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CIDER DERMS Community Resilience Event Response



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1. Executive Summary

This report was created to help rural electric cooperatives seeking to improve resilience and increase consumer-member engagement through new programs and tailored upgrades. Designing and communicating effective programs can be challenging alongside existing operational demands. Through deliberate program design approaches that are tailored to local priorities, resilience programs can strengthen engagement by making benefits visible and relevant to consumer-members. This document seeks to support co-op decision-making by presenting considerations and examples gathered from literature, workshops, and other insights that arose as part of the Community-Integrated Distributed Energy Resilience (CIDER) initiative, which was a federally-funded project that investigated utility control of behind-the-meter (BTM) distributed energy resources (DER) and the programs that enable them.

2. Introduction

Rural electric cooperatives continuously make decisions that balance reliability, consumer-member satisfaction, cost, and long-term resilience. Many co-ops already recognize opportunities to improve resilience through new technologies, strategic upgrades, and consumer-member-focused programs, but designing and implementing these efforts requires time, planning, and coordination alongside existing operational demands. Selecting technologies, identifying priorities, communicating benefits, organizing outreach, and evaluating outcomes can become significant efforts on their own. This report was developed to support co-ops in those decisions by presenting approaches, examples, and considerations that may reduce the effort required to design effective resilience initiatives while preserving flexibility to adapt them to local needs.

Resilience and consumer-member engagement are closely related and can reinforce one another over time. Improving resilience can strengthen engagement by increasing consumer-member confidence that the co-op is responsive, effective, and attentive to the priorities of their consumer-members. At the same time, engaged consumer-members can contribute to stronger resilience outcomes by providing feedback, participating in programs, and supporting initiatives intended to improve service reliability and preparedness. Communication plays an important role in this relationship, both during outage events and throughout long-term resilience efforts, but communication alone does not determine success. Program outcomes themselves can drive engagement when consumer-members experience visible and meaningful benefits.

Program design plays an important role in creating those outcomes. Decisions made early in planning influence not only technical performance but also whether programs feel relevant and accessible to consumer-members. Metrics and data can help identify local priorities, inform where investments may be most effective, and provide a way to communicate program value. Combining different sources of information and selecting measures that align with co-op goals can help tailor programs to the needs of different service areas and consumer-member populations. Engagement considerations such as outreach, education, and events can further support participation and sustain interest over time.

Deployment decisions can similarly influence program success. Once goals have been identified and a program structure has been selected, co-ops may face choices around which technologies to include, how those technologies are managed, and what partnerships or implementation approaches are most practical. Existing platforms, third-party providers, consumer-member-facing tools, and approaches to technology control can affect both operational burden and the consumer-member experience. Thoughtful deployment can help ensure that resilience improvements are visible, practical, and aligned with co-op priorities.

Because these considerations operate at different stages of planning and implementation, this report discusses program design and technology deployment as separate but connected topics. Program design focuses on defining goals and shaping initiatives through planning, data selection, metrics, and engagement strategies. Technology deployment focuses on implementation decisions and the practical choices that influence how programs function in practice. Together, these perspectives provide an approach for co-ops seeking to strengthen resilience while supporting meaningful consumer-member engagement and informed decision making.

3. Background

Rural electric co-ops can employ numerous approaches to engaging their consumer-members when it comes to improving resilience, such as outage response improvements and other programs that foster a greater sense of loyalty and collaboration.

3.1. Communicating About Outages

Among these various engagement avenues, improving outage communication offers a strong opportunity to support consumer-member satisfaction. During outages, consumer-members generally appreciate proactive, clear, and multi-channel updates that inform and acknowledge their contributions without overwhelming them. Communicating what is happening and approximately how long it will last can assist consumer-members in making informed decisions about how to weather the event [1,2]. Some consumer-members want more two-way communication with their co-op, particularly regarding outages [3], such as having their proactive outage reporting efforts acknowledged by speaking to a representative when calling, or by receiving confirmation messages when they text or email [4]. They also tend to appreciate preparatory guidance like notifications to boil city water supplies before drinking, as well as real-time updates about outage causes and restoration time estimates [3,5]. Co-ops can consider balancing the quantity of information provided with how relevant it is to consumer-members so that it remains easy for them to digest and act upon. Co-ops can also consider prioritizing the comprehensible presentation of relevant information, with options to view expanded details for consumer-members who wish to do so [6]. Some consumer-members living far from others may need specific, separate guidance and, for those who may have reduced access to other forms of communication, providing battery-powered radios may help those consumer-members to receive critical information [1,2]. Whether during an outage event or a small interruption, consumer-members want their contributions to make a difference, and they don't want to be "left in the dark".

3.2. Engaging Members

Moving beyond outage communication, co-ops can generally also benefit from fostering a deeper relationship with their consumer-members during normal operations. Building a sense of loyalty to a co-op can not only promote new resilience initiatives, but help sustain them long-term. One aspect of engaging consumer-members lies in how they identify themselves with their co-op. To illustrate this, those who identify themselves as co-op “members”, rather than “customers” show higher satisfaction [4]. While this suggests a benefit to something as simple as using the specific lexical terminology in communications (e.g. member, member-consumer, member-owner), it also may help consumer-members feel that their co-ops communicate clearly and provide opportunities to make member voices heard. This can be seen in the Member Loyalty Index (MLI), defined in Figure 1, which measures the impact of engagement efforts by quantifying not only satisfaction, but fondness and loyalty to a co-op in hard times [7]. Of the six actions identified by the MLI to drive consumer-member loyalty, they all center on effective communication, whether about issue transparency, aligning expectations, clarifying value, or ensuring that consumer-members know that their needs are a priority for the co-op.



Figure 1. Member Loyalty Index Tips

4. Program Design as Engagement

A well-designed program that meets a co-op's specific needs in clear and understandable ways can communicate its own value to consumer-members. As a result, program design itself can be thought of as a powerful avenue for engagement. This section explores ways to build momentum and visibility for new energy programs before delving into how effective metrics can inform program design. This is followed by a discussion of selecting metrics and data sources to address specific co-op priorities, as well as how to layer metrics to capture more complex concepts. Finally, general program design structure and considerations are discussed and examples are provided for illustration.

4.1. Engaging Members Through New Energy Programs

The same effective communication that drives loyalty can help engage consumer-members when launching new resilience programs. When pursuing these programs, it can be helpful to connect the right consumer-members to the right outage mitigation strategies by tailoring marketing and outreach efforts to the membership. For example, reaching consumer-members who are geographically isolated or less digitally active requires extending communications beyond only apps and internet channels to direct phone calls, radio, and physical media like notice boards and leaflets taken door-to-door [1,2]. Generally, consumer-members want more convenient access to services and more transparent communication [8], they want their energy bills to be easier to understand, and they receive value from “services that simplify, inform, and save time” [4]. By combining strategic outreach with clean, low-friction program design, co-ops can establish a dual-pronged approach where the program's value effectively promotes itself by being easy for consumer-members to observe and discuss.

When the net benefits of a program are strong enough that consumer-members begin discussing them with their friends and neighbors, new interest develops organically. Minimizing barriers to entry can help transition this initial interest into active program participation. Easy and accessible enrollment and participation [9] with minimal disruption to current practices and systems [10] can help support this. Trust can be built by being upfront about benefits and limitations [5] and by explicitly communicating any prohibition on subscription fees, early termination fees, and credit checks [9]. Likewise, meaningful savings or other benefits can be conveyed without including not-directly-relevant details [9]. Word-of-mouth can be facilitated by making sure that consumer-members who are champions of a program within their circles have straightforward explanations and the resources they need to speak informedly [5]. Notably, because individuals tend to interact with neighbors who are geographically closer and/or have shared interests, this word-of-mouth advocacy can drive localized “clumping” in program uptake. This can make efforts to promote programs to consumer-members in specific parts of a service-area particularly effective.

Word-of-mouth can also be bolstered through one or more in-person kickoff events where co-ops can communicate about a project and its expected benefits while bringing consumer-members together to celebrate. In-person kickoff events provide a space for consumer-members to socialize, and hosting multiple kickoff events allows word-of-mouth to spread between them. Co-ops can capture excitement at these events by offering handouts with program sign-up instructions or direct onsite registration [9]. After a kickoff has built consumer-member enthusiasm, interest can be maintained by providing them with access to real-time data about the program so they can see and affect tangible outcomes [11].

4.2. Metrics and Program Design

While effective communication is critical for driving participation, meaningful and sustained engagement also relies on designing programs that meet real needs and capture opportunities where they arise. Taking advantage of relevant metrics can do more than just help communicate with consumer-members about the tangible changes resulting from a program, they can inform program design from the start. If you have a good metric, you can design a good program that concisely serves a particular need.

An example of a metric that can serve as the foundation for a program is Outage Impact Potential (OIP). OIP is a metric explored under the CIDER project to quantify the potential impact of an outage on consumer-members in a census block group based on weather risk factors and statistics about the people living in the area. It can be customized to emphasize or exclude any of those factors based on a co-op's needs. High-resolution outage impact analysis specifically tailored to the needs and experiences of a particular community can be aided by a customizable metric like OIP.

4.3. Aligning Metrics to Member Needs

Choosing a good metric requires a clear understanding of co-op and consumer-member priorities. While capturing these priorities can be challenging, rural electric co-ops can have a unique advantage over for-profit utilities because of the close, collaborative relationships they often have with their consumer-members. These relationships can make workshops and surveys more fruitful, in turn allowing co-ops to anchor their planning in high-confidence internal data and to more easily identify where external data fails to align with real consumer-member experiences. In a series of outage event response workshops hosted by the CIDER project team, participants discussed the reasons that grid resilience is important to their area and how resilience supports the health and safety of their communities. Participants also discussed how their consumer-members value the safety and welfare of their communities, including mitigating potential medical or financial impacts. This alignment of priorities between utilities and consumer-members indicates a good opportunity for development of programs that will improve service and drive engagement. If those goals had been disparate, it may have indicated that conversations about resilience were in nascent stages among consumer-members, and their support for following programs could be more challenging to obtain.

In the same workshop series, attendees were asked to rate the degree to which they agreed with FEMA's measure of the level of susceptibility to natural disasters in their areas. The results showed a slight disagreement with the measure and, in their commentary, many respondents noted specific areas that have fewer resources than urban areas, lack backup power, and do not have good access to transportation. Similarly, when asked about FEMA's measure of how often natural disasters affect their areas, respondents slightly disagreed, noting that various categories like "Strong Wind" seemed too low compared to their experience in the area, especially in recent years. Both of these examples showcase the importance of selecting a good metric suited to a co-op's needs and circumstances: if a project were leveraged primarily on either of these measures, it could lead to results that do not align with needs and could be perceived by consumer-members as unnecessary.

Such mismatches can be caused by poor data resolution, though low resolution may not render that data entirely useless. FEMA data tends to cover a large area compared to the service areas of many co-ops, so in cases like those of the aforementioned FEMA measures, the data may be accurate for the large area

described, but still not reflect the realities along different parts of a co-op's feeder. Differences in conditions on different parts of a feeder can get flattened out when summarized by too-low resolution measures. However, such lower-resolution measures are sometimes the best data available for capturing particular concepts. For this reason, it is important for co-ops to be able to combine these measures covering larger areas with higher resolution data to restore a degree of granularity. This is the approach taken to calculate the OIP metric explored in the resilientCommunity model. OIP is calculated at the census block group resolution by aggregating other statistics taken at that resolution where available and using lower-resolution census tract data to fill in the gaps. Because co-ops hold the most reliable ground-truth-like data about their particular service area and consumer-member needs, that data should be used where applicable, using lower confidence and/or lower resolution public data to supplement it where necessary. Depending on a co-op's needs for a particular project, there are many different metrics they may find useful to collect or use as inspiration for their own custom metrics. A list of metrics quantifying outage impacts can be found in Appendix A.

Some of the most informative metrics cannot be captured well by publicly available datasets. In these cases, co-ops may be able to collect data by deploying surveys to representative samples of consumer-members or local businesses across their service area. For a technical discussion of survey methodology and sampling techniques, see [13]. Because of their consumer-member-owned structure, co-ops have the unique benefit that such surveys can show commitment to local economic recovery and can empower consumer-members to share their experiences, in addition to their primary data collection focus. By leveraging their collaborative nature, co-ops can transform data collection into an engagement opportunity while also gathering high-value ground truth data to verify, complement, or replace public datasets in their resilience analyses.

4.4. Selecting Metrics for Programs Tailored to Specific Market Segments

Just as data sources can be layered, individual metrics are often most informative when paired together to tailor efforts toward specific operational and member-oriented goals. For instance, while a technical reliability metric like a feeder's outage rate is useful on its own, pairing it with a locational-impact metric such as critical load ratio can help identify high-leverage opportunities for upgrades. Combining metrics like this can more insightfully guide decisions around physical equipment hardening, mobile microgrid deployment, or where consumer-members might be most interested in enrolling in BTM DERMS programs.

