GRID MODERNIZATION LABORATORY CONSORTIUM
U.S. Department of Energy

Considerations for Resilience Guidelines for Clean Energy Plans

For the Oregon Public Utility Commission and Oregon Electricity Stakeholders

September 2022

JS Homer
KM Boenker
AA Lippert
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Executive Summary

Background

The Oregon Public Utility Commission (PUC) must establish reasonable and prudent industry resilience standards and guidelines that Oregon investor-owned utilities (IOUs) will address in Clean Energy Plans, as required by House Bill 2021, Section 4. This document summarizes approaches, considerations, and examples of risk-based approaches for power system and community resilience planning.

Resilience has been defined as the robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize service interruptions during an extraordinary and hazardous event. This paper emphasizes a customer-focused approach to planning for resilience that addresses grid and customer-sited resilience measures and impacts.

The main difference between reliability and resilience is the relative frequency and magnitude of the event. Most reliability events are generally high-probability/low-consequence events. In contrast, resilience events are singular, infrequent large-scale incidents, like severe weather events, earthquakes, and cyberattacks, with more severe consequences.

A proposed resilience planning analysis process includes four key steps described below.

This paper is organized into the following sections: risk assessment; accounting for variations in hardship, consequences, and costs experienced; and opportunity analysis. Key points from each section are summarized below.

Risk Assessment

A risk or threat assessment is an essential part of planning for resilience. Methods for identifying and assessing risks include the following:

- **Leverage existing risk assessments from federal, state, and local organizations.** Use and build on existing risk assessment information. For Oregon, information can be gleaned from the Oregon

Guidebook for Local Energy Resilience from the Oregon Department of Energy (ODOE) (ODOE 2019) and the U.S. Department of Energy (DOE) State and Regional Energy Sector Risk Profiles, among other sources. ODOE identified key risks for Oregon as the Cascadia subduction zone earthquake; climate change, including ice storms, heat domes, wildfires, heavy snowfall, floods, and storm surges; and cyber and physical attacks.

- **Perform a quantitative assessment of historical threats.** Review past storm and hazard event frequency and costs and summarize regional threats to characterize community and system risk.
- **Engage stakeholders to develop a threat-risk prioritization.** Engage relevant stakeholders to identify and prioritize risks by location.
- **Utilize a bowtie risk assessment process.** Use a bowtie assessment process to identify potential vulnerabilities that will cause a specific failure, identify preventative measures, model impacts, and identify mitigative solutions. Bowtie risk assessment methods are used in many sectors and are increasingly used in the power industry.
- **Conduct a climate change vulnerability assessment.** Conduct a climate change vulnerability assessment, similar to those conducted by some New York and California utilities. Consider the exposure of critical assets or operations to an adverse climate event or trend, the probability of damage to assets or disruption to operations because of exposure to those climate threats (or risks posed by threat), and the likely consequences if the event were to occur (severity of impacts). Vulnerability assessments can also consider climate change impacts on resource adequacy resulting from the following:
  - changes to generation due to extreme weather and changing water availability for hydroelectric generation and hydropower
  - impacts on loads and demand side management measures due to temperature/weather changes
  - interregional grid impacts
  - impacts on power markets.

  These impacts can be considered in isolation or as cumulative or cascading impacts.

Accounting for Variations in Hardship, Consequences, and Costs Experienced

Different communities and households have different capabilities to endure adverse impacts from electricity service disruptions. The concept of "zone of tolerance" is used in this paper to account for the different capabilities of households and communities to endure the adverse impacts of service disruptions (Esmalian et al. 2021). Potential approaches that can be used to account for variations in hardship, consequences, and costs experienced by customers include the following:

- **Institute zone of tolerance informed weighting and scoring techniques to assess potential projects**. Emerging weighting and scoring techniques are used by utilities to address the disproportionate impacts of outages on vulnerable or traditionally disadvantaged communities. Based on extensive stakeholder input, California utilities have developed a scoring methodology for potential microgrid projects, where points are given for projects that support low-income customers, vulnerable customers, and critical facilities, including those that serve disadvantaged communities.
- **Map vulnerable communities**. California and Washington have developed maps that identify vulnerable communities. These maps are used to characterize targeted communities to be included in community engagement plans, specify where potential projects would benefit vulnerable communities, and determine eligibility for specific incentives, such as California's residential equity resiliency battery storage incentives. Oregon HB 4077 paves the way for equity mapping in Oregon.

- **Develop community engagement plans.** Some states are developing planning requirements to ensure that vulnerable and disadvantaged communities are meaningfully included in resilience planning. For example, the California PUC requires large IOUs to identify and map vulnerable communities, use specific criteria, and develop community engagement plans submitted one year prior to the climate change vulnerability assessments. Washington has also developed maps and requirements for utilities to use to consider highly impacted communities and vulnerable populations within their service territories as part of their Clean Energy Implementation Plans.
- **Identity where customers experience poor reliability**. Traditional reliability metrics, such as System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI), represent *averages* across the utility system. Other customer-centric metrics, such as Customers Experiencing Long Interruption Duration of t or More Hours (CELIDt) and Customers Experiencing Multiple Interruptions of n or More (CEMIn) can be used to point to customers potentially experiencing more than their fair share of outages.
- **Establish resilience hubs in targeted areas**. Resilience hubs are community centers or other central, accessible locations that provide reliable energy during widespread power outages. They can include solar energy and battery storage. Resilience hubs can be implemented in designated communities to deliver critical services in a service disruption.

Opportunity Analysis

Many different types of measures can support resilience. While it is impossible or prohibitively expensive to eliminate all power system risks, a reasonable approach is to figure out "how to reduce the magnitude and duration of damage caused by an outage, help customers and society better survive an extended outage, and try to recover from it as quickly as possible" (Silverstein et al. 2018). Measures that are threat-agnostic and provide multiple benefits, including during normal operations, are likely to be more cost effective. Key considerations and methods for identifying and prioritizing resilience measures are summarized below.

- **Consider end-to-end resilience measures that span the customer premises through distribution, transmission, and power generation**. Resilience investments can be diverse and include investments in system design/modeling, threat analysis, tree trimming, asset redesign, emergency drills, spare equipment, mutual aid agreements, and customer-sited generation and energy efficiency. Customer-sited measures may have multiple benefits, including improving survivability or the ability of customers to withstand an outage. However, enabling equipment may be required.
- **Take a holistic approach to benefit-cost analysis.** Not all benefits of resilience measures can be quantified; therefore, traditional benefit-cost analysis is difficult for resilience investments. While the *costs* of resilience investments are readily quantified, the *benefits* are not. In performing benefit-cost analysis for resilience investments, utilities should characterize the full suite of benefits to the extent possible, even if representing and considering some benefits qualitatively. Regulators can also recognize that traditional benefit-cost analysis for resilience represents an incomplete picture, and just because some benefits cannot be quantified does not mean they are not important.
- **Consider risk spend efficiency to help prioritize investments.** A resilience solution prioritization methodology emerging in literature and practice is risk spend efficiency. A risk spend efficiency score can be determined for specific solutions by dividing the solution cost (i.e., capital investment or third-party solution expenditures) by the benefit expressed as the magnitude of community/customer outage risk reduction in terms of avoided interruption duration. A broader "value spend efficiency" metric is emerging that can be used to evaluate how projects or investments perform relative to multiple planning objectives, including resilience.

- **Incorporate resilience objectives in distribution system investments.** Silverstein et al. (2018) states over 90 percent of outages occur because of distribution level problems. Therefore, it is suggested that measures that strengthen distribution and hasten recovery would be highly cost effective. Many existing distribution system investment areas can also support resilience if distribution resilience considerations are explicitly integrated into distribution expansion, upgrade, and asset planning
- **Increase resilience through distributed energy resources (DERs), including microgrids and resilience hubs**. DER-focused microgrids and resilience hubs are being developed by some customers and utilities to support survivability in case of a loss of service. DERs can support resilience, although their resilience value depends on many factors, including the following:
  - type of extreme event
  - level of service desired during an outage
  - presence of enabling equipment, such as switches and controls
  - presence of reliable maintenance and operations support
  - siting relative to critical loads
  - availability when needed.

In summary, reliability and resilience are connected, and investments, if properly planned, can be designed to support both. Approaches described in this paper can help identify critical threats and their probabilities and consequences, the impacts of different resilience measures in mitigating threats, the relative benefit and cost efficiency of different potential investments, and ways to engage community members directly and ultimately plan for community survivability when resilience events occur.

Acronyms and Abbreviations

BCA	benefit-cost analysis
CAIDI	Customer Average Interruption Duration Index
CBI	customer benefit indicators
CELIDt	Customers Experiencing Long Interruption Duration of t or More Hours
CEMIn	Customers Experiencing Multiple Interruptions of n or More
CEMM	Customers Experiencing Multiple Momentariness
CEMSMI	Customers Experiencing Multiple Sustained and Momentary Interruptions
CETA	Clean Energy Transformation Act
CIP	critical Infrastructure Protection
CPUC	California Public Utilities Commission
DER	distributed energy resource
DOE	Department of Energy
DOH	Department of Health
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
GMLC	Grid Modernization Laboratory Consortium
HRWG	Hawaii Resilience Working Group
HUD	Housing and Urban Development
IOU	investor-owned utility
LBNL	Lawrence Berkeley National Laboratory
NARUC	National Association of Regulatory Utility Commissioners
NASEO	National Association of State Energy Offices
NERC	North American Electric Reliability Corporation
NIAC	National Infrastructure Advisory Council
PG&E	Pacific Gas and Electric
PSE	Puget Sound Energy
PUC	Public Utility Commission
RAMP	Risk Assessment Mitigation Phase
RMP	Resilient Minneapolis Project
RSE	risk spend efficiency
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SGIP	Self Generation Incentive Program
USDN	Urban Sustainability Directors Network

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1.0 Introduction

In 2021, the Oregon Legislature enacted a 100 percent clean electricity by 2040 standard that requires the Oregon Public Utility Commission (PUC) to oversee utility planning for aggressive clean energy deployment through Clean Energy Plans (House Bill 2021, Sec. 4).[1] In addition to meeting emissions reductions targets, Clean Energy Plans must also:

> *Include a risk-based examination of resiliency opportunities that includes costs, consequences, outcomes, and benefits based on reasonable and prudent industry resiliency standards and guidelines established by the Public Utility Commission.*

This document summarizes relevant and emerging approaches, research, models, and national examples that may help inform the Oregon PUC in developing best practice guidelines for risk-based resiliency planning for utility Clean Energy Plans.

[1] https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/HB2021

2.0 Defining Resilience

Deciding on a resilience definition is an important step in advancing resilience through planning, investments, or operations. This section covers the definitions of resilience, the differences between reliability and resilience, and reliability standards from Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC).

2.1 Resilience Definitions

Oregon's House Bill 2021 includes several contextual definitions for resilience that emphasize rapid recovery following non-routine disruptions:

- *"Energy resilience" means the ability of energy systems, from production through delivery to end-users, to withstand and restore energy delivery rapidly following non-routine disruptions of severe impact or duration.*
- *"Community energy resilience" means the ability of a specific community to maintain the availability of energy needed to support the provision of energy-dependent critical public services to the community following non-routine disruptions of severe impact or duration to the state's broader energy systems.*
- *"Community energy resilience project" means a community renewable energy project that includes utilizing one or more renewable energy systems to support the energy resilience of structures or facilities that are essential to the public welfare.*

Resilience is similarly and more generally defined by other expert sources as described below:

- **National Infrastructure Advisory Council (NIAC)**: The NIAC developed and submitted "A Framework for Establishing Critical Infrastructure Resilience Goals" to President Obama in November 2010. This report builds on the Council's 2009 Critical Infrastructure Resilience report. The 2009 report provided the following common definition of resilience: "Infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to and/or rapidly recover from a potentially disruptive event." The 2010 report provided a framework construct based on risk management practices of the electric utility industry and included the four elements of resilience: robustness, resourcefulness, rapid recovery, and adaptability (NIAC 2009, 2010).
- **Presidential Policy Directive 21 (PPD-21)**: PPD-21 defined resilience as "the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents" (White House 2013).
- **National Association of Regulatory Utility Commissioners (NARUC)**: **"**Robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event" (NARUC 2013).
- **Federal Energy Regulatory Commission (FERC)**: "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event" (FERC 2018).
- **Electric Power Research Institute (EPRI)**: "Resilience includes the ability to harden the system against—and quickly recover from—high-impact, low-frequency events. Enhanced resilience of the power system will be based on three elements:

– Damage prevention: The application of engineering designs and advanced technologies that harden the power system to limit damage.

– System recovery: The use of tools and technologies to restore service as soon as practicable.

– Survivability: The use of innovative technologies to aid consumers, communities, and institutions in continuing some level of normal function without complete access to their normal power sources" (Schwartz 2019).

Silverstein et al. (2018) proposes a customer-focused framework for electric system resilience where the grid is viewed "end-to-end, spanning from the customer premises (including customer-sited energy efficiency and distributed generation and storage) through distribution and transmission up to power generation and fuel supply." Key metrics that are part of this customer-focused framework are:

- **Frequency**: How many outages happen.
- **Scale**: Number of customers affected by an outage.
- **Duration**: Length of time before interruption can be restored.
- **Customer Survivability**: The ability of customers to withstand a grid outage.

Watson et al. (2015) suggests the following taxonomy of resilience capacities with the associated example infrastructure attributes (Figure 1).

Capacities	Prepare	Withstand	Adapt	Recover
Example Infrastructure Attributes	Advance warning	Robustness	Rerouting	Mutual Aid Agreements
	Prepositioning	Redundancy	Substitution	Situational Awareness
	Stockpiling	Storage	Rationing	Resource Availability
		Separation	Reorganization	

Figure 1. Resilience Capacities and Example Infrastructure Attributes (Watson et al. 2015)

A resilience analysis process is proposed by Watson et al. (2015) and Silverstein et al. (2018) as illustrated in Figure 2 and described in the steps below.

