PNNL-29738

Pacific Northwest NATIONAL LABORATORY

Planning Considerations for Energy Storage in Resilience Applications

Outcomes from the NELHA Energy Storage Conference's Policy and Regulatory Workshop

March 2020

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U.S. DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy
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Abstract

This report presents the proceedings and lessons learned at a conference workshop that discussed the role of energy storage in supporting electric system resilience, which took place at the Natural Energy Laboratory of Hawaii Authority's (NELHA) Conference on Energy Storage Trends and Opportunities in December 2018. Staff from the Pacific Northwest National Laboratory (PNNL) made two presentations on the topic of resilience: the first covering a conceptual framework for incorporating resilience into resource planning processes, and the second covering a tool developed for microgrid planning that can assist in identifying resource mixes that will meet site-specific resilience needs. Throughout the presentations, presenters and workshop participants discussed the obstacles to improving electric system resilience and potential solutions for overcoming them. Following the workshop, the authors conducted additional research to further contextualize the topics discussed at the workshop and to frame the resulting recommendations for future engagement on this subject by the Department of Energy and the national laboratories.

Executive Summary

On December 5-6, 2018, the Natural Energy Laboratory of Hawaii Authority (NELHA) held the Conference on Energy Storage Trends and Opportunities 2018 in Kona, Hawaii. At the request of conference organizers, staff from the Pacific Northwest National Laboratory (PNNL) prepared a workshop session on regulatory and policy issues related to energy storage, with specific topics selected by staff of the Hawaii Public Utilities Commission (HPUC or Commission). Commission staff identified two priority topics, interconnection and resilience. The workshop was attended by regulatory staff, utility professionals, project developers, consultants, and researchers.

The purpose of this report is to share the information presented in the resilience component of the workshop, capture the discussions that took place, present additional research conducted to further contextualize the topic of resilience, and make recommendations for future resilience research based on the information gathered and needs identified throughout this process.

High electricity prices, driven by Hawaii's historical reliance on oil for power generation, have spurred high adoption rates of distributed generation (DG) on the islands. In recent years, the state has attempted to manage that generation by adopting policies that send a clear signal to customers to shape the output of their distributed generation to benefit the grid, either with the utility's assistance or by installing energy storage to control it. As a result, adoption of behind-the-meter (BTM) storage on the islands is rapidly growing, which led HPUC staff to question whether the state's interconnection policies were ready for those installations and the degree to which storage investments could be leveraged for increasing energy resilience on the islands.

High-profile proceedings involving the U.S. Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) have recently drawn national attention to the topic of energy resilience and illustrated its complexities. Unlike reliability, which is an objective concept defined by many standards and metrics, resilience is a subjective concept that has no formal definition or standards. Conceptual definitions of resilience exist, such as one adopted by DOE describing resilience as "the ability of a system or its components to adapt to changing conditions and withstand and rapidly recover from disruptions" (DOE 2017). However, absent formal definitions, standards and metrics for resilience do not exist. Standards and metrics form the basis of utility system planning – the targets that planning models must meet.

The absence of resilience standards and metrics has two important ramifications: utilities can't identify resilience needs in their planning practices, and even if investments were made to increase resilience, there would be no direct mechanism for recovering their costs. Under that paradigm, investments in resilience must prove cost-effective through traditional mechanisms: provision of energy and other grid services, made monetizable by the need to meet adequacy and reliability standards. Energy storage, which can both store energy for use when the grid is disrupted and provide flexibility and other services when it is operating normally, has the potential to a be a key component of such investments.

The first presentation at the workshop explained that absent standards, increasing resilience at a system level is an ambiguous and economically challenging proposition. However, by setting aside traditional system-level investment planning models and instead taking a locational approach to identify resilience needs, resilience goals can be broken into more achievable subtasks and cost-effective solutions can be more easily identified. This paper identifies five principles for such a locational planning framework:

- Define critical loads;
- Identify major events of concern;
- Establish planning objectives;
- Engage in iterative planning between the project and the local grid to meet the needs of both; and
- Throughout the process, consider questions of ownership, cost allocation, and rate design.

To demonstrate the type of granular resource planning tool needed for resilience applications, the second workshop presentation discussed the Microgrid Component Optimization for Resilience (MCOR) tool, developed at PNNL for the U.S. Army Office of Energy Initiatives and the U.S. Army Reserve. Unlike traditional grid planning models, which look at the broader electric grid and seek to minimize operational costs over an extended period of average conditions, MCOR is a granular model that seeks to optimize a subset of resources at a specific point on the grid to meet a stated resilience goal. The resilience focus, coupled with a stochastic approach that considers weather variability and its impact on resource performance, as well as external economic drivers such as utility rate structures and net metering policy, are the primary benefits of MCOR in microgrid planning. The tool has been used to identify optimal resilient energy portfolios for multiple military installations.

Receiving feedback from industry professionals was a key goal of the workshop. As resilience is a developing concept, presenters wanted to hear about the challenges the industry faces as it explores the topic and identify how research efforts may be directed to inform the conversation. Five themes emerged during the workshop discussion:

- Identifying and prioritizing critical loads;
- Quantifying the grid impacts of catastrophic events;
- Defining the relationship between the military, utilities, and customers in building resilience;
- Determining where microgrids are needed and developing the technical and regulatory infrastructure necessary to enable them; and
- Further refining resilience planning tools to increase functionality.

To test these principles, the report presents four brief case studies of recent projects in military and civilian applications. This review demonstrates four common principles shared by successfully deployed resilience projects:

1. **Resilience benefits are hyperlocal.** In each case, a single entity is capturing the resilience benefits of the project.
2. **Project feasibility is achieved by providing grid services.** By providing valuable grid services during normal operations, projects can earn offsetting revenue that makes them cost-effective.
3. **Local value drives each project.** Full optimization of a resilience asset requires capturing multiple revenue streams, but the value of each project is primarily driven by meeting a specific, local grid need.

4. **Energy storage is a key enabling technology in resilience applications.** Three of the four case study projects included energy storage, and the fourth was considering adding it. The flexibility of storage assets facilitates multiple project goals.

Based on the research conducted to prepare for this workshop and the needs identified by industry professionals in the audience, the authors recommend the following principles for future efforts by the Department of Energy (DOE) and the national laboratories to support grid resilience:

1. Planning and investment paradigms – as well as supporting research – should adopt a locational approach to energy resilience, defined by critical loads.

2. To support resilience investment decision making, utility resource planning tools should continue refinement toward more temporal and spatial granularity that fits the scale of resiliency benefits and, where appropriate, toward greater integration of distribution system and bulk power system needs and benefits.

3. To incent and enable customer investment in resilience resources, new types of tariffs will be necessary. Additional research is needed to inform the development of tariffs that will compensate customers for their investments and provide appropriate price signals for them to use those assets to the benefit of the grid.

Acknowledgments

This report and PNNL’s involvement the workshop described herein were made by possible by funding from the U.S. Department of Energy, Office of Electricity, through the Energy Storage Program under the direction of Dr. Imre Gyuk.

The Microgrid Component Optimization for Resilience tool described in this report was developed with funding from the U.S. Army Reserve’s Installation Management Directorate and the U.S. Army’s Office of Energy Initiatives.

Finally, the authors wish to thank the Natural Energy Laboratory of Hawaii Authority for organizing the conference and inviting the laboratory’s participation, and the Hawaii Public Utilities Commission for its guidance in shaping the workshop agenda and its contributions to the final report.

Acronyms and Abbreviations

APS	Arizona Public Service
ASAI	Average Service Availability Index
BTM	Behind the Meter
CAIDI	Customer Average Interruption Duration Index
DG	Distributed Generation
DOE	Department of Energy
FERC	Federal Energy Regulatory Commission
HPUC	Hawaii Public Utilities Commission
IEEE	Institute of Electrical and Electronics Engineers
KIUC	Kauai Island Utility Cooperative
kWh	Kilowatt-hour
MCAS Yuma	Marine Corps Air Station Yuma
MCOR	Microgrid Component Optimization for Resiliency Tool
NELHA	Natural Energy Laboratory of Hawaii Authority
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
PMRF	Pacific Missile Range Facility
PNNL	Pacific Northwest National Laboratory
PV	Photovoltaic
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index

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1.0 Introduction and Background

On December 5-6, 2018, NELHA held the Conference on Energy Storage Trends and Opportunities 2018 in Kona, Hawaii.[1] At the request of conference organizers, PNNL staff prepared a workshop session on regulatory and policy issues related to energy storage, with the specific topics selected by HPUC staff. Commission staff identified two priority topics, interconnection and resilience.

PNNL staff delivered three presentations during the workshop; one on interconnection practices and two on resilience. The interconnection presentation covered current interconnection standards and gaps in Hawaii's interconnection rules. The first resilience presentation discussed the obstacles to grid resilience improvement and proposed a planning framework for navigating them, while the second resilience presentation shared a microgrid planning tool developed at PNNL. Since the interconnection portion of the workshop shared established technical standards and the resilience portion was focused on discussing new and developing approaches to a complex topic, this paper focuses on the resilience aspect of the workshop.

This section presents additional research conducted by the authors to contextualize the workshop, including the policy drivers behind the Commission's interest in energy storage technologies, the role that energy storage can play in meeting resilience goals, and the broader national conversation on resilience.

