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Consumer Benefits of A Clean Energy Transition: The resilience value of residential solar + storage systems in the continental U.S.

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Consumer benefits of a clean energy transition:

The resilience value of residential solar + storage systems in the continential United States

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December 2024

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The resilience value of residential solar + storage systems in the continental U.S.

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This paper is an overview of a series reports on **Consumer Benefits of a Clean Energy Transition.**

Meeting national and state decarbonization goals requires a transition to clean energy technologies. Energy efficiency, demand flexibility, renewable energy and storage can reduce consumers' electricity bills, lower total electricity system costs, and provide health and resilience benefits. Berkeley Lab developed a series of briefs that explore these consumer benefits of a clean energy transition:

1. ***Contribute to a least-cost electricity system*** by using low-cost resources such as end-use efficiency, demand flexibility, behind-the-meter solar PV and storage, and utility-scale renewable energy.
2. ***Greenhouse gas emission reductions and improved outdoor air quality*** from consumers shifting their home energy consumption from direct combustion of natural gas to efficient electric appliances, taking into account increased electricity generation due to demand growth.
3. *Improved resilience* of homes to grid outages due to installation of BTM solar PV coupled with storage.

Together, these briefs highlight how investments in clean energy technologies can provide benefits to all electricity system customers – not just those who invest in these technologies for their homes. The series also outlines options that state policymakers can pursue to facilitate the beneficial outcomes discussed.

Download the reports here.

Executive Summary

Clean energy resources that are located behind the meter have the potential to benefit the hosting customers by providing affordability, environmental, and reliability and resilience value (see Akhil et al. (2015), Balducci et al. (2018)). In turn, an electricity customer's motivation to adopt backup power systems is driven by a desire to mitigate long duration interruptions – "resilience events" that are defined as interruptions lasting longer than 24 hours – and increase their resilience (Gorman, 2023). Solar plus storage systems (PVESS) are clean energy resources that can supply backup power without requiring fuel resupply or increasing local emissions. PVESS can also allow users to consume more of their own PV production rather than exporting it to the grid, reducing energy bills. Whereas these benefits are well studied, the quantitative resilience benefits of PVESS are less understood. Estimating resilience benefits of PVESS requires quantifying the inherent value of mitigation of loss of load and accounting for regional differences in outage characteristics, both of which are challenging and complex. Furthermore, economic adoption of PVESS depends on the benefits of resiliency outweighing the upfront cost to invest; relatively uncertain costs of PVESS as an emerging technology that relies on incentives and shifting future costs complicate these benefit cost analyses.

This report examines the regional value of PVESS for resilience by calculating a benefit-cost ratio (BCR) that considers the annual resiliency benefits of PVESS and the annualized cost of the investment. A BCR above 1 means that the expected annual benefits surpass the annualized costs of storage, supporting investment in the technology. We first estimate the likelihood of occurrence for long duration events at the county level by combining reported long duration outages from 2000 to 2022 with probability curves for extreme events to calculate the average frequency and duration of these *resilience events*. Next, we estimate the expected technical mitigation potential of PVESS systems at the county-level to these expected events. We then characterize the customer interruption costs by determining the value of lost load (VOLL) at the state level. Using regional cost estimates for PVESS, we then conduct a partial benefit-cost analysis of PVESS operation for resilience benefits that includes a sensitivity of the base case that considers the financial benefits of the Investment Tax Credits (ITC) and bonus tax credits in the Inflation Reduction Act (IRA). This analysis is complemented by a comprehensive sensitivity analysis to the number of resilience events, PVESS costs, and VOLL to examine their impact on customer decision making.

On a technical level, the introduction of PVESS mitigates and in some cases eliminates expected load loss across all regions. The range of annual expected loss of load was 0 to 63 kWh among all counties before PVESS. The introduction of PVESS substantially reduced demand losses during simulated resilience events, resulting in a reduced expected loss of load ranging from 0 to 15 kWh (a mean reduction of 96%). When we apply a sensitivity of more frequent weather events, we find loss of load reduction remains 96%, which means that 96% of the potential energy lost due to interruptions is actually mitigated by the PVESS.

The BCR for this base case suggests resilience benefits provided by adding storage units to existing PV accounted for an average of 14% of the costs of the battery storage investment (i.e., a 0.14 BCR), with a range spanning from zero to 58% of the costs. Roughly half of the 2,519 counties have a BCR under 0.1 and only 12% have a BCR greater than 0.3 (see Figure ES-1)

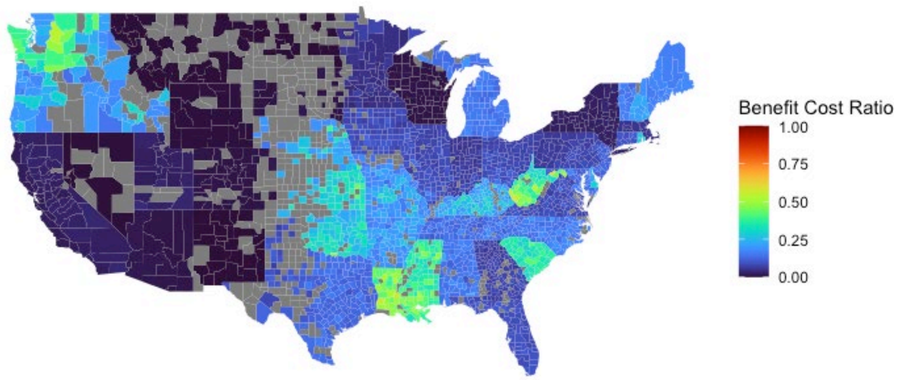

Figure ES-1 Resilience BCR of storage in by FIPS region in the baseline scenario.

We examine the BCR with respect to four key sensitivities:

- More frequent extreme weather events: Doubling of resilience event frequencies roughly corresponds to doubling of the resilience BCR of the baseline scenario: regions with higher numbers of resilience events of longer duration exhibited improved resilience BCRs. The resilience benefits of storage were found to account for an average of 41% of the investment costs for the storage system, ranging from 0% to 117%. Note this sensitivity only accounts for increased frequency, not for increased severity of events.
- Higher and lower VOLL: We considered a broader range of values for the VOLL during resilience events by calculating the resilience BCR with a VOLL equivalent to 0.25 and 2.5 times the base value, respectively. Regions higher VOLL exhibited an increase in their average resilience BCR from 0.14 to 0.36.
- Lower storage costs: We examined conservative and advanced cost reduction scenarios for storage. The maximum BCR achieved increases from 0.58 to 1.05 and 1.74 in conservative and advanced cost reduction scenarios, respectively. The average BCR increases from 0.14 to 0.25 and 0.41 in conservative and advanced cost scenarios, respectively. In the conservative cost scenario, only regions in states that experience frequent extended periods of resilience challenges (e.g. Louisiana and West Virginia) had a BCR exceeding one. However, when considering the advanced cost reduction scenario, counties in a broader range of states, including Washington, Mississippi, South Carolina, Kansas, Oklahoma, Kentucky, Missouri, and Nebraska, have BCR values greater than 1 and support the economic rationale for storage investments.
- ITC and bonus tax credits support: Finally, the application of ITC increases the average resilience BCR by 6.1% and the maximum by 25% (from BCR of 0.58 to 0.83). The application of bonus tax credits in addition to ITC increases the average resilience BCR by 8.7% and the maximum by 36% (from BCR of 0.83 to 1.19). The BCR only exceeded 1 in a few regions experiencing more and longer resilience events, even after applying both ITC and bonus tax credits support (21 out of 2,519 regions). However, it is worth noting that applying both incentives can lead customers in certain counties to make investments in storage systems solely based on the expected resilience benefits.

The results demonstrate that, in most counties, resilience benefits alone are insufficient to justify the economic addition of storage to existing PV systems. The coinciding occurrence of higher frequency of resilience events, higher VOLL, and lower cost can substantially increase average BCR, but these conditions apply to a smaller set of customers. Indeed, the findings indicate that PVESS can significantly alleviate the impact of resilience events on customers, especially in regions that experience a high number of such events. It is worth noting, however, that customers typically consider a range of other value streams when investing in storage solutions, such as mitigating short-duration interruptions, reducing utility bills, capitalizing on monetized avoided costs, and leveraging grid services. Storage investment would have a positive net benefit for a larger number of regions when accounting for these extended benefits.

A spatial analysis reveals substantial disparities in resilience BCR among counties in the continental United States. Some regions, less prone to enduring prolonged outages, reap minimal resilience advantages from PVESS operation and would need to rely on other value streams for economic adoption of PVESS. Conversely, certain areas experience substantial benefits due to a higher frequency of extreme weather events and relatively higher VOLL. The diversity in BCR reveals opportunities for regulatory action and policy-oriented research and intervention to ensure that customers that live in areas that are more likely to experience long-duration interruptions have affordable options to mitigate those impacts. Out of the scope of this paper, customer-level analysis would provide a more accurate representation of the resilience BCR and capture idiosyncratic aspects related to interruption frequency and duration, VOLL, and costs.

Actions that regulators may request from their utilities include:

- **Interruption data sharing and reporting**. Regulators can take several key actions to address current limitations in interruption data access to enable a more robust analysis of the resilience benefits of energy storage: (i) mandating utilities to report outage and interruption data at a granular level, detailing specific locations, durations, and customer impacts; (ii) developing and using standardized metrics for reporting resilience event impacts, such as total customer outage minutes; and (iii) encourage utilities to make anonymized resilience data publicly accessible, facilitating research and analysis by independent experts and energy storage vendors to assess market volume.
- **Enhance quantification of the VOLL**. Regulators should work with utilities to significantly enhance the rigor and quality of measurement of VOLL across its service territory, ideally at a customer level or at least for highly disaggregated types and locations of customers. This approach would allow utilities to make informed and effective resilience investment decisions based on the specific vulnerabilities of their region and assist developers in designing value-adding propositions to customers.
- **Develop resilience value maps and online assessment tools**. Hosting capacity analyses and publicly available maps allow developers to targets specific areas of the distribution system with value-adding resources. A similar approach could be developed for resilience value, in which a utility would integrate its outage management system data and granular VOLL estimates to quantify areas of the grid in which storage may have a high resilience value. Furthermore, a utility could develop and make available to customers, vendors, and other stakeholders tools to assess the multiple value streams accrued by PVESS - especially including reliability and resilience benefits. An easily accessible web-based version of the results developed in this study augmented with other value streams may be valuable in supporting customers to make investment decisions on PVESS. Users of this tool could take short surveys to assess their VOLL and hence produce cost-benefit analysis that directly applies to them.

Further research is needed to refine these findings and to design targeted policy interventions. For example, the VOLL may increase as customers transition to be more dependent on electricity when adopting energy efficiency, electrification, and other decarbonization measures. A higher VOLL will increase the resilience BCR of PVESS. In turn, these new end uses will change the demand profile from customers and their energy needs and these would need to be modeled and analyzed to assess the actual PVESS performance in this new scenario. . In addition, better information on how the resilience value of storage differs across spatial and socio-demographic scales would help to anticipate support for customers with increased resilience benefits from storage.

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1. Introduction

Clean energy resources that are located behind the meter have the potential to benefit the hosting customers by providing affordability, environmental, and reliability and resilience value (e.g. Akhil et al. (2015), Balducci et al. (2018)). Figure 1.1 shows common value streams provided by behind-the-meter storage at the customer, community (mini-grid), and system levels. Typical customer-level value streams include increased self-consumption of PV production, electricity bill savings, demand charge reductions, and backup power. The first three value streams in this list have been studied extensively, but the resilience and reliability value provided through backup power applications of storage has been under-explored (Gorman et al. (2023), Balducci et al. (2021)). This policy brief focuses exclusively on the resilience benefits of residential behind-the-meter solar-plus-storage systems (BTM PVESS) to mitigate long duration interruptions, specifically referring to significant and extended electric disturbance events lasting more than 24 hours.

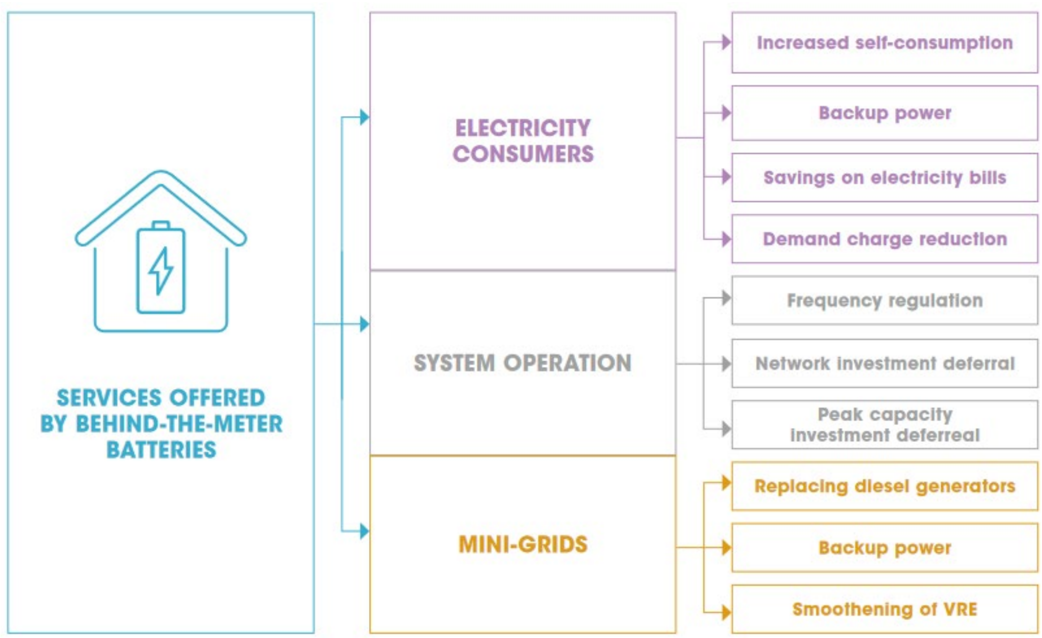

Figure 1.1 Value streams provided by behind-the-meter storage (source: IRENA, 2019)

Widespread and prolonged power interruptions are occurring more frequently than in the past and their spatial extent makes restoration efforts harder (National Academies of Science, 2017). The significant economic and societal consequences of these interruptions is driving research on power system resilience. Recent Berkeley Lab work has examined the effectiveness of BTM PVESS in delivering backup power across diverse residential customer profiles, geographical and climatic conditions, as well as various power interruption situations (Gorman et al., 2023). This approach offers an evaluation of PVESS's technical capability to improve resilience at the customer level.

This brief extends on prior work by quantifying the resilience value of PVESS at the county level across the entire United States and comparing this value to the cost of adding battery storage to an existing PV system. This evaluation encompasses (i) assessing the likelihood of occurrence for these long duration events, (ii) assessing the expected technical and monetary impacts of long-duration power interruptions, and (iii) conducting a benefit-cost analysis of PVESS operation considering the benefits achieved from mitigating long-duration power interruptions against the investment in battery storage installation with and without financial benefits of the Investment Tax

Credits (ITC) and bonus tax credits in the Inflation Reduction Act (IRA). As such, this brief does not quantify the additional customer, community, and system benefits of storage as outlined in Figure 1.1. This brief answers three primary research questions:

- What is the regional distribution of the capability of residential PVESS to mitigate long duration interruptions (> 1 day)?
- Assuming regionally-differentiated storage costs and values of lost load (VOLL), how does the resilience value of mitigating long-duration power interruptions compare to the cost of adding storage to an existing PV system?
- How does the net resilience value change considering ITC and bonus tax credits support?

This brief presents the framework, data, and methods used to develop the analysis. It then organizes the results based on the three questions described above. The brief concludes with a set of policy insights and further research needs.

2. Methods and data

This section introduces the method developed and data sources used to estimate the technical and economic mitigation potential of residential PVESS for counties in the continental U.S. We developed a general techno-economic framework to identify, analyze, and value resilience interventions (Figure 2.1). The framework shows the logical relationship between threats/hazards, asset outages, interruptions, and impacts on customers. Reliability and resilience interventions may affect one or more of these components; PVESS, as analyzed in this brief, benefits customers after an interruption takes place by reducing the amount of energy that is not served by the grid. Monetizing the energy not served before and after an intervention reflects the dollar value of the resilience benefits accrued to customers from an intervention.