1. **Define resilience goals**: Identify key stakeholders, possible conflicting goals, and high-level goal language.

2. **Develop system and resilience metrics**: Develop system and resilience metrics that will be used to characterize system performance and the performance of alternative resilience measures. These metrics should be driven by goals and data availability.

3. **Characterize threats and their probabilities and consequences**: Include information on the likelihood of each possible threat scenario and impacts or consequences of the threat, including the ability of customers to tolerate disruptions.

4. **Evaluate effectiveness of alternative resilience measures for avoiding or mitigating threats**: Use metrics to compare effectiveness of alternative resilience measures for avoiding or mitigating threats, including the ability of measures to increase the customer's survivability in case of service disruption. This step includes costing alternative measures for the purpose of trade-off analysis.

Figure 2. Resilience Analysis Process

Resilience metrics can be based on specific consequence categories. Table 1 includes a list of example consequence categories from Petit et al. (2020) that could serve as the basis for resilience metrics. In addition to the consequence categories described in Table 1, other entities are including consequence categories specific to traditionally disadvantaged communities and customer survivability, or ability of customers to withstand an outage. See Section 4.0 for more information on this.

Table 1. Consequence Categories for Consideration in Developing Resilience Metrics (Petit et al. 2020)

Consequence Category	Resilience Metric
Direct	
Electrical Service	Cumulative customer-hours of outages
	Cumulative customer energy demand not served
	Average number (or percentage) of customers experiencing an outage during a specified time period
Critical Electrical Service	Cumulative critical customer-hours of outages
	Critical customer energy demand not served
	Average number (or percentage) of critical loads that experience an outage
Restoration	Time to recovery
	Cost of recovery
Monetary	Loss of utility revenue
	Cost of grid damages (e.g., repair or replace lines, transformers)
	Cost of recovery
	Avoided outage cost
Indirect	
Community Function	Critical services without power (e.g., hospitals, fire stations, police stations)
	Critical services without power for more than *N* hours (e.g., *N*> hours of backup fuel requirement)
Monetary	Loss of assets and perishables
	Business interruption costs
	Impact on Gross Municipal Product or Gross Regional Product
Other Critical Assets	Key production facilities without power
	Key military facilities without power

2.2 Resilience vs. Reliability

In most definitions, the main difference between reliability and resilience is the relative frequency and magnitude of the event. Most reliability events are generally high-probability/low-consequence events, while resilience events are singular, infrequent large-scale incidents, like hurricanes, earthquakes, and terrorist attacks, with more severe consequence.

The U.S. Department of Energy (DOE), through the Grid Modernization Laboratory Consortium (GMLC), developed a report on resilience metrics (Petit et al. 2020). Definitions provided by the DOE GMLC are as follows.

- **Resilience**: The ability of the system to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions, including the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents
  – *Resilience metrics* are more useful for capturing the impacts of singular, infrequent large-scale events, like hurricanes, earthquakes, and terrorist attacks, that result in long-term electricity outages.
- **Reliability**: The ability of the system or its components to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components
  – *Reliability metrics* are defined in the context of outages and disruption under routine or design operating conditions and typically are calculated as aggregated totals over all events—large and small—occurring over the course of a year.

The concept that "resilience is a time-based component of reliability" is widely accepted in the electric industry and was promoted by NERC to FERC in their response to Docket No AD18-7-000 (NERC 2018). NERC emphasizes the point that their definition of "adequate level of reliability or 'ALR' includes resilience as a time-based component of reliability" (NERC 2018).

The Hawaii Resilience Working Group (HRWG) Report for Integrated Planning (HRWG 2020) illustrates the difference between reliability and resilience as shown in Figure 3. The figure highlights that most reliability events are generally high-probability/low-consequence events while resilience events are singular, infrequent large-scale incidents, like hurricanes, earthquakes, and terrorist attacks, with more severe consequence. The HRWG states that reliability is a level of assurance that power will stay on during normal events, characterized by limited customer outages and generally expected conditions during the life of facilities in the system. Resilience addresses the performance of the power system under more rare and severe conditions, such as natural disasters that could cause damage that requires weeks or months to repair. (HRWG 2020).

Paul De Martini, in a presentation to the National Association of Regulatory Utility Commissioners (NARUC) and National Association of State Energy Offices (NASEO) Task Force on Comprehensive Electricity Planning in 2020 points out that: "Distribution resiliency events involve similar types of infrastructure failures (e.g., wire down, poles broken, transformer failure, fuses blown, etc.) involved with reliability events, but at a greater scale, which creates significant complexity to address" (NARUC and NASEO 2020).

Paul De Martini also points out that major resilience events have larger geographic impacts on distribution or bulk power systems with long-duration outages (i.e., greater than 24 hours and classified as "major events" following Institute of Electrical and Electronics Engineers (IEEE) Standard 1366).

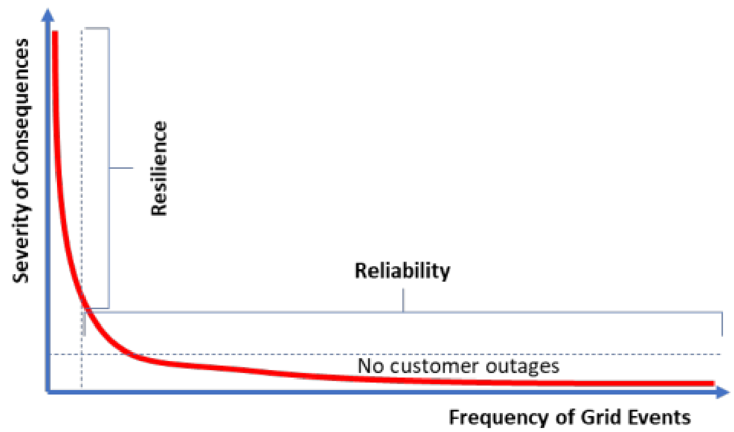


Figure 3. Grid Reliability versus Resilience from Hawaii Resilience Working Group Report (HRWG 2020)

2.3 Using NERC/FERC Reliability Metrics to Assess Resilience

Section 215 of the Federal Power Act requires the Electric Reliability Organization to develop mandatory and enforceable reliability standards, which are subject to FERC review and approval. FERC-approved reliability standards become mandatory and enforceable in the United States according to the implementation plan associated with the reliability standard, as approved by FERC (NERC 2022).

The mandatory standards include, but are not limited to, balancing control, cyber system and security control, physical security, event reporting, emergency operations, transmission maintenance and operations, load shedding, and relay loadability. A complete list of mandatory standards can be found on NERC's website.[2]

According to a report prepared by LBNL (Schwartz 2019):

> *"As threats to the reliability of the bulk power system have evolved, the reliability standards developed and enforced by NERC and FERC have evolved, too. Although there appropriately is not a resilience standard or requirement, FERC has taken steps directed at elements of resilience, including significant work to address bulk power system reliability through NERC reliability standards, assessments, and risk identification."*

The reliability standards, according to NERC, take resilience into account by supporting robustness, resourcefulness, rapid recovery, and adaptability (Schwartz 2019).

- **Critical Infrastructure Protection (CIP) Standards** address risks from cyber and physical attacks. Many of the CIP requirements provide enhanced protections that help ensure that systems can resist, absorb, and rapidly recover from coordinated physical and cyberattacks.
- **Transmission Planning Standards** are designed to ensure that the bulk power system operates reliably through many system conditions and contingencies, including solar events, spare equipment shortages, and generation retirements, assuring affected systems appropriately absorb the impacts of changing conditions and continue to remain reliable throughout.

[2] https://www.nerc.com/pa/Stand/Pages/USRelStand.aspx

- **Emergency Preparedness and Operations Standards** ensure entities have plans, facilities, and personnel in place that are capable of recovering rapidly from events (e.g., system restoration, loss of control center functionality, geomagnetic disturbance) that could impact the reliable operation of the bulk power system.
- **Protection Control Standards** include loadability standards that ensure that key elements of the bulk power system will remain in service while absorbing short-duration overload conditions, allowing time for system operators to mitigate the situation without unnecessary loss of load or damage to equipment. The Protection Control Standards also address stable power swings to ensure bulk power system elements do not trip unnecessarily during system oscillations resulting from large disturbances. That allows the system to absorb and recover without unnecessary loss of load or contributing to events that might result in much larger power disturbances.

LBNL (Schwartz 2019) also notes the following:

> *"In addition to developing and enforcing the reliability standards, NERC assesses various risks that may impact the reliability of the bulk power system, including resource adequacy issues that cannot be addressed fully by reliability standards or requirements. However, NERC's reliability assessments and historical operational information can inform discussions between electric companies and state regulators responsible for addressing potential resource adequacy issues. The states and RTOs/ISOs may need to conduct additional analyses to identify issues unique to their local systems, including impacts caused by factors outside of NERC's bulk power system focus, expertise and regulatory authority."*

Transmission and generation metrics are used by FERC and NERC for the bulk power system, while distribution-level metrics are normally used by state regulatory agencies.

3.0 Risk Assessment

This section addresses the ways utilities and states can 1) identify risks and 2) how they can be measured, ranked, and weighted.

3.1 Community and System Threat Identification and Risk Assessments

An important first step in resilience planning is assessing resilience event threat risk through a structured threat-risk assessment. DeMartini and Taft (2022) describe the steps of a threat/risk assessment as the following:

1. Conduct detailed empirical climate and other threat-risk analysis.
2. Identify community resilience needs to identify and prioritize the scale and scope of resilience needs.
3. Identify specific grid infrastructure that may be at risk.

Based on historic data cited in Silverstein et al. (2018), most U.S. outages happen at the distribution and transmission levels from routine causes such as storms, vegetation, squirrels, and equipment problems, and 90 percent of all outages occur on the distribution system. Research by Eto et al. (2019) demonstrates that regardless of whether major events are included or excluded, distribution impacts have the highest contribution to grid unreliability issues. Further, Silverstein et al. (2018) indicates that less than 0.1 percent of customer outage-hours between 2012 and 2016 were caused by generation shortfalls or fuel supply issues. While most *outages* occur due to routine causes, low-frequency, high-impact events, such as winter storms and hurricanes, cause about half of the customer *outage-minutes* as shown in Figure 4. For further discussion on reliability metrics with and without major event days, see Section 6.0.

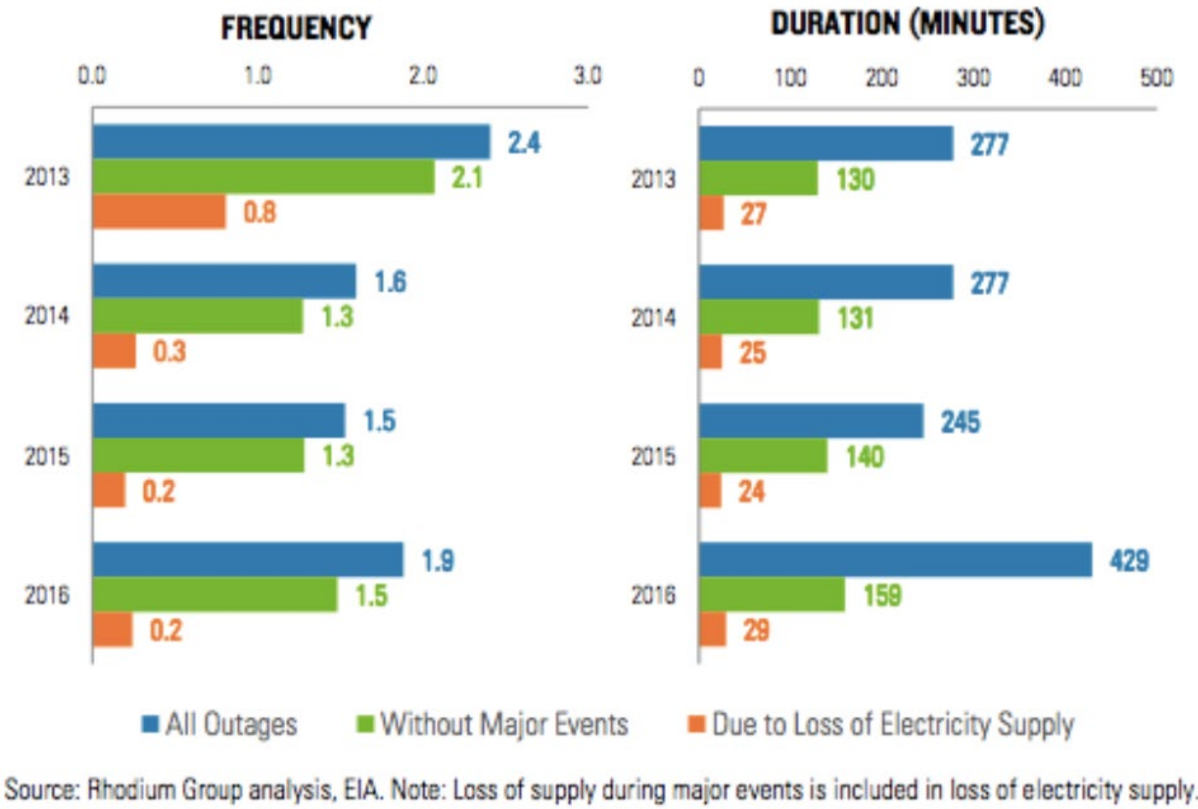


Figure 4. U.S. Average Customer Electric Outages, 2013-2016 (Source: Larsen et al. 2017) Note: Loss of supply during major events is included in loss of electric supply.

Silverstein et al. (2018) points to the following broad conclusions about electric service interruptions:

- Over 90 percent of outages (frequency) occur due to distribution-level problems.
- Typically, no more than 10 percent of all power outages (frequency) are due to major events.
- About half of outage durations are due to high-impact major events.
- Adverse weather is the primary cause of both outage frequency and duration.

