ELECTRICITY
ADVISORY
COMMITTEE

Conceptual Basis for Evaluating Resilience Capabilities

Recommendations for the U.S. Department of Energy

JUNE 2023

Introduction

For several years, the Electricity Advisory Committee (EAC) has been deliberating and turning its focus to issues around grid resilience. The EAC has addressed the topic of resilience in past recommendations, including its 2019 *Policy and Research Opportunities for Grid Resilience*. That work product emerged from a panel session held during the EAC's October 2018 meeting and provided recommendations to the U.S. Department of Energy (DOE) on improving grid resilience. The EAC followed this work product with an additional recommendation in October 2019 for the development of a resilience handbook to assist states and regions in developing resilience standards. In 2019, various EAC subcommittees began discussions on issues related to resilience and this resulted in several activities and initiatives. One was recognition by DOE's Office of Electricity of the need to focus on specific resilience efforts related to military and defense critical infrastructure, leading to the formation in 2020 of the EAC's Grid Resilience for National Security (GRNS) Subcommittee.

Contemporaneously, these deliberations led to the EAC producing a work product in January 2021 that sought to identify ongoing DOE or related efforts and catalog and assess any existing resilience valuation frameworks or metrics. The EAC held a panel discussion on these efforts at its public meeting in April 2021. This session included representatives of the National Laboratories who have been seeking to create metrics and frameworks that value resilience. However, there are still no comprehensive frameworks or metrics that have been produced or are readily available to the industry, policymakers, or regulators. Thus, the EAC and its subcommittees have realized that this need still exists and they believe that there is a role that DOE could still undertake to support the establishment and development of such assessment tools and resources.

Approach

The reliability of electric systems has been measured for many years and common metrics are available. Utility companies and regulators use these metrics to balance investments to improve reliability in areas where the need is the greatest. The increasing dependence on fully available electric service and the increasing challenges facing that level of service are leading to planning for resilience, where the system will perform at a level that exceeds the historic levels of reliability and such that service to critical areas can be restored quickly and with virtual continuity. There is a desire in the industry to have metrics for resiliency and to evaluate the investments that would be required. There is significant ongoing work to develop these metrics. Resilience metrics are more difficult to develop because, unlike reliability metrics, which are based on historical outages, resilience means being prepared to avoid or minimize the outages that may occur in the future.

Because the metrics are so difficult to develop, this EAC work product is recommending a basic approach to the task of valuing resilience.

Initially, the GRNS Subcommittee addressed resilience in this work product at the distribution customer level. The EAC recognizes that there are also resilience metrics that should be developed for sub-transmission and transmission systems, as well as for resource adequacy levels, which ultimately affect overall resilience for customers. These complicated resiliency factors are not within the scope of this document. This document is focused on evaluating the capability for resilience at a particular site and the benefits of improvements at that site. It may be expanded to evaluate small areas of a distribution system. There are wide area factors that affect resiliency such as cost-effective mutual aid and supply chain issues and while these are important for large scale resiliency they are outside the scope of this document.

This work product also provides an explanation of the current level of resilience that exists, in general, across the U.S. electric grid and the challenges of going to the next level of resilience with the current funding available and the pressures on utilities to limit cost increases to customers.

Findings

Resilience Planning Tool: The EAC has drafted a tool to assist in evaluating and planning for resilience at a specific site. This draft framework or resilience capability model is not based on any extensive mathematical calculation. It ranks any particular site based on the attributes of the site and the utility service to the site. The site attributes include the availability and duration of on-site generation, the number of circuits on-site and their reliability, and the amount of automated switching for the on-site circuits. The utility attributes include the number of service delivery points to the site; the number of utility circuits, substation transformers, and transmission circuits available for backup; the reliability of the backup circuitry; and the amount of automated switching available. The resulting product of applying these factors is a point-based ranking. This can be used as a relative metric of the capability for resilience. This model is a draft, with attributes, point scales, and multipliers based on one planning engineer's experience. The model will need to be refined by a larger team for widespread use.

This model was developed for a site-specific analysis, but it can be adapted to a site, facility, campus, circuit, or localized regional service territory. In addition to traditional utility attributes, such as reliability and infrastructure health, non-utility attributes may include socioeconomic factors, transportation access, housing availability, and infrastructure accessibility. As part of the Justice40 Initiative, the White House and federal agencies have been directed to prioritize federal funding and bonus incentives for resilience investments within disadvantaged communities that have been disproportionately affected by lower reliability and resilience levels and are eligible for additional funding streams (e.g., federal funding and bonus incentives).

The model can also be used to evaluate the impact of potential improvements to find the most cost-effective improvements to be considered for investments. Consideration of backup generating assets should include climate change risks, health risks, environmental risks, pollution risks, and fossil fuel industry impacts. The impacts need to be analyzed considering the limited run time of the assets and the use of renewable assets to provide energy during normal periods to mitigate the effects when fossil-fueled assets must run. The environmental analysis needs to include the ability to provide the needed backup for the long-term outages that can occur.

The Draft Capability Model is attached.

