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Beyond linear outage costs: Estimating duration-dependent economic impacts in Puerto Rico☆

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ABSTRACT

Electric power disruptions impose substantial economic and societal costs, particularly in islanded power systems exposed to extreme weather, geographic isolation, and limited opportunities for grid support. Existing outage cost estimates are largely derived from mainland U.S. data and short-duration interruptions, limiting their applicability to prolonged outages in islanded systems. In addition, conventional approaches implicitly assume customer coping strategies, such as geographic relocation and spatial substitution, that are often unavailable in island environments, where constrained import capability, limited reserve sharing, and slower restoration may amplify the impacts of extended disruptions. This study presents the first empirical assessment of customer interruption costs in Puerto Rico for outages lasting one to 30 days. Using large-scale survey data and non-linear econometric modeling, we estimate duration-dependent customer damage functions for residential, non-residential, and public-sector customers. Results show that outage costs increase non-linearly with duration. Expressed as average daily costs, impacts initially decline as customers rely on available mitigation measures, but increase again during extended outages as mitigation resources become increasingly constrained and cumulative losses grow. Territory-wide economic impacts are estimated at approximately $1 billion, $5 billion, and $29 billion for 1-, 14-, and 30-day outages, respectively. The findings demonstrate that linear valuation approaches, including FEMA's Value of Unit Service assumptions, may substantially misrepresent the economic consequences of prolonged outages. While the estimated customer damage functions are specific to Puerto Rico, the methodological framework provides a foundation for improving outage valuation and resilience planning in other islanded systems and, with appropriate adaptation, interconnected mainland systems.

1. Introduction

Electric power underpins household, commercial, industrial, and public services, making system reliability a central consideration in utility planning and infrastructure investment. Long-duration and widespread interruptions (LDWIs) are becoming increasingly consequential, with extreme events occurring more often than historical outage patterns would suggest (National Academies of Sciences, Engineering, and Medicine, 2017). These disruptions generate substantial economic and societal impacts that extend beyond directly affected customers through reduced economic activity, degraded public services, and constrained regional recovery.

Islanded populations face increasing risks from both acute hazards, such as hurricanes, and long-term climate change, resulting in a greater likelihood of widespread and prolonged power interruptions (Shah and Niles, 2016). Geographic isolation, limited interconnections, and concentrated infrastructure can amplify outage severity and delay restoration. Recovery is further constrained by remote geography and dependence on marine supply chains, making energy resilience a continuing priority for islanded systems (To et al., 2021). These characteristics also influence customer interruption costs (CICs). In interconnected mainland systems, customers may mitigate prolonged

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outages through geographic relocation or spatial substitution by accessing goods, services, or operational facilities in nearby unaffected areas. These options are largely unavailable in islanded systems, increasing reliance on onsite mitigation and extending the economic consequences of prolonged outages. These vulnerabilities continue to grow as extreme weather events become more frequent and intense (U.S. Department of Energy DOE, 2013; U.S. Global Change Research Program USGCRP, 2018; Zamuda et al., 2019; Pörtner et al., 2022).

Puerto Rico provides a clear example of these challenges. Over the past decade, the island has experienced multiple large-scale grid disruptions, including the cascading system failures following Hurricanes Irma and Maria in 2017, widespread outages during the 2020 earthquake sequence, and Hurricane Fiona in 2022, which disrupted service to more than 1.4 million customers with full restoration requiring more than three weeks (World Bank, 2024; NASA Earth Observatory, 2025; LUMA Energy, 2022). Tropical Storm Ernesto left nearly 750,000 homes and businesses without power, with restoration in some areas extending well beyond the initial event (LUMA Energy, 2024; T&D World, 2024). These events underscore the need for resilience investments that can reduce outage severity and accelerate recovery. Utilities and public agencies require credible outage cost estimates to evaluate grid hardening, distributed energy resources, backup systems, and other resilience measures.

Existing outage valuation approaches face important limitations, particularly when applied to LDWIs. In this study, LDWIs are defined using both temporal and spatial dimensions. Long-duration interruptions are defined as outages lasting more than 24 h, beyond which conventional CIC methods become less applicable because customer responses, mitigation strategies, and economic impacts become increasingly complex (Sullivan et al., 2018). Widespread interruptions refer to outages extending beyond a localized area to affect a substantial portion of a utility service territory. The geographic extent considered widespread depends on the characteristics of the power system and the geographic context of the study region. In Puerto Rico, this can range from outages affecting one or more municipalities or a substantial region of the service territory to outages affecting the entire territory. These temporal and spatial characteristics can change how customers experience and respond to outages and, consequently, how outage costs evolve over the course and geographic extent of an interruption. First, most methods were developed using evidence from short-duration interruptions and are extrapolated to LDWIs using simplified linear assumptions. The widely used Federal Emergency Management Agency (FEMA) Value of Unit Service for Electricity (VUSE) framework applies a constant outage value regardless of interruption duration (Federal Emergency Management Agency FEMA, 2023). This structure cannot capture how outage costs evolve during prolonged disruptions as backup resources are depleted, operational disruptions accumulate, and financial losses compound over time (Ericson and Lisell, 2020; Leddy et al., 2023; Rickerson et al., 2024).

Second, existing CIC estimates rely largely on survey evidence from large interconnected power systems, where restoration logistics, infrastructure redundancy, and resource availability differ substantially from conditions in islanded systems (Baik et al., 2024). As a result, valuation approaches developed for mainland systems may not adequately represent how customers in islanded regions experience and adapt to prolonged outages.

This study addresses both limitations by providing the first empirical assessment of CICs in Puerto Rico and using Puerto Rico as an empirical setting to evaluate how outage impacts in islanded systems differ from assumptions commonly embedded in resilience investment analysis. Using large-scale survey data and econometric modeling, we estimate economic damage trajectories for residential, non-residential, and public-sector customers under prolonged outage conditions. The resulting estimates provide locally grounded inputs for resilience investment planning in Puerto Rico and offer a practical framework for improving outage valuation methods in other islanded and disaster-prone power systems. The findings also provide evidence to inform ongoing efforts to improve outage valuation practices used in federal and utility resilience planning.