This multi-metric approach is built directly into software tooling created under the CIDER project. One of these tools is the resilientCommunity model, which combines technical grid data with the locational outage impact data captured by OIP to rank the relative criticality of each piece of equipment, feeder section, or load. Because OIP is highly customizable, co-ops can leverage their first-hand knowledge of their own territories. When a co-op identifies pockets of its service area with unique challenges, such as limited vehicle access during a winter storm, the relevant parameters of *vehicle ownership* and *winter storm hazard* in the OIP can be tuned up or down as appropriate. By using these locally tuned metrics, co-ops can pinpoint which parts of the system have the greatest combined technical and consumer-member importance and should therefore be prioritized for hardening, vegetation management, or upgrades.

As an example of using locally tuned metrics to complement physical upgrades, another software tool was created under the CIDER project - called the restoration model - that simulates outage recovery sequences and can optionally ingest load priorities in the same format as those produced by the aforementioned resilientCommunity model. The restoration model considers these weighted priorities, if provided, as it optimizes switching and DER dispatch strategies during simulated outages. This linkage allows planners to test how different restoration approaches affect system-wide outcomes, restoration times, and consumer-member experience during recovery. Through this integration, co-ops can move from qualitative assumptions about consumer-member priorities to quantifiable, explainable, data-driven restoration plans.

While output metrics from both the resilientCommunity and restoration models can be used on their own to identify program opportunities, they can also be used later in the program design process to enhance tailored deployment and analyze potential effectiveness. For instance, if a co-op has identified particular technologies whose adoption they want to incentivize, the resilientCommunity model could be used to prioritize where the program should be introduced first based on the criteria they used to weight the calculation of OIP. The restoration model could then be used to test how adoption of such technologies in those areas would impact resilience during simulated outage events. As demonstrated by this sequence, good metrics can not only form the basis for successful projects but, when used thoughtfully, can also help tailor and assess project deployment to maximize benefit to consumer-members.

4.5. Program Design Structures

In addition to identifying relevant metrics and consumer-member engagement strategies, developing a BTM DER program can provide another avenue for consumer-member engagement, resilience, and financial benefit to both the utility and the consumer-member. How utilities design BTM DER programs differs from utility to utility, and there are a variety of technologies that can be used for demand response including chemical battery energy storage, smart thermostats, smart plugs, and fossil fuel generators. This section covers some of the factors a utility should consider when designing an engaging BTM DER program, including the utility's wholesale electricity tariff structure, the residential tariff offered to consumer-members, whether to offer rebates or recurring incentives to the consumer-member, the utility's geographical location and weather patterns, the existing technologies in the service area, and whether the program will pay itself back in a reasonable amount of time. Most BTM DER programs are structured to provide value to consumer-members through control of enrolled devices such that the consumer-member's power consumption is changed to better respond to the demand on the wider power grid. Demand response programs might encourage consumer-members to reduce their energy usage, shift some or all of the current usage to another (usually cheaper) time, or generate power on-site to create a temporary microgrid (also known as "islanding").

BTM DER demand response programs will typically result in shaving the utility's peak demand by dispatching member-owned generators, discharging member-owned batteries, or turning off water heaters and HVAC systems during peak time during the utility's most expensive peak demand time. The times when a distribution utility pays the highest premium for wholesale supply power almost always corresponds to when consumer-members' electricity usage, in aggregate, is at its highest. The peak demand cost depends on the applicable tariff structure from their bulk/wholesale power provider, usually a generation and transmission (G&T) cooperative. Some distribution utilities may pay a demand charge

consisting of a certain amount for the peak kW per month, while others might be beholden to a more involved demand tariff at hourly or daily timescales. Utilities that offer variable residential tariff structures (i.e. Time of Use, Time of Day, etc.) encourage consumer-members to reduce or shift their demand usage away from more expensive times. Predicting when exactly a coincident peak, or the largest peak demand for all consumer-members combined, will occur can sometimes be challenging. Some utilities use third party providers to help forecast peak demand usage. Cooperatives often rely on historical data and experience to determine when to anticipate the coincident peak and switch on or off some/all of the BTM DER in response. After the load control events, it is possible that a new demand peak might be created from the BTM DER devices coming back on again - a phenomenon known as the rebound effect. Since this new peak occurs during a time when power is cheap (i.e. after the peak), it does not cost the co-op any significant additional money compared to the savings produced through the control event. When designing a program, utilities having more variable wholesale tariff structures might consider when to anticipate BTM DER devices coming back online after a load control event or outage.

To determine if a BTM DER program will be financially advantageous for both the utility and the consumer-member, distribution co-ops can consider how residential tariff structures affect participation and outcomes. Consumer-members are more likely to enroll and participate in a program that offers financial incentives or reduced energy bills. Some utilities offer a Time of Use (TOU) or Time of Day (TOD) tariff structure for consumer-members, which encourages consumer-members to reduce or shift their electricity demand to times of the day that are less expensive. Similarly, BTM DER technologies can provide the most financial benefit when they are used at financially advantageous times. Utilities that offer a flat energy rate for residential consumer-members (e.g. \$0.12/kWh all day, every day) would not expect to see organically-climbing member enrollment by offering a BESS program to consumer-members without very attractive subsidization. Without it, the main driver for BESS adoption is its usefulness to consumer-members during outages or emergency situations, rather than providing savings on monthly electricity bills. Similarly, when compared to those having more complex tariffs, consumer-members that have a flat rate residential tariff also do not benefit directly from a water heater program or a smart thermostat program that strategically pre-cools or pre-heats the home. In fact, they benefit less because these thermal and chemical storage technologies slightly increase the overall energy usage of the home. For co-ops that expose a flat tariff to their consumer-members, any peak-shaving program involving BTM devices may need to include attractive subsidies that can be paid on an up-front basis to encourage initial adoption or as ongoing payments to maintain continuous enrollment. Utilities that offer a residential TOU or TOD tariff structure, on the other hand, can design a BESS program that stores energy when prices are cheaper and discharges when prices are more expensive, saving consumer-members money on their electricity bills. In this way, peak shaving provided by BTM DER can result in natural savings to the consumer-member without requiring the utility to offer additional monetary incentives because a reduction in grid usage means a reduction on electricity bills. However, financial incentives or additional support from the utility may still be warranted if the program involves a change to the consumer-member's home or routine, such as installing a new BTM DER device or introducing a new software application that enables control of DER. Even when such user involvement is needed, once installed, well-controlled dispatch generally has little to no impact on consumer-member comfort, eliminates energy usage during peak times, and has financial benefits for both the utility and consumer-members. When cooperatives save money through BTM DER programs, the entire membership benefits

because savings are distributed back to consumer-members in the form of on-bill credits or used to further improve the system by funding upgrades.

Some programs might offer more financial rewards to incentivize enrollment and continued participation in a program, especially if programs require consumer-members to purchase, install, and/or learn new devices. These additional incentives might be in the form of a one-time sign-up bonus for enrolling a smart thermostat in the program or a rebate for purchasing devices like fossil fuel generators or water heater controllers. Some programs might offer a monthly or annual monetary incentive for continued participation in the program in the form of an on-bill credit or a pre-paid credit card, or programs might use a combination of upfront and ongoing monetary incentives¹, dependent on their cooperative area, membership, rate structures, and type of program. For some demand response programs, the monetary incentive might be calculated based on the home's energy usage, rather than a flat dollar amount. In these cases, the monetary reward paid to the consumer for reducing their energy usage is calculated as the difference in cost between the household's energy use during the demand response event and the average baseline energy use of the home on similar days prior to the event². Other programs, like Agralite Electric Cooperative's load control generator program, offer a discount³ on electricity prices to consumer-members in addition to a \$500 rebate for enrolling [27]. Agralite Electric Cooperative encourages members to stack their savings by enrolling in all of their load control programs, which in turn further benefits the utility as additional demand reduction potential.

Striking a balance between savings vs. costs of BTM DER programs can be challenging for utilities, especially when designing a brand new program. A typical approach is to determine how quickly the program should begin to pay for itself, then identify the total value that can be recovered from a technology within that time. In determining appropriate subsidies for the program, it is necessary to approximate the total value provided by the technology in question. This can be a very challenging calculation that involves identifying the ideal dispatch for a specific technology under the co-op's electrical, economic, and environmental constraints. As part of the CIDER project, software models were created to help co-ops perform this evaluation. These models, *derUtilityCost* and *derConsumer*, help visualize the impact of up-front and monthly monetary incentives for individual DER technologies for both the utility and the consumer-member, respectively. One advantage of the *derUtilityCost* model is seeing estimated net annual savings of a fleet of BTM DER from which the utility can decide how much of those savings could be offered as upfront and/or monthly incentives to consumer-members for enrollment and continued participation. Likewise, the *derConsumer* model shows how upfront and ongoing incentives from their utility combine with estimated savings from using their BTM DER

¹ Ameren (Missouri and Illinois) Peak Time Savings program provides an initial \$50 prepaid Mastercard to enroll a qualifying smart thermostat and \$25 prepaid Mastercard annually for continued participation.

<https://www.thermostatrewards.com/ameren-il/>

² Ameren (Illinois)'s Peak Time Rewards program. See <https://www.ameren.com/efficiency/programs/peak-time-rewards> under **FAQ → How Peak Time Savings Works → "How is my personal baseline energy use calculated?"**

³ Agralite Electric Cooperative's discount on electricity tariff offered to members came from a rate study that is performed every couple of years by third party engineers.

throughout the year, which can aid utilities in their decisions of whether certain BTM DER programs would be attractive to their consumer-members, financially.

Another consideration in the program design process is whether the utility or the consumer-member has direct control of the DER technologies during a load control event. Fostering consumer-member loyalty through relationships of trust and transparency can help consumer-members feel comfortable allowing the utility to control their BTM DER devices. If the consumer-member has direct control over the BTM DER devices, there is generally an agreement with the utility that the consumer-member will either shift/reduce their electricity usage (e.g. using a smart thermostat) or switch to using a BTM DER that provides alternative power to the home (e.g. a fossil fuel generator or energy stored in a battery) at predetermined times. If the utility has direct control over the BTM DER devices, load control events can happen automatically and remotely without direct consumer-member involvement. In a typical program agreement between the utility and consumer-member, the consumer-member agrees to the utility controlling the technologies for either planned load control events or whenever the utility has the need for load control (e.g. such as after a severe storm). Many utilities leverage a third-party whitelabeled app to send a push notification to consumer-members informing them that the load control event will happen automatically at a specific date and time.

Some BTM DER technologies make the consumer-member's home more resilient during complete grid outages or emergencies. Fossil fuel generators and fully charged BESS can form a temporary microgrid that provides enough power to the home during a grid outage, emergency, or a pre-planned utility load control event. This provides the home with an alternative power source separate from the grid that potentially lowers costs for the utility while increasing resilience and peace of mind for consumer-members, especially in rural and remote areas that often experience long term grid outages sometimes lasting for days or weeks at a time. Rural and remote areas often have additional complexities during outages, such as being farther away from food and support services where one big storm can bring snow or trees down and block the only road in and out. They may also experience delays in restoring power because of difficulty accessing remote or blocked areas. Programs involving microgridded resources might exist as a standalone program (e.g. a backup fossil fuel generator program) or they might exist as additional “opt-in” enhancements to existing energy saver programs that operate more regularly, depending on what the distribution utility offers. Creating a microgrid environment also respects the legal, operational, financial, and safety considerations currently delineated between the utility and the consumer-member at the meter. Bi-directional power flow across this boundary (i.e. power flowing from the grid to the residential meter and vice versa) is still an active area of research that can provide an avenue for sharing excess power generation from BTM DER back to the distribution power grid to serve neighboring homes or other interconnections [14, 15, 16]. Member loyalty with the broader cooperative area could increase if neighbors feel enabled by their BTM DER technologies to give back to and sustain their community.

Starting and maintaining a BTM DER program can often require more cooperative staff, resources, or outsourcing support from third parties. Cooperatives can lean on their relationships with consumer-members and the broader community and invite them to share some of those responsibilities. Providing as many options as possible to consumer-members can lead to program success, which can include allowing consumer-members to bring their own device or allowing them to choose their preferred vendors (e.g. electricians, contractors). In rural communities, households often have pre-existing, trusted

relationships with contractors and service workers. Cooperatives can strengthen ties with the community by leveraging these relationships and supporting consumer-members' sense of ownership and responsibility for the devices they own and maintain. Sharing responsibilities in the BTM DER program where feasible can lead to a greater sense of member loyalty, involvement, and satisfaction.

5. Deployment Considerations as Engagement

BTM DER programs provide opportunities for utilities to engage with consumer-members through the deployment of different DER, supporting software, and communication infrastructure. Some utilities use a third-party DER management system (DERMS) for controlling and dispatching DER, while others directly manage their program in-house. Managing DER requires signals to be transmitted to and from the devices, usually in the form of Wi-Fi, cellular, or radio-based communications. In addition to communicating directly with the DER devices, the utility will often use another communication method to notify consumer-members when their devices will be controlled. Some utilities prioritize controlling DER that have the least impact on consumer-member comfort first, such as water heaters. Regular load control events can also provide opportunities to improve resilience since the utility can regularly monitor the BTM DER devices and notify consumer-members when devices malfunction or need repair. This can catch and fix problems early before an emergency or outage occurs.