The consequences of most major events are the same—damage to distribution and transmission assets, resulting in customers losing electric service. Silverstein et al. (2018) suggests that a wise approach to reliability and resilience would focus on how to address and mitigate these common consequences, managing risks by taking measures that mitigate risks against as many threats as possible. While it is impossible or prohibitively expensive to eliminate all power system risk, a reasonable focus should be to figure out "how to reduce the **magnitude** and **duration** of damage caused by an outage, help customers and society better **survive** an extended outage, and try to recover from it as quickly as possible." (Silverstein et al. 2018)

The Oregon Guidebook for Local Energy Resilience (ODOE 2019) identifies three key resilience threats to Oregon's electric sector:

1. **Cascadia subduction zone earthquake**: Megathrust earthquake of magnitude 9.0 or higher followed by a tsunami. The chance of this earthquake and tsunami happening in the next 50 years is between 15 and 20 percent.
2. **Climate change**: Ice storms, heat domes, wildfires, heavy snowfall, floods, and storm surges and longer-term changes in average weather and hydrologic conditions. Historical trends will no longer be a reliable predictor of future expectations and a new normal will need to be integrated into decision-making.
3. **Cyber and physical attacks**: The wide geographic reach of the electric grid makes it inherently vulnerable to physical attack and increased connectivity of the electric grid creates new pathways for cyberattacks.

Similarly, DOE publishes State and Regional Energy Sector Risk Profiles that highlight the magnitude of risks impacting energy infrastructure. For example, the Energy Risk Profile for the State of Oregon can be found on the DOE website.[3]

Other papers, such as Silverstein et al. (2018) point to the risks caused by geomagnetic disturbances from solar weather and from electromagnetic pulses.

3.2 Empirical and Stakeholder Approaches

The following examples point to methods for conducting threat and risk assessments.

Michigan, in their Michigan Hazard Mitigation Plan, looked back at storm event frequency and cost and summarized historical threats by region (Figure 5) to characterize community and system risk. Michigan also looked at the seasonality of different hazards (Table 2), noting that many natural hazards are strongly associated with particular times of year, and should encourage patterns of preparedness to occur on an annual cycle (Michigan 2019).

[3] https://www.energy.gov/sites/default/files/2021-09/Oregon%20Energy%20Sector%20Risk%20Profile.pdf

Quantitative Summary by Region
Source: NCEI Storm Events online database* (1996-2017)

Geographic Division→	Upper Peninsula: Average annual events	Average annual deaths	Average annual injuries	Average annual property and crop damage	Northern Lower Peninsula: Average annual events	Average annual deaths	Average annual injuries	Average annual property and crop damage
Hail	**2.2**	**0**	**0**	**$3,302,677**	**1.3**	**0**	**> 0**	**$2,012,844**
Lightning	**0.1**	**0.1**	**0.2**	**$24,600**	**0.1**	**0.3**	**1.3**	**$49,337**
Ice and sleet storms	**0.2**	**0**	**0**	**$14,063**	**0.1**	**0**	**0**	**$83,205**
Snowstorms	**8.8**	**0.1**	**0.1**	**$70,900**	**3.7**	**0**	**0**	**$1,243,754**
Severe winds	**3.0**	**0.1**	**0.1**	**$1,064,335**	**1.9**	**0.2**	**2.6**	**$4,647,190**
Tornadoes	**0.1**	**0**	**0**	**$351,568**	**0.1**	**> 0**	**0.2**	**$348,474**
Extreme heat	**> 0**	**0**	**0**	**$0**	**> 0**	**0**	**0**	**$0**
Extreme cold	**1.4**	**> 0**	**0**	**$0**	**0.1**	**0**	**0**	**$3,492,242**
Fog	**0.2**	**0**	**0**	**$0**	**> 0**	**0**	**0**	**$0**
Flooding	**0.8**	**> 0**	**0**	**$2,374,256**	**0.3**	**0**	**0**	**$2,591,244**
Shoreline hazards	**1.1**	**0.5**	**0**	**$9,469**	**> 0**	**0.2**	**> 0**	**$0**
Drought*	**> 0**	**0**	**0**	**$0**	**> 0**	**0**	**0**	**$0**
Wildfires	**> 0**	**0**	**0.2**	**$849,201**	**> 0**	**0**	**0**	**$109,689**

Figure 5. Excerpt from Michigan Hazard Mitigation Plan Summarizing Historical Threats by Region (Michigan 2019; De Martini et al. 2022)

Table 2. Michigan Hazard/Threat Summary by Month (Michigan 2019)

March:	Final month for the highest-risk period involving influenza epidemics or pandemics
April:	Winter risk season (involving significant risk of **extreme cold, snowstorms, blizzards, and ice/sleet storms**) ends in the Lower Peninsula
May:	Winter risk season ends in the Upper Peninsula, non-winter risk season begins in the Lower Peninsula (involving a significant risk of **extreme heat events, severe thunderstorms, lightning, hail, tornadoes, and wildfires**)
Late **May**:	Non-winter risk season begins in the Upper Peninsula
Early **September**:	End of the non-winter risk season in the Upper Peninsula
Late **September**:	Winter risk season begins in the Upper Peninsula, end of non-winter risk season in most of the Lower Peninsula
Early **October**:	End of non-winter risk season in the southernmost counties of the Lower Peninsula
October:	Start of the highest-risk period for influenza epidemics or pandemics
Early **November**:	Winter risk season begins in the Northern Lower Peninsula
Late **November**:	Winter risk season begins in the Southern Lower Peninsula

Hawaiian Electric convened the HRWG as part of the Integrated Grid Planning process. HRWG members were surveyed on their prioritization of threat risks. Figure 6 is a summary of responses from the HRWG Report.

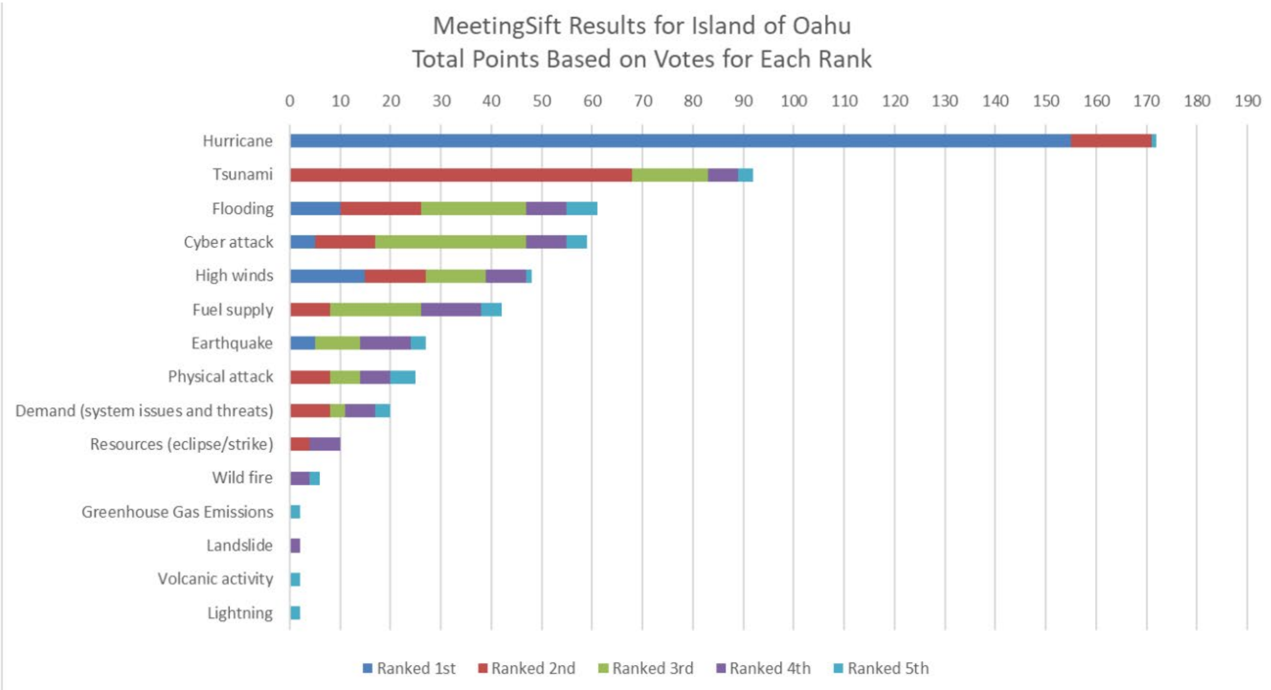


Figure 6. Survey from Hawaii Threat-Risk Prioritization (HRWG 2020)

Stakeholders can and should be consulted in risk assessments and threat prioritization. Once threats have been assessed, a structured bowtie risk analysis process can be conducted as described in Section 3.3.

3.3 Bowtie Risk Assessment Process

A bowtie assessment is a process used to identify potential vulnerabilities that will cause a specific failure, identify preventative measures, and identify mitigative solutions in case the preventative measures do not work. Bowtie methods are used to structure planning and operations best practices in many sectors, and they are increasingly used in the power industry. Figure 7 illustrates the bowtie assessment process for electric utilities (NARUC and NASEO 2020, De Martini et al. 2022).

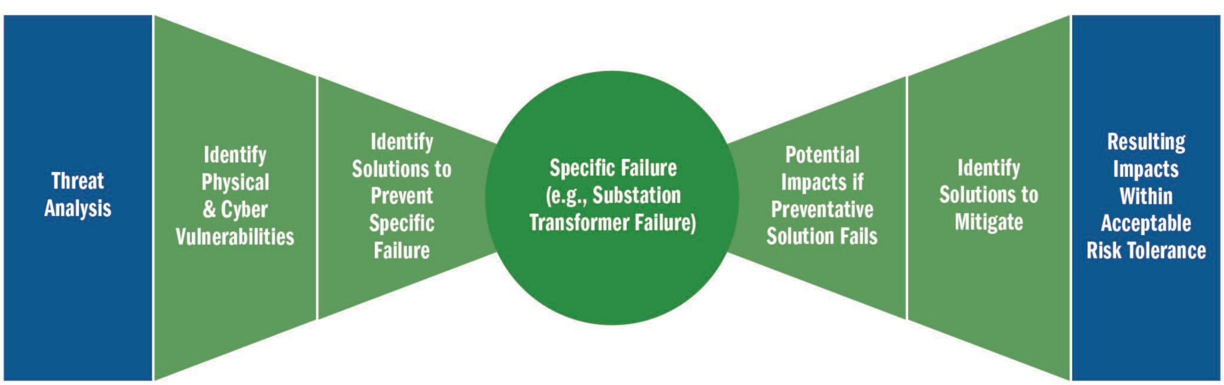


Figure 7. Resilience Bowtie Method (adapted from De Martini and Taft 2022)

The general steps in a bowtie assessment are the following:

1. **Identify physical and cyber vulnerabilities**, including vulnerabilities to people, processes, and assets.
2. **Identify solutions to prevent specific failures**. Consider grid solutions and customer/third-party solutions to avoid or withstand a risk.
3. **Identify potential impacts if preventative solution fails**. Calculate consequences of the hazard.
4. **Identify solutions to mitigate impacts of hazard**. Consider solutions that reduce the scope or duration of the event and/or increase survivability. Such solutions can include enabling customers to better withstand interruption of services due to failure of system infrastructure.

A nested bowtie approach can be used to evaluate multiple potential hazards or threats and identify and characterize preventative and mitigation measures to meet system goals. A nested bowtie approach is described in Culler et al. (2022) and illustrated in Figure 8.

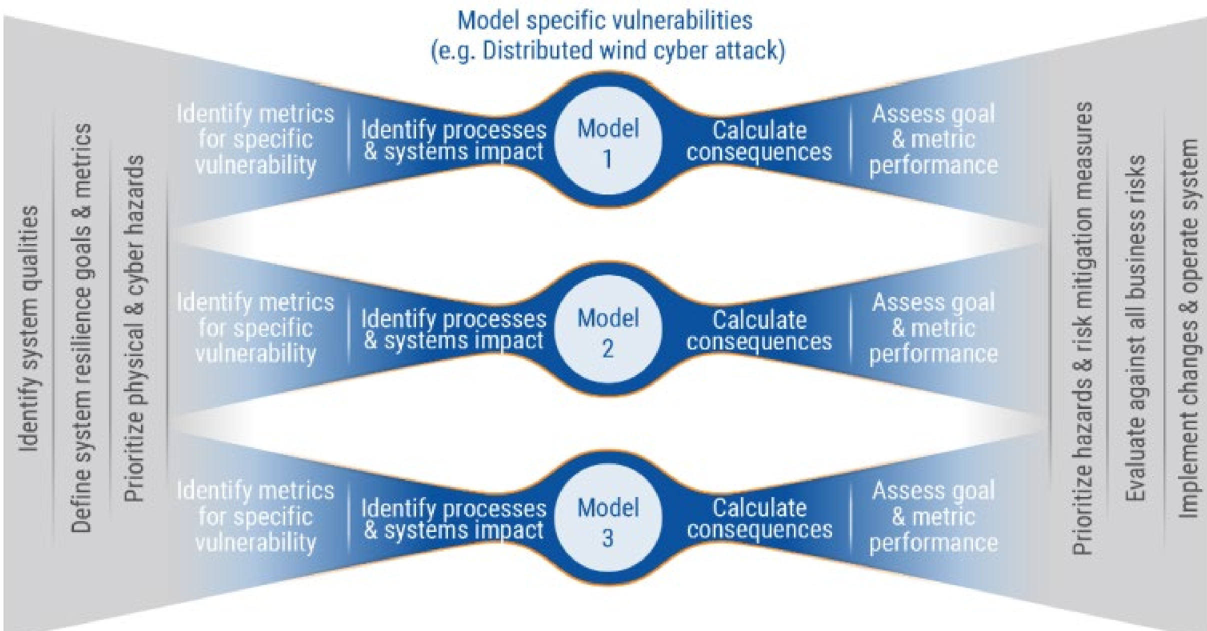


Figure 8. Nested Bowtie Approach (Culler et al. 2022)

3.4 Climate Change Vulnerability Assessment

Climate vulnerability assessments are increasingly being performed by states and utilities to identify and characterize risks. Assessments ultimately consider the exposure of critical assets or operations to an adverse climate event or trend, the probability of damage to assets or disruption to operations as a result of exposure to those climate threats (or risks posed by threat), and the likely consequences if the event were to occur (severity of impacts).