2. Methodology and data

LDWIs arise from extreme weather, natural hazards, and physical or cyber events that disrupt critical electricity infrastructure. These events generate five categories of economic cost: (1) damage to utility generation, transmission, and distribution assets; (2) service disruption costs borne by residential and non-residential customers, including lost production and foregone services; (3) spillover losses to local and regional economies as outages propagate through supply chains and labor markets; (4) monetizable non-market impacts, including health risks, environmental damage, and legal liabilities (Zamuda et al., 2019); and (5) expenditures on risk reduction and resilience measures undertaken before an event to reduce outage frequency, duration, or consequences (Meyer et al., 2013).

Fig. 1 below organizes these costs across three nested levels. The first level captures the economic consequences of power interruptions borne by electricity customers. These impacts include both direct CICs and broader economic effects that arise as outage-related losses propagate through local and regional economies. The second level adds costs borne by utilities, public services, and communities as outages propagate beyond the meter. The third level includes the full economic cost of the underlying natural hazard, including damages that occur even in the absence of power loss. This study estimates only the direct CIC shown in the green box in Fig. 1.[1] Investment and policy decisions, however, require the broader accounting captured in the second and third levels because grid investments affect utility costs, regional economic activity, and the performance of interconnected critical infrastructure, not only customer outage costs.

Reliability planning has historically followed engineering targets rather than economic optimization. Utilities designed generation, transmission, and distribution capacity to meet criteria including a loss-of-load expectation of one day in ten years (North American Electric Reliability Corporation NERC, 2011), then evaluated investments largely on utility cost and system performance. Value-based reliability planning adds CICs to this framework. Munasinghe (1979) defined the efficient reliability level as the point that minimizes the sum of utility costs and customer outage costs. U.S. utilities operationalize this principle by using CIC estimates, typically derived from customer surveys, to evaluate and prioritize reliability investments.

CIC studies estimate the direct economic losses customers experience during power interruptions. Traditional methods classify customers into residential, small and medium non-residential (SMNR), and large non-residential (LNR) groups (Sullivan et al., 2018). This structure reflects the original purpose of CIC surveys, which is to estimate reliability value by customer class. The studies rely on two measurement approaches. CIC studies apply direct cost measurement to non-residential customers as their interruption costs are often quantifiable and can be directly estimated. Surveys present standardized interruption scenarios and ask firms to report the measurable losses and cost changes associated with each event, including value of lost production, interruption-related costs (e.g., damage to equipment, labor to restart production process, costs to operate backup generation equipment), and interruption-related savings (e.g., cost saved on raw materials, fuel costs saved). Conversely, estimating residential customers' interruption costs using direct cost

[1] The analysis does not quantify indirect regional economic impacts resulting from customer losses or broader utility and community impacts. These additional effects can be evaluated through complementary approaches, including regional economic modeling and multiplier-based methods that translate direct customer costs into wider economic consequences (Sullivan and Schellenberg, 2013).

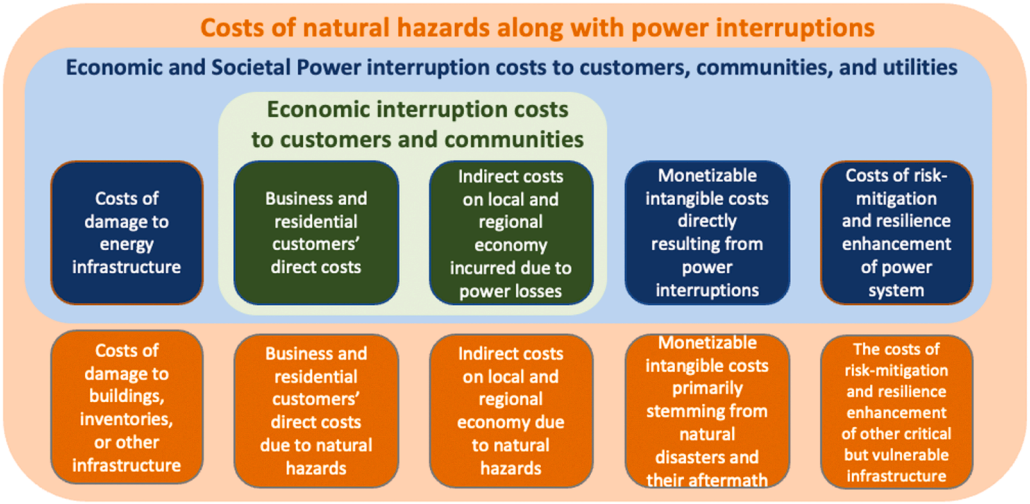


Fig. 1. Cost components related to direct customer power interruption cost assessments, total power interruption cost assessments, and damage assessments for power interruptions along with natural disasters. Adapted from Baik et al. (2021).

methods is challenging due to the intangible costs associated with inconvenience or discomfort. Instead, these less tangible costs (e.g., inability to use appliances, lack of air conditioning during extreme heat) are monetized using stated-preference (SP) methods like willingness-to-pay (WTP) elicitations (Baik et al., 2024; Sullivan et al., 2018). Existing frameworks like the Interruption Cost Estimate (ICE) Calculator[2] use these approaches but have historically focused on short-duration outages (<24 h) and have not been validated for LDWIs.

SP methods are subject to well-recognized limitations, including hypothetical response bias and the cognitive challenges associated with evaluating complex outage scenarios (Hausman, 2012). In response, recent studies have increasingly applied revealed-preference (RP) methods to infer the value of electricity reliability from observed customer behavior. For example, Harris (2023) estimates reliability values using portable generator purchases associated with prolonged outages and hurricane warnings, while Brown and Muehlenbachs (2024) examine residential adoption of solar-plus-storage systems in response to California's public safety power shutoffs. These studies provide valuable empirical evidence and complement traditional SP approaches by grounding estimates in observed decisions (Macmillan et al., 2023).