Sections two and three summarize the resilience presentations in the workshop, section four relates the discussion that took place at the workshop, section five presents lessons learned from resilience projects that have been successfully deployed in recent years, and section six offers a conclusion and recommendations for future research.

1.1 Hawaii's Energy Landscape

In selecting the topics of interconnection and resilience for the workshop, Commission staff cited Hawaii's unique position as a high-cost, island grid as a driving source of growing customer and utility investments in energy storage, and the potential to harness those investments for the benefit of the grid. Served primarily by oil-fired generation resources (71 percent of all electric generation in 2017), Hawaii residents face the highest retail electric rates in the nation (EIA 2018a). Those high prices create a strong incentive for customers to invest in distributed generation (DG), and as a result, Hawaii has the highest per-capita customer energy production in the country, at more than 680 kilowatt-hours (kWh) average per person in 2017 (EIA 2018b).[2] By comparison, California, which had the most total distributed solar generation in 2017, had a per-capita average of about 269 kWh.[3]

As the influx of DG began to impact the electric grid, HPUC updated its policies governing how customers connect their generating facilities to the grid and receive compensation for their output. In 2015, the Commission determined that the net energy metering (NEM) model, which compensated customers at the retail rate for all energy transferred to the grid, was inadequate for managing the state's significant growth in DG and creating the type of markets that would be necessary for the state to reach its recently adopted 100 percent clean energy goal (Hawaii Public Utilities Commission 2015).

[1] Conference details, including agenda, presenter biographies, and presentations available at https://nelha.hawaii.gov/energy-initiatives/energy-conference-december-5-6-2018/.
[2] Figure calculated by dividing EIA's estimate of distributed solar generation in Hawaii of 69,000 MWh in 2017 by the U.S. Census Bureau population estimate for Hawaii as of July 1, 2017, which was 1,427,538.
[3] Figure calculated using the same process described in the previous footnote.

The Commission closed the NEM program to new participants and replaced it with two program alternatives: Customer Self-Supply and Customer Grid-Supply (Hawaii Public Utilities Commission 2015). When the Customer Grid-Supply program met its program cap in 2017, the Commission authorized two replacement programs, Smart Export and Controllable Grid Supply (Hawaii Public Utilities Commission 2017), and created the Enhanced Net Metering Program, which allows existing NEM customers to add capacity to their system – as long as it does not result in the system putting more energy onto the grid – and retain their status in the NEM program.

In sum, the Commission has established the following options to support the continued development of DG resources in Hawaii, which offer customers a variety of options to manage electricity use and provide support to the grid:

1. Self-Supply: Customers consume the electricity they generate onsite, with an allowance for small, inadvertent export to the grid that is uncompensated. Given the minimal grid impacts of self-supply systems, customers selecting this option are eligible for an expedited interconnection review by the utility. In addition, the Commission anticipates that self-supply customers may choose to provide and be compensated for grid services in the future.

2. Customer Grid-Supply Option: Customers may export electricity to the grid, for which they will be compensated at an island-specific rate approximating that system's avoided cost. The grid-supply program follows a net billing approach, in that customers are able to consume electricity they generate, and receive compensation for any electricity that they export to the grid. Customers are subject to a traditional interconnection review, and participation is capped on an island-by-island basis. This program has met its caps and is no longer available.

3. Controllable Grid-Supply: As a successor to the Customer Grid-Supply program, the Controllable Grid-Supply program follows a similar net billing approach, allowing customers to consume electricity they produce with any excess generation compensated at an island-specific rate approximating each system's updated avoided cost. In contrast to its predecessor, however, this program requires customers to meet communication requirements that allow the utility or a third-party aggregator to control the output of the DG system when conditions require it to maintain system reliability.

4. Smart Export: Offers an additional option for customers installing a rooftop photovoltaic (PV) system combined with a battery energy storage system. Under the Smart Export program, customers' energy storage systems would recharge during the daytime with energy captured from their solar PV system. The energy storage system would then power their home in the evening with an option to also export electricity back to the grid. If customers send power back to the grid during non-daytime hours, they receive a monetary credit on their electric bill.

5. Enhanced NEM: Current NEM customers can add non-exporting capacity to their systems, including battery energy storage, and retain their status in the NEM program.

Collectively, these policies and programs aim to facilitate customer choice and investment in DG that, at a minimum, has no impact to the grid and, at best, actively supports it. Two of the policies in place, the Self-Supply and Smart Export programs, place the responsibility of managing DG on the customer, while the Controllable Grid Supply program places the responsibility on the utility or a third-party aggregator.

Customers wanting to retain control over their DG production and maximize its economic value have a strong incentive to install energy storage, as the Self-Supply and Smart Export programs require customers to either keep all generation onsite or export it to the grid between 4 p.m. and 9 a.m., respectively. In either case, energy storage provides the practical means of capturing and shaping the output of their DG resources. As a result, the amount of behind-the-meter (BTM) energy storage in Hawaii has rapidly increased, from 0.3 MW installed in 2016 to 3.9 MW in 2017 (Smart Electric Power Alliance 2018), and Hawaii was second only to California for BTM storage installations in the third quarter of 2018 (Wood Mackenzie 2018).

With this context in mind, PNNL worked with Commission staff to identify the most useful topics for a regulatory issues workshop within the NELHA conference. Staff explained that the rapid growth in BTM storage on the islands presents several regulatory challenges, such as identifying the use cases of BTM storage, designing tariffs to extract the value associated with those use cases, and establishing the relative values of BTM storage and utility-scale storage. However, staff identified two issues as most pressing: leveraging BTM storage for resilience applications and understanding best practices for interconnecting those devices with the distribution grid.

1.2 Resilience: The Broader Context

HPUC's interest in deploying energy storage to enhance resilience comes at a time when the concept of resilience is the subject of an ongoing national conversation. The U.S. Department of Energy (DOE) took two steps in 2017 to define resilience and implement policies to improve resilience of the electric grid. First, in the second installment of the Quadrennial Energy Review, DOE defined resilience as "the ability of a system or its components to adapt to changing conditions and withstand and rapidly recover from disruptions" (U.S. Department of Energy 2017a).

Also in 2017, DOE issued a proposed Grid Resiliency Pricing Rule for consideration by the Federal Energy Regulatory Commission (FERC), which would have further defined resilience in terms of fuel supply and required the development of tariffs that provide additional compensation for generators that have at least a 90-day fuel supply onsite (U.S. Department of Energy 2017b).

During the ensuing proceeding, an analysis of electric outages from around the country between 2012 and 2016 found that of all major outages in the U.S. during that time, 96.2 percent were caused by severe weather, while 0.00865 percent were caused by insufficient generation or fuel supply emergencies (Rhodium Group 2017).

A single event, Hurricane Sandy in 2012, accounted for 31.7 percent of those outages. The North American Electric Reliability Corporation (NERC) analyzed Sandy's impacts on the electric system and found that despite damage to multiple generation resources, there was sufficient generation to meet electric demand. NERC's report indicated that Sandy's extended and widespread outages, which lasted for more than two weeks for some customers, were driven by extensive damage to transmission and distribution facilities, exacerbated by inclement weather that delayed restoration efforts (NERC 2014).

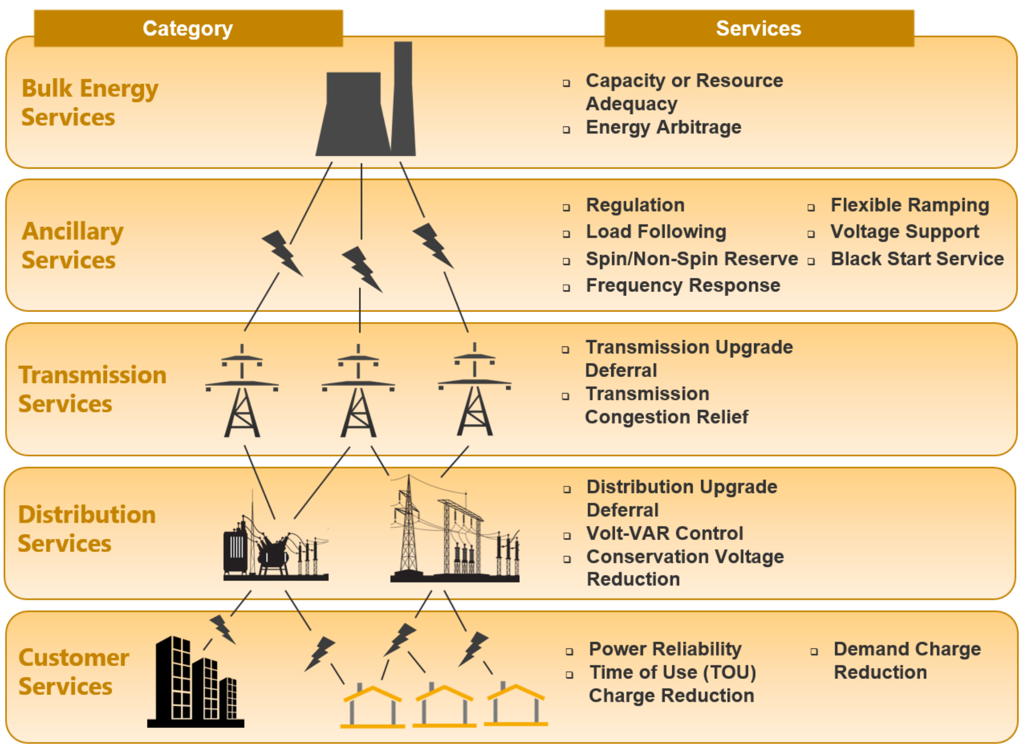
The lessons of Hurricane Sandy demonstrate that electric reliability standards have resulted in a robust generation system with extensive redundancy – enough to survive a major regional storm with sufficient generation remaining online. That extended outages were the result of delivery system interruptions suggests that making the electric grid more resilient against major events will require a more localized approach, which focuses on strengthening energy delivery systems and deploying grid-independent sources of generators closer to load.