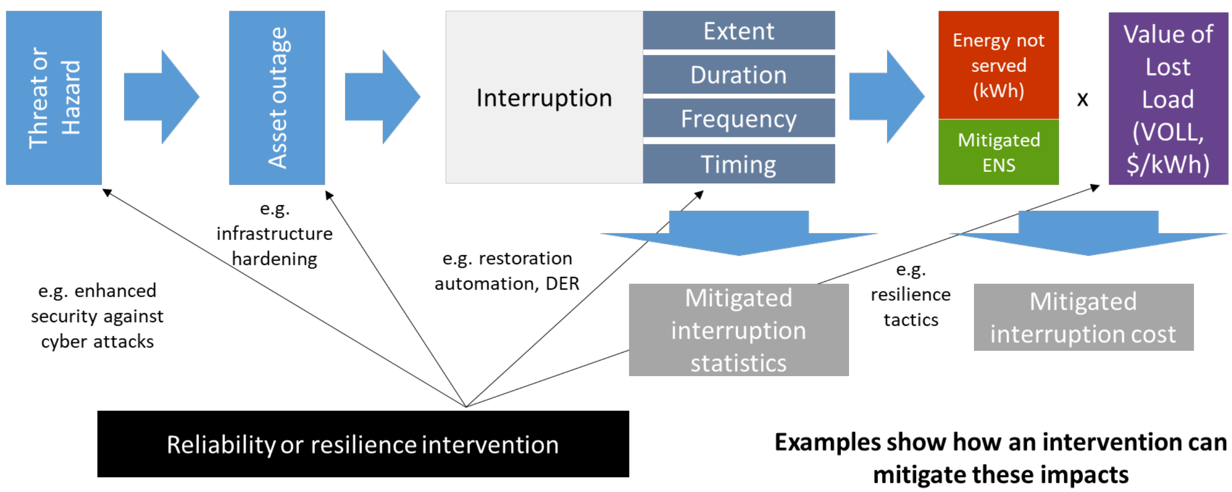

Figure 2.1 Techno-economic framework to estimate resilience benefits

This brief develops a calculation of resilience benefits and costs for PVESS using the best publicly available data, and estimated input data that was not available. In addition, the input data that is available or that we calculate does not have a consistent spatial and temporal resolution. Table 2.1 summarizes the key variables used in our analysis and their spatial and temporal resolution.

Table 2.1. Spatial and temporal resolution of key variables used in this analysis

Variable	Spatial resolution	Temporal resolution
PVESS operation	County	Hourly
PVESS costs	State	Annual
PVESS mitigation potential	County	Monthly
Resilience events	State	Annual
VOLL	State	Annual

In general, we chose to use county level resolution for results, making state level values applicable to each county within that state. Consequently, we aggregate temporal estimates at the annual level from hourly and monthly values. Future work may focus on producing higher resolution estimates for some of the variables reported in Table 2.1, such as county level counts of resilience events, VOLL across different income groups, or PVESS costs, to improve result accuracy.

As indicated, PVESS have many benefit streams in addition to resilience, including bill reductions, renewable energy and carbon reduction credits that may be monetized, and reliability benefits due to mitigation of short duration interruptions. Therefore, a complete benefit-cost analysis of PVESS would monetize all these benefit streams. In this brief, we focus on the monetary value of the resilience benefits only. Hence, instead of comparing this benefit to the entire cost of the PVESS, we only use the cost of the energy storage component in the system. While storage can also accrue other benefits, residential customers tend to add storage to PV systems as they concern over electric system reliability and resilience (EnergySage, 2022). Comparing the resilience benefits of this incremental storage against its costs will provide valuable information on location and conditions under which storage is more likely to be adopted for these benefits.

As indicated, the key variables used in the analysis are (i) the frequency and duration of resilience events, (ii) the mitigation potential for the PVESS (PVESS operation), (iii) the VOLL, and (iv) the cost of the storage component of the PVESS. We made an effort to find the most granular and accurate values for these variables, but most of them are inherently uncertain or vary substantially even across our smallest unit of spatial analysis, the county (see Table 2.1 for the spatial and temporal resolution of key variables and parameters).

2.1 Frequency and duration of resilience events

The estimation of interruption frequencies uses historical long duration interruption data to train a simple model that predicts the probability of an interruption of a given length occurring in a given state.

2.1.1 Data sources

The U.S. Department of Energy's (DOE) Office of Electric Delivery and Energy Reliability collects mandatory electric disturbance reports called DOE-417.[1] Filings are mandatory when specific criteria are met, which include: actual physical or cyber attacks causing outages; impacts to critical infrastructure or operations; complete system failure; system separation (islanding); uncontrolled interruption of 300 MW or more firm load; emergency load shedding of 100 MW or more; system-wide voltage reductions; public appeals for reduced electricity use; suspected attacks. Loss of power to 50,000 customers for at least one hour; or fuel supply emergencies. While some criteria, such as cyber threats or vandalism, may not directly result in customer outages, others can lead to widespread and long-duration power outages.[2]

We compiled a comprehensive inventory of significant electric emergency incidents and disturbances that occurred from 2000 to 2022. Within these extreme events, extensive and prolonged occurrences have the capacity to create noteworthy effects on customers. In this context, we classify 'resilience events' as those exceeding the 24-hour threshold, concentrating predominantly on their repercussions throughout this document. While widespread and long-duration power outages can affect multiple states, we have separated the events at the state level to align with the geographic level of VOLL, which is also reported at the state level. In cases where an event affected multiple states, the event is counted for each state affected.

2.1.2 Method to produce frequency and duration of resilience events

The number of resilience events within specific duration intervals in 2022 requires two components for estimation: the probability of occurrence of a resilience event with a given duration and the total count of

[1] Available at https://www.oe.netl.doe.gov/oe417.aspx

[2] While the exact percentage of outages reported through the OE-417 system compared to all electric disturbances across utilities is unknown, severe weather remains a significant cause of (bulk) power outages. Between 2002 and 2012, 58% of reported outages and 87% of outages impacting at least 50,000 customers were attributed to severe weather events like thunderstorms, hurricanes, and blizzards (e.g., winter storms in Northeastern states, hurricanes in Southeastern states, and wildfires in Western states, etc.).

resilience events in a given year.

We calculate the first component following the approach of Ericson et al. (2022) by conducting an analysis to estimate exceedance probability curves for extreme events in the contiguous United States. The curve shows the probability of a resilience event exceeding a certain duration. For instance, considering a resilience event taking place in the state depicted in Figure A-1 (Appendix), there is a 48% probability that the event will persist for more than 24 hours. Additionally, there is a 15% likelihood that the event will last longer than 5 days, and a 4% probability that it will extend beyond 10 days. Details for this calculation are reported in the Appendix.

For the second component, we calculated the expected total number of resilience events by considering both the events that occurred in 2022 and the potential impact from neighboring states. Subsequently, we distributed the estimated statewide extreme events across counties by utilizing the median portion of electricity customers affected by such events between 2000 and 2022. The detailed calculation method is supplied in the Appendix.

The resulting numbers of expected total resilience events, which includes only events lasting longer than 24 hours—the primary focus of this study— are summarized in Figure 2.2 below. For easier comparison, we report the expected number of events over a ten-year period following the traditional bulk power system reliability standard that the grid is built to have one shortfall every ten years on average.

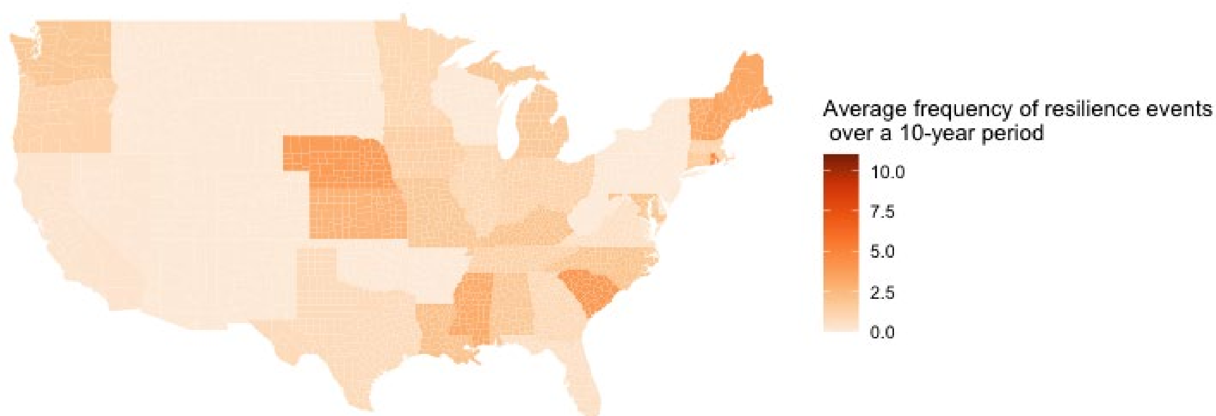

Figure 2.2. Number of resilience events (power interruptions lasting longer than 24 hours) by counties in the baseline scenario.

2.2 PVESS operation to estimate mitigation potential

We model the operation of PVESS during long duration interruptions using a storage dispatch model from recent Berkeley Lab research (Gorman et al, 2023). The storage dispatch model calculates the total load served during outage interruptions based on PVESS parameters, building profile, PV generation profile, and outage conditions (see Figure 2.3).

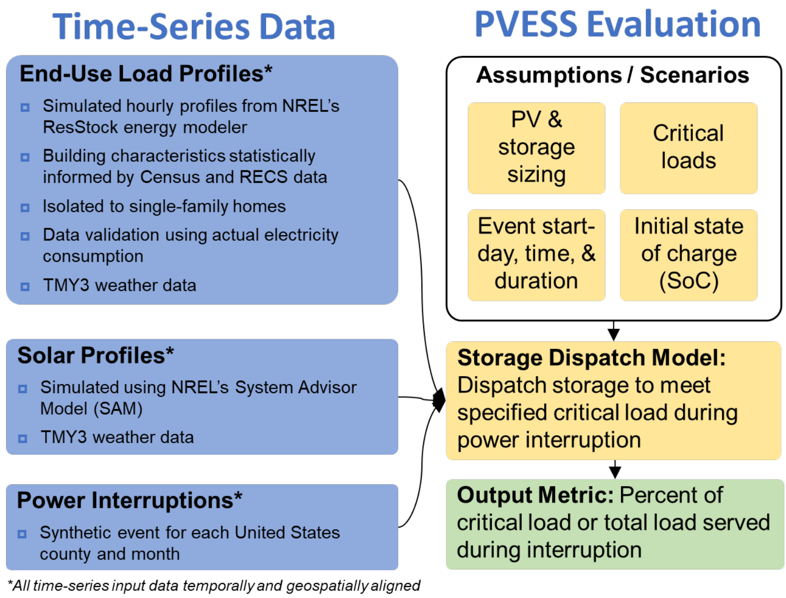

Figure 2.3 Schematic of storage dispatch model's key data inputs and output

Mitigation potential was modeled for one single-family detached home per county, which was sourced from NREL's End-Use Load Profiles database. The full database contains more than 500,000 residential buildings modeled in ResStock; each building we selected represents the typical single-family home building for each county (i.e. its envelope and equipment characteristics are typical for that county). For each building, we used regional weather data aligned with input weather profiles from ResStock to simulate nominal PV generation profiles to calculate the PV capacity such that annual PV generation is equivalent to the building's annual total consumption profile. For storage, we apply a default size of 10 kWh (5 kW) to each building, which represents a typical size for commercially available systems based on data from Berkeley Lab's 2022 Tracking the Sun report.[3] We assume a 92% one-way charge or discharge efficiency, but the battery is not subject to additional physical constraints such as degradation or reserve capacity.

2.3 PVESS costs

We collected PVESS cost data from Berkeley Lab's Tracking the Sun (TTS) database, EnergySage's 2023 Solar and Storage Marketplace Report, and NREL's Annual Technology Baseline (ATB).

Berkeley Lab's TTB database provides empirical data, such as sizing, cost, location, and installation date, for installed PV and PVESS systems across the United States. Using TTS, we collected both median PV system costs and count of installed systems for 21 states in 2021. For states without available cost data, we applied available state costs to their respective census division or region, depending on availability (e.g., costs were not reported for any state in the East South Central division, so we used costs for the entire South region). If divisions or regions had costs for multiple states, we applied a weighted average to the area using the number of installations.

EnergySage's annual Solar and Storage Marketplace Reports provide overviews of pricing, financing, and consumer behavior based on data generated through their online quoting services. We collected energy storage costs by state from EnergySage since TTS only provides costs for entire system (i.e., we were not able to separate

[3] More detail about Berkeley Lab's annual Tracking the Sun report is available here: https://emp.lbl.gov/tracking-the-sun

energy storage costs). EnergySage only provides energy storage costs for 10 states, so we applied the same method as above to apply costs to all states in the United States.

NREL's ATB is updated based on market research and economic indicators and provides a useful unified source for cost assumptions. We used the ATB to collect national PV and battery capital costs, fixed operation and maintenance costs, and the cost recovery factor at the national level for 2022 and 2050. We use these costs to estimate total lifetime system costs, calculate annualized system costs, and finally estimate statewide PV and energy storage for 2050 using the ratio of national 2022 and 2050 costs.

We use overnight costs (i.e., no financing) as it provides a cleaner comparison given the high dependence of financing costs on customer's creditworthiness. We also consider coverage of annual fixed O&M costs over a 25-year lifetime of the system. We ignored battery degradation and replacement assumptions, including only the initial cost of the battery system. System inputs are included in Table 2.2.

2.4 Value of lost load

There are no nationwide estimates for the VOLL that customers accrue due to long-duration interruptions. The ICE Calculator, developed by Berkeley Lab, provides reasonable estimates for state-level VOLL for short duration interruptions of up to 24 hours.[4] The ICE Calculator accounts for several factors, beyond just interruption duration and timing, to determine residential customer interruption costs. These additional factors, which vary by state, include annual electricity consumption and median household income. Due to the limited information on how VOLL varies across different states for long-duration outages, we leverage on the ICE Calculator values to estimate state-level differences in long-duration VOLL, assuming that the influence of these factors, like electricity consumption and income, remains consistent for both short-duration and long-duration interruptions. We apply these state-level differences to a single-state survey recently developed by Berkeley Lab that for the first time captured the direct and indirect costs of long-duration interruptions of one, three, and 14 days for a Midwest utility's customers occurred during summer or winter. Utilizing the single customer damage function derived from the survey responses, we computed the median state-level VOLL for extended power outages by integrating state-level scaling factors with the customer damage function, which characterizes the average VOLL by duration in the Midwest IOU's service area, regardless of weather conditions, seasons, nor timing of power interruptions. Figure 2.4 below illustrates the estimated median 10-day long power interruption for each state. Details of this calculation can be found in the Appendix.[5]

Table 2.2. Summary of PVESS costs by components for 2022 baseline

Cost component	Baseline values
National PV capital cost ($/kW)	2,468
PV operation & maintenance cost ($/kW-yr)	25
PV cost recovery factor	0.0756
Battery capital cost ($/kWh)	1055

[4] Available at https://icecalculator.com/

[5] The multiplier derived from the ICE calculator reveals a range of variations, from 89% (in Maine) to 121% (in Alabama). The discrepancies in VOLL across states are influenced by a variety of factors, encompassing customer demographics and environmental attributes. For more in-depth information about the ICE calculator, refer to Sullivan et al. (2009, 2015).

Battery operation & maintenance cost ($/kWh-kW-yr)	5
Battery Cost Recovery Factor	0.0756

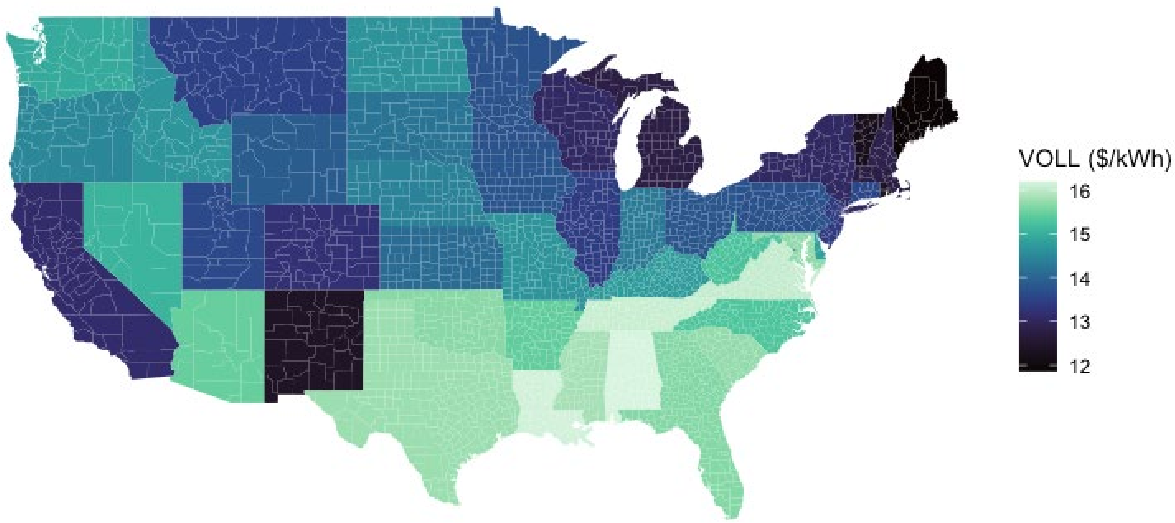

Figure 2.4. Median VOLL estimates for a 10-day-long power interruption at the state level.

