. Wildfire mitigation efforts are generally categorized into the following key areas:

- System hardening to improve resilience: deploying insulated/covered conductor in high fire-risk areas to significantly reduce ignition sources caused by foreign objects such as palm fronds, debris, metallic balloons, etc.; contacting overhead lines; and using fire-resistant composite poles and cross-arms.
- Further bolstering its situational awareness capabilities by adding weather stations and high definition cameras to more quickly and fully assess potential wildfire threat conditions and response readiness.
- Enhancing its operational practices to include, among other things, infrared and corona detection technologies to inspect electrical equipment, implementing more aggressive vegetation management activities, and significantly expanding customer outreach and community engagement as a part of overall stakeholder collaboration.

6.11 NERC Reliability and Cyber Security Standards

NERC reliability standards and definitions are discussed in detail in section 3.1. Further, the NERC Critical Infrastructure Protection (CIP) standards[55] provide cyber and physical security standards for providers that fall under a particular set of criteria. While many electric utilities do not meet these criteria, the standards themselves provide various recommendations that would help electric utilities increase their physical and cybersecurity and their resilience postures. The standards begin with CIP-002.5-1a (BES Cyber System Categorization). This standard describes categorizing BES cyber systems and their associated assets into low, medium, and high impact ratings in terms of loss or disruption of that portion of the system. This categorization allows an electric utility to better focus limited resources on protection and resilience for those areas deemed to have a higher impact while limiting focus on lower impact areas.

Another key element within the standards contributing to electric utility cyber systems' resilience is covered in CIP-009-6 (Recovery Plans for BES Cyber Systems).[56] This standard provides information on the creation of a recovery plan to respond to a successful cyber-attack. Having such a plan in place will make an electric utility much more resilient in a cyber-attack event. More importantly, the standard also provides guidelines for testing the plan. Testing a plan allows people who respond to be familiar with their roles and responsibilities and the appropriate response procedures when an event happens. These elements contribute to the electric utility's resilience to a wide variety of possible cyber disruptions, be those via malicious attack or other events.

In addition, regarding the risk management framework, NERC identifies risk in both a leading and lagging manner. NERC scans the horizon for emerging risks such as grid transformation and critical infrastructure interdependencies.[57] [58] At the same time, the ERO is gathering data and information on the performance of the existing BES to uncover unexpected risks such as large quantities of photovoltaic generation ceasing to operate under certain system conditions.[59] The ERO's policies, procedures, and programs are then used to address these identified risks.

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[54] *See e.g.,* Gov. Brown's Executive Order B-52-18, issued on May 10, 2018, ordering several projects to improve forest conditions and increase fire protection. The order notes the pace and scale of prescribed fire, fuel reduction, and thinning of overly dense forests "are far below levels needed to restore and maintain forest health."

[55] https://www.nerc.com/pa/Stand/Pages/CIPStandards.aspx

[56] https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-009-6.pdf

[57] https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC%20ERO%20Priorities%20Report_Board_Accpeted_November_5_2019.pdf

[58] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf

[59] https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2020.pdf

Section 7 CONCLUSION

The potential hazards that are likely to impact the electric grid's critical function are very broad. Many of them unpreventable and difficult to predict or control in terms of magnitude and intensity. Present resilience frameworks and methods are complex, identifying the need for a more simplistic approach, focused on establishing metrics that can be more easily and consistently applied across the various stakeholder groups.

Ultimately, the value of metrics lies in their ability to be benchmarked and compared across industry participants to facilitate continuous improvements. There is no "one-size-fits-all" solution for resilience metrics and investments as they are dependent on various factors (regional, functional, regulatory, and business). **Therefore, it is impossible to have simple, industry-accepted resilience metrics addressing all-inclusive events affecting resilience. The proposed approach is to identify individual parameters/events and associated system-dependent metrics, which are then applied based on pre-defined priority weights/factors and by using the appropriate framework to facilitate the investment decision process.**

We propose that any process for improving the electric grid's resilience should incorporate a threat-based risk assessment that can guide investment decisions balanced with other priorities associated with enhancing grid performance against stated objectives. This process should include a continuous improvement feedback loop. An effective resiliency framework should strive to minimize the likelihood and impacts of a disruptive event from occurring and provides the right guidance and resources to respond and recover effectively and efficiently when an incident happens. It should also address comprehensive and integrated planning and investment process. There is a need for a regulatory framework and policies that enable utilities to make appropriate system hardening measures proactively ahead of the major events. The regulatory framework and policies should support multi-stakeholder collaboration and acceptance of shared responsibility as a pre-requisite for a more resilient electric grid. Furthermore, the industry needs processes to support effective system-wide resilience planning across larger regions so that regional planners can co-develop strategies with state/local planners.

In conclusion:

- **The recommendation is to apply the all-hazards framework toward assessing and developing a program with five main focus areas: Prevention, Protection, Mitigation, Response, and Recovery.**
- **Resilience considerations must be included in an integrated generation, transmission, and distribution planning and investment prioritization process.**
- **A comprehensive approach to developing a resilience plan must include the active involvement of diverse stakeholders—starting with regulators and policymakers at the federal and state levels.**

We conclude that some of the best solutions are built on combining the technologies, tools, and methods (TT&Ms), as highlighted in Section 5. IEEE has an important role in identifying best practices and applicable standards.

Understanding the practical perspective is required to strengthen the resilience, including learning from some of the more common practices and use cases (SCE, Con Edison, Entergy, Florida utilities, SDG&E, ComEd, Austin Energy, as well as NERC reliability and cyber-security standards).

Finally, the resilience of the electric grid is the foundational building block for our clean energy future. This resilience will require renewable resources, energy storage, and electrification—the optimal deployment of which requires investments in a resilient, modern grid.