Some G&T cooperatives have developed DERMS to help distribution cooperatives manage and dispatch BTM DER in their service areas. Understanding how these platforms work and how they can serve individual utility BTM DER programs can support a smooth transition and deployment for both the utility and participating consumer-members. A recent report [17] led by NRECA and the DER Operational Alignment Working Team subgroup of the G&T DER Subcommittee provides a standardized view of 15 different DERMS vendors and their capabilities with a focus on multitenancy, interoperability, and integration with systems like Advanced Metering Infrastructure (AMI), Supervisory Control and Data Acquisition (SCADA), and Advanced Distribution Monitoring System (ADMS). This resource can help a utility decide if a DERMS platform would be useful for their program and help narrow down DERMS vendors in their decision.

Many different communication networks that can support control for DER devices rely on Wi-Fi, cellular, or radio-based systems⁴. Each type of communication method requires the utility to interface with the consumer-member in different ways. For controllable loads that rely on Wi-Fi communication, dependence on the consumer-member's home Wi-Fi setup makes the consumer-member responsible for maintaining the device's network connection. Industry partners, cooperatives, and pilot studies have all reported issues connecting with and maintaining connection to Wi-Fi enabled devices. This has led to delays in deploying BTM DER programs and the requirement of extra support resources from the utility to triage connectivity issues. Persistent issues with Wi-Fi connectivity can also cause members to become discouraged from participating in a program. These issues have led to increasing disinterest among rural electric cooperatives and other utilities when it comes to choosing Wi-Fi enabled devices for demand response programs. Utilities like Agralite Electric Cooperative and Duke Energy have found more success with BTM DER programs using either radio or cellular AMI networks that eliminate the need for Wi-Fi dependent communications. Utilities interested in Wi-Fi based communications may

⁴ Agralite Electric Cooperative upgraded their Landis+Gyr metering system to a radio frequency mesh AMI system. Landis+Gyr helped survey the land to determine where would be best to place the 6 collectors and 257 routers in their mesh setup, all working in concert with consumer-member meters. Agralite Electric Cooperative deployed the equipment and continues to maintain the radio mesh infrastructure.

want to plan to offer additional support to consumer-members in the event they have trouble connecting their DER to Wi-Fi. Cellular and radio-based communications, on the other hand, may provide more responsive and reliable communications than Wi-Fi connections, assuming there is sufficient infrastructure (e.g. cell towers, radio mesh equipment, etc.) present. The geographic location of the utility service area also becomes important for these kinds of systems. More mountainous regions might require the utility to deploy additional radio signal repeaters to transmit signals over the mountains, and these may need to be installed on member-owned land, depending on the terrain and property bounds.

In addition to communicating directly with DER devices, communicating directly with consumer-members can support program success and help maintain transparent and trusted relationships. Most electric cooperatives and utilities already have a preferred method of communication with consumer-members that could be adapted to send notifications to control BTM DER, such as a member-facing app. Some utilities use SmartHub, a mobile and web application provided by the National Information Solutions Cooperative (NISC) [18], where consumer-members pay their bills and view their energy usage. SmartHub also supports the ability for utilities to message consumer-members about upcoming utility load control events. If utilities already utilize a communication service like SmartHub then consumer-members may experience an easier transition to a load control program with a program interface they are familiar with already.

If a utility has direct control to deploy each kind of BTM DER device separately, it may be useful to consider which devices to prioritize during a load control event. Some utilities might control water heaters first, since it tends to be the least impactful technology to consumer-member comfort and most consumer-members do not notice when it turns on/off. Space heating and cooling technologies, however, can have more of an impact on demand yet can also have a greater effect on consumer-member comfort.

5.1. Technology Example: Water Heater Controllers

Storage (tanked) water heaters are the most common type in the U.S. [19] and provide a natural opportunity for thermal energy storage since water has a high heat capacity and can hold heat for a long time, depending on tank size and insulation level. Water heaters are also the third highest energy users in the home after space heating and air conditioning [20], which has motivated some cooperatives to consider programs targeting water heaters to prepare hot water only when it has historically been needed (see Program Design Highlight: Agralite Electric Cooperative). The two common power sources for water heaters are natural gas and electric, with growing programs to incentivize replacing old gas-fueled water heaters with fully electric ones.

Most demand response programs for water heaters specifically target fully electric, rather than gas-fueled, electric-ignition ones as these are typically simpler and safer to control. With electric water heaters, there are no combustion or gas emissions in the home to be concerned about. Demand response programs might even encourage participants to upgrade their old gas-fueled water heater with an electric

one or one equipped with digital communication and load control capabilities. A pilot study⁵ conducted by Illume Advising, LLC [21] found that water heater demand response programs that include full equipment replacement showed measurable program success and customer satisfaction. The study also shared concerns with Wi-Fi connectivity and the steep cost of a full replacement.

Some electric water heaters have built-in Wi-Fi capabilities [22] that allow consumer-members or utilities to control them remotely while other electric water heaters may need to be retrofitted with a controller device to enable load control. Load controller devices usually communicate via Wi-Fi⁶ signal, radio signal, and cellular signal, while others operate mechanically. Some utilities use a mechanical time switch for their load control water heating program [23] which can cost around \$140 retail [24]. These devices require manually inserting metal pins to define the switch-on and switch-off times throughout the day. This generally works well for predictable load control schedules, but if the utility expects the control windows to change at any point during the life of the program, the device may need to be manually reconfigured. This controller eliminates the need to rely on Wi-Fi or other remote signals for load control, but adds responsibility to the consumer-member or utility to manually monitor and adjust the device. In any case, this device would introduce an additional touchpoint with the consumer-member if used in a load control program.

⁵ The study tested several factors in a southeastern U.S. utility's demand response program for 100 participants (70 heat pump water heaters and 30 electric resistance water heaters).

⁶ Wi-Fi enabled water heater controllers (e.g. manufactured by companies like Aquanta, Shifted Energy, and TrickleStar, etc.) can typically cost around \$150 retail.

Program Design Highlight: Agralite Electric Cooperative

Agralite Electric Cooperative (AEC) is a great example of a cooperative with a suite of successful BTM DER programs involving multiple technologies. A few of these programs are highlighted here, including a load control program for home propane-fueled generators, a peak shaving and an energy storage program for water heaters, and a dual fuel heating load control program. AEC serves about 3,665 members in rural West Central Minnesota, where temperatures can drop to -30°F in the winter. Their cold climate presents unique challenges and opportunities for deploying BTM DER in their area.

AEC recently integrated their own Advanced Metering Infrastructure (AMI) [25], providing an automatic two-way communication network that allows AEC to measure, collect, and analyze energy usage data from electric meters. The cost and the method of communication were big factors in AEC's decision to upgrade to a radio mesh AMI system. Cellular and Wi-Fi based AMI systems would not have been able to reach all of Agralite's service area in the undulating and varied altitudes of West Central Minnesota's terrain. A radio frequency mesh system could traverse drops in the terrain by having more routers (signal repeaters). This setup provides them with wide area coverage and direct load control over enrolled water heaters, propane generators, irrigation systems, and dual fuel heating/AC units. Competitors of Landis+Gyr offered similar radio mesh systems, but these would have required every household meter to send a signal directly to a router, whereas the Landis+Gyr system allows a household meter's signal to pass through multiple meters before encountering a router and then a collector. This increased the resilience of Agralite's communications system through meshed networking while also avoiding the need for more routers. All BTM DER technologies enrolled in a load control program with AEC are connected to a separate submeter that is connected to the main meter at that location [26].

To communicate with consumer-members, AEC uses the NISC platform SmartHub [18], which consumer-members use to pay their bills, view their energy usage, and receive load control notifications. The process by which consumer-members create a SmartHub account and elect to receive load control notifications is seamless and easy for consumer-members to navigate.

AEC is billed by their generation and transmission provider for coincident peaks, or the highest amount of electricity consumption on the distribution power grid, which tend to happen sometime between 11am–10pm for their service area. Their load control events comprise a daily 4-hour window chosen by AEC to capture the time when the coincident peak is predicted to occur. Jonathan Messner, the Member Services Manager at Agralite Electric Cooperative, mentioned that in the last three years the weather has become more variable which makes prediction of peak times more challenging than it was in the past. The hardest days to predict are hot weather Sundays and holidays.

Fossil-Fuel Generator Program

One of the BTM DER programs offered by AEC supports propane-fueled generators [27]. The program started in 2018 when Messner performed a pilot study in his own home. When transitioning from the pilot phase to the full program offering, AEC anticipated needing more staff and resources for program startup. As the program grew and required more staff capacity, they outsourced to third parties within their service area, but only temporarily since one of their goals was to start the program and not be tied to it too much. Taking lessons learned about connecting the generator to the grid via an automatic transfer switch and operating the generators in a very cold climate, AEC has been able to offer it as a program for their members. After purchasing a generator, members can elect to enroll their generator in the Interruptible Generator Program to allow AEC to control their generator during 2–4-hour windows per load control event which happens a few times a month.

An automatic transfer switch is installed with the generators that seamlessly transitions the home's electric load between the grid and the generator. The goal, Messner said, is for any load control event to go smoothly; if the member notices the load control events happening then something isn't set up correctly. He noted that in 2023 there were about 150 units owned by members, averaging roughly \$144,000 in annual savings for AEC and between \$500-\$1200 in annual savings for members. Just three years later, the program doubled in size to around 300 units. When asked how members found out about the program, Messner said while AEC does provide some advertising in the form of bill stuffers and on-bill announcements, the primary way is by word of mouth – as is often the case for consumer-facing programs. Messner mentioned it is apparent when neighbors talk to each other about the generator program because clusters of neighbors start to get generators through the program soon after one neighbor joins. Approximately two-thirds of members who own generators elected to enroll in the load control portion of the program, which is the typical adoption percentage AEC has observed for most of their load control programs.

In addition to the financial incentives, AEC provides to consumer-members other benefits for enrolling in their Interruptible Generator Program. When members purchase a generator through AEC, all of the necessary equipment, delivery, and initial installation are provided by the cooperative. AEC works with Briggs and Stratton, a generator supplier, who offer a 7-year warranty program. The member is responsible for the first 96 hours of fuel after which AEC will reimburse load control participants for fuel (not including outages). Members are also responsible for contracting with electricians and certified propane technicians to get the generator running properly, as well as for establishing regular maintenance of their generators including regular oil changes. Messner approached a local engine shop who agreed to offer discounts on oil changes, which he says costs about \$200/year for members. AEC is happy to offer this service partnership as another way to make it easy for members to participate in the Interruptible Generator Program. They let consumer-members work with their preferred vendors (e.g. electricians, contractors) because homeowners may have their own trusted people to do work on their property.

Enrolled members are eligible to receive a \$500 rebate and qualify for special discounted electricity rates [27]. AEC determined their \$500 rebate for enrolling a generator in their load control program based on calculated savings that the generators would provide, with the goal of recouping costs within the first year of the program. After the first year, when all costs are paid off, the generator program will continue to provide direct savings for both the cooperative and program participants.

In addition to financial savings, the generator program has made Western Minnesota farmer and AEC member, Martin Thielke, more resilient to “terrible whiteouts in the winter, [where] nobody can get to you for days,” [28]. These kinds of occurrences are fairly common in rural and remote areas that experience heavy snow and extreme winter weather. Messner added that the load control program is also a way to monitor and detect when generators aren’t working, whether due to electrical faults, cold weather, or other reasons, so they have the opportunity to notify the member for proactive repair and prepare for future emergencies.

Electric Water Heater Programs

AEC provides two kinds of programs in which consumer-members can enroll their electric water heaters: a Peak Shave program and an Energy Storage program. Members who upgrade their gas-fueled water heaters to an electric water heater AND enroll in one of the load control programs qualify for a \$300 rebate, while members who choose not to participate in load control programs will only qualify for 50% of that rebate [29].

Peak Shave program: The Peak Shave program has about 2,000 electric water heaters enrolled for potential load control events. Water heaters are able to heat at any time outside of the load control event time window. AEC notifies the member when the event is going to happen and they control (turn off) the water heater either early in the morning or late in the evening for no more than 4 hours at a time per event.

Energy Storage program: The Energy Storage program heats the water heater overnight from 10pm-7am, providing enough stored hot water (e.g. 100-gallon tanks stored at 125°F supporting 1-2 people) for use throughout the day. This is not a load control program like the Electric Water Heater Peak Shave Program, but it provides daily savings for both the members and AEC by shifting heating to times when electricity prices are low (typically at night, when most members are usually asleep). Households with families or more than two occupants might find that the Peak Shave program is a better fit in terms of having enough hot water for everyone while benefitting from the savings from the load control portion of the program.

Dual Fuel Heating Program

Dual fuel heating uses electricity (i.e. via electric resistance heating or baseboard heating) in addition to a second type of fuel source to heat the home. During times of high electricity demand or very cold outdoor air temperatures (dropping below 0°F) the heater can switch to using alternative fuels

(e.g. propane) instead of electricity. AEC operates their dual fuel load control program [30] for about 1200 members using an installed Landis+Gyr load control switch that works in conjunction with their AMI.

Final Remarks

Both Agralite Electric Cooperative and their members benefit from having various load control and energy saver programs. They provide additional opportunities to engage with members, save money on electricity bills, and increase resilience to grid outages. Messner recommends starting small, keeping an open mind, and being unafraid because you have to start somewhere to get somewhere.