FERC ultimately rejected the DoE proposal, stating that it had failed to demonstrate that existing tariffs were "unjust, unreasonable, unduly discriminatory or preferential," as required by the Federal Power Act. It also cited comments from grid operators stating that there were no imminent threats to reliability or resilience based on plant retirements (FERC 2018). FERC did, however, acknowledge the need for further exploration of resilience needs, and initiated a separate investigation.[4] In its order establishing the investigation, FERC noted that there is no uniform definition of resilience in place, and adopted a modified version of the National Infrastructure Advisory Council's definition of resilience for the proceeding, which defines resilience as "the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes to the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event." (*id.*)

After two initial rounds of comments, FERC has not taken any further action. In response to requests that the proceeding be resolved, FERC has generally indicated that the docket was meant to start a discussion about resilience and that meaningful action is taking place in other proceedings.

1.3 Energy Storage's Role in Resilience

From a site-based perspective, securing electric resilience requires an onsite source of generation that can meet energy needs when grid-supplied energy is unavailable. Acquiring that generation requires significant financial commitments, both in terms of up-front capital costs to purchase it as well as ongoing expenditures to maintain and, as necessary, fuel it. Unless there is an opportunity to recoup some of those costs by providing compensable grid services, the owner will bear them all, and resilience investments will be limited to parties capable of making significant capital expenditures. In this report, "grid services" refers to services other than energy and capacity that are needed to maintain a reliable grid. Figure 1 summarizes these services:



Balducci 2018a

Figure 1: Taxonomy of Electric Grid Services

[4] Docket AD18-7.

Distributed resources, however, face two barriers in the provision of grid services: compensation and operation. Compensation is a challenge because grid services are generally transacted at the megawatt scale, while distributed resources are generally constructed at the kilowatt scale, and are simply too small to participate in markets on an individual basis. Aggregators, which coordinate the operation of many small devices to create a virtual, megawatt-scale resource, can reduce or eliminate this barrier. However, this service is not universally available, and even where it is available, additional communications and control infrastructure is required to enable a distributed resource to receive and respond to grid signals.

Second, many grid services are temporally granular in nature; that is, they need to be provided on an instant's notice and may only be measured in seconds or minutes. Examples of this type of service include spinning reserves, frequency response, and flexible ramping. To provide these valuable grid services, a resource must be "always on" – connected to the grid and running to ensure an instantaneous response.

Traditionally, diesel generators have been the primary source of resilient generation, given their technological maturity and relatively low costs. An aggregator or direct utility control can enable these generators to provide grid services and thus help recover costs for these investments. Still, the operational barrier remains: any unpredictability in revenues will make it difficult to justify the equipment and fuel impacts of keeping a generator running for extended periods – the "always on" mode required for the provision of many grid services.

Due to these barriers, the traditional resilience model – the one based on an onsite diesel generator – requires the customer to take on all the costs and risks. As a result, resilience has historically been a high-cost proposition limited to facilities that have a mission-critical need for resilient power (hospitals, manufacturing, etc.). [5]

Energy storage has the promise to change that model. Like diesel generators, storage can support electric loads from brief frequency deviations to hours-long interruption of electric services, and, where enabled by tariff and regulatory structures, earn revenue while doing so. By its technology characteristics, energy storage is well suited to overcome the barriers that limit diesel generators from earning revenue from grid services. Inverter-based storage devices are capable of providing an instantaneous and precise response, which helps them excel at high-speed short-term grid services. Where equipped with a smart inverter, as encouraged by current standards, storage devices have the communication capabilities to receive and respond to grid signals, making them eligible for aggregation services or tariff structures that provide compensation for grid services.

Beyond inverter-based capabilities, energy storage technologies have additional characteristics that enable them to provide grid services. As storage can act as either a generator or a load, it can provide a wider range of services (injecting or withdrawing power and energy as needed) than a generating resource (which can only inject power and energy). And since it doesn't require fuel to be active and connected to the grid, it can operate in "always on" mode and provide grid services as needed without incurring significant costs. A storage device will lose a small amount of energy while operating in standby mode, and may degrade more rapidly if maintained at a high state of charge. But those costs can be managed and, when compared to the fuel costs associated with keeping a generator running, are relatively minimal.

What energy storage cannot do, however, is generate electricity. It can charge from the grid or connected generators and inject that energy into the grid when needed, but it cannot create energy. Storage is also an

[5] Some utilities offer cost-sharing programs for privately owned backup generators to provide grid services when needed. Portland General Electric, for example, pays for maintenance and fuel for private generators in exchange for the right to call on them when required by critical grid needs. See https://www.portlandgeneral.com/business/get-paid-to-help-meet-demand/dispatchable-standby-generation. However, such programs are not standard.

energy-limited resource, meaning that it can only provide as much energy as it is capable of storing before needing to recharge. And because there are efficiency losses involved in storing and discharging energy, a storage device will always provide less energy than what it takes in.

However, when paired with a generator, energy storage offers unique characteristics that create a new paradigm for resilience applications. The storage resource is no longer required to be held at a high state of charge (which incurs losses and degradation effects) or limited to supplying a few hours of electric supply during an outage. When optimized with a solar array, for example, the charge is available from a zero-cost fuel resource and the system as a whole can maintain electric supply over extended periods of electric service disruption. The system's flexibility can provide a range of grid services with a high degree of accuracy, speed, and dispatchability, including instantaneous mode-switching from charging to injection. That versatile combination makes energy storage an enabling resource that, when coupled with generation resources, can leverage and shape that generation to provide backup power to meet resilience goals and, when resilience is not needed, earn offsetting revenue by providing other grid services.

By earning revenue from grid services, energy storage tips the cost-effectiveness scale of resilience investments, thereby enabling a shift from *mission-critical resilience*, where high costs limit participation to sites where resilience is a necessity (such as hospitals and military facilities), to *economic resilience*, where resilience can be pursued by a much wider range of facilities on the basis of cost effectiveness. Figure 2 illustrates this concept:

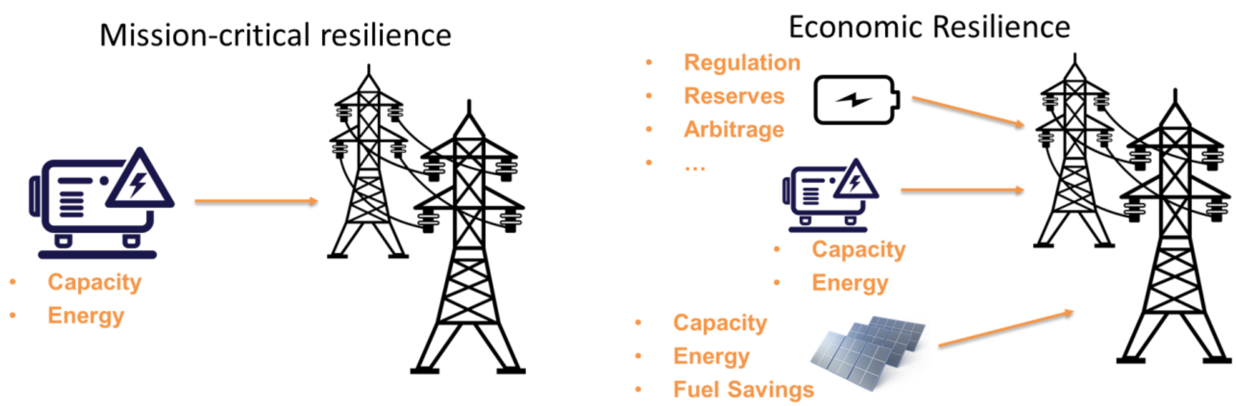


Figure 2: Energy Storage's Role in Enabling Cost-Effective Resilience Applications

The challenge, however, is that while energy storage can offer many services, not all of them are compensated, the value of those services will vary by location, and many of those services are mutually exclusive; that is, the selection of one service for a given time period prevents the selection of other services in that and future time periods. Recent research has illustrated how the value of grid services can change by location and how the value of energy storage can be determined at different points on the grid (Balducci 2018b). Maximizing the value of energy storage requires detailed modeling that can optimize use of the device, subject to local values for grid services and other project objectives, such as resilience.

2.0 Planning for Resilience

The goal of the first resilience presentation at the workshop was to approach resilience from a planning perspective – that is, discussing how to incorporate resilience goals into grid planning processes that are not designed to include them. It had three goals: establishing a common understanding of resilience, exploring the economic challenges associated with resilience investments, and presenting a locational planning framework that defines resilience in terms of critical loads.