However, RP approaches remain less well suited for evaluating LDWIs. Investments in backup resources, such as generators or solar-plus-storage systems, are concentrated among customers with sufficient financial resources and therefore may not represent the broader population (Harris, 2023; Baik et al., 2021; Gorman, 2022). In addition, most customer-owned backup technologies are designed to support relatively short interruptions and therefore provide limited information about customer impacts during outages lasting several weeks (Gorman, 2022). Finally, while RP methods estimate customers' willingness to avoid outages through observed mitigation investments, they do not directly quantify many of the outage-related economic impacts captured by CIC surveys, including equipment damage, inventory spoilage, and additional labor costs associated with prolonged service disruptions (Baik et al., 2021). These considerations motivate the use of a SP framework for estimating customer impacts during long-duration outages.

To our knowledge, no CIC study has been conducted specifically for Puerto Rico. Previous efforts, including PREPA's 2019 Integrated Resource Plan (IRP), relied on value of lost load (VOLL) estimates from studies in other regions. PREPA selected the New Zealand VOLL study as a proxy, citing similarities in economic and demographic characteristics, and adjusted the estimates using Puerto Rico's reliability metrics (North American Electric Reliability Corporation Puerto Rico Electric Power Authority PREPA, 2019). The 2019 IRP applied these estimates across customer segments using expected unserved energy and customer counts, providing a preliminary assessment of outage costs and representing the first formal effort to explicitly address resilience and reliability following Hurricanes Irma and Maria and subsequent earthquakes. LUMA Energy, the current utility operator, continues to incorporate system-wide VOLL estimates and assess the economic impacts of load-shedding events in its ongoing IRP. This approach, however, assumed a linear cost relationship with outage duration and failed to capture local customer behavior or grid constraints, highlighting the need for a Puerto Rico-specific, survey-based CIC assessment.

To fill this gap, this study applied and extended an improved CIC methodology developed by Baik et al. (2024). This methodology moves beyond the assumptions of traditional CIC studies by recognizing the nonlinear accumulation of economic costs as outages extend, consistent with findings from Apt et al. (2004), Sullivan et al. (2010; 2015; 2018), Shuai et al. (2018), and Larsen et al. (2025). We adapted the approach to Puerto Rico's unique hazard profile, grid topology, and economic structure, producing duration-dependent customer damage functions (CDFs) that quantify direct customer costs across a range of outage scenarios. The underlying CIC framework is consistent, while scenario construction and survey design are customized to reflect the characteristics of the power system and customer groups being studied. The framework includes four key components:

- **Scenario Development**: The study developed three representative outage scenarios reflecting Puerto Rico's hazard exposure, grid characteristics, and resilience challenges. Scenario design followed established CIC estimation practices (Baik et al., 2024; Sullivan et al., 2018) and incorporated expert judgment, simulation results, and stakeholder review. The scenarios were designed to capture differences in outage duration and geographic extent while accounting for customer mitigation options under each outage condition. For Puerto Rico, geographic isolation and limited interconnection were considered when assessing the mitigation options available to customers. Two assumptions guided the design: (1) the duration and geographic extent of interruptions correlate with the severity of underlying power system damage, coupling time and spatial scope together across our resilience tiers, and (2) weather conditions are fixed to those associated with the highest economic costs (Baik et al., 2024). Three representative scenarios were selected: a one-day

[2] https://icecalculator.com/

localized outage from equipment failure on a typical summer day; a two-week regional outage from seismic-related generation disruptions; and a month-long, territory-wide outage from a major hurricane. These scenarios represent a plausible range of LDWIs observed in Puerto Rico and provide a policy-relevant basis for evaluating how outage costs evolve as disruptions become increasingly widespread and prolonged.