Utility distribution planning has historically included planning for reliable service to customers and some level of resilience in the form of backup service. This planning has considered equitable service levels across all classes and locations of customers since rates are calculated based on the aggregate cost to provide service across the jurisdiction.

Reliability and resilience planning should also include a financial evaluation of the investments required and part of this should include determining who pays for the improvements. Historical models have included the following:

- **Reliability and resilience provided by the utility without specific contributions by the customer**
- **Rural areas where higher reliability and resilience levels are very costly**
- **Customer-funded on-site improvements**

Reliability and resilience provided by the utility without specific contributions by the customer

In the more populated urban and suburban areas, growth in load and growth in the number of customers have driven system improvements. These improvements have included higher capacity substations and lines and the ability to provide backup service when part of the system has an outage. Planning horizons of 10+ years have resulted in good levels of backup circuitry and capacity. In many cases, the levels of needed reliability and resilience have justified even higher levels of backup availability. Cost recovery for these improvements has been included in rates across the utility's jurisdiction. Distribution automation has also allowed higher levels of reliability and resilience in these areas where capacity is available, and only the investments to automate switching and some small level of circuitry improvements are needed. This type of resilience typically supports large groups of customers in an area served by multiple substations and circuits.

Over the past decade, customer expectations have increased from that found during historical levels of potential disruption. Further, critical facilities containing defense critical electric infrastructure have identified the need for rapid restoration, and industry has identified additional investments that are necessary to harden systems or implement measures to ensure more rapid restoration and increased resilience. With these trends, regulators have been confronting the need for increased investments beyond what might have been considered appropriate in the past for reliable service. Therefore, it is necessary for regulators to acknowledge the need for this enhanced level of investment in resilience measures. However, it is appropriate that regulators have some effective tools or frameworks to evaluate the wisdom of such resilience measures and investments. By having tools such as those proposed here, there can be discussions between industry and regulators about the costs, benefits, and wisdom of such investments.

Rural areas where higher reliability and resilience levels are very costly

Customers in the most rural areas tend to have reliability and resilience in the lower range due to limited backup service and infrastructure that has been in place for many years. The more rural the area, the less likely that the rebuilding of infrastructure has been driven by growth. For most utilities, these areas include a high percentage of the total service area but a much lower percentage of the total customers in the jurisdiction. Many of the customers in these rural areas are served by single-transformer substations and long radial lines with no backup. Some customers may be served by larger substations with multiple circuits that have some interconnectivity with other circuits, which provides some level of backup but still much lower backup than for urban and suburban areas. The cost of providing greater levels of reliability and resilience tends to be very high, including the extension of transmission lines, new substations, and distribution circuits. Generally, customers understand the reality that living in these areas has a higher risk of extended outages. A growing number of customers are installing their own backup generators, including with manual or automated switching. Some are installing solar panels with battery backup.

Some customers who need higher levels of reliability and resilience have contributed to utilities for improvements specific to their service (e.g., hospitals, industrial complexes, military sites, airports, emergency services). Alternate circuit feeds, with automated switching for the service, are common improvements. The business arrangements for these higher service levels vary from utility to utility. It is common for the customer to contribute to the utility's capital investment and pay a fee to reserve the capacity on the alternate circuit.

Customer-funded on-site improvements

Some customers who need higher levels of reliability and resilience have invested in on-site improvements, including emergency generators and automated switching. These investments are usually coordinated with the utility but are installed on the customer's site and are maintained by the customer. The improvements may include hardening/undergrounding of on-site circuitry, adding on-site circuitry, adding automated switching for backup circuitry, and adding on-site generation. An improvement plan probably includes a combination of these investments. These systems usually include a brief outage when the utility circuit de-energizes, with the on-site generator switching in within cycles or seconds. Most of the systems include a brief parallel operation (<100 milliseconds) when the utility's power returns. The customer funds these improvements.

On-site backup or other distributed generation is often one of the most effective and least costly solutions for providing a needed level of resilience. The most cost-effective generating sources utilize fossil fuel; however, there is some level of resistance to continued use of such fuel due to concerns about greenhouse gas emissions. Given the prevailing public policy of utilizing renewable energy sources, any resilience framework should evaluate such solutions as these may work in some situations. However, for larger loads and longer duration backup and on-site generation needs, fossil-fueled sources may be required. Given the need for continuity of service, traditional fossil fuel on-site generation sources should be evaluated, as well as emerging distributed generation technologies, such as fuel cells, biogas generation, power electronics, energy storage, and, for larger loads, technologies such as advanced nuclear. When considering resiliency improvements, the tradeoffs and increased complexity associated with local areas that have high penetrations of rooftop photovoltaic systems should be recognized.

Some customers and utilities are installing renewable sources and energy storage to increase their on-site resilience. However, there may still be the need to deploy fossil fueled sources to meet resilience requirements. In such locations the renewable sources can be designed and operated to be available during normal and abnormal operating conditions to balance the expected run time of the fossil-fueled sources. The goal should be to identify the needed level of resilience for a site or an area and the solution should balance resilience capability, cost, and greenhouse gas emissions.