Operations of many utility assets are predicated on specific temperature maximums (or minimums) and load range. Temperatures above or below the specified maximum or minimum can lead to derating, damage, and failure. Existing equipment (transformers, conductors, etc.) may not be designed for temperatures being experienced. Higher temperatures can reduce equipment capacity and increase maintenance requirements. Higher temperatures also correspond to higher loads. In some cases, utility assets now find themselves located in Federal Emergency Management Agency (FEMA) floodplains. Many basic layers of utility design standards and assumptions need to be reevaluated. Utilities have traditionally used guidelines and rules of thumb for asset planning and operations; these have been developed and adjusted over time based on the history of how things have operated. Many assumptions should be reassessed, and possibly adjusted considering evolving environmental and threat profiles. Regulators can encourage utilities to do so and ask for updates on how they are assessing and adjusting assumptions where necessary.

Maintenance cycles may also need to be adjusted. Transformers may need more frequent maintenance or inspection. Additional emphasis on vegetation management is required in some areas. Utilities may also change the amount and types of spares kept on hand. Some utilities now want increased observability in the system to more actively monitor systems, including installing more sensors and more advanced distribution management systems. Many design requirements come from standards, and as expected conditions change, standards may need to be reconsidered. The updates to standards will likely vary based on region. Equipment vendors will also need to adapt their equipment ratings and specifications as expectations of operating conditions evolve. Utilities can identify planning analogs and learn from other regions that have adapted their design requirements. While regulators can be flexible and understanding with utilities as they move into operational regions they have not seen before, the regulators can also require that the utilities in their jurisdiction are assessing and making adjustments for the evolving threat profile.

In addition to climate change impacts to utility assets, climate change can impact generation and resource adequacy. Climate change effects on hydrological cycles may adjust the timing, temperature, and volume of water availability for thermal electric cooling and for hydropower generation. Changing temperatures can lead to changes in loads and in the demand side resources predicated upon the timing and magnitude of loads. Changes in the overall generation resource mix, as well as loads, can impact wholesale power markets and wholesale prices as well as grid reliability. Interregional climate change impacts exist and can impact generating resource availability and market conditions. **Taken together, these represent cumulative areas of significant potential uncertainty and impact.** New standard methods and tools may be needed in integrated resource plans and beyond to properly plan and account for water and climate-based impacts to generation, loads, and markets (Cooke et al. 2021).

3.4.1 Con Edison Example

Con Edison is often cited as a good example of a utility incorporating climate change considerations into planning and operations

Con Edison completed a Climate Change Vulnerability Study in response to several major weather events, including Superstorm Sandy, and requirements from the New York Legislature and the New York Public Service Commission.[4] Con Edison used downscaled global climate model data to identify portions of their system at risk to heat events, severe precipitation events, and sea-level rise. Downscaling is a technique to translate large-scale global climate model data into smaller spatial scales, which can then be used by local utilities to address their specific needs.[5] **Downscaling global climate models is considered a best practice in planning for climate variability and determining risks and threats.** Con Edison

[4]New York Assembly Bill 8763 from the 2021-2022 Legislative Session required that "The climate change vulnerability study shall evaluate the electric corporation's infrastructure, design specifications, and procedures to better understand the corporation's vulnerability to climate-driven risks, and shall include, but not be limited to, adaptation measures to address vulnerabilities and any other information deemed necessary by the commission."
[5] For more information on downscaling global climate models, see: https://www.usgs.gov/news/data-spotlight-downscaled-climate-projections-inform-climate-research-south-central-us-region

identified new planning criteria for construction and hardening existing facilities. The Climate Change Vulnerability Study directly led to a climate change implementation plan to implement hardening measures over the next 5, 10, and 20 years (Con Edison 2019)

Figure 9 shows the downscaled climate model-based temperature forecasts that are part of Con Edison's Climate Change Vulnerability Study. In Figure 9, the historic (black line) and projected (colored bands) data are for Central Park during the summer under two different greenhouse gas concentration scenarios, representative concentration pathway (RCP) 4.8 and RCP 8.5.[6] RCP 8.5 is consistent with the current trajectory of greenhouse gas emissions and is often considered a worst-case scenario, or high emissions scenario. RCP 4.5 is a stabilization global climate emissions scenario and assumes the imposition of emissions mitigation policies.

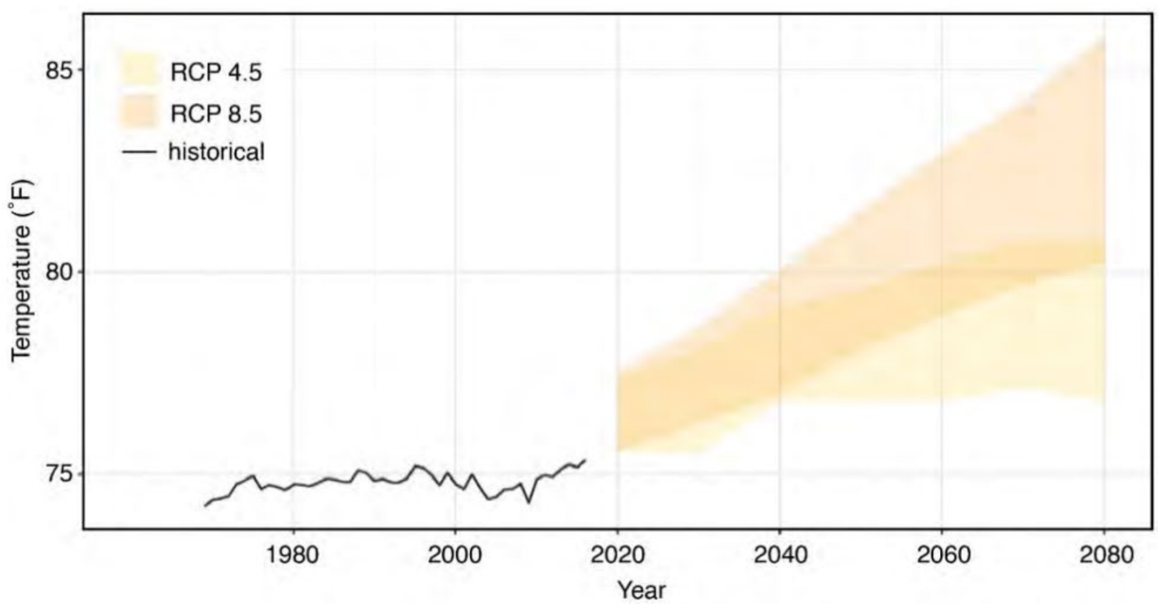


Figure 9. Average Summer Air Temperature Forecast in Central Park Based on Downscaled Global Climate Models. Note: Historic (black line) and projected (colored bands) are average air temperature in Central Park during the summer under two different greenhouse gas concentration scenarios, RCP 4.5 and 8.5.

Con Edison also prepared a Climate Change Resilience and Adaptation Report with a summary of 2020 activities. Table 3 contains a summary of climate change resilience and adaptation activities. Some key findings from the report include the following:

- The electric summer peak is expected to increase by 700 to 900 megawatts (MW) due to increased temperature variations by 2050.
- Temperature increases and extended heat waves are expected to affect the reliability of distribution networks by 2030, absent adaptations.
- Due to increases in temperatures, the size of the cooling equipment in Con Edison's facilities may require an increase of up to 40 percent by 2040.
- An increase in temperature and heat index may exacerbate worker heat stress.

[6] RCP 4.5 and 8.5 assume a concentration of carbon that delivers global warming at an average of 4.5 and 8.5 watts per square meter, respectively, across the planet.

Table 3. Con Edison Summary of Process Updates and Key Findings from Climate Change Resilience and Adaptation – Summary of 2020 Activities (Con Edison 2021)

Key Areas	Summary of Process Updates	Key Findings
Load Forecasting	• Climate information will be included in future load forecasts for all commodities beginning in 2020. • Con Edison will incorporate anticipated temperature variable (TV)[9] increases into load forecasting, currently estimated at a 1-degree TV increase per decade beginning in 2030.	• The electric summer peak is expected to increase by 700 to 900 megawatts (MW) due to increased TV by 2050.
Load Relief	• Beginning in 2021, Con Edison will incorporate projected climate change-driven increases in load and reductions in power equipment ratings in the 10- and 20-year load relief plans.	• A relatively small impact on power transformers and network transformer ratings is expected due to ambient temperature rise between 2040 and 2050.
Reliability Planning	• Reliability modeling will use forward looking climate change-adjusted load forecasts and projected increases in TV. • In 2021, the Company will conduct a review of extreme event projections to determine whether additional model updates are warranted.	• Temperature increases and extended heat waves are expected to affect the reliability of distribution networks by 2030, absent adaptations.
Asset Management	• Con Edison processes will assess the extent to which expected future temperature changes impact ratings. • The Climate Change Planning and Design Guideline sets a flood design standard to account for increasing sea level rise, which applies to the electric, gas, and steam systems.	• The sea level projection exceeds the current design criterion of one foot of sea level rise by 2040.
Facility Energy Systems Planning	• Con Edison is updating designs to provide more flexibility for modifications during heating, ventilation, and air conditioning system replacement.	• Due to increases in temperature, the size of the cooling equipment in Con Edison's facilities may require an increase of up to 40% by 2040.
Emergency Response Activations	• Discussions are underway on how to incorporate heat, flooding, and precipitation projections into the weather and impact forecast model used to establish the Company's emergency response preparation to weather events. • The Company will plan for drills and exercises based on projected pathway criteria.	• Projected climate pathways could impact future weather and storm impact forecasts. • The Company will continue reviewing ways to incorporate climate change into a forward-looking model.
Worker Safety	• Con Edison will monitor climate change for impacts on worker safety. In 2022, the Company will consider whether additional heat stress protocols for climate change adaptation are warranted.	• An increase in temperature and heat index may exacerbate worker heat stress.

3.4.2 Southern California Edison Example

Rulemaking 18-04-019 in California required California's large investor-owned electric and gas utilities to develop climate adaptation and vulnerability assessments. The California Public Utilities Commission (CPUC) is prescriptive in its requirements to the utilities (CPUC 2020). Vulnerability assessments in California must focus on climate risks to operations and services as well as to utility assets; options for dealing with vulnerabilities, ranging from easy fixes, where applicable, to more complicated, longer-term mitigation; and options for green and sustainable remedies for vulnerable infrastructure. These vulnerability studies must focus on the following climate impacts: temperature, sea level, variations in precipitation, wildfire, and cascading/compounding impacts. Vulnerability assessments must address the "actual or expected climatic impacts and stimuli or their effects on utility planning, facilities maintenance and construction, and communications, to maintain safe, reliable, affordable and resilient operations," as required by Commission Decision 19-10-054, Ordering Paragraph No. 1.

Investor-owned utilities in California are required to use the Department of Water Resources two-step vulnerability assessment methodology that 1) combines exposure and sensitivity to determine risk, and 2) combines risk and adaptive capacity to determine vulnerability.

In California, utilities must submit vulnerability assessments every four years. The vulnerability assessment must be submitted at the same time as each utility's Risk Assessment Mitigation Phase (RAMP) Application, which covers the assessment and mitigation of key safety risks facing the company for the designated future four-year period. (In 2022, a RAMP is submitted that covers 2025–2028 for a 2025 test year.) The RAMP is a prerequisite to filing the general rate case, which allows the Commission to review in detail how utilities identify and propose to address critical safety risks.

California uses the term "adaptive capacity" in the climate adaptation context to refer to "the broad range of responses and adjustments to daily and extreme climate change related events available to communities. This includes the ability and resources communities have to moderate potential damages, take advantage of opportunities, and cope with consequences." (CPUC 2020) Utilities are directed to consult with and consider advice from Disadvantaged Vulnerable Communities and other parties to the proceeding that submitted comments on the issue in determining the levels of adaptive capacity.

Costs associated with the vulnerability assessments and incremental costs related to the community engagement must be tracked through a separate rate setting process. Investor-owned utilities (IOUs) are directed to set up memorandum accounts for the purpose of tracking costs directly related to the vulnerability assessments and the related community engagement.

Southern California Edison (SCE) is the first California utility to submit its plan, which followed the analytical framework shown in Figure 10. The first step was a scoping step that included identifying the assets, operations, and services to consider in the plans. In the next step, for each climate change risk for which the CPUC required assessment (i.e., temperature, sea-level rise, precipitation/flooding, wildfire, and cascading events), they analyzed assets, operations, and services to determine whether they were exposed to risks and the sensitivity of risk exposure. The next step was for SCE to identify the consequences of each vulnerability and whether SCE had the capacity to adapt and thereby mitigate or eliminate the consequences (e.g., responding to a flooded substation by routing power through an existing, neighboring substation). The final step was to use the overall risk analysis and the community resilience input to prioritize risk and develop adaptation options (SCE 2022).

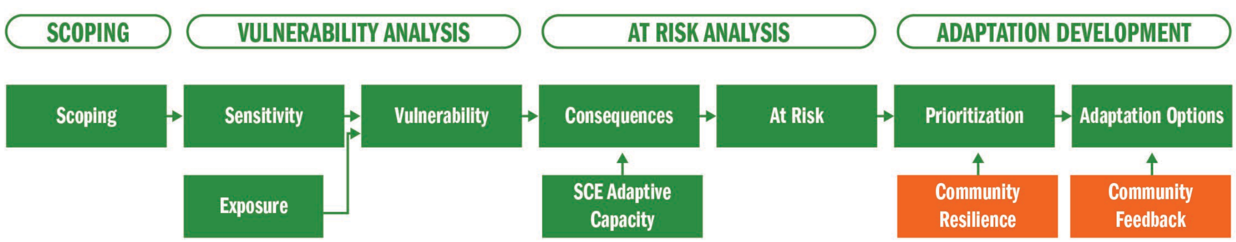


Figure 10. Southern California Edison Climate Adaptation and Vulnerability Assessment Analytical Framework (adapted from SCE 2022)

4.0 Accounting for Variations in Hardship, Consequences and Costs Experienced

Different communities and households have different capabilities to endure adverse impacts from service disruptions. This section describes some methods that can be used to 1) understand and define those discrepancies, and 2) incorporate them into prioritization and decision-making.