2.5 Sensitivity analysis

The input data used to determine the resilience value of PVESS generally respond to “typical” values for frequency of events, costs, and VOLL. In reality, these values vary across populations such that some customers will suffer higher frequency of events due to their location within the grid, or will have a higher VOLL due to personal preferences. In order to capture some of these characteristics, we implement several sensitivity analyses that use an alternative value for some of these key parameters in order to explore potential impacts of those alternative values. Table 2.3 reports the different scenarios considered that are based on combinations of these sensitivity analyses, including the impact of bonus tax credits on PVESS costs as well.

Table 2.3. Scenario configuration for cost-effectiveness sensitivity analysis

ID	Scenario	Frequency of interruptions	VOLL	PVESS cost
1	Base	Base values	Base values	Base values
2	HighFreq	More frequent extreme weather events resulting long-duration power interruptions	Base values	Base values
3	VOLL-High	Base values	Higher VOLL than base	Base values
4	VOLL-Low	Base values	Lower VOLL than base	Base values

5	ConsLowCost	Base values	Base values	Conservative cost reductions
6	AdvLowCost	Base values	Base values	Advanced cost reductions
7	JointSensitivity	More frequent extreme weather events	Higher VOLL than base	Optimistic cost reductions
8	Bonus tax credits -Impact	Base values	Base values	ITC and bonus tax credits -reduced costs

Sensitivity scenarios may describe the actual characteristics of interruption frequency, value of lost load, and costs for subset of customers depending on their location and preferences. However, this brief does not attempt to quantify what share of customers fall under one or more sensitivity scenarios. Specification for each sensitivity variable is provided below.

2.5.1 Sensitivity to number of resilience events

While the baseline analysis considered the present-day frequency and duration of resilience events, it is important to recognize that the landscape could evolve in the future. This is evident in the United States, where the annual economic impact of blackouts stemming from weather-related factors varies significantly, ranging from $20 to $55 billion (Schaeffer et al., 2012). Notably, the historical trajectory of such incidents in the past three decades demonstrates a clear uptick, particularly pronounced during the 2000s (Mirasgedis et al., 2007). As our climate undergoes shifts, there is a projected escalation in both the frequency and severity of extreme weather events (National Academies of Sciences, Engineering, and Medicine, 2017; Karl et al., 2009). It is worth noting that potential triggers for substantial future outages extend beyond conventional factors and could encompass emerging threats like acts of terrorism or significant solar mass ejections (Crane, 1990; McMorrow, 2011). Considering these factors, we can anticipate that the frequency of events requiring resilience and adaptability is likely to increase in the coming years.

Therefore, in addition to our baseline analysis, we have provided a simple illustration of this alternative scenario. We assume double the frequency of resilience events compared to the baseline scenario, representing the upper bound. However, the probability that any individual resilience event is assumed to fall within a specific duration interval remains unchanged.

2.5.2 Sensitivity to PVESS costs

Two critical sensitivities need to be considered when analyzing PVESS cost. The first sensitivity pertains to the potential cost reductions in the future, driven by advancements in technology and the learning curve effect. The second sensitivity focuses on the incentives provided to customers through the IRA to encourage the widespread installation of PVESS systems.

Regarding future PVESS costs, we utilized national costs from NREL's ATB alongside the baseline PVESS cost data mentioned earlier. We formulate two distinct scenarios—one labeled as "conservative" and the other as "advanced" and employed a state-specific approach to project alternative PV capital costs. We multiplied the state-specific PV costs by the ratio of the projected national sensitivity PV capital costs to the baseline PV capital costs, as provided by the ATB. The resulting cost assumptions are reported in Table 2.4. The projected conservative costs reflect the ATB's "low" scenario costs while advanced costs reflect the ATB's "high" scenario. In the conservative scenario, the high PV capital cost is 85% greater than the low-cost scenario, while the high battery capital cost is 40% higher than the low-cost scenario.

Table 2.4. Summary of PVESS costs by components for baseline and future scenarios.

	Baseline costs	Costs under advanced scenario	Costs under conservative scenario
National PV capital cost ($/kW)	2,468	550	1,016
PV operation & maintenance cost ($/kW-yr)	25	9	13
PV cost recovery factor	0.0756	0.0738	0.0738
Battery capital cost ($/kWh)	1055	392	551
Battery operation & maintenance cost ($/kWh-kW-yr)	5	2	3
Battery cost recovery factor	0.0756	0.0738	0.0738

We differentiate between two alternative scenarios by applying the ITC of 30% in isolation as well as applying a 60% tax credit that includes the 30% ITC and three 10% tax credits from each ITC for Energy Property bonus. Table 2.5 below provides the tax credit for each incentive. We assume the overnight capital costs of the PVESS receive the full value of each incentive, as applicable.

Table 2.5. Incentives and IRA Sections for PVESS cost calculation

Incentive	Tax code section	Tax credit value (i.e., capital cost reduction applied)
Residential Clean Energy Credit (residential ITC)	25D	30%
ITC for Energy Property: domestic content bonus	48	10%
ITC for Energy Property: energy community bonus	48	10%
Low-income bonus: <5 MW projects in low-to-middle income communities or Indian land	48E	10%

2.5.3 Sensitivity to the VOLL

The base case considers median VOLL estimates. However, customers have a wide range of preferences related to sustaining critical operations during power interruptions, thus the VOLL varies based on their individual needs and preferences. Some customers, such as those with medical devices, vulnerable household members, or sensitive equipment, place a higher value on an uninterrupted power supply, while others who are less affected by service interruptions may have lower VOLL. We account for these varying needs and/or preferences and their impacts of resilience events by conducting a sensitivity analysis.

We used the probability distribution of the VOLL during long-duration power interruptions to identify two additional points to represent higher and lower VOLL scenarios: the 20th percentile VOLL (represented by the dashed red vertical line in Figure 2.6) and the 80th percentile VOLL (represented by the dotted red vertical line in Figure 2.6), in addition to the median VOLL (represented by the blue vertical line in Figure 2.5). The 20th percentile of VOLL corresponds to ~0.25 times the median and hence it is used as the lower bound of VOLL. The 80th percentile of VOLL corresponds to ~2.5 times the median and becomes the upper bound of VOLL. Incorporating these two bounds provides a more comprehensive perspective on the potential range of customer preferences in mitigating the impacts of resilience events.

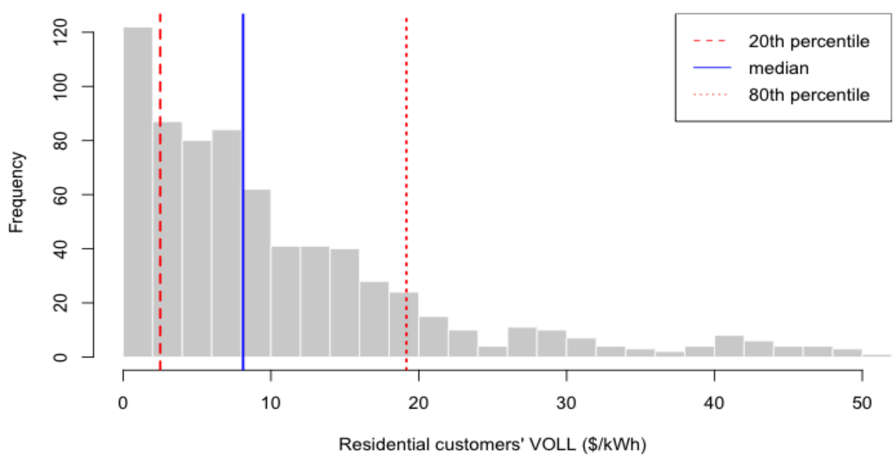

Figure 2.5. Distribution of the residential customers' VOLL during a 14-day-long power interruption elicited from a Midwest IOU.

3. Results

Results are organized based on the three core research questions outlined in the Introduction. Scenarios with sensitivity analysis results are reported for the same questions.

3.1 What is the regional distribution of the capability of residential PVESS to mitigate expected long-duration interruptions (> 1 day)?

In this subsection, we calculated the technical capability of residential PVESS to mitigate long-duration interruptions. The technical mitigation capability reflects the electricity lost without and with the operation of a backup PVESS system.

We first calculated the annual expected loss of load with and without PVESS during simulated resilience events to understand how PVESS can help to avoid resilience event impacts in different regions. This calculation involves multiplying each duration bin by its probability of occurrence over a typical year and adding up the lost load for that year. For simplicity, we assumed that resilience events simulated for each duration range were evenly distributed across 12 months.

Figure 3.1 shows the annual expected loss of load (in kWh) in each county in the continental United States, with and without the PVESS. Loss of load levels are generally proportional to residential loads; higher expected losses will occur in places with relatively higher load levels. In addition, states with high numbers of resilience events of longer duration, such as Louisiana, West Virginia, Rhode Island, and Washington, experienced greater expected loss of load when there is no PVESS-supplied mitigation. Conversely, some regions are inherently less affected by long-duration interruptions and hence have lower loss of load even without mitigation. Introduction of PVESS can effectively mitigate, if not eliminate, expected load loss across all regions.

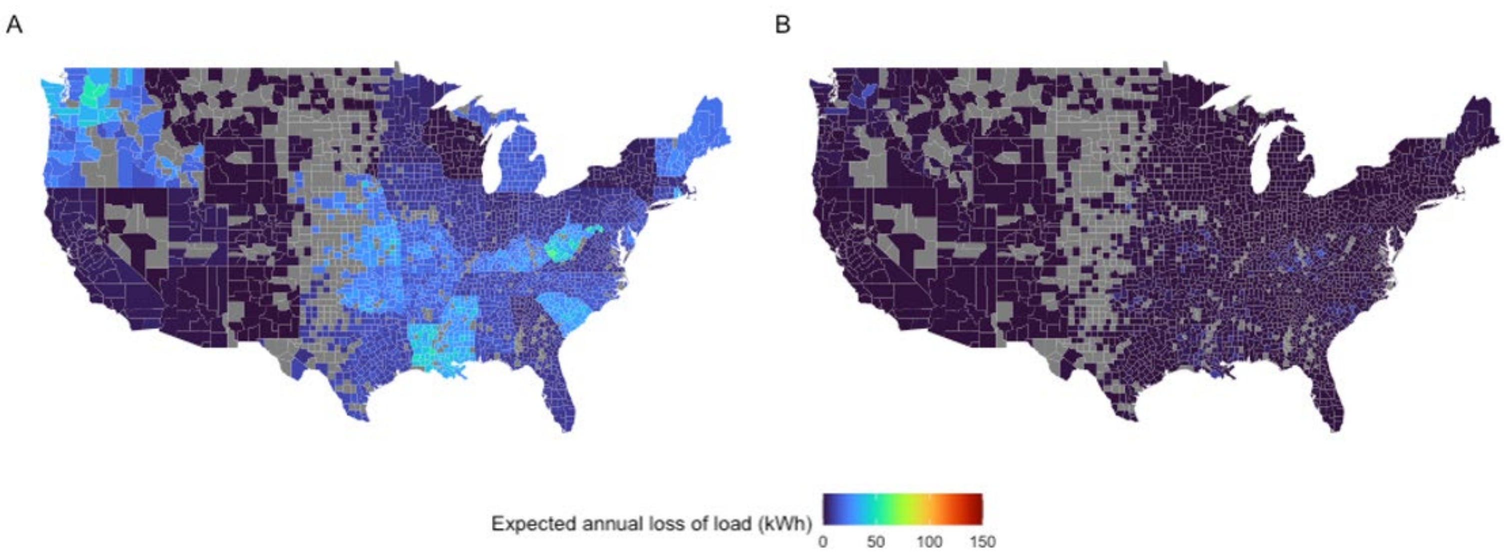

Figure 3.1. The annual expected loss of load without (A) and with (B) PVESS in the baseline scenario for a representative single-family building in each region. Counties shaded in grey correspond to regions with missing information.

Figure 3.2 shows the probability distributions of the expected loss of load without and with PVESS. The range of annual expected loss of load was 0 to 63 kWh before PVESS. Note that this is an expected value. In most years, there will be no loss of load due to a long-duration event because no such event will occur; in certain years, a resilience event will occur producing larger losses. On average, losses will fall in the 0 to 63 kWh range indicated above.

The introduction of PVESS substantially reduced demand losses during simulated resilience events, resulting in a reduced range of 0 to 15 kWh. When expressed as a percentage of mitigation, PVESS mitigation potential was 95.8% on average. The system displayed a broad range of mitigation rates, spanning from 55.6% to a 100%, implying its effectiveness across diverse scenarios. Despite the introduction of PVESS, some residual load still required shedding, with an average of approximately 0.66 kWh per household per year across all counties.

The tail in the distributions before PVESS (red bars in Figure 3.2) is due to the states with higher numbers of resilience events with longer duration, such as Nebraska, Kansas, and Missouri. In these states, the expected annual loss of load was much higher without PVESS, but it was significantly reduced after the introduction of PVESS (blue bars in Figure 3.2), resulting in a substantial reduction in the variance of the distribution. In other states, the expected annual loss of load was already relatively low without PVESS, and it was further reduced by PVESS.

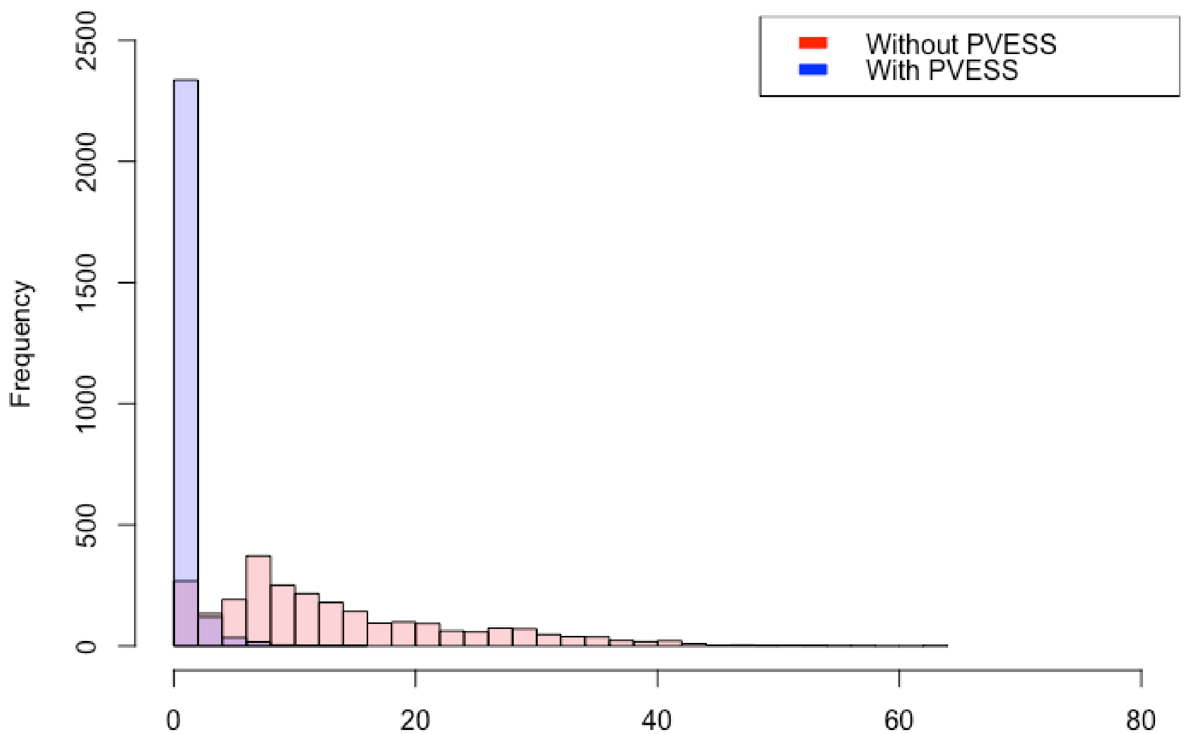

Figure 3.2. The distributions of annual expected loss of load without PVESS (red) and with PVESS (blue) in the baseline scenario.