2.1 Conceptualizing Resilience

While no standard definition of resilience has been adopted, it is helpful to refer to DOE's working definition for resilience as "the ability of a system or its components to adapt to changing conditions and withstand and rapidly recover from disruptions" (U.S. Department of Energy 2017b). This definition establishes the key difference between reliability and resilience. Reliability is an internal concept, measuring how the grid operates under normal circumstances. Resilience, on the other hand, is an external concept, measuring how the grid withstands and recovers from major disruptions such as storms, cyberattacks, and natural disasters.

Another key difference between reliability and resilience is the existence of standards. Reliability is an objective construct, defined by multiple metrics and standards that can be quantified as objectives for planning processes to achieve.[6] While specific practices vary by utility, resource planning processes generally use linear models designed to solve for a series of variables – such as necessary generation levels, environmental regulations, and reserve requirements. Reliability targets are readily adaptable into this process because they provide concrete variables for the planning model to solve.

Resilience, on the other hand, remains a subjective concept that lacks a standard definition, let alone metrics that can be used to develop tangible planning objectives. As such, traditional resource planning models are not equipped to develop the least-cost, least-risk solution to resilience needs in the same manner as they solve for reliability needs.

For example, IEEE 1366-2012 identifies 13 metrics for measuring distribution system reliability, four of which are commonly used by electric utilities in reliability reporting:

- System Average Interruption Frequency Index (SAIFI): how often does the average customer experience an outage?
- System Average Interruption Duration Index (SAIDI): How long is the average customer without service?
- Customer Average Interruption Duration Index (CAIDI): Among customers who experienced an outage, how long were they without service?
- Average Service Availability Index (ASAI): Throughout the year, what was the percentage of hours in which the average customer had service?

[6] NERC has developed 100 different mandatory standards to ensure electric system reliability. See https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States.

Each of those standards provides a metric that can be used to track reliability performance and plan for improvements. If a particular distribution circuit is underperforming, it can be identified, and planning models can be employed to develop an improvement plan.

IEEE 1366-2012 also identifies two categories of outages that are exempt from reliability reporting: a Major Event Day, which is defined as any day in which SAIDI values are 2.5 times higher than the daily average over the previous five years; and a Catastrophic Day, which is identified, but the definition of which is left to regulators and utilities on a case-by-case basis. Omitting those circumstances ensures that reliability performance is measured under normal operating circumstances and prevents major outages from driving up baselines and obscuring reliability issues.

To illustrate the effect of removing major and catastrophic events, figures 3 and 4 present the SAIDI scores (the total number of minutes that the average customer was without power) for the three subsidiary utilities of the Hawaiian Electric Companies from 2008-2017. Figure 3 presents non-normalized scores (including outages from major events and catastrophic days), while Figure 4 presents normalized scores (excluding outages from major events and catastrophic days):[7]

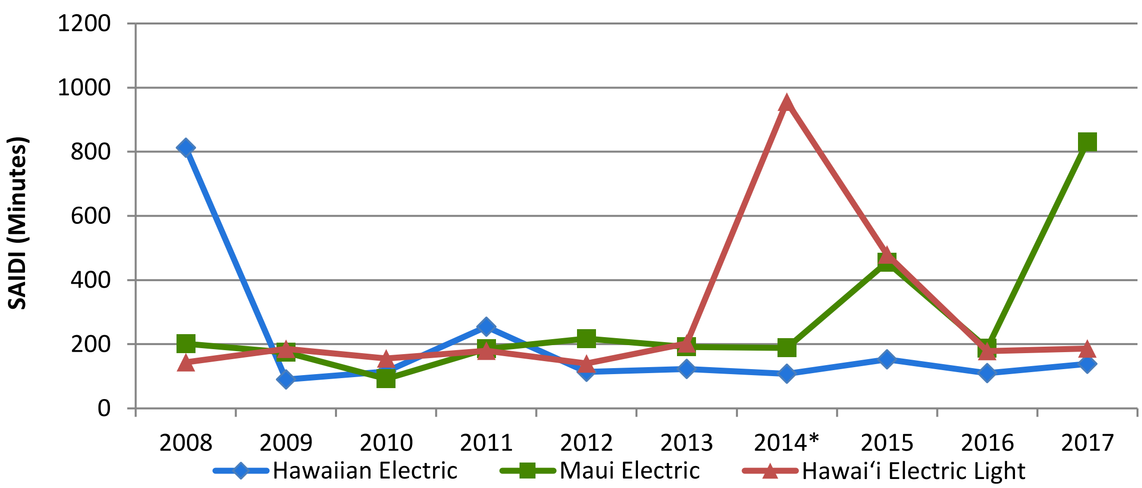


Figure 3: Hawaiian Electric Companies' Non-Normalized Annual SAIDI Scores

[7] SAIDI scores for Hawaiian Electric Companies obtained at https://www.hawaiianelectric.com/about-us/key-performance-metrics/service-reliability.

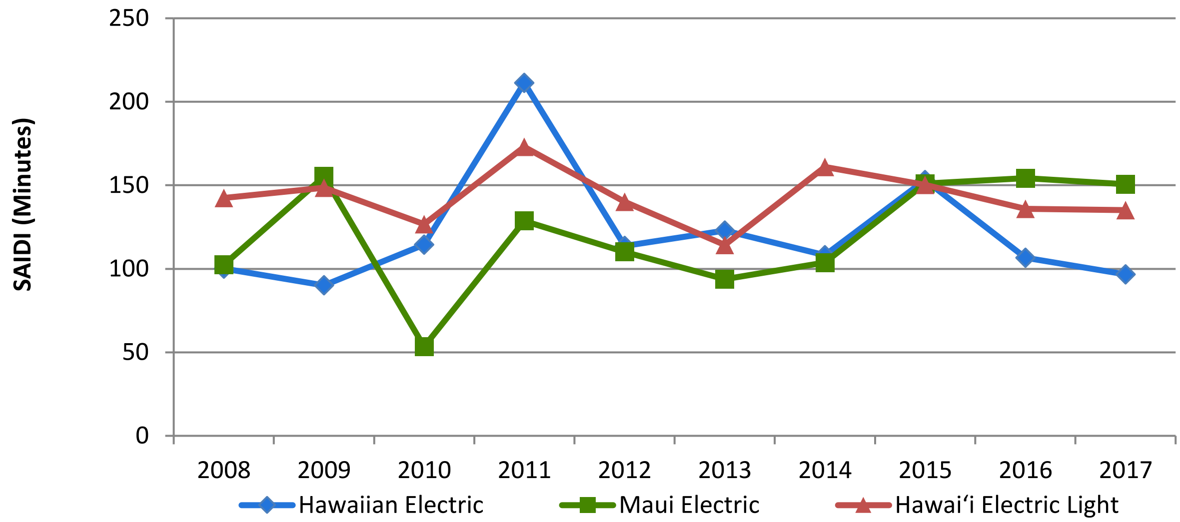


Figure 4: Hawaiian Electric Companies' Normalized Annual SAIDI Scores

Figures 3 and 4 illustrate the impact of normalizing SAIDI scores. Before normalization, each of the three utilities had a year in which SAIDI scores were in excess of 800 minutes, meaning that the average customer in the utility's territory spent more than 13 hours without power that year. After normalization, only one score rises above 200 minutes. Table 1 presents the average SAIDI scores, non-normalized and normalized, for each of the three utilities from 2008-2017:

Utility	Average Non-Normalized SAIDI Score, 2008-2017	Average Normalized SAIDI Score, 2008-2017	Difference
Hawaiian Electric	201.8	121.7	39.7%
Maui Electric	272.5	120.3	55.9%
Hawai'i Electric Light	280.8	142.8	49.1%

Table 1: Average SAIDI Scores for Hawaiian Electric Companies, 2008-2017

As Table 1 demonstrates, normalization has had a significant impact on reported SAIDI scores for the three utilities. Over the previous decade, on average, the act of normalizing SAIDI scores removed 39.7 percent of the outages faced by Hawaiian Electric customers, 55.9 percent of the outages faced by Maui Electric customers, and 49.1 percent of the outages faced by Hawai'i Electric Light customers. In each of the three years in which a non-normalized SAIDI score spiked above 800, the normalized scores removed more than 80 percent of that year's outages from reliability reporting. While normalization ensures that major events do not mask reliability issues on the system, it also removes a large share of the outages that customers experience from the formal reliability reporting and planning process.

But as utilities, regulators, and policymakers increasingly focus on grid resilience, it is those major and catastrophic events that provide a starting place for resilience-based analysis and planning. The underlying data are already available, because utilities are documenting the source and impacts of those major events through the reliability reporting process. In the Hawaiian Electric Light Companies' service territories, for example, the utilities documented the cause and associated impacts of 68 discrete major events from 2008-2017.

A review of those 68 events reveals how location-specific major events can be. The primary source of major events for Hawai'i Electric Light, for example, was under-frequency load shedding events,[8] accounting for 15 of the 32 major events from 2008-2017. Wind and storms accounted for another nine events. In Maui Electric's territory, wind and storms were responsible for 13 of 29 major events during that period, while equipment failures drove six major events. And for Hawaiian Electric on the island of Oahu, wind and storms were responsible for five of the seven recorded events, including an island-wide blackout in 2008.