- **Customer Survey Design**: The survey instruments were customized to reflect the characteristics and potential outage impacts of each customer group in Puerto Rico. We developed survey designs for four customer classes: residential, SMNR, LNR, and critical public sector such as hospitals, utilities, and emergency services. This design extended the traditional classification of Sullivan et al. (2018) by explicitly including public sector customers and tailoring content to each group's risk exposure and service priorities. Survey instruments were tailored to each class: residential surveys used a multiple-bounded discrete choice WTP format, consistent with established CIC practices (Baik et al., 2024; Sullivan et al., 2018); non-residential customers provided direct cost estimates for lost production, restart costs, and operational savings; and public sector organizations estimated expected disruptions, operational delays, and projected increases in morbidity and mortality, following approaches from prior resilience valuation studies (Apt et al., 2004; Hanna et al., 2019). The instruments and instructions were carefully designed to prompt respondents to report costs directly attributable to the loss of electricity while excluding physical damages caused by the initiating hazard. To reduce the potential for conflating hazard impacts with outage-related impacts, the surveys relied on predefined cost categories rather than open-ended damage reporting. For example, residential respondents were asked to estimate specific expenses such as the cost of fuel for alternative non-electric cooking and spoiled food, while non-residential respondents reported outage-specific costs associated with labor, mitigation, and operational disruptions. The complete survey instruments are provided in the Supplementary Information. The specific customer groups, survey content, and mitigation strategies considered may require adjustment when applying the framework to other regions with different customer characteristics or access to alternative services and resources.
- **Survey Sampling and Administration:** Survey sampling drew from selected LUMA Energy rate schedules to represent each class, with SMNR and LNR frames further refined using Standard Industrial Classification (SIC) codes and unique entity counts to avoid duplication (see Supplementary Information, Table S1). Public sector participants included both those billed under government rate classes and others identified via SIC codes in healthcare, education, and public administration. Residential and SMNR samples were proportionally allocated across LUMA's six operational regions, while LNR and public sector customers were recruited without regional segmentation due to their smaller populations and multi-regional operations. Industry-sector and regional information were used in sample selection and allocation to reflect the industry structure and geographic distribution of the Puerto Rico service territory as closely as possible, although the resulting samples are not statistically representative of the territory-wide customer population. Population sizes from LUMA's February 2024 database were 1390,741 (residential), 17,441 (SMNR), 353 (LNR), and 3282 (public sector) (Table S2). Minimum target responses—408, 197, 39, and 66 for these groups, respectively—were calculated using Dillman's methodology to balance statistical confidence with project resources (Table S3). A detailed comparison of respondent demographics to the broader population is provided in the Supplementary Information. Surveys were administered from July–November 2024 using a multichannel approach including direct mail, email, and phone calls. Incentives were offered to residential and business respondents, while public sector participation was secured through direct engagement with government offices and agency leadership.
- **CDF Construction** Following survey closure, the data were compiled, cleaned, and analyzed. The cleaning process confirmed customer eligibility, eliminated duplicate responses, verified survey assignments, and removed protest responses. For the residential survey, 38 ineligible respondents and 59 zero-WTP responses were excluded to reduce potential bias associated with factors such as backup generator ownership or dissatisfaction with electric service. For non-residential respondents, cleaning focused on verifying customer classifications and preventing duplicate entries. The final dataset included 540 residential, 135 SMNR, 19 LNR, and 45 public-sector responses. While the residential target was exceeded, response counts for non-residential segments fell below target levels (Table S3). Limited participation from large industrial customers, particularly within Puerto Rico's pharmaceutical sector, constrained the LNR sample size. In addition, public-sector respondents exhibited operational characteristics and outage impacts similar to those reported by LNR customers. Consequently, responses from these groups were combined into a single LNRP (large non-residential and public-sector) category to improve statistical robustness while preserving representation of customers with large energy demands and critical service functions. CDFs were then developed to characterize how interruption costs vary with outage duration and to estimate interruption costs across a range of outage scenarios. The functions reflect the nonlinear accumulation of costs associated with LDWIs, consistent with prior research (Sullivan et al., 2010, 2015, 2018; Shuai et al., 2018; Larsen et al., 2025). Costs were constrained to remain non-negative, increase gradually for short outages, and escalate during extended outages to reflect compounding operational and public safety effects. Functional forms and escalation rates were selected to align with observed survey responses and existing outage valuation literature while incorporating Puerto Rico's hazard conditions, grid vulnerabilities, and customer profiles (Baik et al., 2024).

The integration of these components—realistic disaster scenarios, tailored survey instruments, and non-linear cost modeling—yields the foundational data presented in the Results section. This comprehensive approach provides a robust, empirical framework for valuing LDWI costs, one specifically designed to address the unique resilience challenges of an islanded system like Puerto Rico.

3. Results

3.1. Residential customers report increasing willingness-to-pay to avoid outages as duration increases

The residential survey collected information on household income, access to backup generation, monthly electricity expenses, and work-from-home status (Table S4 in Supplementary Information). Respondents provided upper-bound WTP estimates to avoid the impacts of three hypothetical power interruption scenarios. WTP values increased substantially with outage duration, with median values per customer of $15 for a one-day outage, $200 for a 14-day event, and $600 for a 30-day outage (see top panel of Fig. 2). Expressed as average daily values, this corresponds to approximately $15/day, $14/day, and $20/day, respectively, indicating that daily WTP remains relatively stable during the first two weeks before increasing for longer-duration outages. Paired Wilcoxon signed-rank tests confirmed the statistical significance of these increases ($p < .05$) across all comparisons, indicating that customers placed growing economic value on uninterrupted service as outages lengthened. The distribution of WTP values also widened with duration, reflecting increasing uncertainty and variation in household coping capacity as outages extend beyond familiar thresholds.

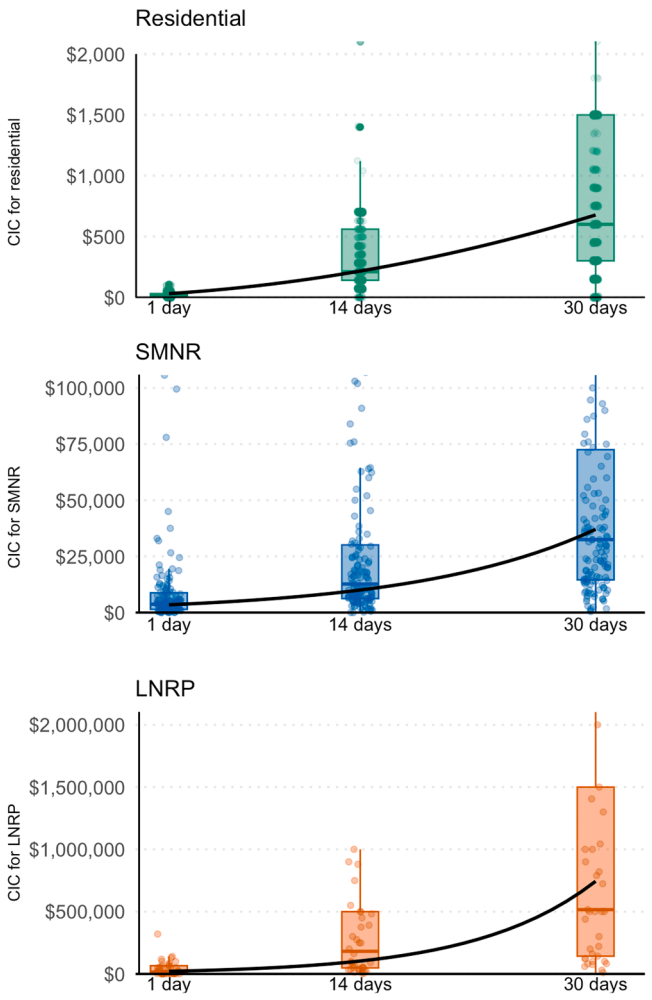


Fig. 2. Distribution of the Customer Interruption Costs (CICs) collected from the Residential (top), Small/Medium Non-Residential (SMNR, middle), and Large Non-Residential and Public (LNRP, bottom) electricity customers with the fitted Customer Damage Functions (CDFs). Residential CICs are based on stated willingness-to-pay (WTP), whereas SMNR and LNRP CICs are based on reported incurred and avoided costs.