3.1.1 Sensitivity 1: More frequent extreme weather events

We evaluate the sensitivity of resilience event frequency by calculating the regional distribution of the capability of residential PVESS system when subject to more frequent weather events. Figure 3.3 shows a consistent trend: states with a higher number of resilience events with longer durations have a greater annual expected loss of load without PVESS. Many FIPS regions in the Pacific Northwest, Great Plains, and showed greater annual loss of load, up to 125 kWh per year. However, as with the base scenario, the introduction of PVESS can mitigate a substantial amount of expected lost load across all regions.

Figure 3.4 provides an overview of the expected loss of load distributions, comparing scenarios with and without the integration of PVESS. The incorporation of PVESS reduces the annual expected loss of load range from 0 to 125 kWh to a narrower interval of 0 to 29 kWh. The system demonstrated its effectiveness across a wide range of event characteristics, with mitigation rates ranging from 55.6% to 100%. When expressed as a percentage of mitigation, the resilience system exhibited an average reduction of 95.8% in demand losses during resilience events, with274 FIPS regions able to completely prevent power outages caused by resilience events. Despite its effectiveness, approximately 1.3 kWh per household per year across all counties is shed.

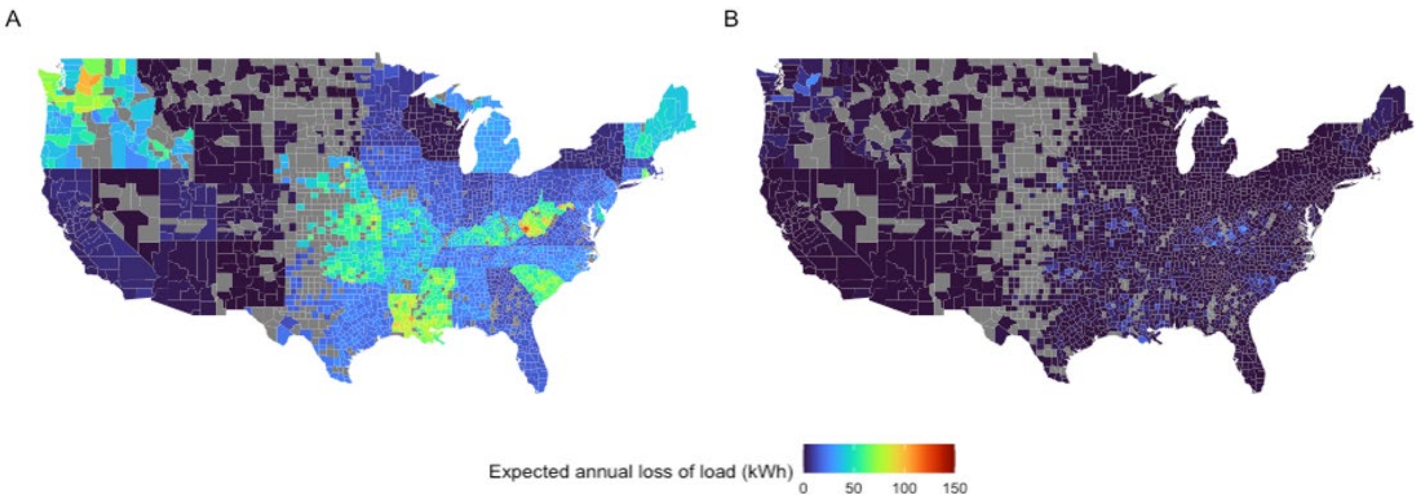

Figure 3.3. The annual expected loss of load without (A) and with PVESS (B) under the assumption of increased frequency of long-duration interruptions. Counties shaded in grey correspond to regions with missing information.

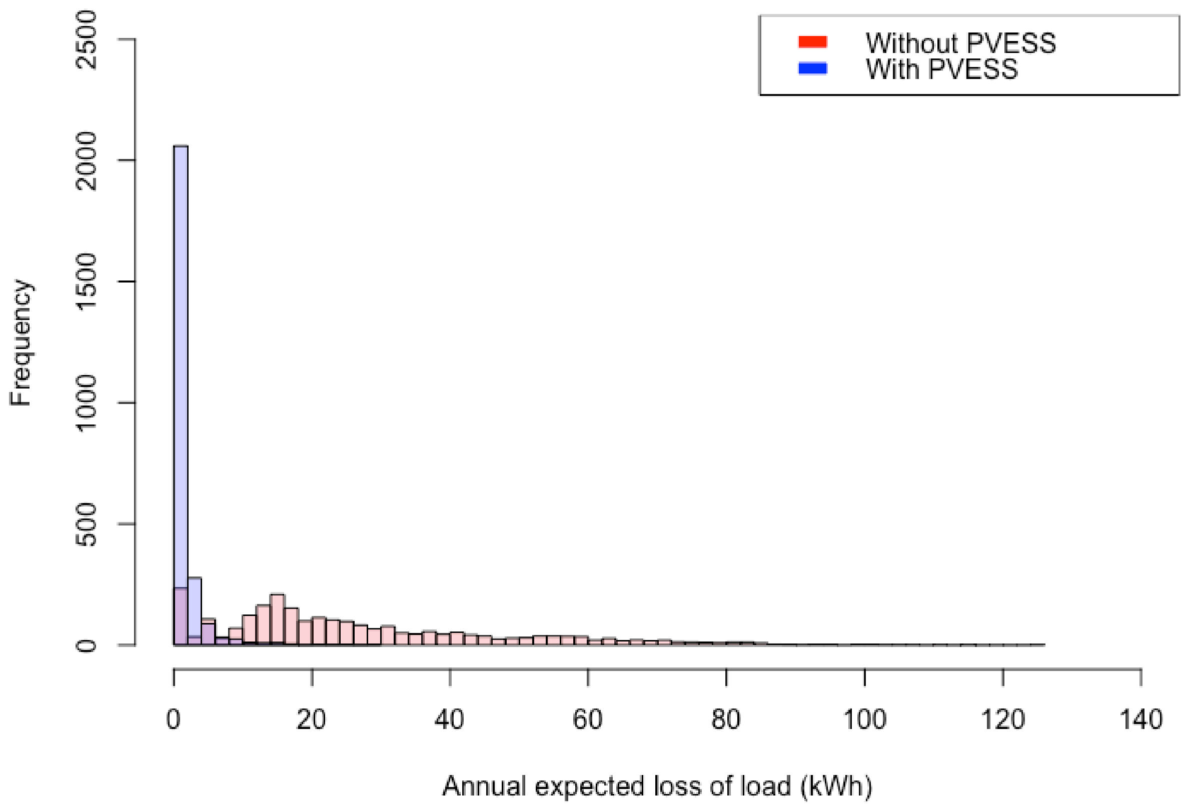

Figure 3.4. The distributions of annual expected loss of load without PVESS (red) and with PVESS (blue) under the assumption of double frequency.

The findings indicate that PVESS can significantly alleviate the impact of resilience events on customers, especially in regions that experience a high number of such events. Intuition suggests that regions with infrequent and short-duration interruptions may not experience as much economic benefit from deploying PVESS compared to regions with higher frequency of long-duration events. In the next subsection, we delve into this issue by conducting a benefit-cost analysis of PVESS operation for resilience improvement.

3.2 Assuming regionally differentiated storage costs and VOLL, how does the resilience value of mitigating long-duration power interruptions compare to the cost of adding storage to an existing PV system?

In this subsection, we monetize the resilience benefits of adding storage to existing PV arrays for typical residential customers in each count in the continental U.S. We estimated the expected benefits of incremental storage investments in each FIPS region by considering the amount of load served by PVESS, the expected frequency and duration of resilience events, and the VOLL estimates at the state level. We then calculated the benefit-cost ratio (BCR) of the storage component of the PVESS at the FIPS level by comparing these benefits to the annualized costs of deploying and operating incremental battery storage to existing PV systems (see equation (1)). The BCR is a unitless metric that takes values below one when the annual resilience benefits of the investment are below the annualized costs and values above one when benefits surpass costs. The BCR can also be interpreted as the percent of annualized cost that is covered by an economic value stream. A higher BCR tends to give more confidence that the investment's benefits will exceed costs even with uncertainties in the numerous variables involved.

$$BCR_{FIPS} = \frac{\sum_1^m \sum_1^d (VOLL_{FIPS} \times Expected\ number\ of\ resilience\ events_{m,d} \times Load\ served\ by\ PVESS_{m,d})}{Annualized\ cost\ of\ the\ PVESS\ storage_{FIPS}}$$

$where\ d = resilience\ event\ duration\ interval\ (ranging\ from\ 1\ day\ to\ 10\ days),$

$m = month,$

$VOLL_{FIPS} = VOLL\ estimate\ assigned\ to\ each\ FIPS\ region\ belonging\ to\ each\ state$

Eq. (1)

Figure 3.5 illustrates the resilience BCR of battery storage investments for all 2,519 FIPS regions with baseline values (Scenario 1 in Table 2.3). Regions in states with a higher number of resilience events and longer durations, such as West Virginia, Louisiana, Washington, and Mississippi, have higher resilience BCRs compared to other regions. However, no counties were able to completely offset the storage investment costs solely through resilience benefits (i.e., they have a resilience BCR < 1).

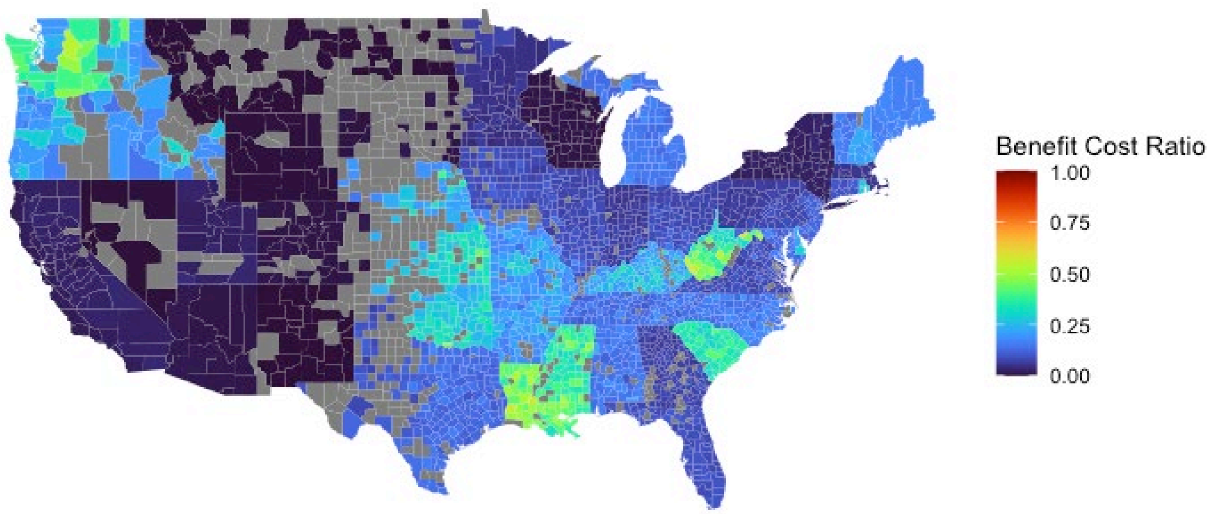

Figure 3.5. Map of resilience BCR of storage in by FIPS region in the baseline scenario. Counties shaded in grey correspond to regions with missing information.

The resilience benefits provided by incremental storage systems accounted for an average of 14% of the costs of battery storage investments, with a range spanning from zero to 58% of the costs. Among the 2,519 FIPS regions, only 26 FIPS regions in New Mexico (1%) had a resilience BCR of zero due to the absence of resilience events during the year, making storage investment have no resilience value.[6] For the remaining regions, the breakdown of resilience BCRs is as follows: 1,159 regions (46%) had a resilience BCR greater than 0 but lower than 0.1, 738 regions (29%) had a resilience BCR greater than 0.1 but lower than 0.2, 329 regions had a resilience BCR greater than 0.2 but lower than 0.3, (13%), and 293 regions had a BCR greater than 0.3 (12%). See Figure 3.6, grey boxplots below for the distribution of BCRs by state. The range of BCR for a given state is a reflection of the heterogeneity in the load profile for the typical building in each county. States with counties with very different load profiles will show a wider range in their BCR compared to states whose counties have relatively similar load profiles.

[6] The state experienced zero recorded resilience events due to a few factors: 1) only six unique events resulted in demand loss or disruptions to customers; 2) these events were spread over several years (2000, 2008, 2011, and 2016); and, 3) no events were reported between 2018 and 2022. However, it's important to note that New Mexico is not completely immune to resilience event risks. Uncertainties exist, and the risk of such events could increase in the future.

As a benchmark, we estimate resilience BCR using the entire cost of the PVESS instead of the incremental cost of battery storage used throughout this paper (see orange boxplots in Figure 3.6). These alternative resilience BCR estimates are significantly lower, with values between the 0% and 17% of PVESS costs and an average of 4.8% of PVESS costs.

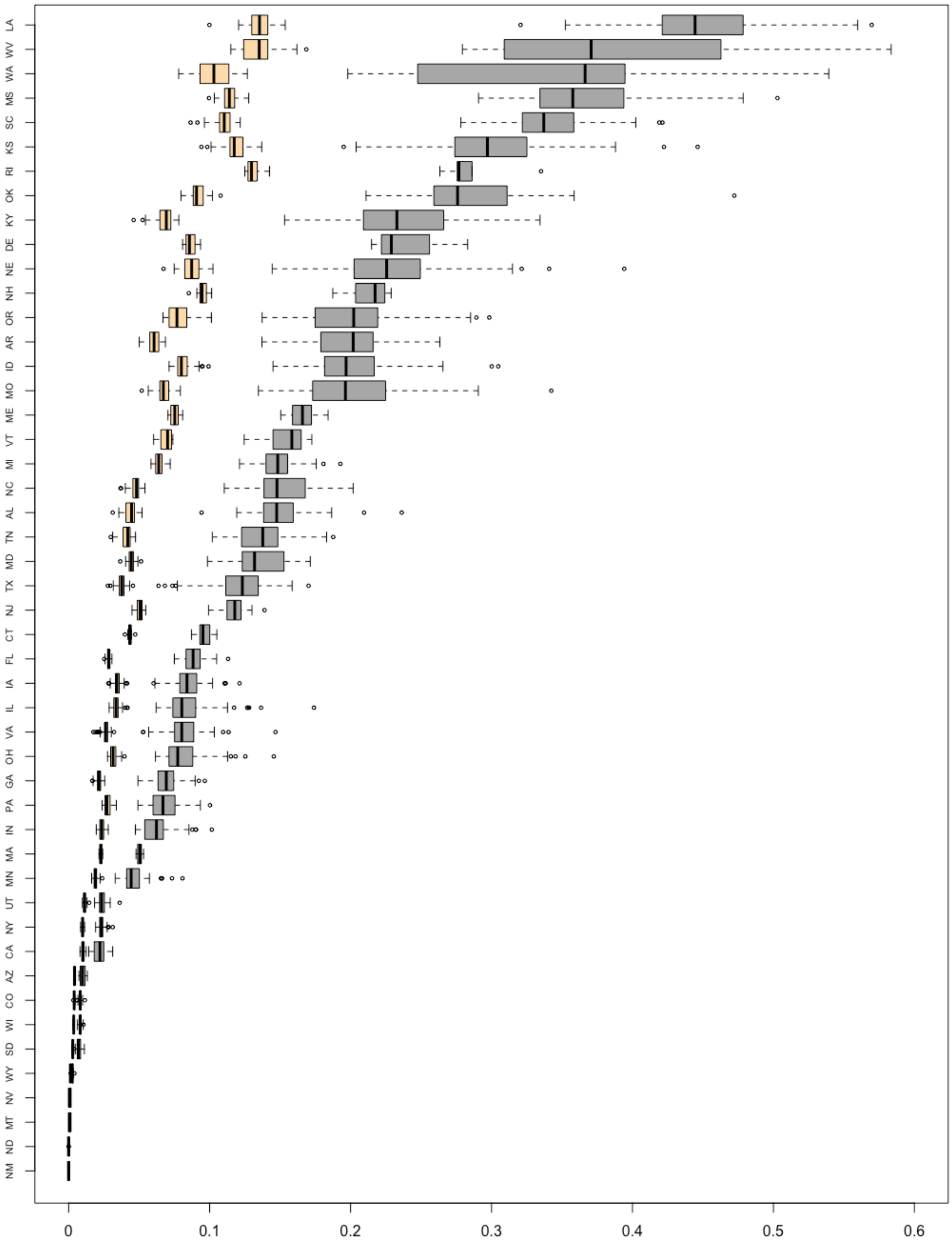

Figure 3.6. Distribution of resilience BCRs of storage in each state under the baseline scenario with entire system costs (yellow) and only with storage costs (grey).