These events indicate that the most immediate challenges to a resilient grid vary from one utility to another, potentially even in neighboring utilities with similar climates. While wind and storms are a recurring theme across the three utilities, Hawai'i Electric Light's multiple load shedding events and Maui Electric's equipment failures indicate that each utility has different challenges when it comes to resilience. The type and impacts of those major events have significant implications on the type and siting of investments that will offer material improvement in grid resilience. As will be discussed in Section 4, translating those events into grid impacts is an important, but challenging part of the resilience planning process.

2.2 The Economics of Resilience

Identifying where resilience investments may be needed is only the first challenge, however. Once those needs have been identified, resilience faces economic hurdles that other grid values do not face. As noted above, NERC has set reliability standards that utilities are required to meet. If a particular planning scenario identifies a reliability deficiency, the investment need is treated as a necessity by both the utility and its regulators, and the only question relates to identifying the most cost-effective means of meeting the reliability need. But there is no corollary standard for resilience, and absent some form of standard or other policy support, resilience investments must be cost-effective based on the values created by reliability standards.

But given how rarely resilience is needed, pursuing it on a standalone basis is unlikely to ever prove cost effective. For example, refer again to Table 1. The difference between average non-normalized and normalized SAIDI scores for the Hawaiian Electric Companies range from about 80 minutes to about 152 minutes. On an annual basis, that only accounts for about 0.01 to 0.03 percent of all hours in a year. Even in the outlier years, in which each utility had a non-normalized SAIDI score above 800, the time removed in the normalization process only represents about 0.1 percent of all hours in the year for the utilities.

So even if a resilience investment could eliminate all those outages, it would only be called upon for a few hours each year. With such limited opportunity to recover its costs, any investment would likely prove too expensive. The ability of a resilience investment to prove cost effective, then, depends on its ability to generate value the other 99.9 percent of the year.

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[8] An under-frequency load shedding event is when a large amount of generation drops off the grid and insufficient generation relative to load causes grid frequency to rapidly drop below 60 hertz, and the utility cuts service to a subset of customers to rebalance its load with the reduced level of generation.

Generating value across a larger share of the year requires the inclusion of assets that can provide a broad range of services. As noted above, the multi-faceted nature of energy storage makes it an ideal option for providing resilience alongside other grid services. The need for generating value throughout the year also suggests that a portfolio approach to resilience – investing in a range of resources that can provide multiple services – is not only preferable, but in the absence of clearer standards or policies around resilience, likely necessary.

For example, a solar array provides no-fuel-cost energy, but cannot be dispatched as needed and has very little flexibility. A diesel generator can be dispatched as needed, but requires the purchase and storage of fuel (which carries economic and safety risks), and creates emissions, which carry additional costs in some jurisdictions. Energy storage can create flexibility by shaping generation to loads and providing multiple grid services, but cannot generate power. A portfolio approach that considers the complementary roles of different resources and their tradeoffs enables an adaptive approach to resilience planning that can be optimized to meet each project's specific objectives while maximizing revenue from the provision of grid services.

Economics also have a limiting factor on the scope of resilience investments. For example, if a major event of concern would interrupt service to a large share of the utility's customers, it would likely be prohibitively expensive to build enough resilience into the system to maintain backup service for all of those customers. But if resilience goals can be broken down into more granular tasks – such as improving resilience for a single customer or small subset of customers who have a critical energy need – cost-effective solutions may be more readily identifiable.

2.3 Proposed Planning Framework for Resilience Investments

The preceding sections identified some of the unique challenges associated with improving grid resilience, including the infrequent and varying nature of major disturbances, siting resilient assets, the economic hurdles that resilience investments face under current regulatory structures, and the potentially excessive costs of attempting to improve resilience at the system level.

Traditional utility resource planning processes, which seek to optimize reliability and costs from a systemwide perspective, are not suited to identify the specific, localized needs associated with resilience. Nor are they designed to evaluate the locational benefits of resources deployed to improve resilience and support the local grid. Identifying where increased resilience is needed and evaluating the investment options that can provide both resilience and economic grid benefits requires a more granular approach to planning.

To identify cost-effective resilience investments, traditional, top-down planning processes may be complemented by bottom-up models that take a locational approach to resilience. Since there are no standards for measuring resilience, it is important that the process articulate clear goals for resilient investments to accomplish. By defining success first, those goals can be translated into tangible planning objectives.

Five guiding principles form the framework of this locational approach to resilience:

- Define critical loads;
- Identify major events of concern;
- Establish planning objectives;

- Engage in iterative planning between the project and the local grid to meet the needs of both; and
- Throughout the process, consider questions of ownership, cost allocation, and rate design.

In taking a locational approach to resilience, the first step is to define the critical loads that must be maintained during a major or catastrophic event. It may be helpful as a thought exercise to ask, “If the entire electric grid went down for an extended period, what are the facilities that must be powered?” Some answers, such as hospitals, emergency command centers, and shelters may seem obvious. But as will be discussed in greater detail in Section 4, there may be other, less obvious loads that must be maintained for public health and safety. There is also some subjectivity in this exercise; critical loads from a social perspective will be different from critical loads from a private perspective. Furthermore, those loads will vary from one place to another, and identification and prioritization of those facilities likely requires a broad discussion involving stakeholders from multiple sectors.

Once a critical load has been defined, the first step in planning to make it more resilient is to identify the specific major events that have interrupted service to the load, or that may interrupt it in the future. Historical and recurring events that have affected the load may be identified through a review of utility reliability reports, which should document the source and grid impacts of major events. Consideration should also be given to potential extreme events – the types of “catastrophic” events identified, but not defined in IEEE 1366-2012. Whether it is a hurricane, an earthquake, a flood, or something else, every region faces a potential event that would have severe and widespread impact on the electric grid. Identifying and quantifying those risks serves as an upper bound for planning – the worst-case scenario against which the grid needs to be resilient.

By understanding the “shape” of the need – how frequently the event occurs, the infrastructure that it affects, how long service is interrupted – tangible planning objectives can be defined. Does distribution infrastructure need to be hardened? Is backup generation necessary? How long will that generation need to support the load?

As an example of defining resilience objectives, the U.S. Army issued a directive in 2017 requiring all of its facilities to identify their critical missions and be able to independently sustain the water and energy needs of those missions for 14 days (Secretary of the Army 2017). The planning tool discussed in Section 3 of this report was designed to assist military facilities in meeting that directive, and Section 5 provides some examples of how facilities have responded.

Once planning objectives have been designed, iterative planning must be done at both the infrastructure level and the project level. At the infrastructure level, local grid needs that the resilient asset could monetize should be identified (such as voltage support, transmission and distribution deferral, frequency response, etc.). Additionally, the technical constraints at the selected site should be identified. Is there sufficient interconnection capacity on the distribution feeder? Does the feeder have sufficient communications infrastructure to allow for grid interoperability of the resilient asset(s)?

With the resilience need defined and potential grid values identified, project-level planning can use those as inputs to identify the investments that will most efficiently meet the resilience need while maximizing offsetting revenue from grid services.

Iterative planning between the two levels may be necessary. Just as local grid needs and constraints will inform the selection of a resilient asset, selection of a cost-effective investment may also require local grid upgrades to enable it to interconnect and interact with the grid. Understanding those relationships, and how decisions at one level affect operations at the other level, is necessary to achieve optimal outcomes.

The final principle of the proposed locational approach to resilience planning does not represent a last step; rather it relates to three, interrelated factors that will inform the planning and resource selection process, and should be considered throughout: ownership, cost allocation, and rate design.

Utility ownership of resilient assets may be preferable, given the utility’s visibility into system operations and ability to readily capture the grid values of the asset. But where BTM assets are a viable source of resilience, and prohibitions against utility ownership of BTM assets are in place, there may be a need for customer or third-party ownership of resilience assets. Where state policies establish incentives or preference for customer-owned assets, a utility’s responsibility may shift from procuring its own resilience resources to integrating and potentially managing customer-owned resilient resources.

Regardless of ownership, resilience raises complicated questions of cost allocation. The underlying question of cost allocation is, “Who benefits?” In the instance of resilience, that becomes a complicated question. Reliability is treated as a system property, whose costs are generally socialized across all customers. Even if a required reliability upgrade only directly benefits a subset of customers, all customers generally pay for it. Should resilience be viewed in the same terms? Is it a system property, for which all customers pay, or is it a local property, for which only the benefitting subset of customers pay? Different sites may have different answers; resilience at an emergency command center or shelter available to all customers may be a system benefit, but resilience at a commercial center or industrial facility may only benefit a narrow subset of customers. Regulators may want to consider developing generic approaches for identifying the beneficiaries of resilience investments and fairly allocating their costs among customer groups.

Where customer or third-party ownership of resilience assets is preferred or required, detailed ratemaking will be required to incent customer adoption of resilient assets and their optimal usage while establishing fair compensation for the grid services that they provide. By using tools such as time-of-use rates and demand response, or by creating microgrid service tariffs, customers can be given price signals to use their resilient assets to meet other grid needs, which will also generate revenue for the customer to recoup the costs of the investment.

3.0 Microgrid Component Optimization for Resiliency Tool

The goal of the second resilience presentation was to describe a planning tool developed at PNNL for the Army Reserve and the Army Office of Energy Initiatives to identify the optimal configuration of a microgrid system given a stated resilience goal and economic constraints.