4.1 Zone of Tolerance

Esmalian et al. (2021) assesses and identifies factors affecting risk disparity due to infrastructure service disruptions in extreme weather events. They propose a household service gap model that characterizes societal risks at the household level by examining service disruptions as threats, level of tolerance of households to disruptions as susceptibility, and experienced hardship as an indicator for the realized impacts of risk. The concept of **"zone of tolerance"** has been developed to account for different capabilities of households and communities to endure the adverse impacts of service disruptions.

Esmalian developed and deployed a survey instrument in the Harris County area in Texas after Hurricane Harvey, a category 4 storm that made landfall in Texas on August 25, 2017, and caused a power outage for 336,000 Texas electricity customers. The empirical data collected from the survey was used to validate the proposed household service gap model and test the hypotheses about the factors that influence a household's zone of tolerance. A web-based survey was used nine months after Hurricane Harvey. A total of 715 responses were received and, after filtering, 574 complete responses were utilized for the analysis. The specific questions asked are included in Appendix A.

The results of the surveys and study indicate that the following factors influence the zone of tolerance for a household to cope with service outages:

- a households' need for utility service
- preparedness level
- the existence of substitutes
- possession of social capital[7]
- previous experience with disasters
- risk communication

Sociodemographic characteristics, such as race and residence type, also influence the zone of tolerance and the resulting level of hardship experienced by the impacted households. Population subgroups show variations in the tolerance level of service disruptions.

The overall findings of this Esmalian et al. (2021) study is that it is important to integrate social dimensions into the resilience planning of infrastructure systems. Surveying impacted customers and understanding the results enable "human-centric hazards mitigation and resilience planning to effectively reduce the risk disparity of vulnerable populations to service disruptions in disasters."

[7] Social capital is a concept in social science that refers to the value of social networks and relationships that allows individuals to secure benefits and invent solutions.

4.2 Weighting and Scoring Methods for Populations at Risk

In evaluating impacts of different hazards and threats and weighing potential solutions, vulnerable or traditionally disadvantaged populations can be weighted more heavily to account for potential increased hardship during service outages. Table 4 illustrates a method for evaluating populations impacted by different potential resilient solutions. In this example, vulnerable populations are weighted more heavily than nonvulnerable populations. In Section 5.4.1, these weighted community at risk numbers are used to calculate a risk spend efficiency (RSE).

Table 4. Example of Simple Weighting Method (De Martini and Taft 2022)

	Population at Risk			
Solution	Critical/Essential Facility (Population Served)	Vulnerable Population (x2.0 weight)	Other Customers	Weighted Community at Risk
A	5000	1000	1000	8000
B	0	0	5000	5000
C	5000	0	500	5500
D	2500	1000	1000	5500
E	10000	1000	14500	26500

In California, a Microgrid Incentive Program Implementation Plan was developed by the Joint IOUs, of Pacific Gas and Electric (PG&E), San Diego Gas and Electric (SDG&E), and SCE that includes a weighting methodology to prioritize microgrid projects. The plan includes a scoring methodology that weighs 1) customer and community benefits (that includes impacts to vulnerable communities), 2) resilience benefits, and 3) environmental benefits (California Joint Utilities 2021). The specific elements of the scoring methodology are shown in Table 5. **As part of weighting community benefits, points are given for projects that support low-income customers, vulnerable customers, and critical facilities, including those that serve disadvantaged communities** (California Joint Utilities 2021).

Table 5. Scoring Methodology for Prioritizing Microgrids (California Joint Utilities 2021)

Customer and Community Benefits

Subcategory	Scoring Parameter/Criteria	Validation	Points	Points Cap	Max Points
Low-Income Customers	Number of CARE/FERA customers within microgrid project	Utility Records	0.1 / customer	8	50
Vulnerable Customers	Number of AFN/Medical Baseline/Life Support customers within microgrid	Attestation from Authority having Jurisdiction	0.2 / customer	10	
Critical Facilities	Number of critical facilities within the microgrid	CPUC definition	5 / facility	30	

Subcategory	Scoring Parameter/Criteria	Validation	Points	Points Cap	Max Points
	Number of critical facilities within the microgrid serving disadvantaged communities	CPUC definition	10 / facility		
Community Services	Community Resilience Service facilities within microgrid (min of 1)	CPUC definition	2 / facility	2	

CARE = California Alternate Rates for Energy Program; FERA = Family Electric Rate Assistance Program; AFN = Access and Functional Needs

Resilience Benefits

Subcategory	Scoring Parameter/Criteria	Validation	Points	Points Cap	Max Points
Location Outage Risk	HFTD 2	CPUC HFTD Map	3	6	30
	HFTD 3	CPUC HFTD Map	6		
	Prior PSPS Events – 2 points per historical PSPS event (any year)	Utility Records	2	14	
	1% worst-performing circuits (past two years)	Appears in either of prior two years of Utility Annual Electric Reliability Report	4	4	
Island Duration	Duration of islanded operation provided by microgrid beyond 24 hrs minimum requirement	Each 6-hour period of operation beyond 24 hrs is determined by typical microgrid load profile	0.5 / additional 6-hour period	6	

HFTD = High Fire Threat District; PSPS = Public Safety Power Shutoff

Environmental Benefits

Subcategory	Scoring Parameter/Criteria	Validation	Points	Points Cap	Max Points
Clean Energy	100%	% of installed front-of-meter installed capacity from clean energy	17	17	20
	95-99%		12		
	90-94%		7		
	80-89%		2		
	< 79%		0		
Fossil Fuel Displacement	Fossil Fuel Emergency/Backup Gen Displacement as primary backup (min. of 1)*	Microgrid applicant attestation	3	3	

* points given for displacing an existing fossil fuel emergency/standby generator as the primary backup source of power for at least one critical facility, using the microgrid as the primary backup source instead.

4.3 Identifying Customers Experiencing Poor Reliability

System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI), and Momentary Average Interruption Frequency Index (MAIFI) are utility-centric traditional reliability metrics that focus on the average performance of one entire feeder of the utility's whole distribution system (Watts et al. 2020). Other metrics not as commonly used point to specific customer segments that may be experiencing more outages than the averages listed in traditional metrics. The use of more customer-centered metrics can provide a more complete and balanced picture that includes reliability experienced by the worst-served customers. Customers Experiencing Multiple Interruptions of n or More (CEMIn) and Customers Experiencing Long Interruption Duration of t or More Hours (CELIDt) are defined in the IEEE Standard 1366 and reflect customers' reliability experience with respect to multiple interruptions and long-duration interruptions (DTE 2021; Watts et al. 2020). Other customer-focused metrics include Customers Experiencing Multiple Momentariness (CEMM) and Customers Experiencing Multiple Sustained and Momentary Interruptions (CEMSMI).

CEMIn, CELIDt, CEMM, and CEMSMI may point to specific customers experiencing more than their fair share of outages. Incentives and investments designed to improve system level metrics like SAIDI and SAIFI may "encourage utilities to focus on making good performance better rather than addressing the needs of the worst-served customers at the grid edge" (Watts et al. 2020).

Non-traditional customer reliability metrics are described in more detail below, along with example applications.

- **Customers Experiencing Multiple Interruptions of n or More (CEMIn)**: A count of the number of customers with n or more interruptions. Table 6 shows states and utilities now reporting CEMI, which captures the number of customer experiencing more than a defined number of sustained interruptions in a year.

Table 6. CEMI Reporting in the United States (Watts et al. 2020)

STATE	***CEMI REPORTING***
California	Requirement to report CEMI-12
Connecticut	Requirement to report CEMI-3 to 10
Delaware	Requirement to report CEMI-8
DC	Requirement to report CEMI-8
Florida	Requirement to report CEMI-5 for utilities > 50,000 customers
Maryland	Requirement to report CEMI-2, 4, 6, and 8
Michigan	DTE Energy Reporting CEMI-1 to 10
New Jersey	Atlantic City Electric reporting CEMI on a company and district basis
North Dakota	Northern States Power reporting on CEMI-4 to 6
Washington	Avista reporting on CEMI-0 to 6

- **Customers Experiencing Long Interruption Duration of t or More Hours (CELIDt)**: A count of the number of customers with interruptions lasting t or more hours.
  - DTE reports this metric for time periods of 8, 36 and 60 hours.
  - Delaware Public Service Commission requires utilities to report on the total number of customers that have experienced a cumulative total of more than eight hours of outages (CELID-8).
  - Swedish, and Finnish energy regulators require reporting on the number of interruptions longer than 12 and 24 hours as part of their arrangements for compensation for long-duration outages.
  - British Energy Regulator (Ofgem) requires reporting the number of unplanned and pre-arranged customer interruptions by duration bands for both normal conditions and as part of exceptional events (Watts et al. 2020).

- **Customers Experiencing Multiple Momentariness (CEMM)**: A count of the number of customers experiencing momentary interruptions.
  - Florida Power and Light and Gulf Power are using this metric to drive performance improvements for customers most adversely affected by momentary interruptions and they are achieving significant improvements in performance both during normal and major storm conditions by targeting this metric (Watts et al. 2020).
- **Customers Experiencing Multiple Sustained and Momentary Interruptions (CEMSMI)**: The number of customers experiencing more than a certain number of interruptions a year, including both momentary and sustained outages.
  - Rocky Mountain Power (PacifiCorp) in Idaho and Avista in Washington State are using this metric (Watts et al. 2020).

Figure 11 is from an S&C report (Watts et al. 2020) and shows one interpretation of how regulators and utilities are transitioning to more customer-centric measures.

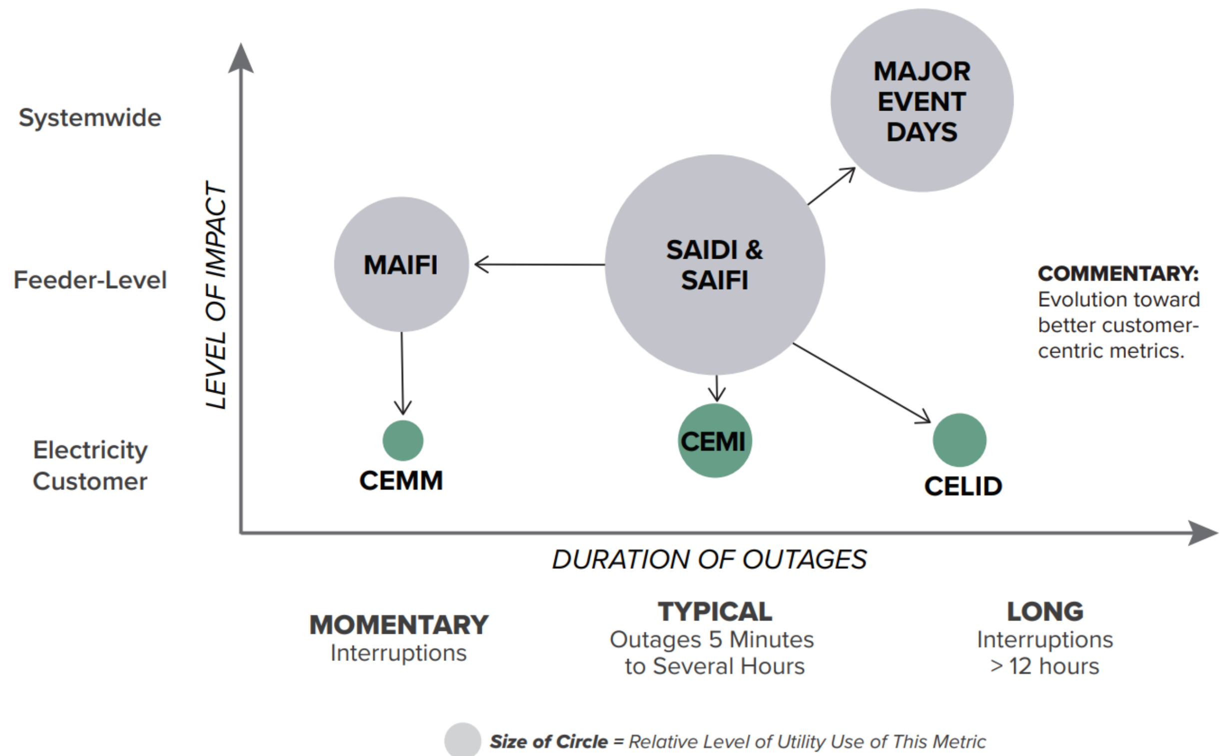


Figure 11. Illustration of How Key Reliability Metrics are Evolving Toward More Customer-Centric Metrics. Source: S&C, Watts et al. 2020.

4.4 State Examples

This section provides examples of how some states are addressing resilience equity and vulnerable communities.

4.4.1 California - Climate Adaptation in Disadvantaged Communities

In September 2020, the California PUC issued a decision order on energy utility climate change vulnerability assessments and climate adaptation in disadvantaged communities. As stated in the order, the decision takes steps to ensure the energy utilities regulated by the CPUC are prepared to upgrade their infrastructure, operations, and services to adapt to climate change, and to ensure safe and reliable energy service to all Californians—including those most vulnerable and disadvantaged (CPUC 2020). The decision weaves together two questions:

1. How should the energy utilities regulated by the PUC assess and adapt to California's vulnerabilities caused by climate change?

2. How should the utilities engage with the most vulnerable and disadvantaged communities on climate adaptation related to the utilities' infrastructure, operations, and services so these communities are not left behind the rest of the state?