6. Conclusions

Supporting meaningful engagement and strengthening resilience go hand-in-hand and can naturally reinforce each other when driven by intentional project design and deployment. In this report, we first discussed the basics of engagement through consumer-member communication, followed by the connected lenses of program design and deployment considerations. This framing reflects the idea that successful resilience projects depend on what data, metrics, and technology are selected, as well as how those factors are organized and communicated about to create visible and meaningful benefits to consumer-members.

The discussion began by establishing the baseline importance of communication for engagement. Generally, consumer-members want to stay informed without being overwhelmed during outages so that they can plan accordingly, and they want to feel that their experiences and feedback meaningfully contribute to co-op decisions. Outside of outage events, clear communication and acknowledgement generally continue to benefit consumer-members. Fostering a sense of loyalty in consumer-members through sustained communication and visible program benefits can prime future resilience initiatives for greater adoption rates and long-term support.

Following broad communication advice, program design can play an important role in engagement. Effective engagement often begins before program rollout through decisions around how benefits are created, measured, and communicated. Programs that provide visible net benefits can become easier to explain and be more likely to self-sustain participation via word-of-mouth. When benefits are visible, outreach efforts such as kickoff events can further support engagement by communicating to consumer-members the ways that their programs are designed to connect to local priorities and outcomes.

Effective program design can be driven by thoughtful metric and data selection alongside a good understanding of local needs and priorities. In the process of selecting metrics that align with local priorities, co-ops generally identify which needs are most important to address and shape programs around those goals from the start. Local priorities are also important when taking any spatio-temporal data into consideration. Because public datasets may not always reflect conditions at the level of detail needed for local decision-making, a co-op's own collected data can provide ground truth and be supplemented with public information where appropriate (instead of the other way around). Just as different data sources may need to be used in concert, individual metrics can also provide more specific and useful information when paired together, helping to identify where program adoption and equipment upgrades can yield the greatest benefit while remaining resource efficient.

Many utilities provide engagement through BTM DER programs, most of which provide resilience through demand response. The structure of these programs introduces a set of design considerations that shape both participation and outcomes. Decisions about which technologies to include, how programs interact with existing tariff structures, and how local conditions such as geography, weather, and consumer-member household characteristics all influence the effectiveness of a program and therefore are considered in its design. Program design is also an opportunity to decide how much involvement and responsibility should be given to consumer-members in whether they are responsible for installation and whether they have direct control over DER.

While program design defines what a resilience initiative aims to achieve and how it is structured at a high level, deployment considerations determine how those designs are realized in practice and how they are experienced by consumer-members. Deployment of BTM DER technologies, supporting software, and communication infrastructure introduces operational complexity, but it also creates additional points of interaction that can shape engagement throughout the lifecycle of a program.

For managing BTM DERs, some utilities use a third-party DERMS while others manage their resources directly. These choices influence how those resources are dispatched and how visible the program's dispatch operations are to members. For example, utilities may choose to first dispatch those DER that have the least noticeable impact to members, which in many instances is the water heater fleet. Engagement-related decisions are also involved when selecting the communication infrastructure that will support the deployment. Wi-Fi, cellular, and radio connectivity each have their own tradeoffs in reliability, infrastructure requirements, and member support needs. Wi-Fi connected DERs may necessitate additional resources and support during installation and usage, while radio and cellular devices may provide more stable and secure communications but rely on sufficient support infrastructure in the area. In addition, consumer-facing platforms such as the NISC SmartHub application can serve as direct communication channels to consumer-members that can be used for notifications about load control events and program activity, which reinforces transparency, autonomy, and trust between utilities and consumer-members.

When considered together, these elements of program design and technology deployment can bolster the effectiveness of a DERMS resilience program and improve clarity of net benefits for consumer-members through the alignment of local- and co-op-specific priorities. When engagement, design, and deployment are treated as connected parts of the same system, programs can become low effort to provide and participate in, and can sustain themselves over time both financially and socially.

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Appendix A: Metrics Addressing Consumer-Members and Outages

Value of Lost Load (VoLL)

Value of Lost Load (VoLL) is a monetary metric where the survey-based economic technique contingent valuation is used to estimate the value to consumers of avoided power interruptions. One way to estimate that value is as the approximate price that consumers are willing to pay to avoid power interruptions, often defined in \$/kWh. VoLL is a static value typically applied to reliability events that does not vary with outage duration or magnitude. According to the source below in which VoLL was featured, its value typically ranges from 1-300 \$/kWh and analysis of “VoLL for outages lasting longer than 12 [hours] is limited, and existing methods (e.g., customer surveys) do not capture the indirect spillover effects to the greater economy that are associated with longer-duration outages.”

Cite Sources

Adopted from:

- This is a widely used monetary metric

Featured in:

- [Integrating the Value of Electricity Resilience in Energy Planning and Operations Decisions](#) by Kate Anderson, Xiangkun Li, Sourabh Dalvi, Sean Ericson, Clayton Barrows, *Member, IEEE*, Caitlin Murphy, and Eliza Hotchkiss

Drawbacks & Benefits

Drawbacks:

- Difficult to obtain input data
- Static value that doesn't represent the impact of dynamic conditions over extended periods of time
- Unfit for real-time analysis due to its reliance on survey data collection
- More investigation needed to determine comparability across different systems and scenarios as a measure of resilience since it is very dependent on economic circumstances as well as outage impacts

Benefits:

- Known industry usage
- Centers impacts on community members

Use Cases and Assumptions

Use Cases:

- A metric is needed to quantify direct short-term economic value of maintaining a load through an outage-causing event, for the purposes of financial and electrical resilience planning

Assumptions:

- The information collected can accurately represent value of lost load across the selected timeframe

Requirements (inputs, compute resources/time)

Inputs:

- Various different survey inputs based on estimation technique

Computing:

- Varying based on survey approach and estimation techniques

Discussion

While VoLL is a commonly used economic tool, it is less useful as a metric of power system resilience due to the time it takes to collect input data and its heavy dependence on economic and social factors outside the scope of the power system.

Customer Damage Functions (CDF)

Customer Damage Functions (CDFs) extend the [VoLL](#) by representing interruption costs dynamically as a function in \$/kW, the output of which changes with outage duration, season, time of day, and notice of outage. They characterize lost load based on: fixed costs which are independent of outage duration; flow/incremental costs which are a function of outage duration; and stock/spoilage costs which result from damage to or spoilage of perishable stock. By accounting for these different cost types and a broader range of contextual variables, CDFs can represent the changing nature of customer damages over the course of an outage, unlike [VoLL](#).

During an outage-causing event, grid operators could theoretically use existing CDFs for different types of customers to strategically allocate limited resources based on expected customer damages, as demonstrated in a case study in the source which expands upon CDFs.

While potentially useful as decision-making tools during outage events, CDFs are predictive tools for cost estimation, not metrics quantifying what has happened or is happening at a given point in the past or present. CDFs are included in this document for completeness because of their close ties to [VoLL](#).

[CDF Calculator from NLR](#)

Cite Sources

Adopted from:

- This is a widely used monetary planning tool

Expanded Upon in:

- [Integrating the Value of Electricity Resilience in Energy Planning and Operations Decisions](#) by Kate Anderson, Xiangkun Li, Sourabh Dalvi, Sean Ericson, Clayton Barrows, *Member, IEEE*, Caitlin Murphy, and Eliza Hotchkiss

Drawbacks & Benefits

Drawbacks:

- Difficult to obtain input data
- Unfit as a resiliency metric since CDFs are predictive tools for decision making but do not quantify what is happening or has happened at a given moment

Benefits:

- Extends [VoLL](#) by representing the impact of dynamic conditions over extended periods of time
- Known industry usage
- Centers impact on community members

Use Cases and Assumptions

Use Cases:

- A tool is needed to quantify dynamic costs resulting from an outage for the purposes of resource allocation during an outage event and resilience planning before an event

Assumptions:

- The relationship between the input variables and outage cost are accurately represented in a given CDF

Requirements (inputs, compute resources/time)

Inputs:

- Outage duration
- Season
- Time of day
- Notice of outage
- Fixed costs (e.g. damaged equipment, lost data, restart costs, process interruption costs, etc.)
- Flow/incremental costs (e.g. backup fuel, rental equipment, lost customer sales, interrupted production, loss of staff productivity, etc.)
- Stock/spoilage costs (e.g. perishable food, missed deadlines, other temperature-controlled products like medication and vaccines, etc.)

Computing:

- Variable based on the CDF used

Discussion

As noted in the description of CDFs above, they are predictive tools for cost estimation, not metrics that quantify a value in the past or present. Their inclusion in this document is for the sake of completeness with respect to extending the [VoLL](#) and because they have the potential to be useful tools during an outage event, despite their inability to function as resiliency metrics.

Population Affected

This metric measures resilience as the number of people affected by an outage, rather than the number of loads

Cite Sources

Adopted from:

- [High-Impact, Low-Frequency Event Risk to the North American Bulk Power System](#), from a Jointly-Commissioned Summary Report of the North American Electric Reliability Corporation and the U.S. Department of Energy's November 2009 Workshop

Featured in:

- [Power Systems Resilience Metrics: A Comprehensive Review of Challenges and Outlook](#) by Habibollah Raoufi, Vahid Vahidinasab, and Kamyar Mehran

Drawbacks & Benefits

Drawbacks:

- Harder to compare across different systems as a measure of resilience since it is an absolute quantity, not a proportion relative to size or cost of the system
- More abstract and harder to quantify - what qualifies someone as "affected"?
- Data is reliant on where people are at a given moment.
- Does not account for severity

Benefits:

- No calculation required
- Useful as a measure of absolute involvement which can be compiled with similar data from surrounding areas to gain insights about the scale of affect across multiple communities
- Could be normalized between 0 and 1 to enable comparison across systems as a measure of resilience by dividing the metric by the total number of people in the population regardless of whether or not they were affected.

Use Cases and Assumptions

Use Cases:

- A basic metric that focuses on scale of affect is needed for resiliency analysis after an outage-causing event. This metric can be compared somewhat well to earlier values corresponding to the same system as a way to measure improvements in resilience between similar outage events, but may not be as useful for comparing different power systems

Assumptions:

- There is a clear way to determine who has been "affected" by an outage. (In practice, criteria would need to be established).
- For comparisons, the severity and nature of compared outage events are similar

Requirements (inputs, compute resources/time)

Inputs:

- Number of people affected by an outage

Computing:

- No computation

Discussion

This metric focuses more on the human impact of outages as a way to measure the resiliency of the power system, since the system is ultimately designed to serve people. That being said, it is limited as a measure of resilience since it is not normalized for the size of the total population in question and thus does not convey a sense of the proportion of people affected.

Geographic Area Affected

This metric measures resilience as the area in square miles of a region with no electricity at a given time.

Cite Sources

Adopted from:

- [High-Impact, Low-Frequency Event Risk to the North American Bulk Power System](#), from a Jointly-Commissioned Summary Report of the North American Electric Reliability Corporation and the U.S. Department of Energy's November 2009 Workshop

Featured in:

- [Power Systems Resilience Metrics: A Comprehensive Review of Challenges and Outlook](#) by Habibollah Raoufi, Vahid Vahidinasab, and Kamyar Mehran

Drawbacks & Benefits

Drawbacks:

- Does not prioritize criticality of areas affected
- Harder to compare across different systems as a measure of resilience since it is an absolute quantity, not a proportion relative to size or cost of the system
- Harder to classify regions with some electricity as a result of backup power sources
 - Makes drawing the borders of an area more complicated

Benefits:

- No calculation Required
- Easy to obtain input data
- Instantaneous - can be used during an event and compared at different points across the event to gauge changes
- Could be normalized between 0 and 1 to enable comparison across systems as a measure of resilience by dividing the metric by the total geographic area under consideration
- Could be specified for zones of interest by only considering the area affected inside those zones of interest. To compare across different zones of interest with different areas, normalize geographic area affected in a zone by the total area of the zone (as above) and compare percentages of area affected.

Use Cases and Assumptions

Use Cases:

- A basic metric is needed to assess the geographic spread of damage from an outage event at a particular time. This metric can be compared somewhat well to earlier values corresponding to the same system as a way to measure improvements in resilience between similar outage events, but may not be as useful for comparing different power systems

Assumptions:

- Clear boundaries can be drawn to define areas that have maintained or lost power
- For comparisons, the severity, nature, and area of effect of compared outage events are similar

Requirements (inputs, compute resources/time)

Inputs:

- The area in square miles of a region with no electricity at a given time

Computing:

- No computation

Discussion

A large geographic area affected at a particular time could make it more difficult for an affected area to receive aid from nearby communities. Geographic area affected could be useful in conjunction with other metrics to inform resource allocation decisions for restoration.

Another factor to consider in implementing this metric is how to classify the geographic area representing a particular load maintained or lost. If someone owns 40 acres of land with a home on it, does power to that home represent 40 acres powered? How does that change if they have irrigation systems and extension cords throughout the land versus having electricity mainly used only in the home?