Greater regional resilience can also be enhanced by having arrangements with utility customers to run their generators during extreme system capacity conditions in order to reduce the load required from the Bulk Electric System (BES). Generators at sites that are not experiencing outages could provide capacity and energy to the grid to reduce the load needed from normal BES sources and the transmission grid. Generation owners could be compensated for the capacity and energy they provide during extreme conditions. This could help offset some of the cost for their on-site resilience. Part of the planning for this extreme availability could include the installation of renewable sources that would be available during normal and abnormal operating conditions to at least offset the emissions expected annually from the limited run time of the fossil-fueled sources. While this capacity requires planning and financial arrangements, such planning should be beyond the norm for peak conditions and be planned specifically for unexpected extremes of load and generation deficiency, such as the 2021 Texas power crisis.

Recovery and risk mitigation are shared responsibilities between the power companies and key customers.

Recommendations

1. DOE should consider adopting the Resilience Capability Planning Model and commission a team to further develop the model. The team would be led by a National Laboratory, with the participation of engineers with distribution utility experience and design engineers with experience designing reliable and resilient on-site electrical systems. Further development should preserve the simplicity of the draft model. The model should be suitable for universal application across the industry and allow for easy input of data and interpretation of the results. The Interruption Cost Estimate Calculator, which was developed by DOE, is a good example of the desired level of simplicity.

2. DOE could consider further adapting the model concept to be used to evaluate the resilience capability of a utility distribution area.

3. DOE should lead conversations with state and federal policymakers and regulators to recognize that going to the next level of resilience requires investments. Most current rate structures do not include funding to attain a level of energy system performance above the traditional level of expected reliability. In fact, most utilities are under pressure to limit rate increases or decrease their rates. These conversations should include ranking the importance of resilience and laying out the possibility of funding from traditional rates, increased rates in high-resilience areas, government funding, and a cost-benefit evaluation of these enhanced investments.

ELECTRICITY ADVISORY COMMITTEE

ATTACHMENT 1

UTILITY SERVICE					
Capability	**Points Scale**	**Multiplier Scale**	**Points**	**Multiplier**	**Points Score**
Electric Service from an Electric Utility	1 per service point		1		
UG delivery at service point	2 per service point		2		
# of Primary Circuits available for back up - manual	2 per back up circuit		2		
# of Substation Transformers for availble circuits	1 per additional transformer beyond 1		1		
# Transmission Feeds to Substations	2 per additional T Line beyond 1				
Multipliers					
% of utility primary circuit route to service UG		< 25% - 1, < 50 % - 1.5, <75% - 2,<100% - 2.5		1.5	
% of back up circuitry UG		< 25% - 1, < 50 % - 1.5, <75% - 2,<100% - 2.5		1.5	
% of Primary Circuitry with automated switching		< 25% - 1, < 50 % - 1.5, <75% - 2,<100% - 2.5		1.5	
SAIDI of primary circuits available		>300 - 0.5, >200 -0.75, >100 -0.9, > 75-1.0, >50-2.0, <50 - 2.5		0.9	
Substation Transformer Automation		Manual SW-1, SCADA SW - 1.5, Auto SW - 2.0		1.5	
Transmission Availability		<95% - .75, <98% -0.9, 99%+ -1.0		1	
Modified Score (Points x each multiplier)			**6**	**4.55625**	**27.338**

ON SITE RESILIENCE					
Capability	**Points Scale**	**Multiplier Scale**	**Points**	**Multiplier**	**Points Score**
% of Critical Loads Covered by on site G	100% - 5, 75% - 3, 50% - 2, <50% -1, 0% - 0	Mo Test w/ Load 100% 1, 80% - .0.8, 50% - 0.5, <50% - 0.0	5	1	
Duration of on site G for Critical Loads		>30 days - 5, >15 days - 4, > 3 days - 3, >1 day - 2, > 4 hours - 1.5, >2 hours - 1		5	
Subtotal On site G - Critical Loads			5	5	25
% of Facility Non-Critical loads covered by on site G	100% - 3, 75% - 2, 50% - 2, <50% -1, 0% - 0	Mo Test w/ Load 100% 1, 80% - .0.8, 50% - 0.5, <50% - 0.0	1	1	1
Duration of on site G for Non-Critical Loads		>30 days - 5, >15 days - 4, > 3 days - 3, >1 day - 2, > 4 hours - 1.5, >2 hours - 1		2	
Subtotal On site G - Non Critical Loads			1	2	2
Total On Site G					**28**
% of Critical loads served by > 1 primary circuits	100% - 3, 75% - 2, 50% - 2, <50% -1, 0% - 0		3		0
% of on site primary circuit routes UG	< 25% - 1, < 50 % - 1.5, <75% - 2,<100% - 2.5, 0% - 0		1.5		
% of Primary Circuitry with automated switching	< 25% - 1, < 50 % - 1.5, <75% - 2,<100% - 2.5, 0% - 0		1.5		
SAIDI of primary circuits available		>300 - 0.5, >200 -0.75, >100 -0.9, > 75-1.0, >50-2.0, <50 - 2.5		2.5	
Total Backup circuitry			**6**	**2.5**	**15**
Total On site Resilience					**43**

ATTACHMENT 2