In the decision, the CPUC identified communities that are the most vulnerable to climate change. These are referred to as **Disadvantaged Vulnerable Communities** (DVCs). DVCs include the 25 percent highest scoring census tracts according to the California Communities Environmental Health Screening Tool (CalEnviroScreen);[8] all California tribal lands; census tracts with median household incomes less than 60 percent of state median income; and census tracts that score in the highest 5 percent of pollution burden within CalEnviroScreen but do not receive an overall CalEnviroScreen score due to unreliable public health and socioeconomic data (CPUC 2020). Utilities covered by the order (PG&E, SCE, SDG&E, and Southern California Gas Company) are required to place maps on their websites illustrating the service territory area covered by their respective Disadvantaged Vulnerable Communities.

Utilities must develop and submit **Community Engagement Plans** every four years, one year before the filing date of their vulnerability assessments. The purpose of Community Engagement Plans is to identify and prioritize utility climate adaptation investments in Disadvantaged Vulnerable Communities. The Community Engagement Plan must include, among other things, a discussion of how IOUs promote equity related to the IOUs' climate adaptations in DVCs based on the communities' adaptive capacity.

The IOUs must survey DVCs and community-based organizations to assess the effectiveness of their community outreach and engagement, and file a survey report the year after the vulnerability assessments. Prior to conducting the survey, the IOUs shall gather input from the parties on appropriate survey questions and methodology through a process that is open to all parties. The meet and concur process must conclude not later than 30 days before the surveys are conducted. Both quantitative and qualitative metrics must be used to determine the reach of the IOU's outreach and community engagement efforts. The Survey Reports will be used to improve future Community Engagement Plans.

4.4.2 California's Self Generation Incentive Program's Equity Resilience Map

Under SB700 in 2018, CPUC was directed to expand the Self Generation Incentive Program (SGIP) by creating a "Residential Equity Resiliency" budget (CPUC 2022). A total of $612 million in ratepayer funds will be collected through 2024 to provide no-cost battery storage systems to vulnerable, low-income households located in high fire threat districts and public power safety shutoff zones. Metrics were used to define eligibility requirements for the program and public maps were created so that households could easily and quickly be pre-qualified by addresses.

[8] 1 More information about CalEnviroScreen is available on the website of the California Office of Environmental Health Hazard Assessment at: https://oehha.ca.gov/calenviroscreen.

As defined by the CPUC (2022), eligible Equity Resiliency budget customers:

- Have experienced two or more utility public safety power shutoffs OR live in a Tier 2 or 3 high fire threat district
- AND have one of the following additional criteria:
  – Live in multifamily deed-restricted housing or a single-family home subject to resale restrictions as defined by U.S. Department of Housing and Urban Development (HUD), AND/OR
  – Currently enrolled in a utility Medical Baseline Program as defined by the CPUC, AND/OR
  – Have notified their utility of serious illness and/or life-threatening condition, AND/OR
  – Have received or reserved other solar-related incentives, AND/OR
  – Home relies on electric pump wells for water AND have an annual household income no greater than 80 percent of area median income, attest that the installation site is their primary residence occupied by either a homeowner or tenants, AND attest that the residence is not provided water by a municipal or private utility.

CPUC created geographic information system (GIS) maps in order to streamline incentive deployment and simplify pre-qualification for this vulnerable population. The HUD, public safety power shutoffs, and high fire threat districts were overlayed within a searchable map that could be used to find an eligible property by address, as shown in Figure 12.

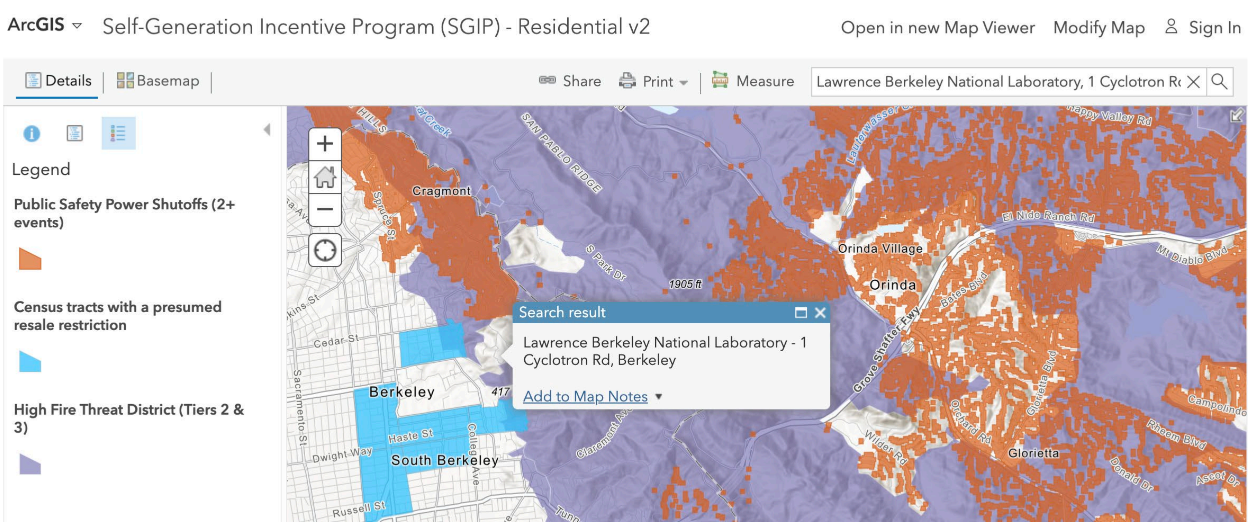


Figure 12. California PUC's SGIP Equity Resiliency Eligibility Mapping Tool (CPUC 2022)

4.4.3 Washington Clean Energy Implementation Plans and Highly Impacted Communities Designation

In 2019, the Washington State Legislature passed the Clean Energy Transformation Act (CETA), which commits Washington to an electricity supply free of greenhouse gas emissions by 2045. As directed by CETA, the Washington State Department of Health (DOH) developed a cumulative impact analysis in order to designate communities highly impacted by climate change and fossil fuel pollution.

The goal of designating highly impacted communities is to highlight communities that are currently experiencing a disproportionate share of environmental risk factors and that must, according to CETA, benefit equitably from the transition to a clean energy economy.

The Department of Health designates as a highly impacted community any census tract with a 9 or 10 overall rank on the environmental health disparities map, or any census tract with tribal lands. The environmental health disparities map ranks the risks communities face from environmental burdens, including fossil fuel pollution and vulnerability to climate change impacts that contribute to health inequities. It is a well-known vulnerability index for environmental health disparities and is being used by other state processes to guide funding to reduce environmental health disparities. In Washington, the environmental health disparities map is based on a conceptual formula of Risk = Threat x Vulnerability. Threat consists of both environmental effects and exposures, and vulnerability consists of socioeconomic factors and sensitive populations as shown in Figure 13.

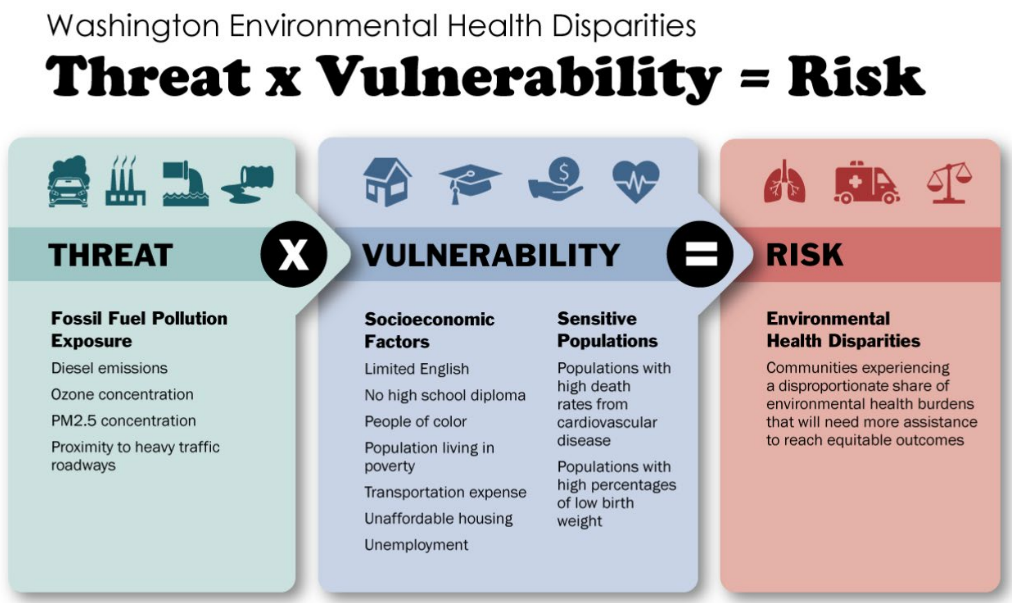


Figure 13. Relationship between Threat, Vulnerability, and Risk (WA DOH 2022)

In Washington utilities' Clean Energy Implementation Plans, Puget Sound Energy (PSE), Avista, and PacifiCorp were required to develop customer benefit indicators (CBIs) describing how each utility will achieve an equitable distribution of benefits to customers while achieving a transition to clean energy. One of the required indicator categories is resilience. The utilities must also identify **highly impacted communities and vulnerable populations** within their service territories. The resilience indicators proposed by all three utilities in Washington that submit Clean Energy Implementation Plans were consistent and related to decreasing the frequency and duration of outages. Utility CBIs were defined as follows for utilities:

- **Puget Sound Energy (PSE)**: For PSE, relative to energy security and resilience, the CBI is decreased frequency and duration of outages. The metrics are the number of outages, total hours of outages, and total backup load served during outage. Relative to risk reduction, energy security, and resiliency, the CBI is increased resiliency, and the metric is the number of customers who have access to emergency power in their home or at a community center (PSE 2021).

- **Avista**: For Avista, the resilience CBI is outage duration. Avista will calculate the average duration of outages for both named communities[9] and for other customers to identify if there are differences between quality of service (Avista 2021).
- **PacifiCorp**: For PacifiCorp, the resilience CBI is the frequency and duration of energy outages; the benefits categories are energy resiliency, risk reduction, and energy benefit; and the metrics are SAIDI, SAIFI, and CAIDI at the area level, including and excluding major events (PacifiCorp 2021).

4.4.4 Oregon Environmental Justice Council

In March 2022, the Oregon Legislature passed HB 4077 codifying the existing Environmental Justice Task Force as the Environmental Justice Council and paving the way for equity mapping in Oregon. The Environmental Justice Council in Oregon intends to include Oregon's most vulnerable populations in policy conversations around climate change mitigation. The effective date of HB 4077 is June 3, 2022. Relevant bill language is summarized below.

> *SECTION 12. (1) The Environmental Justice Council with staff support from the Department of Environmental Quality, in collaboration with the office of Enterprise Information Services, the Institute for Natural Resources, the Portland State University Population Research Center, and natural resource agencies with staff support from the department and the Oregon Health Authority, shall develop an environmental justice mapping tool.*
>
> *(2) When developing the environmental justice mapping tool, the council shall develop and conduct an inclusive community engagement process to receive input from communities across this state and consult with natural resource agencies. The council shall hold at least six meetings in different regions of this state, including at least one meeting in a remote community…*

[9] Of the 143 census tracts located within Avista's service territory, approximately 34 (24 percent) meet the criteria of named communities per the Washington State Health Disparities Map developed by the Department of Health (DOH).

5.0 Opportunities for Investing in Resilience

This section describes specific measures and investments that can increase resilience, including those that address climate change. This section also describes methods for evaluating different resilience measures, including risk and value spend efficiency and cost-benefit analysis.

5.1 Investments that Support Resilience

This section describes specific resilience investments. Figure 14 shows that many existing distribution system investment areas can also support resilience if distribution resilience considerations are explicitly integrated into distribution expansion, upgrade, and asset planning (De Martini 2020).

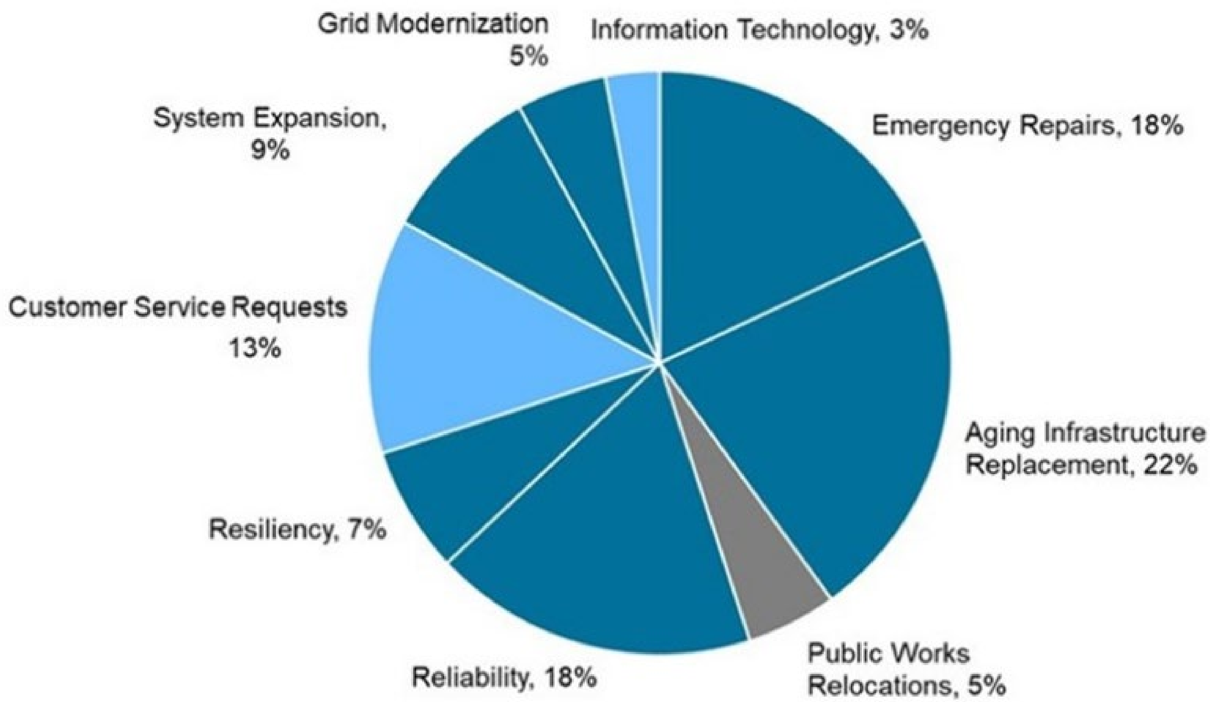


Figure 14. Generalized Breakdown of Distribution Capital Investments. Blue shaded areas impact resilience and reliability. The darker the blue the more potential direct impact (De Martini 2020).