Time to Restore Maximum Power

This metric refers to the amount of time it takes to restore a system to maximum power starting from a particular point in time. Three possible interpretations of the point in time from which to measure are:

- The time of onset of an outage-causing event
- The time at which restoration efforts begin
- The time at which the power system is at minimum functionality across the outage event

Cite Sources

Adopted from:

- An interview with Craig Miller, as recounted in the article [Co-op Tech: The Resilience Reports](#) by Derrill Holly

Drawbacks & Benefits

Drawbacks:

- If there is extremely expensive infrastructure damage for which the repair cannot be paid, there may be a new “maximum power” that is not well accounted for by this metric
- Unfit for real-time analysis because it is based on event durations, which are unknown until after they have ended
- Requires an analyst to define what time events begin and end
- Does not prioritize power restoration to critical loads
- Harder to compare across different systems as a measure of resilience since it is an absolute quantity, not a proportion relative to size or cost of the system

Benefits:

- Aligns with resiliency goals discussed in 2016 by the National Academies of Science, Engineering, and Medicine
- No calculation required
- Easy to obtain input data
- Could be scaled by dividing by size or cost of the system to enable better comparison across systems
- Could be specified to critical loads by only tracking the time to restore maximum power to those loads

Use Cases and Assumptions

Use Cases:

- A basic metric is needed for resiliency analysis after an outage-causing event. This metric can be compared somewhat well to earlier values corresponding to the same system as a way to measure improvements in resilience between similar outage events, but may not be as useful for comparing different power systems

Assumptions:

- Resilience can be described overall for a system by one value looking back at an event, rather than as something that may change during an event
- For comparisons, the severity and nature of compared outage events are similar

Requirements (inputs, compute resources/time)

Inputs:

- The time to restore a system to maximum power
- OR the appropriate start time and the end time when maximum power is restored

Computing:

- No computation
- OR the single operation: (end time - start time)
 - $O(1)$

Discussion

While not incredibly robust, the understandability and attainability of this metric could be useful for providing additional context when looking back on an outage restoration

Time Onset of Failure is Delayed

This metric refers to the amount of time between the beginning of an outage-causing event and the onset of failure. Three possible interpretations of the onset of failure are:

- The time at which pieces of power system infrastructure begin to fail
- The time at which the power system is at minimum functionality across the outage event
- The time at which the power system reaches a chosen threshold of diminished functionality

Cite Sources

Adopted from:

- An interview with Craig Miller, as recounted in the article [Co-op Tech: The Resilience Reports](#) by Derrill Holly

Drawbacks & Benefits

Drawbacks:

- Unfit for real-time analysis because it is based on event durations, which are unknown until after they have ended
- Requires an analyst to define what time events begin and end
- Does not prioritize power failure to critical loads
- Harder to compare across different systems since it is an absolute quantity, not a proportion relative to size or cost of the system

Benefits:

- Aligns with resiliency goals discussed in 2016 by the National Academies of Science, Engineering, and Medicine
- No calculation required
- Straightforward to understand and communicate
- Easy to obtain input data
- Could be scaled by dividing by size or cost of the system to enable better comparison across systems
- Could be specified to critical loads by only tracking the time to onset of failure to those loads

Use Cases and Assumptions

Use Cases:

- A simple, understandable metric is needed for resiliency analysis after an outage-causing event. This metric can be compared somewhat well to earlier values corresponding to the same system as a way to measure improvements in resilience between similar outage events, but may not be as useful for comparing different power systems

Assumptions:

- Resilience can be described overall for a system by one value looking back at an event, rather than as something that may change during an event
- For comparisons, the severity and nature of compared outage events are similar

Requirements (inputs, compute resources/time)

Inputs:

- The time it takes for power system failure during an outage-causing event
- OR the event start time and the end time when failure occurs

Computing:

- No computation
- OR the single operation: (end time - start time)
 - $O(1)$

Discussion

While not incredibly robust, the understandability and attainability of this metric could be useful for providing additional context when looking back on system resistance to an outage

Time Needed to Assess a Situation and Deploy a Crew With Necessary Access

This metric refers to the amount of time it takes, starting from a particular point in time, to assess a situation and deploy a restoration crew with law enforcement knowing to allow the crew access to disaster sites. Three possible interpretations of the point in time from which to measure are:

- The onset of an outage-causing event
- The time at which pieces of power system infrastructure begin to fail
- The time at which the power system is at a minimum functionality across the outage event

This metric could be measured for a system stopping at the first qualifying deployment, or it could be measured individually for each crew deployment.

Cite Sources

Adopted from:

- An interview with Craig Miller, as recounted in the article [Co-op Tech: The Resilience Reports](#) by Derrill Holly

Drawbacks & Benefits

Drawbacks:

- Unfit for real-time analysis because it is based on event durations, which are unknown until after they have ended
- Requires an analyst to define what time events begin and end
- Does not prioritize crew deployment to critical sites (an important site for deployment may be more logistically complicated and take more time, so a longer time to deploy a crew to an important site would be penalized by this metric over a choice to deploy a crew to a more accessible but lower priority site)
- Harder to compare across different systems since it is an absolute quantity, not a proportion relative to size or cost of the system

Benefits:

- Aligns with resiliency goals discussed in 2016 by the National Academies of Science, Engineering, and Medicine
- No calculation required
- Straightforward to understand and communicate
- Easy to obtain input data
- Could be scaled by dividing by size or cost of the system to enable better comparison across systems
- Could be prioritized for crew deployment to critical sites by dividing deployment time by weights based on site criticality. The time to deploy to a more critical site would be divided by a larger weight and might be lower (better) than the time/criticality of a less critical site to which crew could be deployed faster.

Use Cases and Assumptions

Use Cases:

- A simple, understandable metric is needed for resiliency analysis after an outage-causing event. This metric can be compared somewhat well to earlier values corresponding to the same system as a way to measure improvements in response between similar outage events, but may not be as useful for comparing different power systems

Assumptions:

- Resilience can be described overall for a system by one value looking back at an event, rather than as something that may change during an event
- For comparisons between events, the severity and nature of compared outage events are similar
- For comparisons between deployments during a single event, the severity of the event was similar at each deployment site

Requirements (inputs, compute resources/time)

Inputs:

- The time it takes to assess a situation and deploy a restoration crew with law enforcement knowing to allow the crew access to disaster sites
- OR the appropriate start time and the end time when a crew is deployed with necessary access

Computing:

- No computation
- OR the single operation: (end time - start time)
 - $O(1)$

Discussion

While not incredibly robust, the understandability and attainability of this metric could be useful for providing additional context when looking back on outage restoration and coordination of efforts

System Availability

This metric measures resilience as the mean uptime of customers' loads out of the total time resilience is evaluated.

$$R_B = \frac{\sum_{i=1}^N T_{U,i}}{\sum_{i=1}^N T_{U,i} + T_{D,i}}$$

- Base Resiliency for N loads:

- Alternate Format:

$$R_B = \frac{\sum_{i=1}^N T_{U,i}}{NT} = \frac{\frac{1}{N} \sum_{i=1}^N T_{U,i}}{T}$$

- Individual Resiliency for a single load: $R_I = \frac{T_U}{T} = \frac{T_U}{T_U + T_D}$
- $T_{U,i}$ & $T_{D,i}$ are uptime and downtime of the i^{th} customer
- N is the total number of customers under consideration

Cite Sources

Adopted from:

- [Quantitative Model and Metrics of Electrical Grids' Resilience Evaluated at a Power Distribution Level](#) by Alexis Kwasinski

Expanded Upon in:

- [Power System Resilience Metrics Augmentation for Critical Load Prioritization](#), a technical report from PNNL by Vishvas Chalishazar, Shiva Poudel, Sarmad Hanif, and Priya Thekkumparambath Mana

Featured in:

- [Power System Resilience Explained](#), an informational training video by the power management company Eaton for the Electrical Utility companies that it serves

Drawbacks & Benefits

Drawbacks:

- Unfit for real-time analysis because it is based on event durations, which are unknown until after they have ended
- Requires an analyst to define at what times each event begins and ends
- Does not prioritize critical loads (i.e. a hospital load is weighted the same as a car dealership load)

Benefits:

- Some known industry use
- Simple to calculate
- Straightforward to understand and communicate
- Easy to obtain input data
- Comparable across events with normalized output between 0 and 1
- Could be specified for critical loads by only considering the uptime and downtime of those critical loads
- Could be modified to prioritize critical loads, as seen with [System Availability Augmented for Critical Load Prioritization](#)

Use Cases and Assumptions

Use Cases:

- A simple, understandable metric is needed for resiliency analysis after an outage-causing event

Assumptions:

- Resilience can be described overall for a system by one value looking back at an event, rather than as something that may change during an event

Requirements (inputs, compute resources/time)

Inputs:

- Uptime and downtime for each load under consideration
- Number of loads under consideration

Computing:

- Can be computed quickly with few computing resources
 - $O(N)$

Discussion

While not much data could be found to reflect what metrics are used in industry, the power management company Eaton did present this metric in a training video for electric utilities called “Power System Resilience Explained”. Most notably, they presented it as the way that resilience is calculated, rather than one of many possible ways.

System Availability Augmented for Critical Load Prioritization

This metric measures resilience as the average of System Availability values for different groupings of customers, weighted based on load criticality.

- Augmented Base Resiliency for N loads sorted into a set of C customer types: $R_B^{aug} = \sum_{c \in C} w_c \frac{\sum_{i=1}^{N_c} T_{U,i}}{\sum_{i=1}^{N_c} (T_{U,i} + T_{D,i})} = \sum_{c \in C} w_c \frac{\sum_{i=1}^{N_c} T_{U,i}}{N_c T}$
- $T_{U,i}$ & $T_{D,i}$ are uptime and downtime of the i^{th} customer
- T is the total duration under consideration
- N_c is the total number of customers in a given customer type, with $\sum_{c \in C} N_c = N$
- C is the set of customer types within a feeder that represents all customers within a community i.e., $C = \{ 'Hospitals', 'Fire Stations', 'Malls', 'Residential Buildings', etc. \}$
- w_c is the weight of a customer type $c \in C$, with $\sum_{c \in C} w_c = 1$ to keep the resilience metric value in the range of 0 and 1 (i.e., $R_B^{aug} \in (0,1]$)

Cite Sources

Adopted from:

- [Power System Resilience Metrics Augmentation for Critical Load Prioritization](#), a technical report from PNNL by Vishvas Chalishazar, Shiva Poudel, Sarmad Hanif, and Priya Thekkumparambath Mana

Drawbacks & Benefits

Drawbacks:

- This metric is essentially a weighted average of averages, which results in the size of each customer group affecting how heavily a single load within that group is weighted
 - Example: Consider an extreme scenario with 2 customer groups weighted equally and an event duration of 1 hour. Group 1 has 1 load that experienced 100% uptime. Group 2 has 100 loads that experienced 100% downtime. $R_B^{aug} = \sum_{c \in C} w_c \frac{\sum_{i=1}^{N_c} T_{U,i}}{N_c T} = \frac{1}{2} \frac{\sum_{i=1}^1 1}{(1)(1)} + \frac{1}{2} \frac{\sum_{i=1}^{100} 0}{(100)(1)} = \frac{1}{2}$
 - Here, the one load with power in group 1 is given 100x more importance than the 100 loads without power in group 2, despite the weights assigning them equal importance in terms of load criticality.
- Unfit for real-time analysis because it is based on event durations, which are unknown until after they have ended
- Requires an analyst to define at what times each event begins and ends

Benefits:

- Allows for critical load prioritization
- Simple to calculate
- Easy to obtain input data
- Comparable across events with normalized output between 0 and 1

Use Cases and Assumptions

Use Cases:

- A simple understandable metric that can reflect load priority is needed for resiliency analysis after an outage-causing event

Assumptions:

- Resilience can be described overall for a system by one value looking back at an event, rather than as something that may change during an event

Requirements (inputs, compute resources/time)

Inputs:

- Uptime and downtime for each load under consideration, grouped by category
- Weights corresponding to the criticality of loads in each category
- Number of loads in each category

Computing:

- Can be computed quickly with few computing resources
 - $O(NM)$, but similar runtime in practice to System Availability, which has the same number of loads and is $O(N)$. System Availability Augmented for Critical Load Prioritization divides those loads into M smaller groupings.

Discussion

Though there are problems with this metric identified in the drawbacks that result from the metric being a weighted average of averages, the concept of prioritizing System Availability for critical loads is useful and merits further exploration. Though group-size scaling problems arise in part from adding together System Availability values which are fractions with different denominators, it is possible that this metric was designed as it is because the authors only had System Availability values for different customer types, but did not have the raw data from which they were derived.