3.2.1 Sensitivity 1: More frequent extreme weather events

Similar to the analysis for the technical potential of PVESS, we have examined several sensitivity scenarios as for resilience BCR. First, we considered the doubling of resilience event frequencies while keeping the exceedance probability curves unchanged. As anticipated, this adjustment roughly corresponds to doubling of the resilience BCR of the baseline scenario: regions with higher numbers of resilience events of longer duration exhibited improved resilience BCRs (see Figure 3.7). The resilience benefits of storage were found to account for 41% of the investment costs for storage system on average, ranging from 0% to 117%. There were 14 FIPS regions with BCR greater than or equal to 1, most were from the states with high BCR from the base case analysis including Louisiana, West Virginia, Mississippi, and Washington.

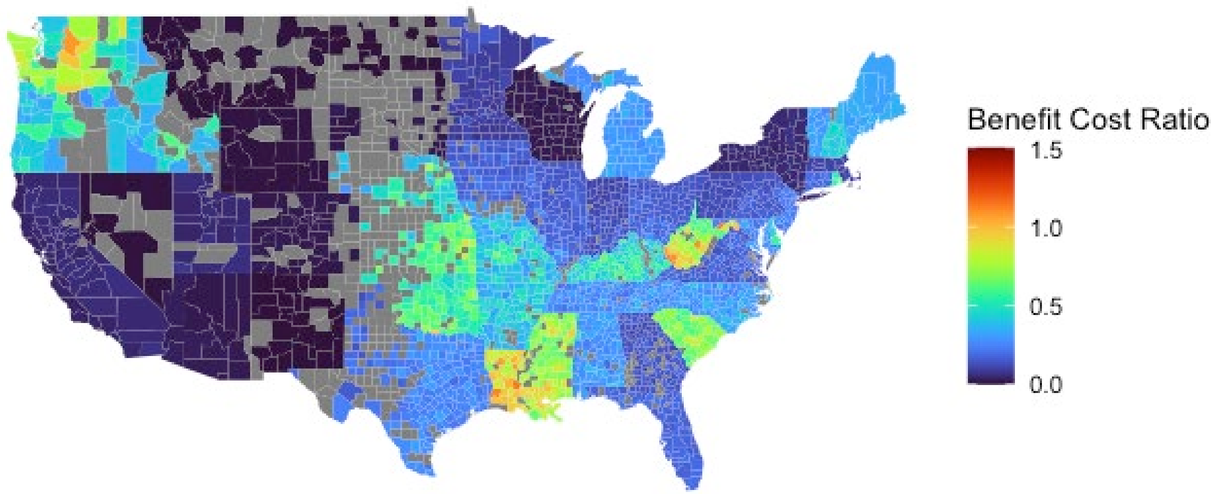

Figure 3.7. Map of resilience BCR of storage investments under the assumption of increased frequency of long-duration interruptions. Counties shaded in grey correspond to regions with missing information.

3.2.2 Sensitivity 2: Higher and lower VOLL

Second, we considered a broader range of values for the VOLL during resilience events by calculating the resilience BCR with lower bound of VOLL (equivalent to 0.25 times the median) and the resilience BCR with upper bound of VOLL (equivalent to 2.5 times the median). As depicted in the top side of Figure 3.8 below, regions with lower VOLL showed an average resilience benefit of PVESS system at 3.6%. 96% of the regions had BCR less than 0.1, and the rest regions had BCR between 0.1 and 0.2 (3.9%). On the other hand, regions with higher VOLL exhibited an average resilience benefit of the PVESS system at 36%, with a wide BCR range spanning from 0 to 1.45 as depicted in the bottom side of Figure 3.8 below. 98 FIPS regions achieved a BCR greater than 1 (mostly in Louisiana, Mississippi, West Virginia, and Washington), making PVESS investment more beneficial in these cases.

The impact of the upper bound for VOLL is slightly larger than the impact of doubling the frequency of resilience events. This suggests that, as may be expected, customers that have needs or preferences for better mitigating resilience events - and hence have a higher VOLL – are more likely to realize a resilience BCR above 1. This is because customers with a higher VOLL are more willing to pay for resilience measures that can help to mitigate the impact of disruptions.

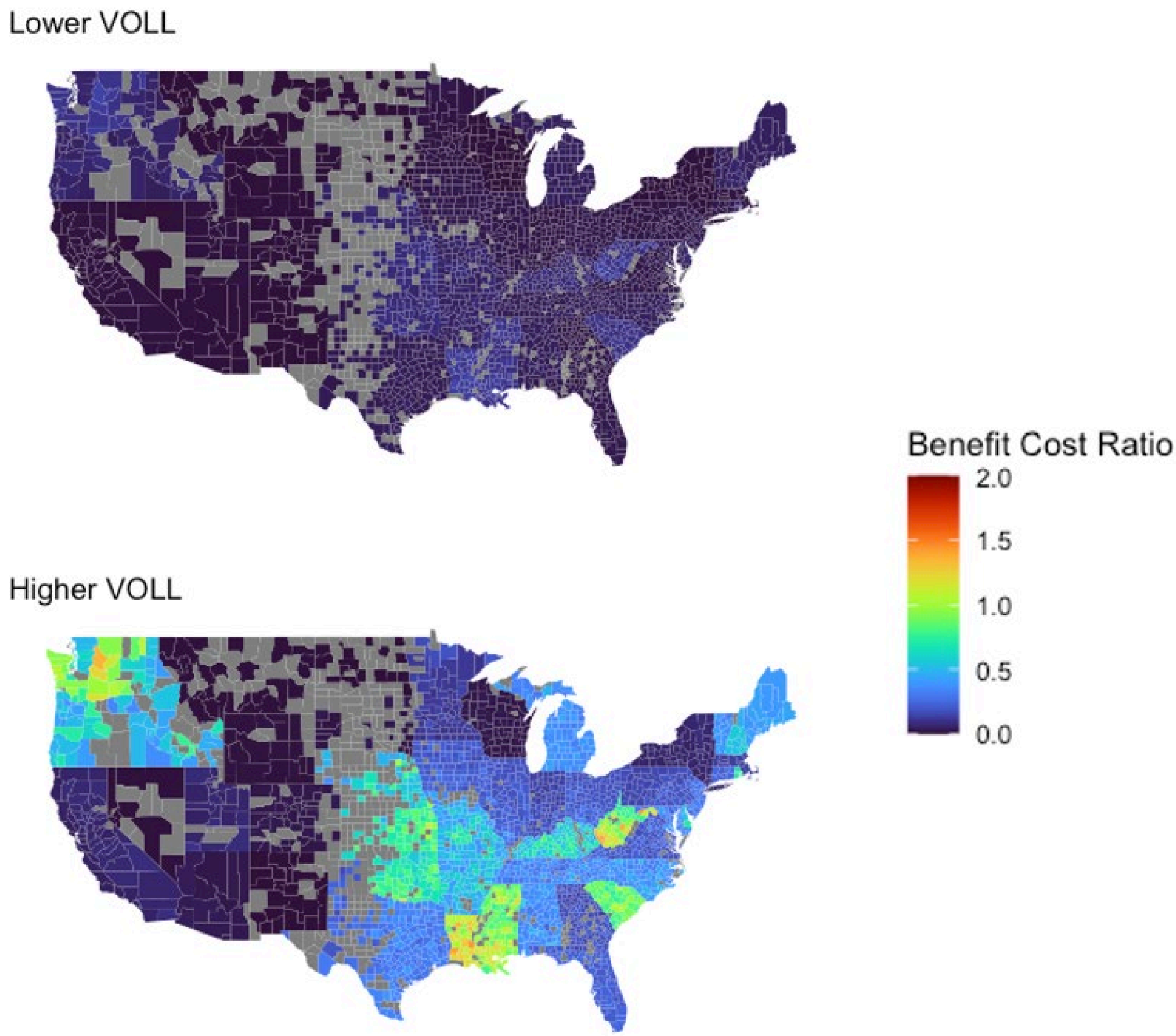

Figure 3.8. Map of estimated BCRs of PVESS investments generated with 20th percentile of VOLL (top) and 80th percentile of VOLL (bottom). Counties shaded in grey correspond to regions with missing information.

3.2.3 Sensitivity 3: Lower storage costs

Third, we examined potential resilience BCRs by applying conservative and advanced cost reduction scenarios defined in Section 2.2, based on NREL's ATB scenarios. Figure 3.9 shows that the maximum BCR achieved increases from 0.58 to 1.05 and 1.74 in conservative and advanced cost scenarios, respectively. The average BCR increases from 0.14 to 0.25 and 0.41 in conservative and advanced cost scenarios, respectively. Five regions (0.19%) and 181 regions (7.2%) in conservative and advanced cost scenarios, respectively, justify the storage investment solely from the resilience benefits. In the conservative cost scenario, only regions in states that experience frequent extended periods of resilience challenges (Louisiana and West Virginia) had a BCR exceeding 1. However, when considering the advanced cost scenario, a broader range of states, including Washington, Mississippi, South Carolina, Kansas, Oklahoma, Kentucky, Missouri, and Nebraska, began to show regions with BCR values greater than 1, strengthening the economic rationale for storage investments.

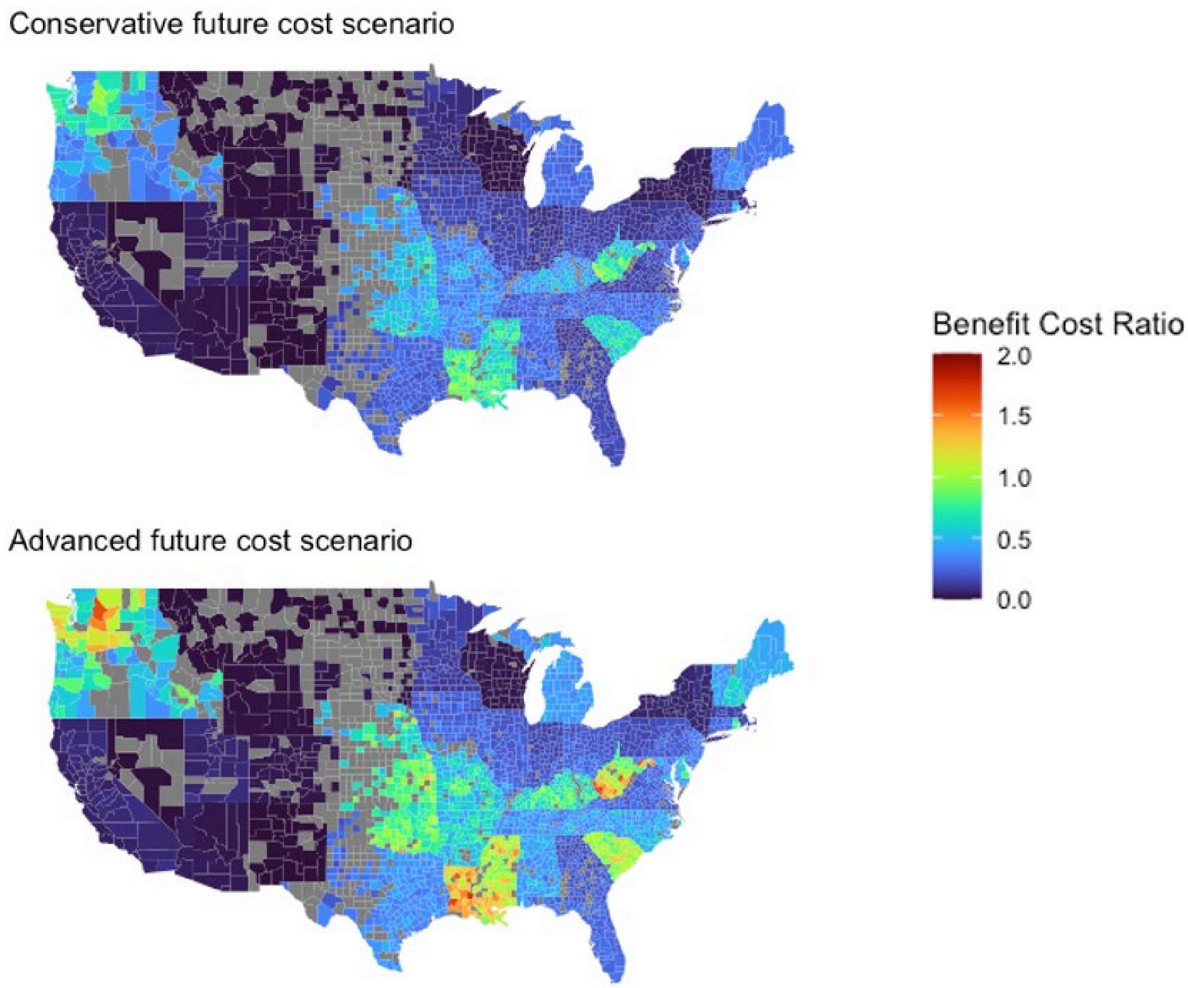

Figure 3.9. Map of estimated resilience BCRs of storage investments, with conservative (top) and advanced future cost scenarios (bottom). Counties shaded in grey correspond to regions with missing information.

We examined the distributions of resilience BCRs by state for each sensitivity scenario and compared them to the resilience BCR distributions in the base cases for comparative purposes to identify the factors that had the most significant impact on increasing the resilience BCR values (Figure 3.10). As Figure 3.11 below shows, we found that the advanced cost scenarios had the most impact, resulting in the largest increase in BCRs among all sensitivity factors. The utilization of the upper bound of VOLL estimates also contributed significantly to enhancing the BCRs. Interestingly, doubling the frequency of resilience events and conservative cost scenarios showed relatively modest impacts compared to the other two scenario variables.