3.2. Small and medium non-residential customers face rising costs and diminishing mitigation capacity

The SMNR survey collected cost data from businesses across diverse industries and sizes (Table S5 in the Supplementary Information provides the industry composition of the sample and BUG ownership). Respondents estimated incurred and avoided costs (i.e., savings) under three outage scenarios. Median reported CICs per customer increased from $3700 for a one-day outage to $13,000 for a 14-day event and to $33,000 for a 30-day outage. Expressed as average daily values, this corresponds to approximately $3700/day, $929/day, and $1100/day, respectively. The average daily cost therefore declines substantially between one and 14 days, followed by a modest increase by 30 days, although the 30-day daily rate remains well below the one-day rate. This pattern suggests that mitigation measures reduce the average daily burden during the initial stages of a prolonged outage, but become less effective as the outage extends. Outliers contributed to notably higher mean values, especially for longer interruptions (see the middle panel of Fig. 2). These results indicate that outage costs evolve nonlinearly with duration. From one to 14 days, costs rise less than proportionally to duration, suggesting partial effectiveness of mitigation strategies over shorter events through operational adjustments and backup resources. However, from 14 to 30 days, lost revenue becomes increasingly dominant and mitigation measures become less effective, resulting in steeper escalation in economic impact.

The composition of costs also evolves with outage length. Equipment damage accounts for a significant share of total costs even during one-day outages. These estimates are based on predefined survey cost categories and include damage to sensitive electrical and mechanical equipment resulting from power loss or voltage fluctuations, as well as spoilage of raw materials and perishable inventory. As outages extend, lost revenue grows steadily and becomes the dominant cost component beyond two weeks (top panel, Fig. 3). Labor costs and other operational losses also increase with duration. Insurance coverage was limited across this customer group, with only 9.6% of SMNR respondents reporting business interruption insurance. These findings underscore that while short outages may be partially mitigated, extended disruptions increasingly exceed businesses' adaptive capacity, resulting in greater economic vulnerability.

3.3. Large non-residential and public sector customers bear disproportionate economic impacts

The LNRP survey captured cost estimates from large businesses, industrial firms, and public agencies (Table S6 in the Supplementary Information provides the industry composition of the sample).[3] Median CICs per customer for this group increased sharply with outage duration, from $15,000 for a one-day outage to $180,000 for a 14-day event and up to $520,000 for a 30-day outage (see the bottom panel of Fig. 2). Expressed as average daily values, this corresponds to approximately $15,000/day, $12,900/day, and $17,300/day, respectively. The average daily cost declines from one to 14 days but increases substantially by 30 days, with the 30-day daily rate exceeding both the one-day and 14-day rates. This pattern indicates that the initial effects of mitigation are followed by increasingly severe economic impacts as prolonged outages exhaust available coping capacity. Outliers drove mean values substantially higher, particularly for longer interruptions, reflecting wide variation in interruption impacts across organizations.

The bottom panel of Fig. 3 shows the breakdown of average cost components for this group. For one-day interruptions, additional labor expenses represented the largest cost. As outages extended to 14 days, lost revenue increased by a factor of 26 relative to one-day interruptions and became the dominant expense, accompanied by substantial equipment damage. For outages lasting 30 days, average lost revenue reached $3.6 million, while costs for labor, equipment replacement, and other categories continued to rise.

Most LNRP respondents (88% or 56 of 64) reported owning backup generation capacity. However, despite widespread generator access, lost revenue increased steeply after the first day of an outage, illustrating that backup systems alone are not sufficient for sustaining long-term operations. Insurance benefits only became financially meaningful during longer outages, with an average benefit of $69,000. However, only a small share of organizations (11 of 64) reported having such coverage, and high deductibles limited its relevance during shorter events. This aligns with the standard structure of business interruption insurance, which often includes waiting periods of 24–72 h before coverage begins and imposes substantial out-of-pocket requirements (Insurance Risk & Management Institute IRMI, 2025; Johnson et al., 2024). These findings emphasize both the scale of risk exposure in this sector and the limitations of conventional risk mitigation practices for LDWIs.

[3] The LNRP CIC estimates reflect the surveyed industry composition and should not be interpreted as industry-neutral costs because outage costs vary across industries and organization types. Limited participation from some sectors, including large industrial customers such as pharmaceutical firms, limits their representation in the Puerto Rico estimates. CICs may also differ in regions with different industry compositions.