In further exploring the concept of augmenting System Availability to prioritize critical loads, we established desired properties and designed a metric which embodies them. These desired properties and metric are as follows:

1. Category sizes should not impact how much a load is valued. If all weights are equal, the metric should be equivalent to unweighted System Availability
2. The new metric should preserve the original output range of 0 to 1

$$R_B^{New} = \frac{\sum_{c \in C} w_c \sum_{i=1}^{N_c} T_{U,c,i}}{\sum_{c \in C} w_c N_c} \times \frac{1}{T} = \frac{\sum_{c \in C} \sum_{i=1}^{N_c} w_c T_{U,c,i}}{\sum_{c \in C} w_c N_c} \times \frac{1}{T}$$

- $T_{U,c,i}$ is the uptime of the i^{th} customer of customer type c
- T is the total event duration in consideration
- N_c is the total number of customers in a given customer type, with $\sum_{c \in C} N_c = N$
- C is the set of customer types within a feeder that represents all customers within a community i.e., $C = \{ 'Hospitals', 'Fire Stations', 'Malls', 'Residential Buildings', etc. \}$

- w_c is the weight of a customer type $c \in C$, the value of which is not restricted

This metric is derived as follows:

$$\text{Arithmetic Mean } \bar{x} = \frac{\sum_{i=1}^N x_i}{N}, \text{Weighted Arithmetic Mean } \bar{x}_{\text{weight}} = \frac{\sum_{i=1}^N a_i x_i}{\sum_{i=1}^N a_i}$$

$$\text{System Availability } R_B = \sum_{i=1}^N \frac{T_{U,i}}{NT} = \sum_{i=1}^N \frac{T_{U,i}/T}{N}, \text{ which is an arithmetic mean with } x_i = \frac{T_{U,i}}{T}$$

$$\text{Thus, an equivalent weighted arithmetic mean: } R_{B,\text{weighted}} = \frac{\sum_{i=1}^N a_i \frac{T_{U,i}}{T}}{\sum_{i=1}^N a_i} = \frac{\sum_{i=1}^N a_i T_{U,i}}{\sum_{i=1}^N a_i} \times \frac{1}{T}$$

let $a_i = w_c$ if $T_{U,i}$ belongs to a customer of customer type c . It follows that:

- $\sum_{i=1}^N a_i = \sum_{c \in C} \sum_{i=1}^{N_c} w_c = \sum_{c \in C} N_c w_c$
- $\sum_{i=1}^N a_i T_{U,i} = \sum_{c \in C} \sum_{i=1}^{N_c} w_c T_{U,c,i} = \sum_{c \in C} w_c \sum_{i=1}^{N_c} T_{U,c,i}$

$$\text{Thus } R_{B,\text{weighted}} = \frac{\sum_{i=1}^N a_i T_{U,i}}{\sum_{i=1}^N a_i} \times \frac{1}{T} = \frac{\sum_{c \in C} w_c \sum_{i=1}^{N_c} T_{U,c,i}}{\sum_{c \in C} N_c w_c} \times \frac{1}{T} = R_B^{\text{New}}$$

Proof of Property 1:

$$\begin{aligned} \forall w_c, \text{ let } w_c &= \text{some real number } \beta \\ R_B^{\text{New}} &= \frac{\sum_{c \in C} w_c \sum_{i=1}^{N_c} T_{U,c,i}}{\sum_{c \in C} N_c w_c} \times \frac{1}{T} = \frac{\sum_{c \in C} \beta \sum_{i=1}^{N_c} T_{U,c,i}}{T \sum_{c \in C} N_c \beta} = \frac{\beta \sum_{c \in C} \sum_{i=1}^{N_c} T_{U,c,i}}{\beta T \sum_{c \in C} N_c} \\ &= \frac{\sum_{c \in C} \sum_{i=1}^{N_c} T_{U,c,i}}{T \sum_{c \in C} N_c} = \frac{\sum_{i=1}^N T_{U,i}}{NT} = R_B \end{aligned}$$

Proof of Property 2:

Upper bound of R_B^{New} will exist when every load has uptime equal to "outage" duration (no outage)
 $T_{U,c,i} = T \forall c, i$ because T is the upper bound of $T_{U,c,i}$

$$\begin{aligned} R_B^{\text{New}} &= \frac{\sum_{c \in C} w_c \sum_{i=1}^{N_c} T_{U,c,i}}{\sum_{c \in C} N_c w_c} \times \frac{1}{T} = \frac{\sum_{c \in C} w_c \sum_{i=1}^{N_c} T \times \frac{1}{T}}{\sum_{c \in C} N_c w_c} = \frac{\sum_{c \in C} w_c \sum_{i=1}^{N_c} 1}{\sum_{c \in C} N_c w_c} \\ &= \frac{\sum_{c \in C} w_c N_c}{\sum_{c \in C} N_c w_c} = 1 \end{aligned}$$

Therefore the upper bound is = 1

Lower bound of R_B^{New} will exist when every load has an uptime of 0, i.e. $T_{U,c,i} = 0 \forall c, i$

$$R_B^{\text{New}} = \frac{\sum_{c \in C} w_c \sum_{i=1}^{N_c} 0}{\sum_{c \in C} N_c w_c} \times \frac{1}{T} = \frac{0}{\sum_{c \in C} N_c w_c} \times \frac{1}{T} = 0$$

Therefore the lower bound = 0

Thus the original output range of 0 to 1 is preserved.

Performance After Disaster

This metric measures resilience as the percentage of households/customers with power at a given time

- Performance at a given time t : $P_t = \frac{n_{p,t}}{N} = \frac{1}{N} \sum_{i=1}^N s_{i,t}$
- $n_{p,t}$ is the number of customers under consideration who have power at time t
- $s_{i,t} \in \{0,1\}$ is the status of each individual customer at a given time
- N is the total number of customers under consideration

Cite Sources

Adopted from:

- [Evaluating the Disaster Resilience of Power Networks and Grids](#) by Masanobu Shinozuka and Stephanie E. Chang

Referenced in:

- [Power Systems Resilience Metrics: A Comprehensive Review of Challenges and Outlook](#) by Habibollah Raoufi, Vahid Vahidinasab, and Kamyar Mehran

Drawbacks & Benefits

Drawbacks:

- Does not prioritize critical loads (i.e. a hospital load is weighted the same as a car dealership load)
- Does not capture information about restoration effectiveness for a whole event in a single value

Benefits:

- Instantaneous - can be used during an event and compared at different points across the event to gauge changes
- Simple to calculate
- Straightforward to understand and communicate
- Easy to obtain input data - Utilities know who is experiencing an outage in real time
- Comparable across events with normalized output between 0 and 1
- Could be specified to critical loads by only considering the status of critical loads

Use Cases and Assumptions

Use Cases:

- A simple, understandable metric is needed that can be used in real-time to reflect resilience by comparing values throughout an ongoing event

Assumptions:

- None

Requirements (inputs, compute resources/time)

Inputs:

- Status of each individual customer under consideration at a given time
- Number of customers under consideration

Computing:

- Can be computed quickly with few computing resources
 - $O(N)$

Discussion

This metric is closely related and can be easily converted to [outage incidence](#) θ_t and vice-versa.

$$\theta_t = (1 - P_t) \Leftrightarrow P_t = (1 - \theta_t)$$

Probability That Performance After Disaster Is Greater Than a Certain Value

This metric measures resilience as the probability that [performance after a disaster](#) is greater than a particular threshold

Cite Sources

Adopted from:

- [Evaluating the Disaster Resilience of Power Networks and Grids](#) by Masanobu Shinozuka and Stephanie E. Chang

Referenced in:

- [Power Systems Resilience Metrics: A Comprehensive Review of Challenges and Outlook](#) by Habibollah Raoufi, Vahid Vahidinasab, and Kamyar Mehran

Drawbacks & Benefits

Drawbacks:

- “The concept of ‘probability’ cannot be defined for most disasters[. ...] Since the ‘disaster probability’ cannot be defined accurately, using any metric which is based on disaster probability is not recommended” - [Power Systems Resilience Metrics: A Comprehensive Review of Challenges and Outlook](#) by Habibollah Raoufi, Vahid Vahidinasab, and Kamyar Mehran
- Requires mathematically modeling a system and simulating scenarios based on historical data
- Difficult to obtain input data
- Requires an analyst to determine a performance threshold
- Does not prioritize critical loads (i.e. a hospital load is weighted the same as a car dealership load)

Benefits:

- Potentially useful for infrastructure planning based on a particular critical threshold of performance that needs to be maintained
- Comparable across events with probability between 0 and 1
- Could be specified to critical loads by only considering the status of critical loads

Use Cases and Assumptions

Use Cases:

- A measure of robustness is needed when planning infrastructure to determine effectiveness of changes

Assumptions:

- A system can be modeled and simulated accurately to represent real outage events

Requirements (inputs, compute resources/time)

Inputs:

- A mathematical model of power system infrastructure
- Historical performance data

Computing:

- Highly variable based on simulation technique
- Likely resource intense

Discussion

This metric seems at face value like it could be useful, but is not rigorously defined in its originating literature and relies heavily on probabilistic impacts of outage events, which cannot be well defined for most disasters, according to [Power Systems Resilience Metrics: A Comprehensive Review of Challenges and Outlook](#) by Habibollah Raoufi, Vahid Vahidinasab, and Kamyar Mehran.

Outage Index/Incidence

This metric measures resilience as the fraction of customers experiencing an outage in an area at a given time.

- Outage Index/Incidence at a given time t : $\theta_t = \frac{n_{o,t}}{N} = \frac{1}{N} \sum_{i=1}^N (1 - s_{i,t})$
- $n_{o,t}$ is the number of customers under consideration experiencing an outage at time t
- $s_{i,t} \in \{0,1\}$ is the status of each individual customer at a given time
- N is the total number of customers under consideration

Cite Sources

Adopted from:

- [Quantitative Model and Metrics of Electrical Grids' Resilience Evaluated at a Power Distribution Level](#) by Alexis Kwasinski

Expanded Upon in:

- [Power System Resilience Metrics Augmentation for Critical Load Prioritization](#), a technical report from PNNL by Vishvas Chalishazar, Shiva Poudel, Sarmad Hanif, and Priya Thekkumparambath Mana

Drawbacks & Benefits

Drawbacks:

- Does not prioritize critical loads (i.e. a hospital load is weighted the same as a car dealership load)
- Does not capture information about restoration effectiveness for a whole event in a single value

Benefits:

- Instantaneous - can be used during an event and compared at different points across the event to gauge changes
- Simple to calculate
- Straightforward to understand and communicate
- Easy to obtain input data - Utilities know who is experiencing an outage in real time
- Compare across events with normalized output between 0 and 1
- Could be specified to critical loads by only considering the status of critical loads
- Could be modified to prioritize critical loads, as seen with [Outage Incidence Augmented for Critical Load Prioritization](#)

Use Cases and Assumptions

Use Cases:

- A simple, understandable metric is needed that can be used in real-time to reflect resilience by comparing values throughout an ongoing event

Assumptions:

- None

Requirements (inputs, compute resources/time)

Inputs:

- Status of each individual customer under consideration at a given time
- Number of customers under consideration

Computing:

- Can be computed quickly with few computing resources
 - $O(N)$

Discussion

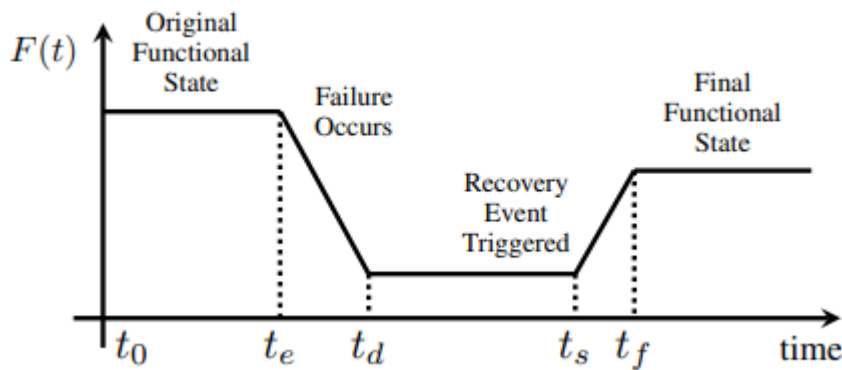
This metric is closely related and can be easily converted to [performance after disaster](#) P_t and vice-versa.

$$\theta_t = (1 - P_t) \Leftrightarrow P_t = (1 - \theta_t)$$

Ratio of Recovered Functionality to Lost Functionality

This metric measures resilience abstractly as a ratio of recovered functionality to lost functionality

- Resilience at a given time t during the recovery process (t_s, t_f) from a specific failure: $\Lambda(t) = \frac{F(t) - F(t_d)}{F(t_0) - F(t_d)}$
 - $0 \leq \Lambda(t) \leq 1$ for all $t \in (t_s, t_f)$, assuming that the recovery action succeeds in restoring functionality.
- $F(t)$ is functionality of a system at time t , measured as some selected quantifiable indicator of system performance
- t_0 is the time at which a system is at full functionality, i.e. $F(t_0)$ is maximal
- t_d is the time at which catastrophic failure occurs, i.e. $F(t_d)$ is minimal for a specific failure
- t_s is the time at which recovery action is initiated. After t_d , the system remains in a catastrophic state until t_s
- t_f is the time at which functionality $F(t_f)$ is considered to be acceptable (though it may not be perfectly functional)
- (t_s, t_f) is the time during the recovery process from the initiation of recovery action to the achievement of acceptable functionality



Cite Sources

Adopted from:

- [Analysis of Reliability and Resilience for Smart Grids](#) by Murtadha N. Albasrawi, Nathan Jarus, Kamlesh A. Joshi, and Sahra Sedigh Sarvestani

Drawbacks & Benefits

Drawbacks:

- Does not capture the effect of resisting damage, only recovery from it
- Does not prioritize critical loads by default (i.e. a hospital load is weighted the same as a car dealership load)
- Requires an analyst to define a threshold for acceptable levels of functionality
- Has no standard data that it pulls from - requires an analyst to choose a quantification for functionality

Benefits:

- Instantaneous - can be used during an event once recovery action is initiated and compared at different points across the event to gauge changes
- Simple to calculate if $F(t)$ is simple to calculate
- Straightforward to understand and communicate
- Comparable across events with normalized output between 0 and 1
- Flexible - various different quantifications of functionality can be used to gain different insights
 - Can be used in conjunction with various other resilience metrics used as quantification of functionality for this metric
- Could prioritize critical loads by using a quantifier of functionality that prioritizes critical loads

Use Cases and Assumptions

Use Cases:

- A simple, understandable metric is needed that can be used in real-time to quantify the effectiveness of restoration efforts with respect to various functionality quantification metrics

Assumptions:

- The metric chosen to quantify system functionality is effective in doing so for the relevant system

Requirements (inputs, compute resources/time)

Inputs:

- The chosen quantification of system functionality at the current timestep, as well as at the time of catastrophic failure and the time of full functionality
- A threshold for acceptable functionality

Computing:

- Depends on $F(t)$. If $F(t)$ can be computed quickly with few computing resources, so can $\Lambda(t)$
 - $O(F(t))$

Discussion

This metric is more of a template for a class of metrics than its own metric since various quantifiable measures of functionality can be chosen and used alongside each other to produce metrics which represent different things in the context of resiliency.