The measures shown in Figure 15 can be part of a customer-centered approach to resilience, improving power system reliability and resilience from both the grid and customer's perspective. These measures address each of the pillars of resilience described earlier in this report: frequency, scale, duration, and survivability. The measures in Figure 15 are threat agnostic. Many of the items in Figure 15, like tree trimming and NERC reliability standards, are routine responsibilities and good utility practice, while others, such as customer energy efficiency and backup power sources, are voluntary best practices.

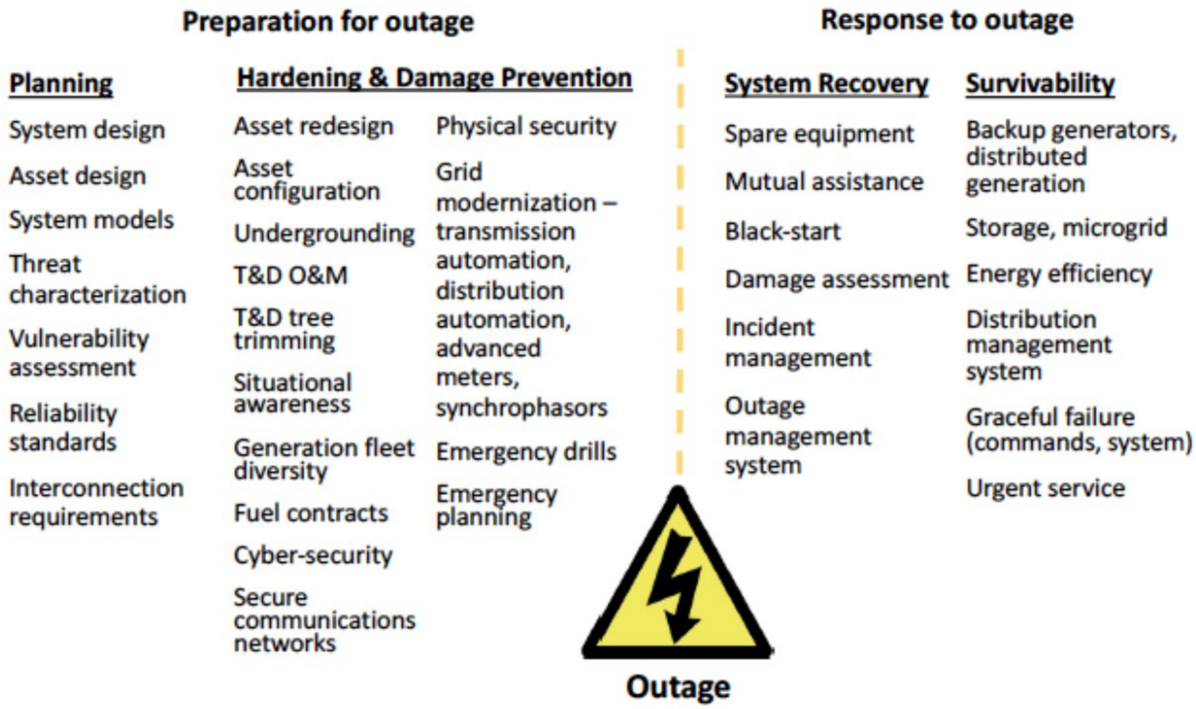


Figure 15. Measures to improve Power System Reliability and Resilience (Silverstein et al. 2018)

Appendix B contains additional lists of resilience measures from Kallay et al. (2021) and Zamuda et al. (2019), respectively.

5.2 Climate Change-Focused Adaptations and Measures

Climate change may require more extensive resilience measures than reliability measures used in response to past outages and conditions. Utilities need to plan for the weather and conditions of the future rather than the weather and conditions of the past. Evaluating historic data and trends are not enough, and forward-looking forecasts and resilience measures need to be explored.

Con Edison, as part of their Climate Change Vulnerability Assessment, developed a list of strategies and resilience measures for increasing the resilience of their system. Specific adaptation strategies and measures are summarized in Table 7. Con Edison also identified customer coping adaptation strategies based on their climate vulnerability assessments. Specific customer coping adaptation strategies are contained in Table 8.

Table 7. Con Edison Emergency Preparedness and System Recovery Adaptation Strategies (Con Edison 2019)

Adaptation Strategy	Measures
Strengthen staff skills for streamlined emergency response.	• Use technology to increase the efficiency of emergency response work crews. • Review the Learning Center courses to ensure that crews are developing the skills required for emergency response. • Incorporate supply shortages into emergency planning exercises.
Plan for resilient and efficient supply chains.	• Develop a resilience checklist for resilient sourcing. • Have a plan already in place for selection and procurement of assets designed to be more resilient in the future. • Ensure that parts inventories are housed out of harm's way and in structures that can survive extreme weather events. • Standardize equipment parts, where possible.
Coordinate extreme event preparedness plans with external stakeholders.	• Continue coordination with telecommunication providers, including through joint emergency response drills. • Continue and strengthen collaboration with the city to improve citywide design, maintenance, and hardening of the stormwater system. For example, improved drainage could alleviate the potential impacts of flooding and increase the effectiveness of adaptation measures in which Con Edison invests (e.g., drain hardening at manholes).
Incorporate low probability events into long-term plans.	• Continue expanding the Enterprise Risk Management framework to include lower probability extreme weather events and long-term issues (e.g., 20+ years). • Conduct additional extreme weather tabletop exercises informed by the future narratives outlined in this report, and consecutive extreme weather events. • Consider expanding the definition of critical facilities and sensitive customers.
Track weather-related expenditures.	• Con Edison's Work Expenditures Group could track expenditures, such as the cost of outages and repairs or customer service calls. Concurrently tracking climate and cost data will enable Con Edison to perform correlation analysis over time.
Update extreme event planning tools.	• Con Edison currently uses an internal Storm Surge Calculator (an Excel workbook that determines the flood measures to be employed for coastal assets based on a given storm tide level) to help plan for coastal flooding impacts. Con Edison could adjust inputs to this program to reflect the following: – Updated storm surge projection information, using high-end forecasted surge – Information from coastal monitoring, such as sea level rise and coastal flooding • In addition, Con Edison could regularly revisit the definition of critical equipment so that the Storm Surge Calculator can best inform prioritization of equipment upgrades.
Expand extreme heat worker safety protocols.	• Implement safety protocols (e.g., shift modifications and hydration breaks) practiced in mutual aid work in hotter locations such as Florida and Puerto Rico. • Examine and report on the levels of workers necessary to prepare for and recover from extreme climate events.
Improve recovery times through system and technology upgrades.	• Consider the use of drones and other technology (satellite subscription) or social media apps for damage assessment. • Use GIS system to facilitate locating and documenting damage. • Expand the use of breakaway hardware and detachable service cable and equipment.

Table 8. Con Edison Improved Customer Coping Adaptation Strategies (Con Edison 2019)

Adaptation Strategy	Measures
Create resilience hubs (see below for more information).	• Use solutions such as distributed generation, hardened and dedicated distribution infrastructure, and energy storage so that resilience hubs can function akin to microgrids to provide a range of basic support services for citizens during extreme events. • Continue to promote the pilot resilience hub at the Marcus Garvey Apartments in Brooklyn, using a lithium ion battery system, fuel cell, and rooftop solar to provide back-up power to a building with a community room that has refrigerators and phone charging. • Support additional deployment of hybrid energy generation and storage systems at critical community locations and resilience hubs. • Use AMI capabilities to preserve service for vulnerable populations, if possible.
Invest in energy storage.	• Continue to enhance customer resilience through continued installation of energy storage strategies, including on-site generation at substations or mobile storage on demand/transportable energy storage system (TESS) units, and compressed natural gas tank stations. • Continue to explore ways to help customers install, maintain, and make use of distributed energy resource assets for power back-up, self-sufficiency, and resilience purposes.
On-site generation	• Con Edison currently supports on-site generation for customers through programs such as rebate and performance incentives for on-site residential and commercial photovoltaic solar generation, incentives for behind-the-meter wind turbines, and incentives for combined heat and power projects that Con Edison currently facilitates in collaboration with the New York State Energy Research and Development Authority. • On-site generation is a recommended approach for locations where resilience hubs may not be affordable or necessary. • Con Edison could continue to encourage on-site generation for individual businesses and residential buildings.
Energy efficiency	• Support improved passive survivability, or the ability to shelter in place for longer periods of time, through enhanced energy efficiency programs. • Continue to support energy efficiency programs and further expand its energy efficiency program portfolio to include additional incentives for energy-efficient building envelope upgrades.

5.3 Microgrids and Resilience Hubs

A microgrid is "a group of interconnected loads and distributed energy resources (DERs) within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode." (DOE 2018).

Important considerations for designing and implementing microgrids are summarized below (ODOE 2019).

- size and location
- energy efficiency
- isolate critical loads
- technology selection
- control equipment.

Resilience Hubs are being developed by some utilities to support survivability in case of a loss of service. The Urban Sustainability Directors Network (USDN) 2018 paper, *Resilience Hubs: Shifting Power to Communities and Increasing Community Capacity* points out that resilience hubs are best designed through engaging community members, including the most vulnerable, throughout planning and implementation, through "a bottom-up approach centered on community co-development and leadership."

USDN identifies key elements of successful resilience hubs as the following (USDN 2018):

- strong community support
- an appropriate building where residents can gather to receive critical services and resources for emergencies (e.g., food supply, refrigeration, medical services)
- on-site energy resources for a potential extended outage (e.g., solar, batteries, standby generators).

The **Resilient Minneapolis Project (RMP)** is an initiative that has been proposed by Xcel Energy in Minneapolis to the Minnesota PUC as part of their Integrated Distributions Plan (Xcel Energy 2021). The RMP, which has been developed with Black, Indigenous, and People of Color (BIPOC)-led partner organizations, includes three Minneapolis project locations.

The projects seek to improve communities' resilience to crises while advancing the Minnesota PUC's objectives for Integrated Distribution Plans.

At each RMP site, Xcel proposes to work with partners to install rooftop solar, battery energy storage systems, microgrid controls, and necessary distribution system modifications to integrate these technologies. The proposed systems would be designed to not only have managed reserve capacity to provide power for critical services during electric system outages, but also be dispatched and optimized regularly to mitigate system peaks, manage and shape demand, and integrate more solar generation.

The process Xcel Energy used to select sites was as follows:

1. Develop a request for applications.
2. Develop evaluation criteria that included four minimum criteria that all projects must meet (geographic location, safety, regulatory compliance, and physical site requirements) and eight scoring criteria, with definitions, scores, and weights assigned to each. The eight scoring criteria that Xcel Energy developed are the following:
    a. scope of benefits
    b. geographic location preference
    c. impact on distribution infrastructure
    d. maturity of proposed technology and innovation of application of technology
    e. project timing
    f. experience of project lead
    g. strength of project team
    h. additional resources leveraged.

Xcel Energy then selected a project, identified costs, and identified non-quantifiable benefits and quantifiable benefits. With the quantifiable costs and benefits, Xcel then performed a cost-benefit analysis for each selected project. Table 9 shows the result of the cost-benefit analysis for the three proposed RMP sites. Relative to quantifiable and non-quantifiable costs, **Xcel Energy urged the Commission to consider the non-quantified benefits as well as the quantified benefits, even though they are not**

part of the benefit to cost ratio presented because although though they can't be quantified in dollar terms, they may be equally as important. Xcel went on to say that "Since all costs are quantified, but only a subset of benefits is quantified, the benefit-to- cost ratios presented... reflect an incomplete picture of the overall benefit of the RMP projects to our communities and customers." (Xcel Energy 2021).

Table 9. Cost and Benefit Summary Table for RMP (Xcel Energy 2021)

	Units	North Minneapolis Community Resiliency Hub	Sabathani Community Center	Minneapolis American Indian Center	Aggregate
COSTS					
Capital					
Total Capital Cost	$	$3,911,367	$2,644,276	$2,383,235	$8,938,878
O&M					
Annual O&M Cost	$	$23,861	$19,091	$19,091	
NPV of Annual O&M Costs (10 years)	$	$172,662	$138,146	$138,146	$448,953
Total Capital and O&M	**$**	**$4,084,029**	**$2,782,421**	**$2,521,381**	**$9,387,831**
BENEFITS					
Resilience/Value of Lost Load	$	$575,076	$575,076	$460,060	$1,610,212
Bulk System Capacity Value	$	$111,344	$54,384	$65,643	$231,371
Generation & Carbon Emissions		$133,138	$25,417	$22,997	$181,551
Arbitrage	$	$62,174	$3,173	$12,417	$77,764
Lifetime Benefit	**$**	**$881,732**	**$658,050**	**$561,117**	**$2,100,899**
BENEFIT:COST RATIO		**0.22**	**0.24**	**0.22**	**0.22**

Lastly, NARUC and NASEO offer new approaches to valuing resilience that can be applied to proposed investments in microgrids and other resources. These include the Interruption Cost Estimation (ICE) Calculator Tool (described in Section 5.5), the FEMA Benefit-Cost Analysis Toolkit[10], and an emerging Social Burden Method being developed by Sandia National Laboratory (NARUC and NASEO 2022).