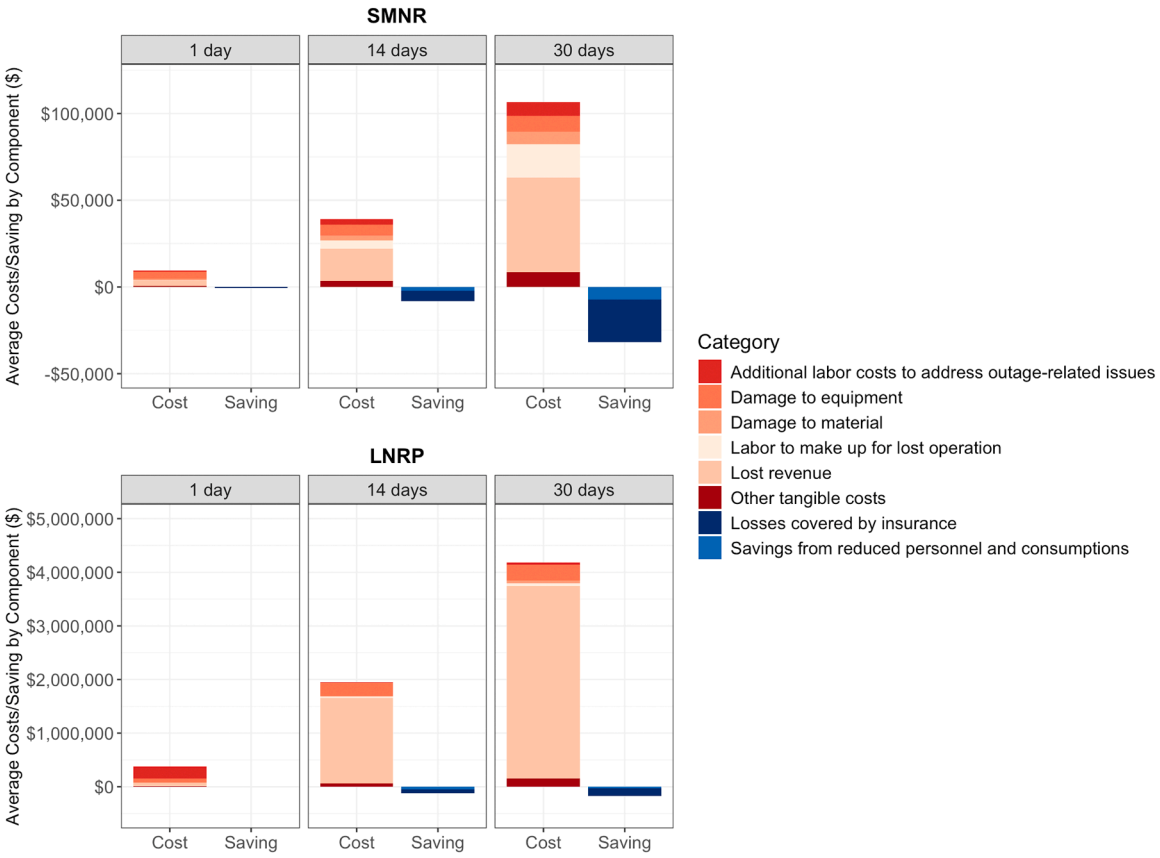


Fig. 3. Breakdown of cost and savings components for SMNR (top) and LNRP (bottom) customers across power interruptions of one-day (left), 14-day (middle), and 30-day (right) duration.

Expressing total interruption costs as average daily values provides additional insight into how customer impacts evolve over the course of a prolonged outage. For non-residential customers, average daily costs are highest during the initial outage period because of immediate operational disruptions, equipment damage, and inventory losses. During the following days, average daily costs decline as businesses rely on mitigation measures such as backup generation to maintain essential operations. As outage duration extends further, average daily costs increase again as mitigation resources become increasingly constrained and cumulative economic losses continue to grow. This temporal pattern highlights the importance of accounting for duration-dependent customer responses when evaluating prolonged power interruptions.

Table 1
Selected duration-dependent CDFs and illustrative estimates of CICs for a 24-hour, territory-wide outage in Puerto Rico (rounded to the nearest million dollars).

Customer Segment	CDF ($/customer)	Total electricity customers	Outage length (hrs)	Cost of one-day outage ($M)
Residential	$(4.78 + (0.030 \times Duration))^2$	1557,541	24	$47
SMNR	$e^{8.07+(0.0034\times Duration)}$	94,744	24	$329
LNRP	$e^{9.82+(0.0051\times Duration)}$	32,728	24	$683
			Total	$1059

3.4. Non-linear customer damage functions reveal escalating economic consequences beyond two weeks

We developed CDFs to estimate how median CICs for a typical customer increase with outage duration across customer groups. Following the framework by Goel and Billinton (1994), we focused on modeling the relationship between outage duration and median CICs, consistent with FEMA's use of VUSE in benefit-cost analyses.

We evaluated several candidate functional forms, including linear, logarithmic, power, quadratic, and exponential specifications, to characterize the relationship between outage duration and median CICs. The residential data were best represented by a quadratic function, while exponential functions provided a better fit for SMNR and LNRP customers (Fig. 2 and Table 1). These results indicate that outage costs evolve nonlinearly across all customer groups and support the use of duration-dependent valuation approaches for representing the economic consequences of prolonged disruptions.

Applying the selected CDFs, we calculated CICs by outage duration and customer group, normalizing values by average monthly household income for residential customers ($25,621 annual household income divided by 12) and by average monthly Gross Domestic Product (GDP) per non-residential customer ($113 billion divided by the number of non-residential customers) (U.S. Census Bureau, 2023; North American Electric Reliability Corporation Puerto Rico Electric Power Authority U. S. Bureau of Economic Analysis BEA, 2024). Results showed:

- Residential CICs are equivalent to 1.1% of monthly income for a one-day outage, rising to 4.4% at 14 days and 26% at 30 days;
- SMNR CICs increase from 4.7% to 14% and 50% of normalized monthly GDP over the same durations;
- LNRP CICs escalate sharply from 28% to 140% and 1000%.

This normalization approach—grouping all non-residential customers into a single category—follows FEMA's VUSE methodology, making the higher percentages for LNRP and lower percentages for SMNR expected outcomes. Nonetheless, the considerable gap between

these groups, especially for longer-duration outages, underscores the significantly greater economic burden borne by LNRP customers. CICs for LNRP can exceed 100% of normalized monthly GDP because their substantial absolute outage costs are compared against a GDP denominator averaged across all non-residential customers. Conversely, SMNR percentages appear lower as their costs are diluted when combined with the higher-impact LNRP subgroup in the per-customer GDP normalization.

We also estimated regional and territory-wide CICs by applying median values to 2024 customer counts. Fig. 4 shows regional costs ranged from $141 million (Arecibo) to $270 million (San Juan) for one-day outages; $628 million to $1.2 billion for 14 days; and $3.8 billion to $7.1 billion for 30 days. San Juan bears the highest costs due to its LNR customer base. Territory-wide costs reach approximately $1 billion for a one-day outage, $5 billion for a 14-day outage, and $29 billion for a 30-day outage. These estimates suggest that the economic consequences of prolonged outages can grow substantially as interruptions extend beyond durations where customer mitigation measures and operational adjustments remain effective, raising important considerations for resilience planning and investment evaluation.