The originating report suggests Violations of Power Flow and Voltage Constraints as measures of the extent of disruption of a grid.

Another option that could be calculated easily is to use [Performance after Disaster](#) as a quantifier of functionality, which simplifies cleanly and has a runtime of $O(N)$.

$$\Lambda(t) = \frac{P_t - P_{t_d}}{P_{t_0} - P_{t_d}} = \frac{\frac{1}{N}n_{P,t} - \frac{1}{N}n_{P,t_d}}{\frac{1}{N}n_{P,t_0} - \frac{1}{N}n_{P,t_d}} = \frac{n_{P,t} - n_{P,t_d}}{n_{P,t_0} - n_{P,t_d}} = \frac{\sum_{i=1}^N (s_{i,t} - s_{i,t_d})}{\sum_{i=1}^N (s_{i,t_0} - s_{i,t_d})}$$

Using this method, the metric measures the proportion of people who lost power by time t_d that have had it restored by time t

Storm Average Interruption Duration Index (STAI DI) and Storm Average Interruption Frequency Index (STAI FI)

STAI DI and STAI FI are the IEEE reliability standards for daily operations SAIDI and SAIFI, extended to severe weather events. The originating source of these metrics points out that since they are static sample averages for an event, they are unsuited for representing the nonstationary nature of failure and recovery during that event. This unfitness is demonstrated in the originating source by calculating each metric with data from a service region in Upstate New York during Superstorm Sandy and finding that the uncertainty in those metrics is so large that they permit negative values. Thus, these metrics are simply included in this report for comprehensiveness.

- Given a severe weather event:
 - $STAI FI = \frac{\text{total \# of customers interrupted}}{\text{total \# of customers served}}$
 - $STAI DI = \frac{\text{total customer storm interruption minutes}}{\text{total \# of customers served}}$

Cite Sources

Adopted from:

- [Resilience of Energy Infrastructure and Services: Modeling, Data Analytics, and Metrics](#) by Chuanyi Ji, Yun Wei, and H. Vincent Poor

Featured in:

- [Power Systems Resilience Metrics: A Comprehensive Review of Challenges and Outlook](#) by Habibollah Raoufi, Vahid Vahidinasab, and Kamyar Mehran

Drawbacks

- Unfit as resiliency metrics, as discussed above

Use Cases

- None

Discussion

These metrics were shown in their originating source to be conceptually unsuited for resiliency analysis and exhibit too much uncertainty to serve any practical use. This was explored as a way to demonstrate that blue-sky reliability metrics cannot necessarily be brute-force extended to function as black-sky resiliency metrics. They are included in this literature review to serve the same informative purpose.

Despite the methods used to analyze the usability of these metrics presented in the original source, the CIDER project team feels that they could still have utility in summarizing limited timeframe outage simulation results in an analogous way.

Customer Minutes Interrupted (CMI)

Customer Minutes Interrupted (CMI) is a reliability metric measuring the cumulative interruption time for all customers in a sample

- Customer Minutes Interrupted for N customers in a given time period: $CMI = \sum_{i=1}^N T_{D,i}$
- $T_{D,i}$ is the downtime of customer i in minutes

Cite Sources

Adopted from:

- This is a widely used IEEE reliability index

Featured in:

- [Bouncing Back](#), a Sandia research magazine article by Stephanie Holinka

Drawbacks & Benefits

Drawbacks:

- Unfit for real-time analysis because it is based on event durations, which are unknown until after they have ended
- Does not prioritize critical loads (i.e. a hospital load is weighted the same as a car dealership load)
- Harder to compare across different systems as a measure of resilience since it is an absolute quantity, not a proportion relative to size or cost of the system

Benefits:

- Wide industry use known
- No calculation required
- Easy to obtain input data
- Straightforward to understand and communicate

Use Cases and Assumptions

Use Cases:

- A simple metric is needed for resiliency analysis after an outage-causing event. This metric can be compared somewhat well to earlier values corresponding to the same system as a way to measure improvements in resilience between similar outage events, but may not be as useful for comparing different power systems

Assumptions:

- Resilience can be described overall for a system by one value looking back at an event, rather than as something that may change during an event
- For comparisons, the severity and nature of compared outage events are similar (because CMI is coupled with overall length of an outage event, two systems with similar resilience could experience very different CMI scores if the severity and nature of outage events are very different)

Requirements (inputs, compute resources/time)

Inputs:

- The downtime of each customer under consideration in a given time period
- Number of loads under consideration

Computing:

- Can be computed quickly with few computing resources
 - $O(N)$

Discussion

CMI is often used as a reliability index and incorporated into other metrics like SAIDI. Its use to quantify resilience may be limited to benchmarking improved scores between similar outage events in a particular system and the source in which it is featured notes that to paint a full picture of resiliency, other factors like security and cost need to be considered. Its attainability and relative understandability could be useful for providing additional context when looking back on an outage restoration.

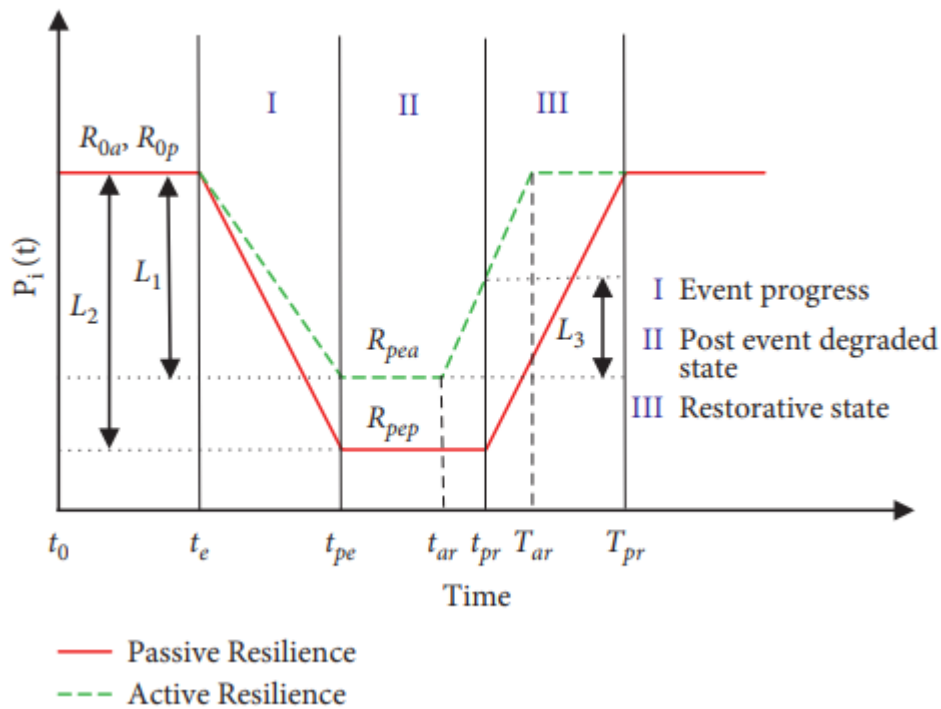
Distribution System Performance Loss (DSPL): Active Resilience & Passive Resilience

Active Resilience and Passive Resilience are metrics generated by finding Distribution System Performance Loss (DSPL) values over repeated probabilistic simulations of extreme weather events affecting a particular system. When generated this way, both metrics are meant to represent the resiliency of a system to future outage events, with Active Resilience corresponding to strategies and procedures while Passive Resilience corresponds to system characteristics that boost or harden critical parts of the system.

Active and Passive Resilience can both be calculated for individual events outside the context of repeated simulations, though this was not addressed in the originating source and thus further investigation is required to determine if this use is appropriate.

- Active Resilience for a single event: $R_a(t) = \int_{t_e}^{t_{pr}} P_1(t) dt$
- DSPL calculation for Active Resilience: $P_1(t) = [t_{ar} - \frac{1}{2}(t_{pe} + t_e)]L_1 + \frac{1}{2}[t_{pr} - t_{ar}]L_3$
- Passive Resilience for a single event: $R_p(t) = \int_{t_e}^{t_{pr}} P_2(t) dt$
- DSPL calculation for Passive Resilience: $P_2(t) = [t_{pr} - \frac{1}{2}(t_{pe} + t_e)]L_2$

Variable	Definition	Variable	Definition
t_0	Time (initial)	$P_i(t)$	Distribution System Performance Loss (DSPL)
t_e	Time (event start)	$L_i(t)$	Demand load not delivered
t_{pe}	Time (post-event start / event end)	R_{0a}	Pre-event active resilience
t_{ar}	Time (restoration w.r.t. active resilience start)	R_{0p}	Pre-event passive resilience
t_{pr}	Time (restoration w.r.t. passive resilience start)	R_{pea}	Post-event active resilience
T_{ar}	Time (restoration w.r.t. active resilience end)	R_{pep}	Post-event passive resilience
T_{pr}	Time (restoration w.r.t. passive resilience end)		



Cite Sources

Adopted from:

- [Probabilistic Quantification of Distribution System Resilience for an Extreme Event](#) by Puspendu Ghosh and Mala De

Drawbacks & Benefits

Drawbacks:

- Originating article is rife with typos and leaves many questions unanswered
- “The concept of ‘probability’ cannot be defined for most disasters[. ...] Since the ‘disaster probability’ cannot be defined accurately, using any metric which is based on disaster probability is not recommended” - [Power Systems Resilience Metrics: A Comprehensive Review of Challenges and Outlook](#) by Habibollah Raoufi, Vahid Vahidinasab, and Kamyar Mehran
- Requires mathematically modeling a system and simulating scenarios based on historical data
- Difficult to obtain input data
- Does not prioritize critical loads (i.e. a hospital load is weighted the same as a car dealership load)
- Unfit for real-time analysis because even if used for single events (as opposed to repeated simulation), it is based on event durations, which are unknown until after they have ended
- Requires an analyst to define various simulation rules
- As presented in the originating paper (and seen replicated above), DSPL is in terms of a variable t , but that variable is not present in the equation itself with only constants being present

representing specific times. Thus, when integrating DSPL over t , it is unclear how that is supposed to be performed.

Benefits:

- Potentially useful for resilience planning
- Method of discriminating between active and passive resilience is novel and could be useful

Use Cases and Assumptions

Use Cases:

- Metrics are needed to probabilistically estimate active and passive resilience of a system to future outage events
- Metrics are needed for active and passive resiliency analysis after an outage causing event (if further exploration confirms that this is an appropriate use case)

Assumptions:

- Outage-causing events can be accurately characterized by probability distribution functions

Requirements (inputs, compute resources/time)

Inputs:

- Outage-causing event probability density function based on historical data
- Power system architecture

Computing:

- Variable based on simulation technique
- Likely resource intense

Discussion

This approach attempts to quantify resilience as a set of predictive metrics looking forward at potential future outage events given the current state of a power system. That makes it somewhat unique among many other metrics which look to characterize resilience per each event. That being said, representing outage events with probability density functions has been advised against as noted in the drawbacks section, especially considering that weather patterns are evolving and historical data may not necessarily represent current or future probabilities.

Aggregated Impact Level (AIL) & Transitional Impact Level (TIL)

Aggregated Impact Level (AIL) and Transitional Impact Level (TIL) are asset level performance metrics which denote the criticality of assets and are used instrumentally in the Risk-based Contingency Analysis Tool (RCAT). RCAT is an integrated modeling framework that uses physics-based probabilistic models to evaluate the criticality and vulnerability of electrical infrastructure to support long-term planning and operational decision making.