The Microgrid Component Optimization for Resiliency Tool (MCOR) was designed to assist Army bases in meeting energy security needs and has been used at seven facilities. Once a facility has identified its critical loads and resilience needs (i.e., how long the facility would need to operate in islanded mode), MCOR considers existing onsite generation resources and identifies how much diesel generation, solar PV, and energy storage will be required to meet those needs.

The tool offers several benefits:

- Incorporation of resilience metrics into the planning process;
- Consideration of multiple resource alternatives, with varying capital costs and fuel requirements for each;
- Identification of the tradeoffs between resource costs and risk tolerance;
- A stochastic approach that considers weather variability and risk; and
- Consideration of external economic drivers, such as utility rate structures and net metering policy.

MCOR's focus on resilience results in slightly different functionality when compared to a system planning model, such as those used in integrated resource planning. A system planning model's primary objective is economic – optimizing a dynamic portfolio of resources against projected needs over long-term, average conditions to minimize costs and risks. MCOR's primary objective is performance – identifying the capability of a microgrid portfolio to meet a given resilience goal under varying conditions.

MCOR's use of stochastics allows it to evaluate how a given portfolio will perform under a wide range of circumstances, not just average conditions. Rather than just identifying how much energy a PV array will produce under average circumstances, for example, the model considers how the array will perform under various conditions – sunny days and cloudy days – and its impact on the microgrid's overall performance. Figure 5 illustrates minimum and maximum potential generation for a 1-kilowatt PV array at an example facility:

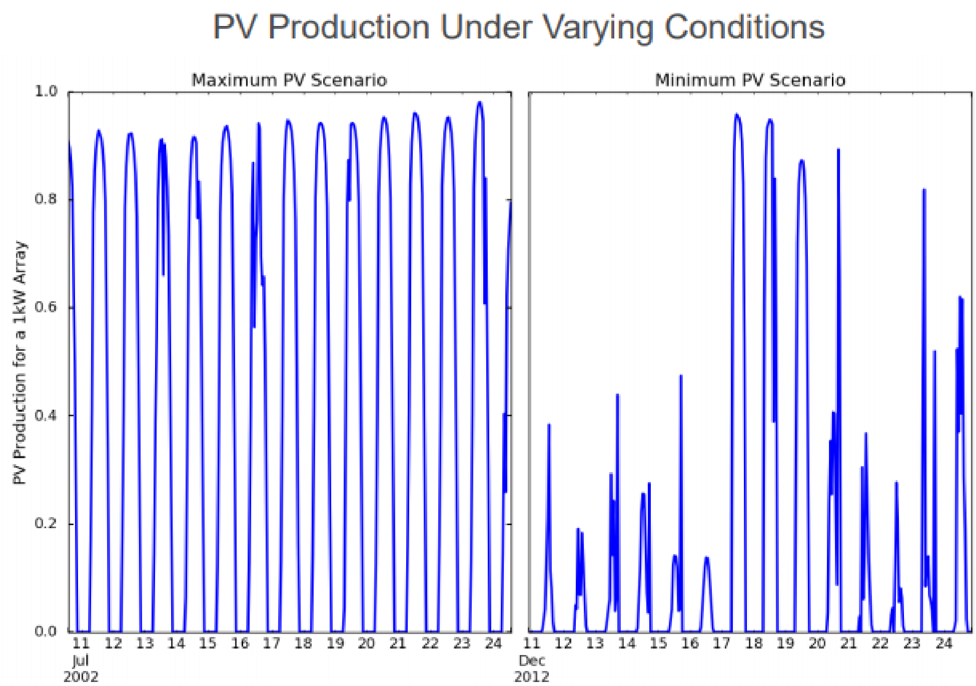

Figure 5: Maximum and Minimum Weekly Solar PV Production at an Example Site
AC power production from a sample 1-kW PV array during two, two-week periods, one with maximal PV resources (left) and one with minimal resources (right). The two-week periods were generated from a stochastic model with historical data used to seed the initial hour.

This stochastic approach adds a risk component to resource analysis – ensuring that decisions are made based not only on resource economics and expected performance, but the risks associated with underperformance and unfavorable external factors, such as inclement weather or high fuel costs. Stochastic analysis is a common tool used in electric system planning, but is not commonly used in planning tools at this scale.

Stochastic analysis is particularly important for resource planning when resilience is a desired outcome. Understanding how resources will perform under a variety of circumstances is a crucial component to assessing the likelihood that a given portfolio will meet a resilience goal. In the case of a microgrid, for example, understanding how the PV array can meet load and charge a storage device under a variety of solar conditions can help size the array in a manner that balances its cost with its performance.
Figure 4 illustrates how the tool considers different microgrid configurations across multiple scenarios to develop an aggregated result that communicates each portfolio's performance in terms of both cost and fuel requirements under a large range of conditions:

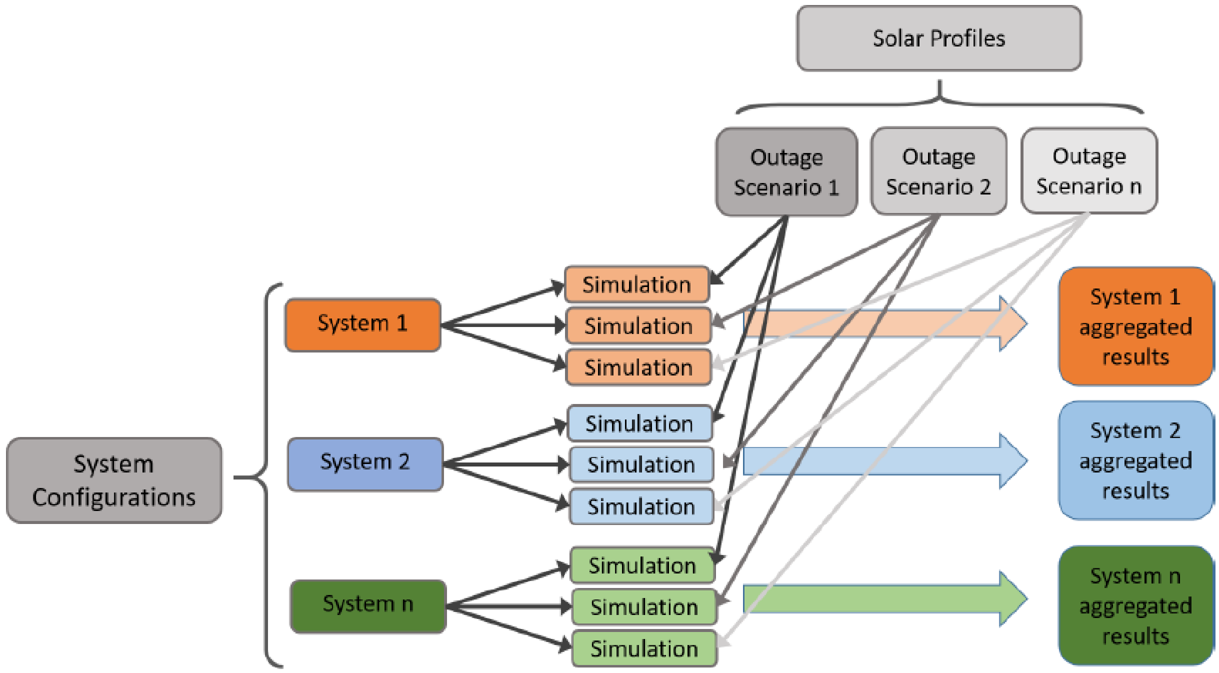

Figure 6: Microgrid Planning and Optimization Tool Overview
MCOR simulates several different microgrid portfolios (called 'systems' above), each under many different outage scenarios. The scenarios are generated according to a stochastic model based on 20 years of historical solar and temperature data, and allow the systems to be simulated under both typical and extreme conditions. Once the simulations are run, they are aggregated for each of the microgrid portfolios, allowing the user to view several performance metrics for each portfolio.

MCOR selects candidate microgrid portfolios by identifying which ones meet the resilience goal in all of the scenarios analyzed. For each candidate portfolio, the tool identifies the capacity of resources (generators, PV, and batteries), capital cost of the portfolio, how much of the load is met by each component, and total fuel consumption.