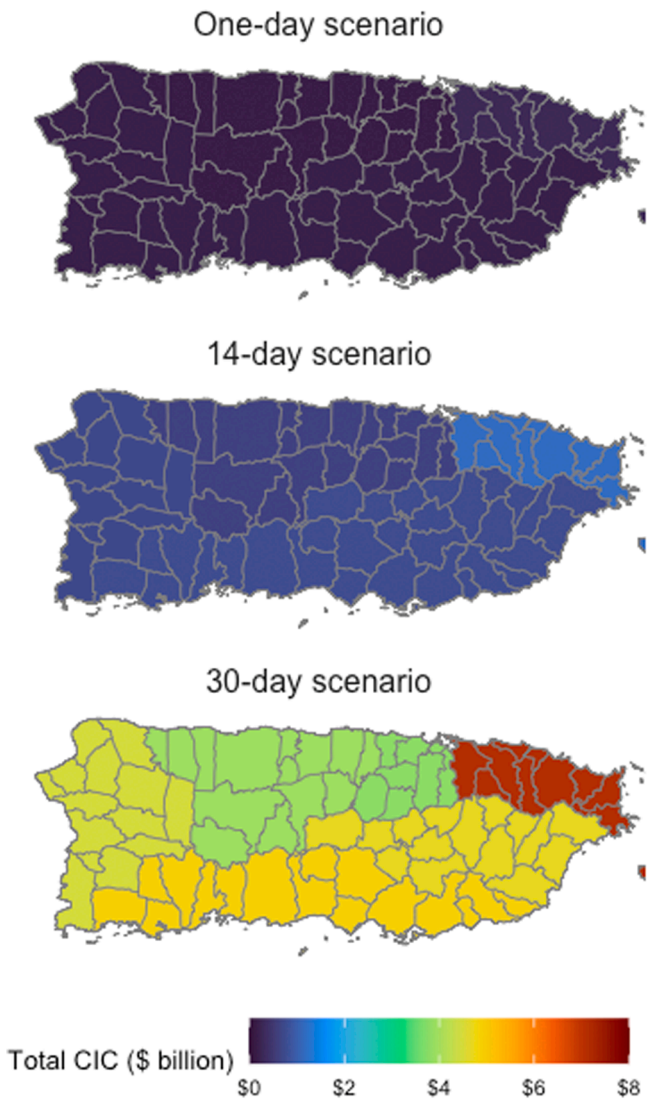


Fig. 4. Regional total CICs for one-day, 14-day, and 30-day power interruption scenarios.

4. Policy implications

The estimated CDFs have direct implications for resilience investment evaluation in Puerto Rico and other outage-prone islanded systems. Territory-wide application reveals substantial economic impacts from LDWIs and demonstrates that outage costs evolve nonlinearly as disruptions persist. These findings have direct implications for resilience investment evaluation in Puerto Rico and other outage-prone islanded systems. Utilities and public agencies frequently rely on CIC estimates to quantify the benefits of investments intended to reduce outage frequency, duration, or severity. Because avoided outage costs often represent a major component of resilience benefits, investment outcomes can be sensitive to whether the underlying estimates adequately reflect local conditions and the consequences of prolonged disruptions.

Comparison with FEMA's VUSE framework highlights the practical significance of this issue. After aggregating residential, SMNR, and LNRP customer functions using total customer counts and normalizing on a per-person basis, the implied one-day outage value for Puerto Rico is approximately $322 per person, which exceeds FEMA's default estimate of approximately $214 per person by roughly 50% (Federal Emergency Management Agency FEMA, 2023).

$$\textit{Value of Unit Service} \quad (\$ \Big/ \textit{person} \Big/ \textit{one day interruption}) = \frac{\$1,059M}{3,285,874} = \sim \$322 \Big/ \textit{person} \tag{1}$$

More importantly, the divergence between the two approaches increases with outage duration (Fig. 5). While the VUSE framework underestimates outage costs for one-day and extended outages exceeding 30 days, it overestimates costs for intermediate durations of approximately 5–25 days. This pattern is consistent with the widespread use of mitigation measures, particularly backup generation, which helps reduce customer impacts during the early stages of prolonged outages. As outage duration increases, however, fuel limitations and other resource constraints reduce the effectiveness of these mitigation strategies, leading to increasingly rapid growth in outage costs. FEMA's linear valuation framework does not capture these duration-dependent changes in customer impacts. Similar non-linear patterns have been observed in previous studies of remote power systems in Alaska and the Pacific (Baik et al., 2023), although the magnitude and timing of these

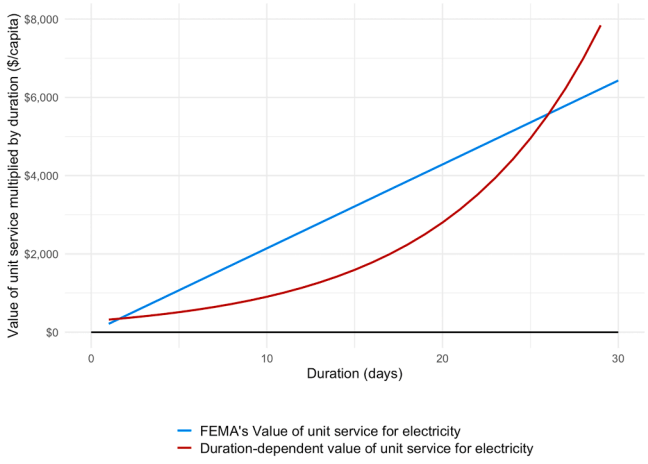


Fig. 5. Comparison of the FEMA's Value of Unit Service for Electricity (VUSE) calculated using the duration-dependent CDF for outage durations ranging from one to 30 days (red) with FEMA's default VUSE estimate multiplied by duration (blue). The y-axis represents the VUSE multiplied by duration, illustrating the economic impact per capita of lost electric service ($/capita) for the specified outage duration.

effects differ across regions. This pattern indicates that marginal outage costs vary with duration rather than remaining fixed over time. The duration-response pattern aligns with prior findings that outage impacts evolve nonlinearly during extended disruptions (Ericson and Lisell, 2020; Leddy et al., 2023; Rickerson et al., 2024). Related work in the broader value-of-lost-load literature similarly suggests that the economic value of unserved electricity may vary across operating conditions rather than remain constant over time (Gibbons and Sergici, 2024). The Puerto Rico results support these findings and suggest the presence of critical duration thresholds beyond which additional outage time produces disproportionately larger economic consequences. This behavior resembles a "resilience cliff," where the marginal impacts of service disruptions increase rapidly once available adaptive capacity becomes exhausted.