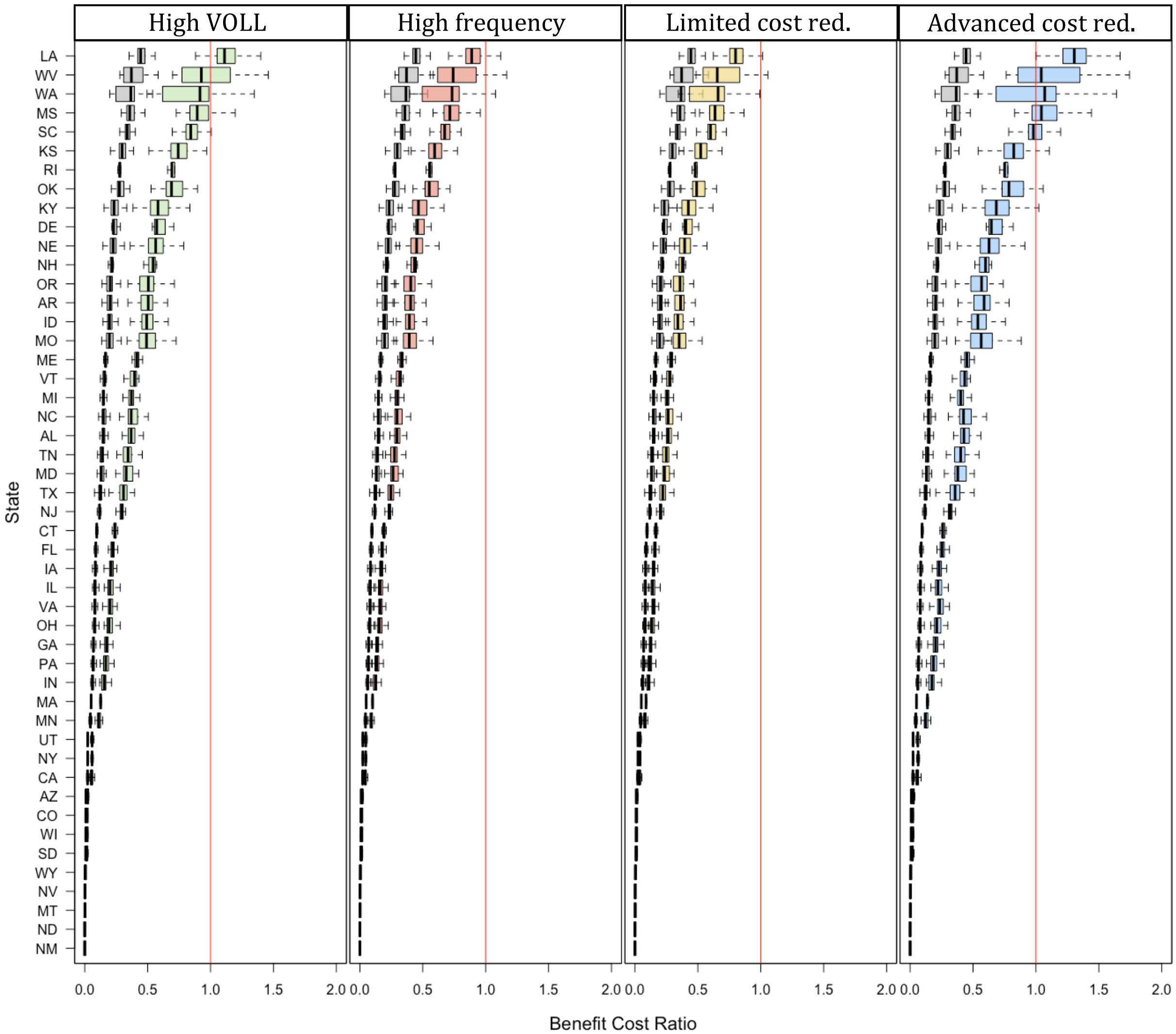

Figure 3.10. Boxplots of resilience BCRs by state under base scenario (grey) and future scenarios with changes in one sensitivity factor each. The leftmost boxplot from the top represents the BCR with respect to VOLL (green), then frequency changes (red), then limited decrease in future costs (yellow), and the rightmost plot depicts the decrease in future costs following advanced scenario (blue).

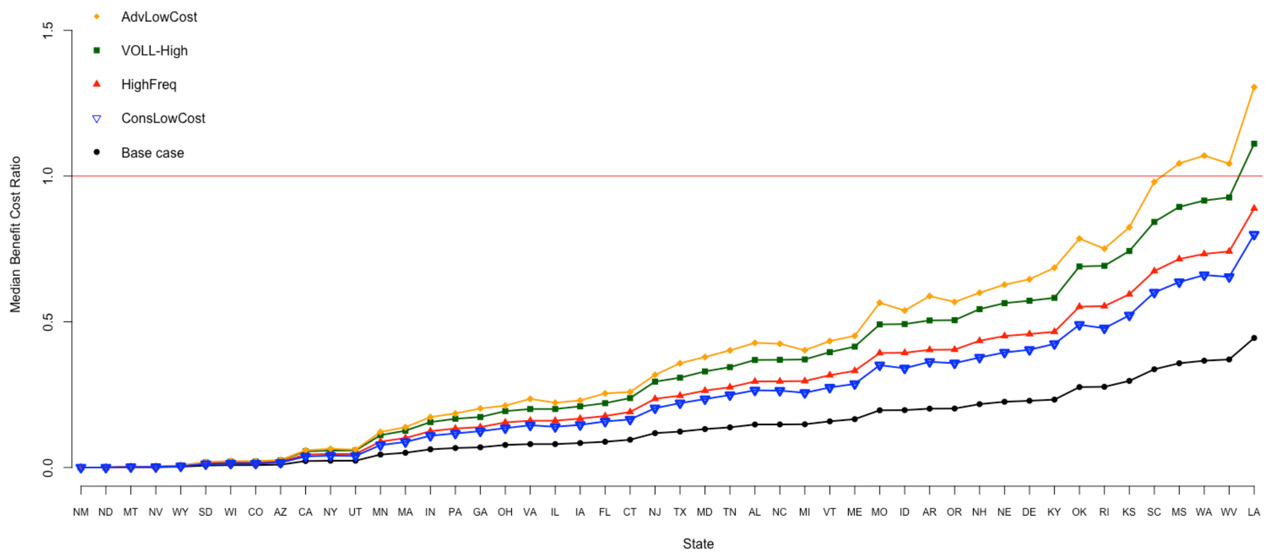

Figure 3.11. Median resilience BCRs of storage in each state under five scenarios: advanced cost reduction (yellow), high VOLL (green), high frequency (red), conservative cost reduction baseline (blue), and baseline (black).

3.2.4 Sensitivity 4: Combined effect of more frequent events, higher VOLL, and lower storage cost

In addition to the three sensitivity analyses conducted individually, we also evaluated the combined impact of storage cost reduction, a high VOLL, and increased frequency of resilience events - the JointSensitivity model in Table 2.3. This combination evaluates the upper bound of resilience benefits, which may seem arbitrary. However, there is reasonable support for this combination based on present and future conditions:

- In the present, households that suffer an unusually higher frequency of interruptions and that have a higher VOLL will be more inclined to deploy storage on existing PV systems for resilience benefits. There is probably enough heterogeneity within any FIPS region to find customers that fall in these categories even if the median BCR is relatively low.
- In the future, we expect climate change to increase the frequency of extreme weather events and potentially the frequency of interruptions. Increased electrification of end uses intuitively suggests that customer's average VOLL will increase: fulfilling any needs will require electricity, with few substitutes available.
- Finally, NREL's ATB and similar research predict consistent cost reductions in PVESS, especially from batteries.

As depicted in Figure 3.12 below, the JointSensitivity scenario resulted in 71% of FIPS regions with a BCR greater than 1. The median BCR across FIPS regions with complete information was 1.67, while the mean BCR was 2.04. The BCR range spanned from 0 to 8.72, almost an order of magnitude larger than the baseline scenario.

The FIPS regions with BCR greater than 5 were primarily concentrated in states experiencing more frequent and longer duration power interruptions with higher portion of customers affected by historical resilience events, such as Louisiana, Mississippi, West Virginia, and Washington. The interplay of these factors appears to be significant. For instance, in the comparison between Louisiana and Texas, where the Values of Lost Load (VOLL) are notably high and almost identical, Texas is projected to experience a greater number of resilience events (18.55 events in Texas compared to 13.6 events in Louisiana). However, Louisiana exhibits a higher proportion of customers affected by resilience events (1% in median in Texas versus 3% in median in Louisiana), coupled with higher likelihood of facing prolonged power interruptions. Consequently, this likelihood leads to a substantially higher BCR in Louisiana than in Texas. These findings underscore the importance of considering a combination of factors, including higher than average frequencies of longer duration events, portion of customers expected to experience resilience events, relatively high VOLL, and future storage cost reduction will encourage storage adoption, even when solely considering the benefits of enhanced resilience.

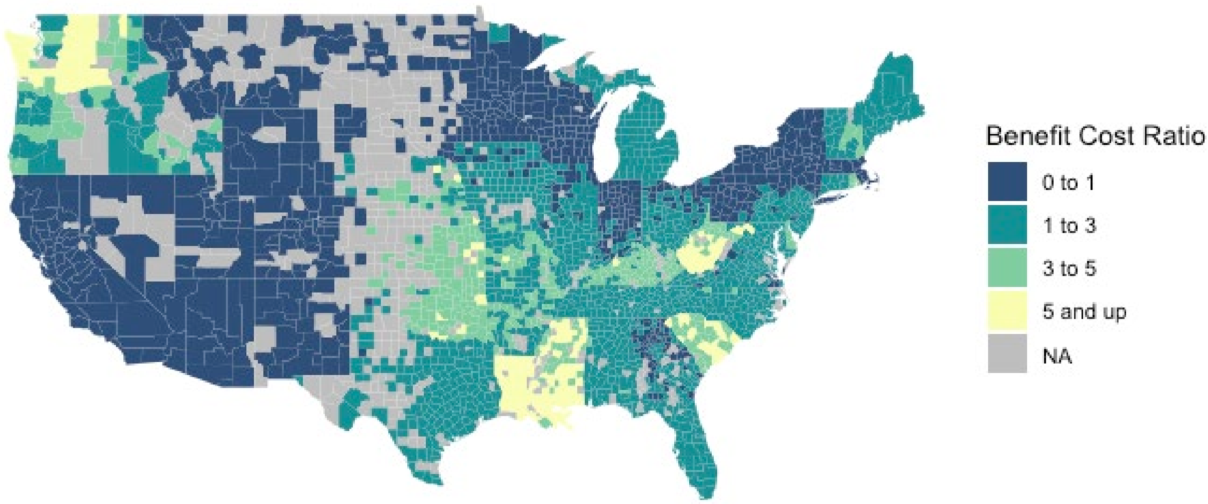

Figure 3.12. Conjoined impact utilizing a combination of assumptions (substantial cost reductions, 80th percentile VOLL, and double frequency of resilience events).

The sensitivity analysis presented in this paper serves as a preliminary and simplified illustration of the potential impact of certain variables. In particular, granular assessments that go beyond the county level may be needed to determine the resilience benefits specific to any given customer given their own reliability and resilience experience, their preference for mitigation, and the costs of storage systems available to them. Pairing the stream of resilience benefit with other well-known benefits such as bill reductions or avoided costs remains a key strategy to promote the adoption of storage for resilience enhancing purposes.

3.3 How does baseline cost-effectiveness change considering IRA support via the ITC and bonus tax credits?

We estimated the potential impact of incentives from the ITC to reduce storage acquisition costs and hence increase resilience value. We applied a 30% cost reduction to the overnight capital cost of the system based on the 2022-2032 ITC value following the IRA extension (see section 2.5 for additional context). We compared the potential benefits of the ITC by calculating BCR for two scenarios: (1) justifying the investments of storage without any incentives and (2) with the 30% ITC. We specifically focused on how incentives can enable more counties to justify storage investments and enhance resilience against long-duration power interruptions.

As can be seen from Figure 3.13, FIPS regions situated in states with higher expected annual losses of load tend to exhibit the highest resilience BCR improvements. The application of the ITC increased the median resilience BCR (see Table 3.1), but was not sufficient to justify the investment in storage solely from the resilience benefits. The results suggest that the ITC can play a role in increasing the adoption of storage by reducing the upfront costs of these systems. However, additional policies may be needed to fully leverage the resilience benefits of storage systems.

Table 3.1 Summary of BCRs in baseline scenario with ITC excluded and included

Resilience BCR	Without ITC	With ITC
mean	0.14	0.20
median	0.12	0.17
max	0.58	0.83

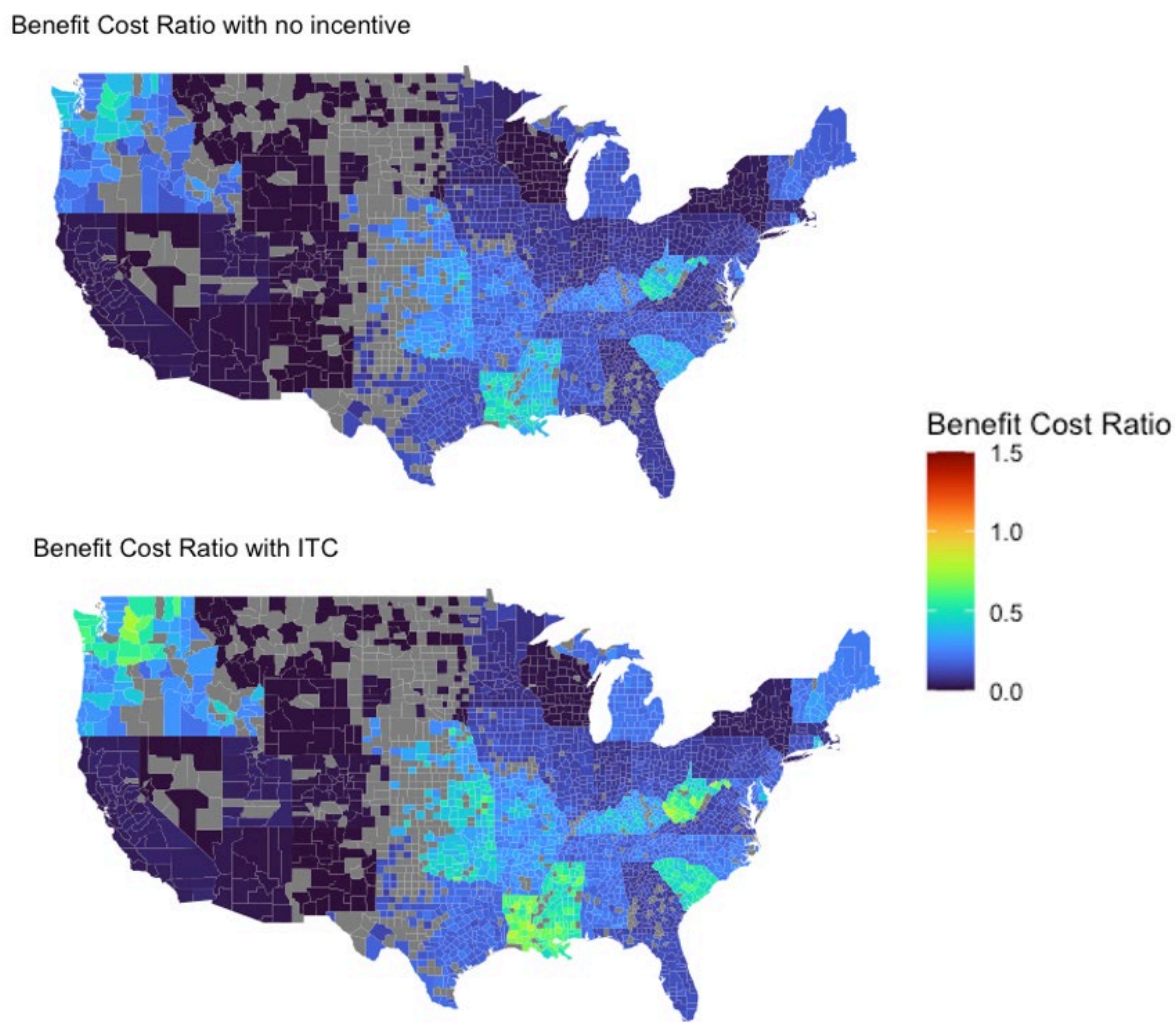

Figure 3.13 Maps of estimated resilience BCRs of storage investments without and with ITC applied. Counties shaded in grey correspond to regions with missing information.

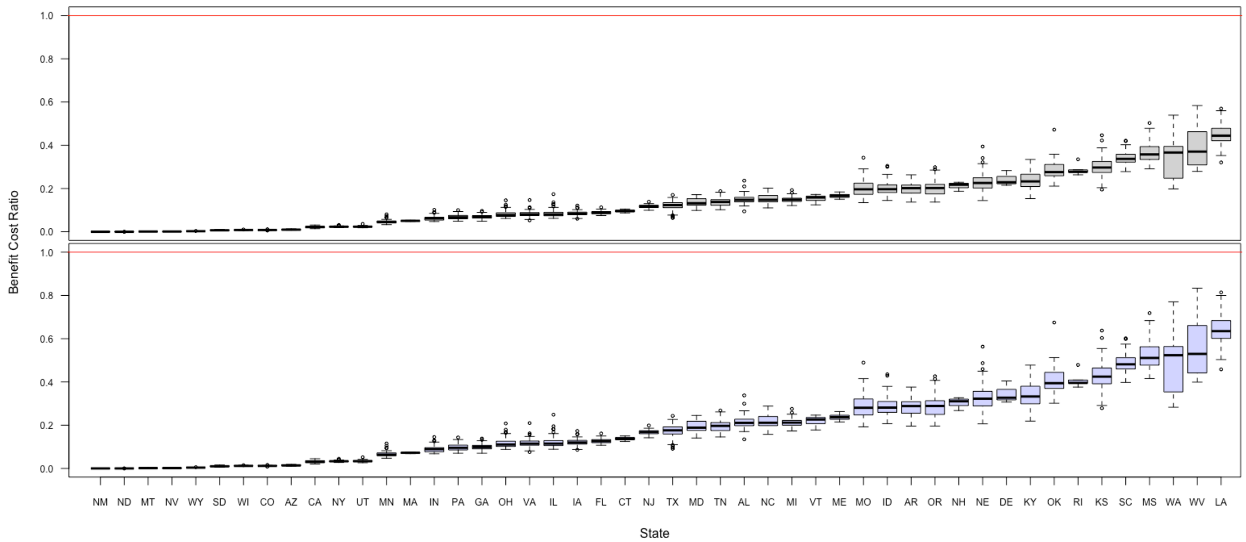

Figure 3.14 Distribution of resilience BCRs for PVESS investments with no incentive (grey) and ITC applied (blue).