Functionally, the tool begins with a fixed amount of PV and storage capacity and then marginally sizes a diesel generator to meet the remaining load in each scenario. It first uses daily PV production to serve the site load, with any excess production used to charge the battery, and then dispatches the battery to meet load overnight. Finally, the model sizes the generator to meet any remaining load in the scenario. Depending on the performance of the PV and battery in each scenario, the size and dispatch of the generator will vary. Figure 7 depicts the range of generator outcomes across scenarios for a given portfolio:

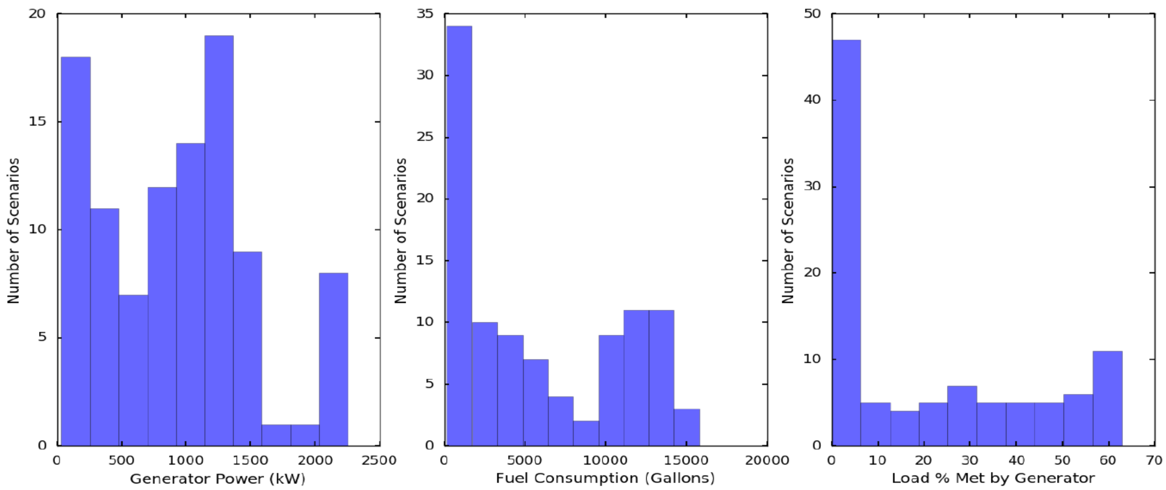

Figure 7: Stochastic Outcomes for Diesel Generation
Histograms of the diesel generator capacity required to meet all load (left), fuel consumption during the islanded period (middle), and percentage of the site's critical load that is met by the generator (right) for a single microgrid portfolio across 100 outage scenarios.

Once several portfolios have been evaluated, the tool offers several metrics for comparing them, including simple payback and fuel consumption, and different ways to visualize those metrics. Comparison graphs include heatmaps which look at how one metric varies across portfolio capacities and bubble charts which compare two metrics simultaneously. Figure 8 demonstrates some of these visualizations:

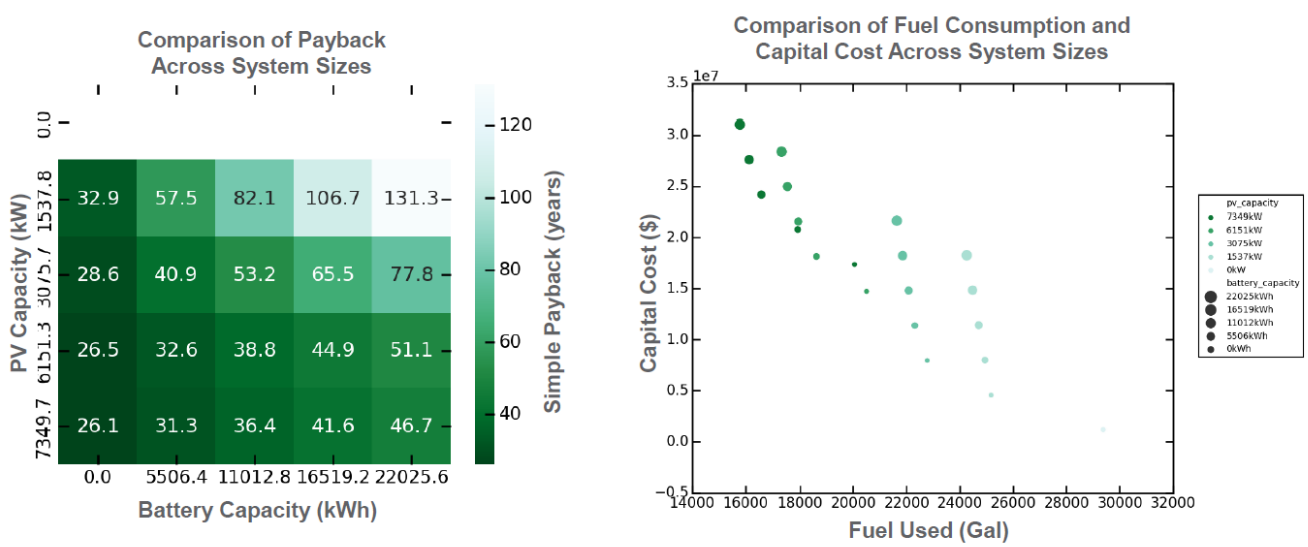

Figure 8: Portfolio Comparison Visualizations
Left: Simple payback time as a function of PV array size and battery capacity for a sample site. Right: Comparison of system capital cost and the average generator fuel consumption as a function of PV array size (represented by bubble hue) and battery capacity (denoted by the bubble size). For both graphs, the battery power to energy ratio is 0.25.

MCOR's developers are planning a series of enhancements to the tool, including an advanced battery discharge algorithm capable of considering ancillary services, more complex pricing options, an improved resource sizing algorithm, and the ability to optimally size multiple generators for redundancy.

4.0 Audience Discussion

Audience participation and feedback was a key goal of the workshop. Organizers wanted to hear directly from electric industry stakeholders about the challenges they face and how research efforts might be directed to assist them in addressing those challenges. Input from a Hawaii audience was of particular interest, as the combination of geography and climate make resilience an issue of immediate concern for the state. Hawaii is an active leader on resilience-based policy development, as the Hawaii Legislature passed a bill in 2018 directing HPUC to facilitate increased electric system resilience through the adoption of a microgrid services tariff (Hawaii State Legislature 2018). The Commission has an active docket to implement the legislation.[1] Hawaii also has a collaborative agreement in place with PNNL to improve resilience throughout the island's infrastructure. Understanding the work being done in Hawaii provides an opportunity to inform electric system resilience policymaking in other states.

Five key themes emerged during the discussion:

- Identifying and prioritizing critical loads;
- Quantifying the grid impacts of catastrophic events;
- Defining the relationship between the military, utilities, and customers in building resilience;
- Determining where microgrids are needed and developing the technical and regulatory infrastructure necessary to enable them; and
- Further refining resilience planning tools to increase functionality.

A key message of the planning section was that identifying critical loads is a location-specific exercise. While presenters identified critical loads such as emergency facilities and shelters, the audience pointed out that in an emergency situation, Hawaii would be dependent on a working port to receive assistance and supplies – making ports a critical load. Additionally, since many of the islands' communities are built on mountain slopes, maintaining the ability to pump water has significant public health impacts. Finally, since the islands consistently host a large number of tourists, restoring power to resorts was identified as a high priority.

The identification of two types of critical load – ports and resorts – that would likely not be a priority for a mainland utility illustrates the highly localized nature of critical load identification. In their discussion, audience members acknowledged that there were likely other critical loads that they hadn't identified, and that a thorough identification of critical loads would likely be a complicated process involving input from multiple sectors of the economy.

Once those loads have been identified, audience members suggested that prioritizing which loads to make more resilient would be an additional challenge. While economics would be an objective way of doing that, by prioritizing the loads where interruptions inflict the highest costs, workshop attendees from California said that a primary challenge their state had encountered in pursuing increased resilience was identifying the costs associated with lost loads to various types of customers. Tools have been developed to generally identify the costs of lost load to broad classes of customers, but a need was expressed for tools that can identify interruption costs at a more granular level. Audience members suggested that DOE

[1] Docket 2018-0163. Accessible at https://dms.puc.hawaii.gov/dms/dockets?action=details&docketNumber=2018-0163.

and the labs could assist by developing generic procedures, metrics, and tools for identifying and prioritizing critical loads.

A second theme was the complexity of quantifying a potentially catastrophic event in terms of grid impacts. In the event of a catastrophe such as a hurricane or a tsunami, the audience wondered, what would the specific impacts to the grid be? Whether the grid would be expected to be down for a period of days, weeks, or months significantly influences the type and size of resilient assets needed, audience members noted, particularly for a large load such as a port. Questions were also raised to the degree of black start planning that the utility had developed, and whether multiple plans were in place to address multiple scenarios. Based on the questions raised, it appears that there may be a need for greater collaboration between emergency management agencies, utilities, and regulators to establish a mutual understanding of potential grid impacts of a catastrophic event and the plan for remedying them.

The third theme explored the relationship between the utility and different customer groups when it comes to making resilience investments. The conversation focused on two particular groups of customers: the military and residential/commercial. Regarding the military, the audience noted that the defense sector accounts for a significant share of Hawaii’s electricity consumption, and that the military has its own internal drivers for energy resilience. Should the utility have a role in helping military facilities achieve those goals? If so, how should those costs be assigned? Conversely, is there a way to leverage the resilience investments made by the military to benefit customers in general?

Regarding commercial and residential customers, as noted in Section 1, electric rates and state policies have already driven a significant level of private investment in BTM resources that could potentially be leveraged for resilience applications. If customers are already willing to make those investments, how can rates be designed in way that will encourage customers to use their assets for resilience purposes, or to incent new investment in BTM resources for resilience? Audience members mentioned that distributed assets may be particularly valuable in black start scenarios, but that rates and tariffs would have to be structured in a way that enables that functionality and compensates customers for providing it. The degree to which a utility can leverage existing private assets may also have significant impact on the need for new utility investments.

The fourth theme related to the usage of microgrids for resilience purposes. As previously noted, there has been significant interest in microgrids in Hawaii, including a legislative mandate requiring HPUC to develop a first-in-the-nation microgrid services tariff. But Commission staff and others in the room noted that microgrid planning introduces a number of complex questions, including siting and sizing of the microgrid. Technical questions, such as the switching infrastructure necessary to isolate the microgrid and the communications infrastructure necessary to enable grid interactivity, were also raised.