According to its originating source, RCAT functions use a “probabilistic representation of [an outage event. ...] Within each event, multiple Monte Carlo scenarios are simulated. Finally, within each scenario, groups of contingencies are simulated in scenario stages, which are essentially groups of outages contained in a particular time step. At each level of this hierarchy, metrics on system performance are calculated and can be leveraged for analysis.”

AIL is the “aggregated impact level of a set of contingencies occurring in a single stage of a scenario based on the resulting performance metrics at that stage.” With scaled performance metrics acting as the features of each contingency, K-means clustering is applied to cluster groups of contingencies based on their level of impact to the system. “The impact pattern of resulting clusters can then be ranked based on severity [to indicate] the relative AIL of each set of contingencies” with a higher AIL indicating greater system impacts. “Since the AIL is indicative of the impact on the system at the end of a particular stage, it also indicates the cumulative impact from all previous asset failures.”

TIL “considers the change in AIL from the previous to the current stage due to a group of asset failures in the current stage. Monitoring TILs for an asset or a group of assets affected in a stage of the event, as well as across Monte Carlo scenarios, can help determine the criticality of an asset based on its immediate impact on the system. [...] If, out of all the occurrences in different [outage] events, the failure of an asset causes severe impact transitions with a high degree of frequency, then that asset can be considered to have a severe impact.”

AIL and TIL are further used to calculate vulnerability and criticality rankings for assets.

Cite Sources

Adopted from:

- [A Risk-Based Framework for Power System Modeling to Improve Resilience to Extreme Events](#) by Emily L Barrett, Kaveri Mahapatra, Marcelo Elizondo, Xiaoyuan Fan, Sarah Davis, Sarah Newman, Patrick Royer, Bharat Vyakaranam, Fernando Bereta Dos Reis, Xinda Ke, and Jeff Dagle

Drawbacks & Benefits

Drawbacks:

- Originating article presents methods that may be useful but details are currently opaque to project team - specifically, how is a “contingency defined”

- “The concept of ‘probability’ cannot be defined for most disasters[. ...] Since the ‘disaster probability’ cannot be defined accurately, using any metric which is based on disaster probability is not recommended” - [Power Systems Resilience Metrics: A Comprehensive Review of Challenges and Outlook](#) by Habibollah Raoufi, Vahid Vahidinasab, and Kamyar Mehran
 - Additionally, historical data cannot be relied upon due to climate change altering historical weather patterns
- Requires mathematically modeling a system and simulation scenarios based on historical data or forecasted threat information
- Difficult to obtain input data
- Requires an analyst to define various simulation rules

Benefits:

- Assesses criticality of assets
- Potentially useful for resilience planning

Use Cases and Assumptions

Use Cases:

- Metrics are needed during resiliency planning to probabilistically estimate the degree of asset failure under future outage-causing events.

Assumptions:

- Outage-causing events can be accurately characterized by probabilistic models

Requirements (inputs, compute resources/time)

Inputs:

- Probabilistic models of an outage event
- Operating state of the power system

Computing:

- Variable based on simulation technique
- Likely resource intensive

Discussion

This approach seeks to identify the impact of grid asset failure as well as the vulnerability and criticality of grid assets. As such, although unsuited to resiliency analysis during or after an outage, it could have a fitting use in resiliency planning. That being said, representing outage events probabilistically has been advised against as has been noted in the drawbacks section, especially considering that weather patterns are evolving and historical data may not necessarily represent current or future probabilities.

Excluded Events $CEMI_X$

Excluded Events Customers Experiencing Multiple Interruptions ($CEMI_X$) measures resilience as the percentage of customers experiencing X or more sustained outages during excluded events (outage events, which are excluded from other measurements of $CEMI_X$ to avoid outliers in tracking reliability). $CEMI_X$ is typically recorded over the course of a year.

- $CEMI_X = \frac{n_{i \geq X}}{N}$
- N is the total number of customers under consideration
- $n_{i \geq X}$ is the total number of customers experiencing X or more sustained interruptions during excluded/outage events in a given period.

Cite Sources

Adopted from:

- This is a widely used IEEE reliability index extended to resiliency analysis

Featured in:

- [Why Resiliency in the Electrical Grid Should Be Measured from the Customer's Perspective](#) by Power Magazine Contributed Content
- [Adapting Existing Energy Planning, Simulation, and Operational Models for Resilience Analysis](#) by Caitlin Murphy, Eliza Hotchkiss, Kate Anderson, Clayton Barrows, Stuart Cohen, Sourabh Dalvi, Nick Laws, Jeff Maguire, Gord Stephen, and Eric Wilson

Drawbacks & Benefits

Drawbacks:

- Unfit for real-time analysis because it is based on interruptions experienced across entire event durations over the course of a year
- Not well suited for individual events if X is sufficiently high
- Requires an analyst to decide what X value to consider
- Requires an analyst to define what times each event begins and ends
- Does not prioritize critical loads (i.e. a hospital load is weighted the same as a car dealership load)
- Heavily dependent on outage event frequency during the time period in question (In a year with 20 outage events versus a year with 1 outage event, Excluded Events $CEMI_X$ will likely be larger even with identical power systems)

Benefits:

- Simple to calculate
- Straightforward to understand and communicate
- Based on a reliability metric with widespread industry use
- Easy to obtain input data
- Comparable across events with normalized output between 0 and 1
- Could be specified for critical loads by only considering interruptions experienced by critical customers
- Customizable - different X values can be chosen to generate multiple versions of the metric

Use Cases and Assumptions

Use Cases:

- A simple, understandable metric is needed for measuring resilience of a power system to outage events over the course of a year.

Assumptions:

- Similar intensity and frequency of outage events are experienced across years for which Excluded Events $CEMI_X$ is calculated

Requirements (inputs, compute resources/time)

Inputs:

- The total number of customers experiencing X or more sustained interruptions during excluded/outage events in a given period.
- The total number of customers under consideration

Computing:

- Can be computed very quickly with few computing resources
 - $O(1)$

Discussion

Although Excluded Events $CEMI_X$ is based on the widely used reliability metric $CEMI_X$, it cannot be automatically assumed that it will be useful for resiliency analysis. This lack of easy adaptation from reliability to resiliency metric is highlighted in [Resilience of Energy Infrastructure and Services: Modeling, Data Analytics, and Metrics](#) by Chuanyi Ji, Yun Wei, and H. Vincent Poor.

Indeed, the reliability metric $CEMI_X$ looks at occurrences over the previous year, which works fairly well for reliability since, with only a few days excluded for extreme events, the time frame remains relatively stable. For Excluded Events $CEMI_X$, that same design makes it hard to use for resiliency since the time frame in question encompasses those excluded extreme event days over the course of a year, the number of which can vary heavily relative to their average quantity. Despite being less suited for resiliency analysis, this metric can still be informative for utilities as a gauge of performance.

Simply dividing Excluded Events $CEMI_X$ by the number of excluded event days to account for the variable number of event days is not a sufficient fix, because X is not relative to the number of event days within a year. Trying to scale X inversely by the number of event days to account for that variation has problems too, as it would change what is actually being measured across different years for which $CEMI_X$ is recorded.

Excluded Events $CELID_X$

This metric measures resilience as the percentage of customers experiencing long interruption durations of X or more minutes during excluded events (outage events, which are excluded from other measurements of $CELID_X$ to avoid outliers in tracking reliability). $CELID_X$ is typically recorded over the course of a year.

- $CELID_X = \frac{n_{t \geq X}}{N}$
- N is the total number of customers under consideration
- $n_{t \geq X}$ is the total number of customers that experience interruptions with durations longer than or equal to X during excluded/outage events in a given period

Some known interpretations of $CELID_X$ consider interruption durations to be per outage while others consider interruption durations to be measured cumulatively over the course of the reporting period.

Cite Sources

Adopted from:

- This is a widely used IEEE reliability index extended to resiliency analysis

Featured in:

- [Why Resiliency in the Electrical Grid Should Be Measured from the Customer's Perspective](#) by Power Magazine Contributed Content
- [Adapting Existing Energy Planning, Simulation, and Operational Models for Resilience Analysis](#) by Caitlin Murphy, Eliza Hotchkiss, Kate Anderson, Clayton Barrows, Stuart Cohen, Sourabh Dalvi, Nick Laws, Jeff Maguire, Gord Stephen, and Eric Wilson

Drawbacks & Benefits

Drawbacks:

- Unfit for real-time analysis because it is based on interruptions experienced across entire event durations over the course of a reporting period
- Requires an analyst to decide what times each event begins and ends
- Does not prioritize critical loads (i.e. a hospital load is weighted the same as a car dealership load)
- If measuring for long reporting periods rather than individual events, heavily dependent on outage event frequency during the time period (In a year long reporting period with 20 outage events versus a year long reporting period with 1 outage event, Excluded Events $CELID_X$ will likely be larger even with identical power systems.)
- Heavily dependent on outage event durations
- Durations are sometimes interpreted cumulatively and sometimes per event, which can lead to incorrect assumptions if not specified alongside the metric when presented
- If $CELID_X$ is considered with interruption duration measured per event over the course of a year, then a customer who has experienced multiple long duration outages in that period is either counted multiple times, allowing for percentages greater than 100%, or not counted

multiple times, which leads to the difference between a single customer experiencing 1 long duration outage versus 20 long duration outages unreflected.

- If durations are considered per outage rather than cumulatively, a 4-hour outage would look better than two 2-hour outages with a brief restoration of power in between

Benefits:

- Usable for individual events
- Simple to calculate
- Based on a reliability metric with widespread industry use
- Easy to obtain input data
- Comparable across events with normalized output between 0 and 1
- Could be specified for critical loads by only considering interruptions experienced by critical customers
- Customizable - different X values can be chosen to generate multiple versions of the metric

Use Cases and Assumptions

Use Cases:

- An easily calculable metric is needed for measuring resilience of a power system to outage events over the course of a year or to individual outage events

Assumptions:

- Similar intensity, duration, and frequency of outage events are experienced across reporting periods for which Excluded Events $CELID_X$ is calculated

Requirements (inputs, compute resources/time)

Inputs:

- The total number of customers under consideration
- The total number of customers that experience interruptions with durations longer than or equal to X during excluded/outage vents in a given period
-

Computing:

- Can be computed very quickly with few computing resources
 - $O(1)$

Discussion

Although Excluded Events $CELID_X$ is based on the widely used reliability metric $CELID_X$, it cannot be automatically assumed that it will be useful for resiliency analysis. This lack of easy adaptation from reliability to resiliency metric is highlighted in [Resilience of Energy Infrastructure and Services: Modeling, Data Analytics, and Metrics](#) by Chuanyi Ji, Yun Wei, and H. Vincent Poor.

Indeed, the reliability metric $CELID_X$ often looks at occurrences over the previous year, which works fairly well for reliability since the time frame and conditions remain relatively stable. For Excluded Events $CELID_X$, that same design makes it hard to use for resiliency since the time frame in question

encompasses those extreme event days over the course of a year, the number of which can vary heavily relative to their average quantity.

Whether $CELID_X$ is measured over the course of a year or for a single event, the cumulative duration of outage events has a large impact on $CELID_X$ that is not accounted for nor represented.

Scaling X inversely by the cumulative event duration to account for its impact would change what is actually being measured across different instances of $CELID_X$

Average Service Availability Index (ASAI)

Average Service Availability Index (ASAI) measures resilience from the customer perspective as the percentage of time an average customer received power when they wanted to.

$$\bullet \text{ ASAI} = \frac{\text{Customer hours of available service}}{\text{Customer hours demanded}}$$

Cite Sources

Adopted from:

- This is a widely used IEEE reliability index extended to resiliency analysis

Featured in:

- [Why Resiliency in the Electrical Grid Should Be Measured from the Customer's Perspective](#) by Power Magazine Contributed Content
- [Adapting Existing Energy Planning, Simulation, and Operational Models for Resilience Analysis](#) by Caitlin Murphy, Eliza Hotchkiss, Kate Anderson, Clayton Barrows, Stuart Cohen, Sourabh Dalvi, Nick Laws, Jeff Maguire, Gord Stephen, and Eric Wilson

Drawbacks & Benefits

Drawbacks:

- Unfit for real-time analysis because it is based on event durations, which are unknown until after they have ended
- Requires an analyst to define what times each event begins and ends
- Does not prioritize critical loads (i.e. a hospital load is weighted the same as a car dealership load)
- What does it mean to not want power? When are customer hours not demanded?

Benefits:

- Simple to calculate
- Comparable across events with normalized output between 0 and 1
- Widespread industry use
- Could be specified by critical loads by only considering critical customers

Use Cases and Assumptions

Use Cases:

- A simple to calculate metric that measures resilience from the customer perspective is needed

Assumptions:

- Customer hours demanded can be clearly defined

Requirements (inputs, compute resources/time)

Inputs:

- Customer hours of available service
- Customer hours demanded

Computing:

- Can be computed very quickly with few computing resources
 - $O(1)$

Discussion

While it is helpful to have metrics that represent the customer perspective, “customer hours demanded” is not rigorously defined, raising questions posed in the drawbacks such as “what does it mean to not want power? When are customer hours not demanded?” For example, during an evacuation, would customer hours not be demanded at a vacant building?