Finally, we estimated the potential impact of combined incentives from the ITC and bonus tax credits on the BCR, with the caveat mentioned before that a small subset of customer would actually be able to claim both these sets of incentives. The application of the bonus tax credits in addition to the ITC increases the median resilience BCR by 7.2% and the maximum by 36% (from BCR of 0.83 to 1.19). Although it only happened in a few regions experiencing more and longer resilience events (21 out of 2,519 regions, see Figure 3.15 and Figure 3.16 below), it is worth noting that applying both the ITC and the bonus tax credits can lead some regions to make investments in storage systems solely based on the expected resilience benefits, which suggests the additional incentives from IRA allow them to cost-effectively mitigate interruptions solely based on the resilience benefits.

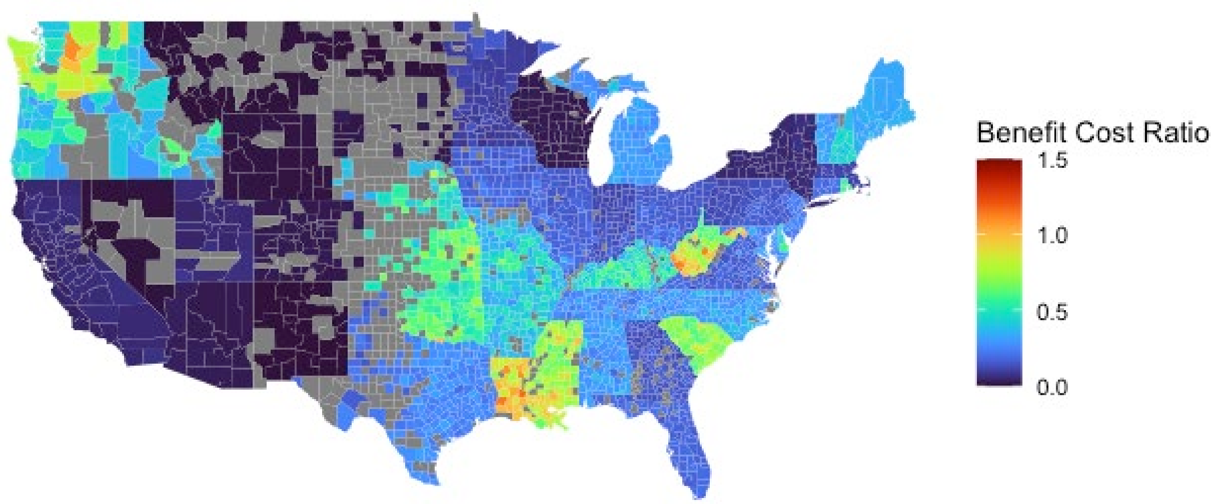

Figure 3.15 Map of estimated resilience BCRs of storage investments with both ITC and bonus tax credits applied. Counties shaded in grey correspond to regions with missing information.

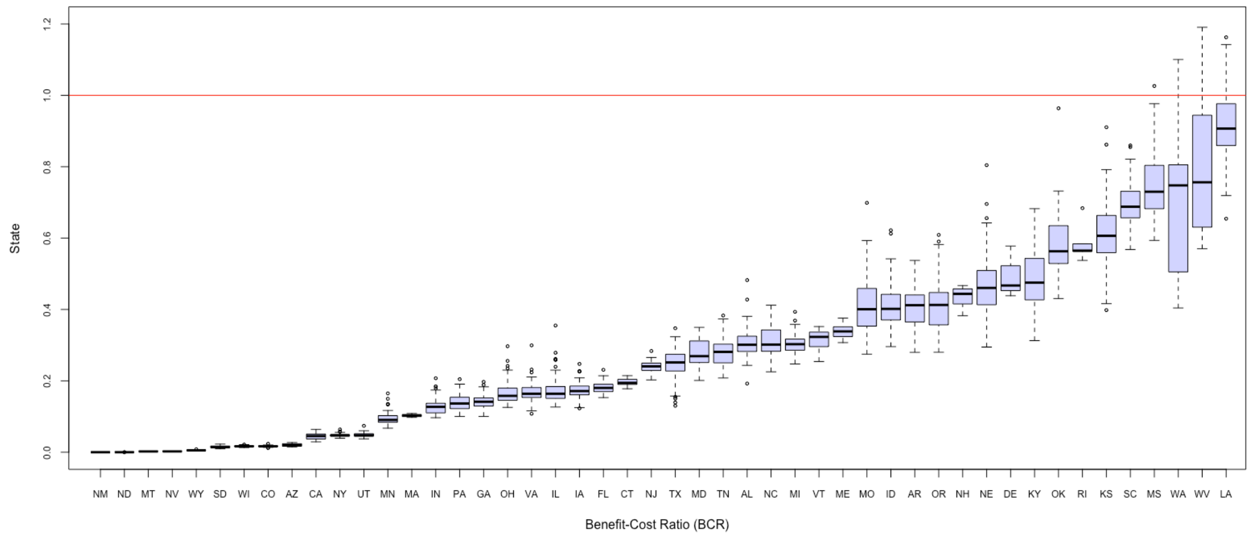

Figure 3.16 Distribution of resilience BCRs for PVESS investments with both ITC and bonus tax credits applied.

4. Summary, policy implications, and future research

4.1 Study goals and approach

The costs associated with power interruptions and their impact on customers and society have become important factors in decision-making regarding the reliability and resilience of the power system. Widespread and long-duration power interruptions occur more frequently than in the past, although still less frequently than short duration interruptions. These long-duration interruptions can have substantial economic and social consequences, affecting electricity customers, utilities, and entire regional economies. This study focuses on investigating the customer resilience benefits of complementing existing PV systems with battery storage to mitigate the impact of long-duration power interruptions.

The study uses a mix of county-, state-, census subregion-, and national-level data to produce median county-level estimates of mitigation potential and cost-effectiveness of PVESS. We develop and use a simple model to estimate state-level frequency and duration of long-duration events in the continental U.S.; state-level estimates for the VOLL under long-duration interruptions and for the cost of storage systems; county-level data on loads from NREL's ResStock tool; and a model to simulate localized PV production and storage dispatch. We simulate interruption impacts with and without PV and storage systems to determine the avoided or mitigated energy loss, and monetize the avoided costs – or resilience benefit – to compare against the cost of the storage system.

The study addresses three fundamental questions concerning the resilience benefits of adding storage to PV systems across the continental United States.

- What is the regional distribution of the capability of residential PVESS to mitigate long-duration interruptions (> 1 day)?
- Assuming regionally-differentiated storage costs and VOLL, how does the resilience value of mitigating long-duration power interruptions compare to the cost of adding storage to an existing PV system?
- How does the net resilience value change considering ITC and bonus tax credits support?

4.2 Key findings

We find that the effectiveness of PVESS in mitigating long-duration power interruptions varies significantly across regions, primarily influenced by the frequency, duration, and distribution of resilience events, typical end use inventory, and solar radiation levels. There was a noticeable but moderate reduction in the expected annual loss of load with PVESS operation. In states characterized by frequent resilience events with extended durations, the operation of PVESS led to a substantial reduction in losses across all counties. On average, PVESS mitigates approximately 96% of the expected load losses. A sensitivity scenario that assumed doubling of resilience event frequency found that the disparities between load losses with and without PVESS became more pronounced.

We conducted a county-level analysis of adding storage to existing PV systems for resilience purposes across the continental United States. PV paired with storage has several customer benefits – utility bill reductions, enhanced reliability, and emissions reductions – but in this study, we focus solely on the resilience benefits. On average, the baseline resilience benefits of incremental storage accounted for 14% of the total storage costs, ranging from 0% to 58% across different cases. The results indicate that resilience benefits are generally not enough to economically justify investment in storage without incentives. Monetization of additional benefit streams would be needed to bridge the remaining gap and fully substantiate these investments.

We perform sensitivity analyses of these results for three key parameters: the frequency of resilience events, customer VOLL, and potential cost reductions through learning curves. The sensitivity analyses showed that the resilience benefits of storage investments are much higher when customers (i) experience increased frequency of resilience events, (ii) have a higher VOLL, or (iii) enjoy reduced storage acquisition costs. In the sensitivity scenarios, the BCR was greater than or equal to 1 in 14 regions (doubled frequency), 98 regions (higher VOLL), 5 regions (conservative future cost reduction), and 181 regions (advanced future cost reduction). These regions with a BCR greater than or equal to 1 were generally in states that experience more frequent and longer resilience events, such as Louisiana, Mississippi, West Virginia, Washington, South Carolina, and Kansas.

We also explored benefits of the ITC and bonus tax credits subsidies. Both subsidy programs increased the BCR of investments in storages, but the resilience benefits alone were still not sufficient to justify the investments even with subsidies. The application of the IRA subsidy allows 21 regions with more frequent and longer resilience events and higher VOLL to cover storage investment solely based on resilience benefits.

4.3 Conclusions

The results demonstrate that, in many regions, depending solely on resilience benefits is insufficient to cover the costs of additional storage. However, certain customers that experience higher than normal frequency of long-duration interruptions or that have inherently higher VOLL may already find this incremental storage cost effective. In addition, as storage acquisition costs continue to decline due to learning curves and subsidies, the economics of storage resilience benefits will continue to improve across the country.

It is worth noting that customers typically consider a range of factors when investing in storage solutions, such as mitigating short-duration interruptions, reducing utility bills, capitalizing on monetized avoided costs, leveraging grid services, and other associated value streams. Consequently, storage investment would have a positive net benefit for even more regions when accounting for these broader benefits. Although the impacts of sensitivity factors outweigh the effect of cost reductions associated with the IRA subsidy on the resilience BCR, such subsidies undoubtedly facilitate a broader customer base in justifying storage investments.

A deeper spatial analysis reveals substantial disparities in resilience BCR among counties in the continental United States. Some regions, less prone to enduring prolonged outages, reap minimal resilience advantages from PVESS operation. Conversely, other areas experience more substantial incentives due to a higher frequency of extreme weather events. BCR disparities across counties differ by an order of magnitude, which can help target locations with potential for reliability and resilience enhancement opportunities. Not explored in this paper, differences in customer preferences and last-mile reliability and resilience issues may result in within-county hotspots for storage deployment solely focused on resilience benefits.

4.4 Policy implications

The diversity in BCR reveals opportunities for regulatory action and policy-oriented research and intervention to ensure that customers that live in areas that are more likely to experience long-duration interruptions have affordable options to mitigate those impacts.

Actions that regulators may request from their utilities include:

- **Interruption data sharing and reporting**. Utilities currently report on power system reliability and resilience through the Annual Electric Power Industry Report (EIA-861) and the Electric Emergency Incident and Disturbance Report (DOE-417). However, the aggregated and anonymized nature of the data hinders deeper analysis and identification of opportunities to improve customer resilience. In very limited cases, utilities are required to file reliability reports that offer in-depth analysis, but the data remains anonymized and unspecified. Regulators can take several key actions to address these limitations and enable a more robust analysis of the resilience benefits of energy storage: (i) mandating utilities to report outage and interruption data at a granular level, detailing specific locations, durations, and customer impacts; (ii) developing and using standardized metrics for reporting resilience event impacts, such as total customer outage minutes; and (iii) encourage utilities to make anonymized resilience data publicly accessible, facilitating research and analysis by independent experts and energy storage vendors to assess market volume.

- **Enhance quantification of the VOLL**. Current VOLL quantifications are relatively limited to a very limited number of customer classes, very short duration, and a single annual value. These estimates may not accurately represent the true value of enhanced power system resilience across the wide range of customer preferences and characteristics. Regulators could work with utilities to significantly enhance the measurement of VOLL across its service territory, ideally at a customer level or at least for highly disaggregated types and locations of customers. This approach would allow utilities to make informed and effective resilience investment decisions based on the specific vulnerabilities of their region. Additionally, granular VOLL would allow customers to understand much better the costs and benefits of adopting storage for resilience purposes, and would assist developers in designing value-adding propositions to customers.
- **Develop resilience value maps and online assessment tools**. Hosting capacity analyses and publicly available maps allow developers to targets specific areas of the distribution system with value-adding resources. A similar approach could be developed for resilience value, in which a utility would integrate its outage management system data and granular VOLL estimates to quantify areas of the grid in which storage may have a high resilience value. Furthermore, a utility could develop and make available to customers, vendors, and other stakeholders tools to assess the multiple value streams accrued by PVESS - especially including reliability and resilience benefits. An easily accessible web-based version of the results developed in this study augmented with other value streams may be valuable in supporting customers to make investment decisions on PVESS. Users of this tool could take short surveys to assess their VOLL and hence produce cost-benefit analysis that directly applies to them.

A policy-oriented research agenda should include the following topics:

- From an R&D perspective, continued support for short-duration storage research that leads to cost reductions would ensure customers with high VOLL and affected by frequent long-duration interruptions have access to this technology regardless of their socio-economic status. In addition, regulators and policy makers may want to ensure that these technologies are available in the locations with higher frequency of interruption events.

- Another potential intervention may provide targeted subsidies for low income customers that have a high VOLL (e.g., customers with critical medical devices) and live in areas with higher frequency of extreme weather events. A storage resilience strategy has evident environmental and operating costs benefits compared to a typical solution based on diesel generators; the tool described above would allow policy makers to monetize these benefits when designing those subsidies

- Specific on-the-ground deployment cases may warrant further research. An example includes how to deploy and utilize short duration storage in multi-family buildings where the resource would most likely be shared across customers with different VOLLs and different income levels. This study identifies locations in the country where resilience benefits are highest, but further work and potentially interventions are needed to develop viable business models for customer-level access.

- Our research shows that one key variable that drives the decision to adopt storage for resilience and reliability benefits is the VOLL. The “Actions” subsection above identifies actions that regulators can require utilities to perform to improve the quantification of the current VOLL across customers. However, as homes electrify in pursuit of lower costs and decarbonization, the higher dependency on electricity may increase future VOLL for most if not all customer types. Forward looking policy interventions may research how much the VOLL is expected to increase and how this increase is spread across spatial and socio-demographic scales to anticipate support for customers with increased resilience benefits from storage.

- The cost of energy storage drives customer's adoption of PVESS. System costs vary across the United States, even within a single state, based on marketplace conditions such as installer availability, labor costs, and local incentives. Regulators can support higher PVESS adoption rates through policies that encourage market growth and reduction in storage soft costs, such as workforce development, and reduction in installation costs.

4.5 Study limitations and further work

This study is a comprehensive but cursory examination of the resilience value of storage and opportunities for adoption of this technology due to its resilience benefits. The main limitations of the study stem from the lack of high quality publicly available data to input into our cost-benefit analysis, which justified the relatively narrow scope that this exploratory analysis proposed and developed. We list some of these limitations and potential routes to overcome them as follows:

- **More granular interruption frequency:**
    - Limitation: The limited publicly available data on long-duration interruptions required the aggregation of electric emergency incidents and disturbances within each state to construct recurrence curves. Additionally, a single recurrence curve was used for each state, disregarding potential variations in the frequency of resilience events within the state. This approach may miss areas within a state that are much more likely to experience long-duration interruptions than others are.
    - Recommendation: Utilize data on the frequency of resilience events within each state that have higher spatial and temporal resolution, allowing for a more granular analysis of resilience events ideally at the county-level.
- **More accurate and granular VOLL estimates:**
    - Limitation: The study encountered difficulties in determining power interruption costs for long-duration outages due to the lack of readily available data. We relied on a combination of data from the ICE calculator and the resilience CIC function derived from a single state to estimate the VOLL at the state level across the United States. State-level values mask the wide range of VOLL within each state; relying on historical VOLL does not capture potential increase in the VOLL due to electrification of end uses.
    - Recommendation: Collect and produce long-duration power interruption cost estimates from various states. An effort in this direction is underway with the overhauling of the ICE calculator, but additional work is needed to properly capture the direct and indirect costs of long-duration interruptions across regions, socio-demographic strata, end use inventories and building characteristics, among others. In addition, further work is needed to understand how the VOLL may change in a highly electrified future.
- **Increased sample size for buildings**:
    - Limitation: We limited our approach to modeling one building per FIPS region due to analytical

constraints. We applied a method of identifying the median representative single-family building per region by isolating buildings with common end use characteristics (e.g., fuel type of water heating and space heating) and selecting the building with median consumption. This generalization produces useful results for average or typical customers, but miss opportunities to characterize customers in the tails of the distribution.