These findings have implications for utility planning, resilience investment prioritization, and public-sector benefit-cost analysis. Many resilience planning frameworks evaluate alternatives based on expected reductions in outage duration or frequency. When outage impacts increase disproportionately during extended disruptions, investments that reduce the likelihood of LDWIs may provide greater benefits than approaches that focus primarily on reducing routine interruptions. Incorporating duration-sensitive outage valuation into planning and benefit-cost analysis can therefore improve the ability to distinguish between investments that deliver similar reliability improvements but different resilience outcomes.

The results also suggest the need to revisit outage valuation assumptions used in federal resilience funding programs and utility planning processes, particularly in islanded and disaster-prone systems where restoration constraints differ from those in large interconnected grids. More broadly, the analysis demonstrates the importance of combining locally derived interruption cost estimates with duration-sensitive valuation frameworks. While the empirical application focuses on Puerto Rico, the methodology is transferable to other islanded and remote systems where generalized mainland-derived assumptions may not adequately represent local operating conditions, customer adaptation behavior, or prolonged recovery constraints.

5. Conclusion

LDWIs pose growing challenges for energy security and resilience planning, particularly in islanded and remote power systems exposed to extreme weather, infrastructure fragility, and constrained recovery conditions. Despite increasing attention to these risks, resilience analyses often rely on outage valuation assumptions derived from short-duration interruptions in large interconnected systems and commonly assume proportional relationships between outage duration and economic impact. These approaches may not adequately represent local operating conditions and customer experiences in islanded systems or capture how outage costs evolve during prolonged disruptions.

This study addresses both limitations by developing the first empirically derived CIC estimates for Puerto Rico and estimating duration-dependent CDFs for outages lasting from one day to one month. A central finding is that outage costs evolve nonlinearly over time, demonstrating that prolonged disruptions cannot be adequately represented using constant duration-value assumptions. The resulting CDFs provide locally grounded estimates that reflect customer behavior, operational constraints, and recovery conditions in an islanded system. They also provide a flexible framework for translating outage scenarios into economic impacts and can be integrated into broader resilience assessment approaches. For example, the functions can serve as inputs to resilience assessment tools such as FRONTIER, where scenario-based outage durations are translated into comparable economic outcomes across alternative resilience pathways.

The methodology developed in this study provides a transferable framework for estimating locally grounded, duration-dependent outage valuation functions. While the empirical application focuses on Puerto Rico, the core survey design and non-linear econometric framework can be adapted to other islanded communities as well as interconnected mainland systems. However, the CDFs and cost estimates developed in this study should not be transferred directly to other Caribbean islands without local calibration. Although many islanded systems share characteristics such as geographic isolation, limited interconnections, and supply-chain constraints, interruption costs also reflect local economic structure, customer composition, industry mix, and infrastructure characteristics. For example, Puerto Rico has a relatively large manufacturing sector, whereas neighboring islands may rely more heavily on tourism or other service-based industries, resulting in different outage cost profiles. Applications to interconnected mainland systems require additional methodological adaptations to represent customer coping strategies that are less relevant in islanded settings. In interconnected mainland systems, for example, customers may reduce outage impacts through geographic relocation and spatial substitution, such as temporarily relocating operations, obtaining supplies from unaffected neighboring regions, or traveling to access substitute goods and services. These differences should be reflected in the scenarios and survey design when applying the framework to other regions.

Several additional opportunities remain for future research. The estimates are based on SP survey methods and therefore remain subject to established survey-response limitations despite the use of accepted mitigation procedures (Mitchell and Carson, 1989; Arrow et al., 1993; Johnston et al., 2017; Boyle, 2017; Dillman and Smyth, 2007; List, Gallet, 2001; Murphy et al., 2005). Although the survey instruments used predefined cost categories to isolate the impacts of power interruptions, we did not conduct formal validation or sensitivity analyses to assess respondents' ability to distinguish outage-related costs from physical damages associated with the initiating hazard. This represents a limitation of the study.

Additional representation of energy-intensive manufacturing sectors and incorporation of indirect economic impacts would further strengthen future estimates (for instance, pharmaceutical manufacturing sector which accounts for nearly half of manufacturing GDP and supplies over 10% of drugs consumed in the United States; Stone, 2017, DHS, 2018). Future work should also explore multivariate CDFs that capture variation across customer characteristics, industry sectors, and backup resource availability.

As long-duration outage risks continue to increase in islanded and disaster-prone systems, improving the empirical basis for outage valuation will become increasingly important for understanding the full economic consequences of power disruptions. The framework developed in this study provides a foundation for advancing that effort by combining locally derived interruption cost estimates with duration-dependent valuation functions that better reflect the realities of prolonged outages.

CRediT authorship contribution statement

Sunhee Baik: Writing – review & editing, Writing – original draft, Visualization, Software, Formal analysis, Data curation, Conceptualization. **Kristina H. LaCommare:** Writing – review & editing, Project administration, Methodology, Conceptualization. **Maria Gabriela Geraci:** Writing – original draft, Investigation, Data curation. **Karen Johnson:** Writing – original draft, Investigation, Data curation. **Peter H. Larsen:** Writing – review & editing, Supervision, Methodology, Funding acquisition, Conceptualization.

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Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supporting information

Supplementary data associated with this article can be found in the online version at doi:10.1016/j.tej.2026.107578.

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