Questions during the MCOR presentation focused on model functionality, and provided insight into the concerns of utilities and stakeholders as they consider resilience investments. Audience members expressed particular interest in whether the tool could be expanded to include ancillary services, as that analysis would provide further economic justification for installing microgrids beyond resilience. Expanding the model to include other forms of generation, including distributed wind, was also suggested.

5.0 Emerging Models for Resilience

To further inform this report and its conclusions, the authors conducted a brief review of four recent, significant projects undertaken in the U.S. that had resilience as a primary objective. Given significant military interest and activity on the subject of resilience, the review looked at two resilience projects at military facilities and two projects at civilian facilities. The structure and usage of these projects offer important insights into the principles of successful resilience investment.

Military: Marine Corps Air Station Yuma (Arizona)

In 2014, the Marine Corps Air Station at Yuma, Arizona (MCAS Yuma) identified a need for improved power quality and reliable backup power, citing the costly impacts of power outages on the base (Monohan and Morton 2018). MCAS Yuma reached an agreement with its utility, Arizona Public Service (APS), by which MCAS Yuma would provide land onsite for APS to build, own and operate a 25-megawatt microgrid on the station, which would operate in island mode to power the base during grid outages and be dispatched by APS to benefit the grid during normal operations (U.S. Navy 2017).

All generation is provided by diesel generators, though an expansion to include energy storage is also being considered (Monohan and Morton 2018). For APS, the MCAS Yuma microgrid provides a capacity resource and relieves transmission congestion on the utility's system. For MCAS Yuma, the reliable backup power meets Marine Corps resilience requirements for 14 days of onsite power generation and reduces maintenance costs by about $300,000 per year (*id.*).

Military: Pacific Missile Range Facility (Hawaii)

The Pacific Missile Range Facility (PMRF), a Navy base on the island of Kauai in Hawaii, has entered into an agreement with its electric utility, the Kauai Island Utility Cooperative (KIUC), for a 14 MW solar and 14 MW/70 MWh storage project to be built on the facility. PMRF provided the land for the installation, and KIUC offered an accelerated interconnection process. The facility will be developed by AES Distributed Energy, Inc., and its output will be sold to KIUC through a power purchase agreement (Hawaii State Energy Office 2019).

For KIUC, project values include low-cost power (10.58 cents per kWh versus retail rates that fluctuate between 30 and 37 cents per kWh based on oil prices), renewable portfolio standard compliance, reduced fuel consumption, and dispatchable power that can serve 6,000 homes per year (Hawaii State Energy Office 2019 and Rockwell 2019). For PMRF, the project will operate in islanded mode during grid outages to provide reliable backup power (Rockwell 2019).

Civilian: Green Mountain Power (Vermont)

In 2015, Vermont utility Green Mountain Power launched a first-of-its-kind program to partner with customers to install BTM storage throughout its service territory. The program has gone through three iterations, but at its core, the utility shares the cost of installing BTM storage devices with customers. During normal operations, Green Mountain Power controls the devices, and can dispatch them based on market needs and grid conditions (St. John 2015). In 2018, the utility used the devices during a heat wave to reduce its demand and save $500,000 (Walton 2018).

Customers who participate in the program are given the ability to island the battery, allowing it to power their home during grid outages. The current version of the program, called Resilient Home, allows participating customers to have up to two storage devices, capable of powering an entire home for 12-24 hours. It is also piloting the use of BTM storage as a meter and a bring-your-own-device program (Green Mountain Power 2019).

Civilian: Sterling Municipal Light Department (Massachusetts)

In 2016, the Sterling Municipal Light Department (Sterling) added a 2 MW, 3.9 MWh battery storage system to an existing 2.4 MW solar array to create a microgrid to support municipal operations. In islanded mode, the facility can provide emergency backup power to the police station and dispatch center for up to 12 days (Clean Energy Group 2019). Under normal grid operations, Sterling can strategically dispatch the system during periods of peak demand to reduce the capacity and transmission charges it pays to ISO New England.

Ex ante analysis of the project estimated the grid benefits to be about $288,000 per year, which would result in a 6.7-year payback on the battery. In the first year of operations, actual grid benefits were about $396,000 (Clean Energy Group 2018).

Common Principles of Resilience Projects

Though these projects were deployed across the country by different entities with different objectives, they collectively demonstrate four common principles of successful resilience development:

Resilience benefits are hyperlocal. In each of these cases, a single entity is capturing the resilience benefits of the project. The size of that entity varies significantly, from a large military base to a single residence. But in each case, the resilience benefits flow to a single, finite customer. Even in the case of Green Mountain Power, where investments are spread across hundreds of customers and grid benefits result from broad participation, the resilience benefits of the program flow individually to each participating residence.

Project feasibility is achieved by providing grid services. Each of the customers in these cases shared in the costs of deploying the project, either through direct cost sharing or in-kind contributions of land. But in every case, financial viability is achieved through an operational partnership with the utility, which has the operational experience and grid visibility to leverage the devices for maximum benefit. While resilience benefits flow to a single customer, partnership with a knowledgeable operator (such as a utility or third-party aggregator) is necessary to generate revenues and cost savings to pay back the cost of the initial investment.

Local value drives each project. While full optimization of a microgrid asset will likely entail capturing multiple revenue streams, each project's primary financial driver is based on meeting a specific, local grid need. Whether managing grid constraints and providing needed capacity for a vertically integrated utility in Arizona, reducing operating costs for a utility co-op in Hawaii, or peak shaving for utilities in a regional market footprint, these projects achieved success by identifying and serving high-value needs of the local grid.

Energy storage is a key enabling technology in resilience applications. Three of the four projects studied included energy storage, and the fourth was considering adding it. In Hawaii, storage serves to shape the solar generation to meet the utility's needs during regular operations and the military facility's needs during an outage. In Vermont and Massachusetts, storage satisfied customer resilience needs, and utilities leveraged it during regular operations to discharge during high demand periods and reduce generation and transmission costs for all customers.

These principles support the themes presented in this paper. Absent direct standards and metrics for resilience, resilience investments must achieve financial viability by providing the monetizable services created by reliability standards. And since improving resilience writ large is a vague and expensive proposition, a local approach allows for resilience goals to be subdivided into more granular, manageable objectives. By identifying resilience needs at a granular level, quantifying monetizable needs on the local grid, and developing a portfolio of resilience investments that can satisfy both, resilience goals become more achievable and investments are more likely to be cost effective.

6.0 Conclusion and Recommendations

Lacking underlying standards and metrics, electric grid resilience remains a subjective, and therefore complicated, topic. While national discussion on the matter continues, no clear process has yet emerged by which resilience standards might be established. Facing urgent risks to the grid, Hawaii and other states are not in a position to wait on uncertain outcomes. This report, chronicling a workshop involving a diverse array of industry stakeholders and additional research, identifies a planning framework that may be used to identify opportunities for cost-effective resilience investments absent underlying standards.

In taking a locational approach, this framework distills the ambiguous and costly proposition of increasing electric grid resilience into manageable increments. By establishing where resilience is needed in terms of critical loads, identifying local grid needs, and employing granular models capable of identifying investments that will satisfy resilience needs while paying for themselves through the provision of grid services, this framework can be employed under current regulatory regimes.

Based on the research conducted for this workshop and the feedback from attendees, we recommend that DOE and the national laboratories consider the following steps to advance energy resilience research:

1. **A practical and implementable approach to energy resilience is a *locational* approach, which defines it in terms of critical loads**. When contemplated at the bulk power level, resilience is a vague and expensive proposition. Absent clear standards, identifying where it is needed and how to cost-effectively provide it is a complex challenge. By using a locational approach to resilience planning, one that defines needs in terms of critical loads, resilience objectives can be expressed in tangible, manageable terms, and solutions can be developed on an incremental basis. However, as identified by workshop audience members, complicated questions remain, such as how critical loads may be identified and prioritized, how to translate major events into grid impacts, and how to enable resilient infrastructure. By taking a locational approach to resilience, research efforts would be better equipped to answer these questions and better assist states in building a more resilient energy system.

2. **Granular planning tools should continue being refined and, where appropriate, integrated with one another.** MCOR's developers indicated that they hope to include a more detailed battery modeling component in future iterations of the tool. PNNL, funded by the Energy Storage Program, has developed the Battery Storage Evaluation Tool (BSET) to conduct detailed modeling of the benefits of energy storage, and work is being done to integrate BSET's capabilities into the MCOR tool and create a publicly accessible microgrid planning tool. Through various programs, DOE and the national laboratories have developed many tools that model the grid from different perspectives. A review of those tools to integrate them where feasible and refine them to be more user-friendly would give utilities, regulators, and other industry stakeholders improved visibility into resilience needs and potential solutions.

3. **Additional research is needed to inform microgrid service tariff development.** Microgrids will be a key component of resilience investment plans, given their ability to both provide local resilience during an outage as well as other grid services during normal operation. Incenting customers to make and optimally operate those investments, however, will require tariffs that establish appropriate price signals and compensation. Developing those tariffs is a challenging exercise that requires detailed inputs about locational values and grid services that generally haven't been included in regulatory proceedings. DOE and the national laboratories, with their modeling tools and expertise in microgrid operations, can be a valuable tool in assisting states through that process and sharing best practices as they emerge.

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