  - Recommendation: For research with a broader scope, we would consider a larger selection of buildings per FIPS region, incorporating additional buildings based on size, fuel type, and building type. This may also help produce results that could feed an online tool in which customers could more accurately identify the results that apply to them based on their specific characteristics.

- **Optimized energy storage sizing:**
  - Limitation: We assume all buildings receive the same energy storage system–a 10 kWh system that can meet any peak load. We made this assumption because 10 kWh is somewhat representative of commercially available residential energy storage systems but also to avoid incorporating optimization modeling into this work. Ongoing work by Berkeley Lab shows that a 10 kWh battery system overshoots many customer needs for long-duration interruption mitigation. A smaller system may serve their needs equally well, but have a higher BCR due to lower costs.
  - Recommendation: In the future, we would apply optimization modeling for resilience-focused PVESS that was developed since the start of this work.

- **Deeper analysis of IRA eligibility**:
  - Limitation: We did not estimate the share of customers that would be eligible for a full 30% or even 40% cost reduction from IRA incentives. This does not allow for accurate characterization of the actual resilience benefits of IRA for PVESS adoption because we have not characterized the frequency of events, VOLL, and costs for the subset of customers that are eligible for IRA benefits.
  - Recommendation: Determine location-based IRA eligibility by researching where energy communities are located, how much domestic-manufactured PVESS is available, and if low-income eligibility is likely based on FIPS region data. We may determine whether IRA-eligible customers are indeed the ones with highest resilience needs, or whether these customers may benefit more from other value streams.

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APPENDIX A.

A.1. Estimating recurrence curves for resilience events

This involved a four-step process:

1. Calculation of the Exceedance Probabilities: For each state, we calculated the exceedance probabilities based on outage durations.
2. Modeling the Relationship: We employed an exponential decay function to model the relationship between exceedance probabilities and outage durations. See Figure A.1 below for an example of exceedance probability curve constructed for a state in the Midwest.
3. Calculation of Conditional Exceedance Probabilities: Utilizing the fitted function, we computed conditional exceedance probabilities for outage durations ranging from 1 day to 10 days. See the left column of Table A.1 for the exceedance probabilities calculated for the state in the Midwest.
4. Probability Calculation: Finally, we determined the probability of experiencing a resilience event within specific duration intervals. These intervals ranged from 0-1 days to more than 10 days, with a daily increment. See the right column of Table A.1 for the probabilities of resilience events fall within given intervals. Calculations presented in Section 3 exclusively rely on the lower bounds of the intervals. For instance, when ascertaining the probability of a power interruption lasting 24-48 hours, we assigned it a value of 12%. However, when computing the expected number of events for specific durations in each month, we have employed these probabilities to calculate the occurrences for single-day events.

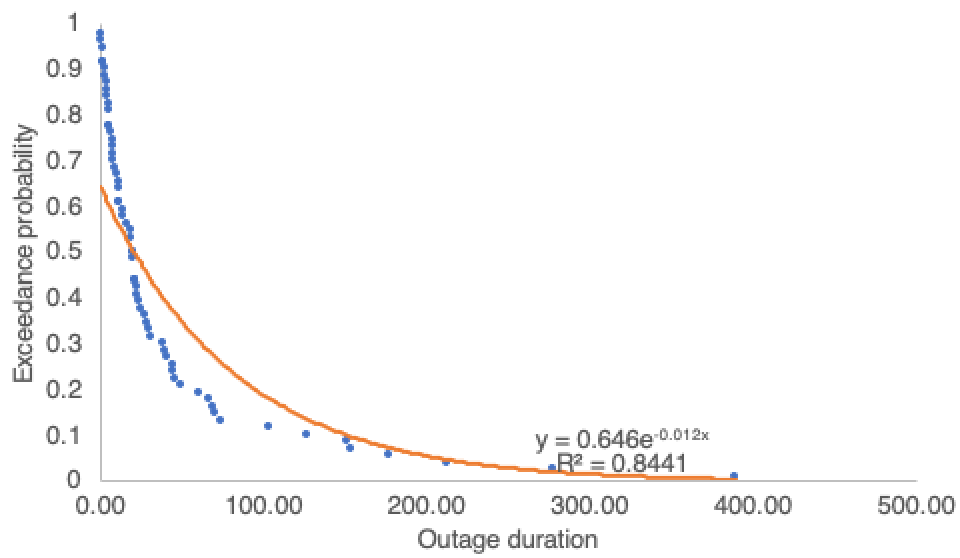

Figure A.1: Exceedance probability curve fitted for a state in the Midwest

Table A.1: Exceedance probabilities and probability outage duration falls within a given interval in the state in the Midwest

Duration (hours)	Exceedance probabilities	Interval	Probability outage duration falls within a given interval
6	60.11%	0-6 hours	39.89%
12	55.94%	6-24 hours	11.68%
24	48.43%	24-48 hours	12.12%
48	36.31%	48-72 hours	9.09%
72	27.23%	72-96 hours	6.81%
96	20.41%	96-120 hours	5.11%
120	15.31%	120-144 hours	3.83%
144	11.48%	144-168 hours	2.87%
168	8.60%	168-192 hours	2.15%
192	6.45%	192-216 hours	1.61%
216	4.84%	216-240 hours	1.21%
240	3.63%	> 240 hours	3.63%

A.2. Calculating the number of baseline resilience events

We estimate the expected number of resilience events across states and at the FIPS level following these steps:

1. Regional segmentation: The contiguous United States was divided into four regions (Figure A.2) based on the methodology outlined by Ericson et al. (2022) to consider the impact of neighboring states.
2. Merging overlapped extreme events: As some electric emergency incidents and disturbances resulting from extreme events (electric emergency incidents and disturbances as defined by DOE-417 between 2000 to 2022) were reported by multiple utilities, we merged overlapping events by updating the start time (earliest start time among all overlapped events) and end time (latest restoration time among all overlapped events), while summing up the number of affected customers, assuming each report was made by different utilities.
3. Determining the portion of customers affected by each extreme event: To assess the impact of resilience events on each state, we divided the total number of affected customers for each resilience event by the estimated number of electricity customers in each state. These estimates were derived from the EIA's Electric Power Annual Table 2.1 (for trends in the number of electricity industry customers) and the EIA-861 2021's electricity customer counts by state.
4. Counting direct and adjacent extreme events at the state level: Within each regional grouping, we

calculated the number of electric emergency incidents and disturbance events that affected a specific state (referred to as "in-state events"), as well as the number of events that impacted other states in the region but not the specific state (referred to as "regional events outside the state") from 2000 to 2022.

5. Adjusting the total extreme events in each state: Extreme events typically span multiple states, although they may be recorded as predominantly occurring in a single state. We capture this by assuming that a given state's events are a function of its own historical experience in addition to the events occurring in neighboring states. We calculated the total number of these events for each state by summing the counts of in-state events with the number of regional events outside the state and then dividing the result by the total number of states in the region. This calculation was only applied to years with at least one resilience event; otherwise, we assumed zero resilience events occurred in that year.
6. Calculating the total extreme events in each state: Recognizing that extreme events occur sporadically, we calculated the average of extreme events over the most recent five years (2018 to 2022) to determine the total number of extreme events in each state.
7. Distributing state-wide extreme events to the FIPS level: Under the assumption that the median portion of customers affected by resilience events in each state represents the probability of each FIPS region being affected, we multiplied the median portion of affected customers for each state by the total assigned resilience events in that state to allocate the events at the FIPS level.
8. Calculating the resilience events occurred at the FIPS level: Using the exceedance probability curves estimated for each state, we calculated the resilience events occurred at the FIPS level by multiplying the number of FIPS-level extreme events with the probability of experiencing an event lasting longer than 24 hours.

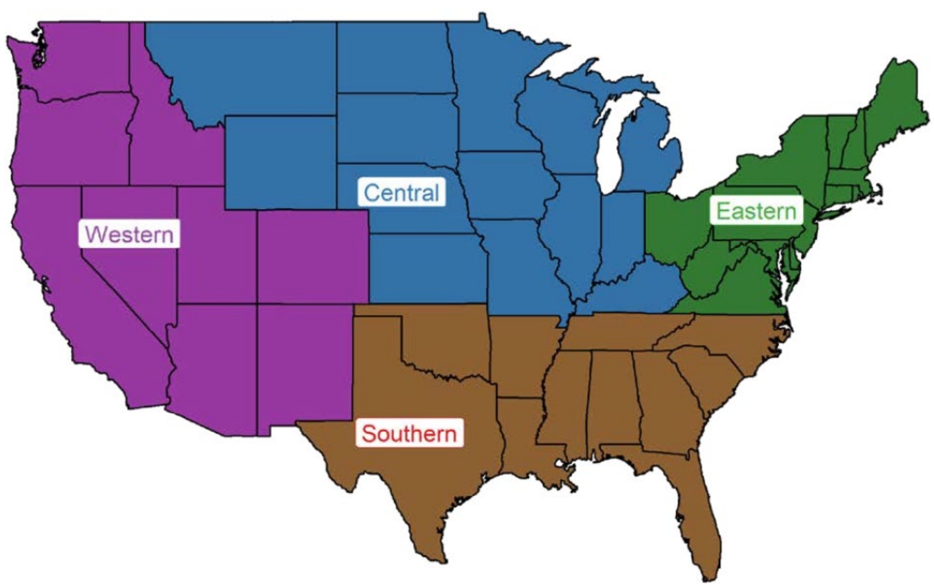

Figure A.2. Regional scheme for understanding the impacts of neighboring states, adapted from Figure 1 in Ericson et al. (2022).

A.3. Calculation of the value of lost load for resilience events

U.S. utilities have conducted surveys of their customers to estimate customer interruption costs (CICs). CIC describe the direct and indirect costs that customers accrue due to unexpected loss of power. Building on the efforts of utilities, Berkeley Lab and Nexant, Inc. aggregated a large number of utility-sponsored CIC studies to estimate CIC functions for general use in utility planning (Lawton et al., 2003; Sullivan, Mercurio, and Schellenberg, 2009, Sullivan, Schellenberg, and Blundell, 2015). The meta-analysis and econometric models serve as the basis for the Interruption Cost Estimate (ICE) calculator. The ICE calculator is a powerful tool that estimates CICs by taking into account utility characteristics, outage characteristics, and various other conditions. This functionality makes it invaluable for conducting approximate comparisons of CICs across different states. However, the ICE calculator was originally intended to estimate costs for short and localized power interruptions (i.e., power interruptions lasting less than 24 hours; referred to as 'reliability events'); thus, it is not appropriate to monetize customer's losses during resilience events.

Berkeley Lab and a Midwest IOU recently conducted an extensive survey of CIC to estimate the economic impact of widespread and long-duration power interruptions within the service territory. The survey of residential customers collected data on various expenses incurred during a power interruption, including lost income, costs associated with operating power generators, and other related expenses such as food, lodging, transportation, and more. We capture the varying durations of power interruptions by aggregating these costs for one day, three days, and 14 days, considering both summer and winter disruptions. Duration-dependent customer damage functions were calculated in terms of $/kWh estimates for energy not served by dividing the elicited power interruption costs by the expected electricity consumption lost.

To estimate the median VOLL during resilience events for the contiguous United States, we integrated ICE calculator and the value of energy-not-served estimates from the survey described above. Specifically, we used the following approach:

- Estimate reliability costs for an average residential electricity customer using the ICE calculator. This involved using the Interruption Costs Spreadsheet to estimate the power interruption costs of a default (representative) residential customer for power interruptions ranging from a momentary event (5 minutes long) up to 24 hours long, with an increment of one hour.
- Calculate the relative multiplier. We assumed the state served by the Midwest IOU as the base state for power interruption costs. The relative multiplier for each state was then calculated by dividing the power interruption costs of each state by the costs of the base state, and then taking the average of the relative multipliers for the entire durations. See Figure A.3 below for the average CIC for residential customers in each state during reliability events (elicited from the ICE calculator).
- Derive the base duration-dependent median VOLL curve from the Midwest IOU's CIC results and estimated value of energy-not-served (ENS).
- Finally, estimate the median VOLL in each state by multiplying the VOLL for each duration range with the corresponding relative multiplier calculated earlier.

Figure A.3 below provides a summary of the estimated VOLL during resilience events at the state level.

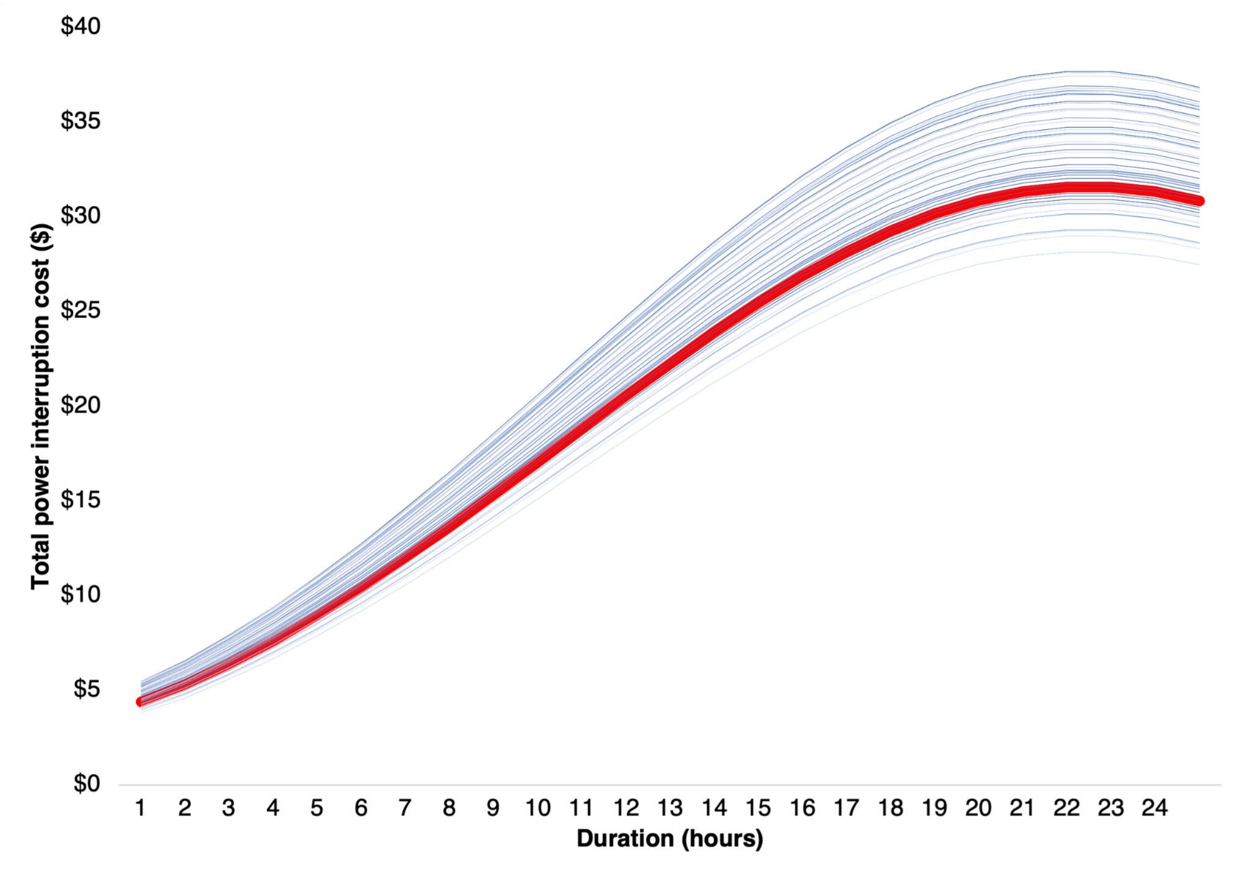

Figure A.3. CIC for reliability events elicited from the ICE Calculator for an average residential customer in each state. Red represents the CIC from the base state.