The report highlights several specific policy actions that State agencies have taken to spur investment in resilient microgrids and to ensure that all customers are getting access to the potential benefits of microgrids, including electricity cost savings, peak power curtailment, and renewable energy. Several actions are outlined, with examples from Massachusetts, Connecticut, Minnesota, Wisconsin, Oregon, Puerto Rico, New Jersey, North Carolina, and New Mexico.

5.4 Evaluating Potential Resilience Investments

The cost effectiveness of resilience measures can be determined by evaluating the impact of the measure on the probability of an outage frequency, magnitude, and duration and on customer survivability. Planning for resilience must be balanced with rate impacts. Utilities cannot prevent all the threats and hazards that result in outages, but some of the consequences can be mitigated. Key questions that regulators and utilities need to grapple with include: **Which risks should the utility and state take, what level of resilience and mitigations costs are we willing to bear and how do we choose among resilience measures?** (Silverstein et al. 2018). This section attempts to provide insights to these questions.

[10] https://www.fema.gov/grants/tools/benefit-cost-analysis#toolkit

Synapse Energy Economics, Sandia National Laboratories, and Bosque Advisors published a report titled *Application of a Standard Approach to Benefit-Cost Analysis for Electric Grid Resilience Investments* (Kallay et al. 2021c). In the report, they describe how utility companies and regulators routinely use benefit-cost analysis (BCA) to guide investment decisions for grid improvements. However, BCAs for grid resilience investments can be more challenging than for other types of grid investments, for several reasons (Kallay et al. 2021), including the following:

- The term resilience is inconsistently defined and poorly understood. Resilience remains a relatively new concept for utilities and policymakers, and it lacks a generally agreed upon definition.
- Resilience encompasses a wide range of threats, with varying types and levels of consequence. Threats can include human-made threats and natural threats.
- Some threats, such as cyberattacks and Category 5 hurricanes, are emerging, and therefore lack robust historical data to aid in the characterization of consequences.
- Resilience encompasses a wide range of solutions. Regulators may be more apt to apply BCA to some solutions over others.
- Developing probabilities of recurrence and severity is harder for certain threat types, such as tornadoes and cyberattacks.
- Utilities, customers, and third parties can make many types of investments that improve grid resilience, including (1) transmission and distribution system, (2) generation, (3) automation and controls, and (4) cross cutting.

A BCA can reflect different perspectives, including a utility system, host-customer, community, or society Appendix B contains a list of resilience measures from the Synapse/Sandia/Bosque report that includes who the benefits accrue to. Table 10 lists the categories of costs that are often used in the BCA for resilience investments as well as who bears the cost. Table 11 provides information on potential benefits of resilience measures (Kallay et al. 2021).

A common issue with BCA for grid investments, including resilience investments is the inclusion of all the costs, but not all the benefits. In performing BCAs for resilience investments, utilities need to be careful to characterize the full suite of benefits to extent possible, even if that means representing and considering them qualitatively. As with the Minnesota resilience hub example in Table 9, it is likely that from a traditional BCA perspective benefits may not exceeds costs in

Table 10. Categories of Costs of Resilience Investments (Kallay et al. 2021)

Type	Impact	Utility System	Host Customer	Community	Society[28]
Project Implementation	Installation, Operation, and Maintenance	X	X	X	
	Transaction	X	X	X	
	Interconnection	X	X	X	
	Financial Incentives	X			X
	Program Administration	X			
	Utility Performance Incentives	X			

Table 11. Potential Benefits of Resilience Investments (Kallay et al. 2021)

Type	Impact	Utility System	Host Customer	Community	Society [31]
Generation, Transmission & Distribution: Energy and Capacity	Reducing Emergency Staff Deployment Costs	X			
	Avoiding Energy Infrastructure Damages	X			
Non-Energy: Economic[32]	Avoiding Damages to Goods and Infrastructure		X	X	X
	Avoiding Lower Revenues from Lower Production and Fewer Sales of Goods and Services		X		X
	Reducing Emergency Staff Deployment Costs		X	X	
	Avoiding Departure of Customers Important to the Community			X	
	Avoiding Lost Economic Development, Education, and Recreation Opportunities			X	X
Non-Energy: Public Health, Safety, and Security	Reducing Medical and Insurance Costs	X	X	X	X
	Avoiding Loss of Quality of Life	X	X	X	X

Figure 16 provides an illustrative example of a cost-benefit analysis for a battery system for an exposed peninsula to avoid upgrades to the utilities' transmission and distribution system (Kallay et al. 2021). The battery can be encased in concrete to protect it from damages due to the increasing likelihood of a hurricane. The benefits exceed the costs, with and without the resilience components. While the total costs increase 25 percent with the resilience component, the benefits increase as well, and to a slightly greater degree. The resilience related costs and benefits are not most of the costs or the benefits, but they nonetheless contribute to each.

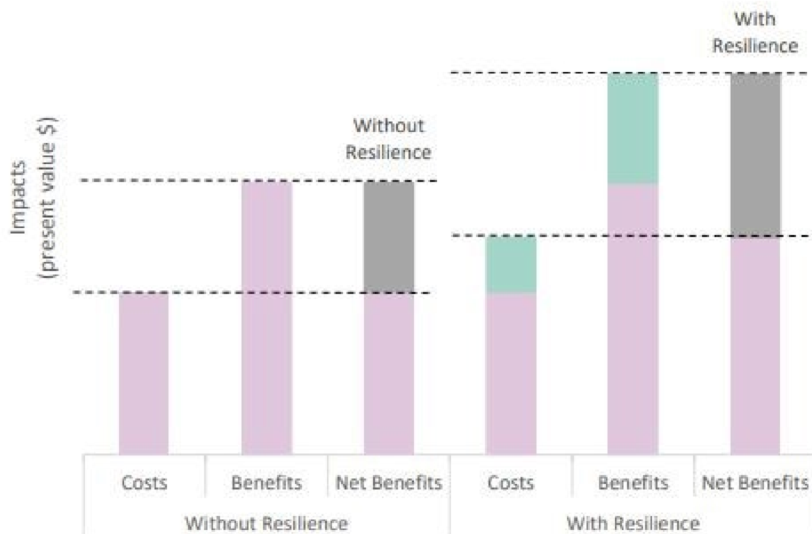


Figure 16. BCA With and Without Resilience Costs and Benefits

The journal article *Monetization methods for evaluating investments in electricity system resilience to extreme weather and climate change* from July 2019 points to categories of resilience measures, definitions, examples, and benefits, as described in Appendix B (Zamuda et al. 2019).

Table 12 (from Zamuda et al. 2019) provides a summary of resilience benefit values found in the literature.

Table 12. Summary of Benefit Values Found in Literature (Zamuda et al. 2019)

Benefit Type	Benefit Amount
Avoided Legal Liabilities	$87,100 per mile - reduced litigation from fewer contact fatalities and serious accidents
Avoided Vegetation Management Costs	$3000 - $12,000 per mile for distribution; $300 - $9000 per mile for transmission
Avoided Revenue Loss	$0.09-$0.32 per kWh (Range of System Average Rates Across U.S.; average SAR = $0.13)
Avoided Short-Duration Customer Interruption Costs: Medium/Large C&I (>50,000 annual kWh)	$12-$37 per unserved kWh (interruptions lasting 30 minutes - 16 hours)
Avoided Short-Duration Customer Interruption Costs: Small C&I (<50,000 annual kWh)	$214-$474 per unserved kWh (interruptions lasting 30 min - 16 h)

Benefit Type	Benefit Amount
Avoided Short-Duration Customer Interruption Costs: Residential Customers	\$1.3-\$5.9 per unserved kWh (interruptions lasting 30 min - 16 h)
Avoided Long-Duration Customer Interruption Costs	\$1.20/kWh (for high priority services) to \$0.35 (for low priority services) (interruptions lasting 24 h; Allegheny County, PA)
	\$190M-\$380 M (24 -h interruption) \$4.4B-\$8.8B (7-week interruption) (downtown San Francisco)
Safety: Avoided Injuries and Fatalities	Fatality: \$7.4 million (\$2006) Injury: up to \$7.4 million (\$2006)
Avoided Aesthetic Costs	Avoided loss in property values due to overhead electricity being undergrounded: 5-20 percent increase in property value
Ecosystem Benefits	Depends on ecosystem, location and other factors
Avoided Emissions	\$5800 per ton - SO_2 from coal plants
	\$1600 per ton - NOx from coal plants
	\$460 per ton - PM-10 from coal plants

Figure 17 contains a subjective assessment of the value of different reliability and resilience measures based on their impact on total customer outage frequency and duration from Silverstein et al. (2018). Many measures in Figure 17 focus on the provision, operation, and maintenance of distribution and transmission assets because those are the power system elements most frequently damaged by both routine events and severe weather. These measures are also threat agnostic and can provide benefits under a suite of different threats and provide additional benefits (such as transmission automation or situational awareness supporting resource integration and customer energy efficiency as well as distributed generation supporting bill savings and comfort) (Silverstein et al. 2018).

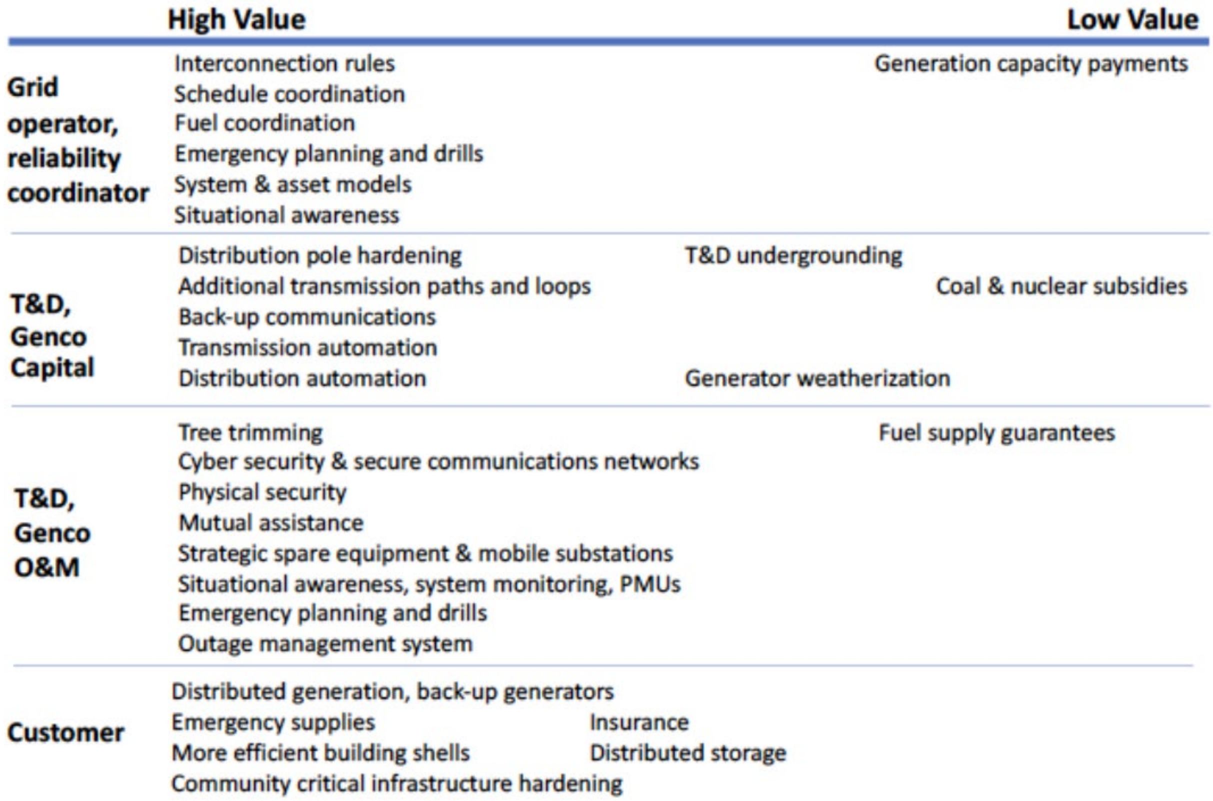


Figure 17. Subjective Ranking of Values ($/customer impact) of Resilience Measures for Outage Reduction and Customer Survivability (Silverstein et al. 2018)

Silverstein et al. (2018) proposes focusing resilience investments on transmission and distribution rather than generation. According to Silverstein et al. (2018), due to the presence of a robust generation fleet and transmission system, customer demand response, and distributed generation, the marginal benefit to the customer of enhancing and protecting generation is quite low, particularly when reserve margins are high. Therefore, generation-related solutions are generally not the most cost-effective means of reducing customer outages on power systems today (Silverstein et al. 2018). Because most outages occur due to problems at the *distribution level* and long-duration outages are caused primarily by severe weather events, it is likely that measures that strengthen distribution and hasten recovery would be highly cost effective. Conversely, measures that make *generation* more resilient, are likely to have "little impact on outage frequency, duration. or magnitude, or on customer survivability" (Silverstein et al. 2018).

5.4.1 Risk Spend Efficiency and Value Spend Efficiency

A resilience solution prioritization methodology that is emerging in literature and practice is RSE. RSE is an estimate of the cost effectiveness of initiatives based on the risk reduction benefits and costs for a specific solution (De Martini and Taft 2022).

$$Risk\ Spend\ Efficiency = \frac{Risk\ Reduction * Number\ of\ Years\ of\ Expected\ Risk\ Reduction}{Total\ Mitigation\ Cost\ (in\ thousands)}$$

An RSE score is determined for specific solutions by dividing the solution cost (i.e., capital investment or third-party solution expenditures) by the benefit expressed as the magnitude of community/customer outage risk reduction in terms of avoided interruption duration (SCG 2016).

See Figure 18 for an illustration of RSE. RSE is being used by some major utilities in the West, including PG&E, SCE, and SoCalGas (PG&E 2022).

For RSE, a solution's benefit is assessed in terms of estimated customer interruption minutes avoided over the planning horizon (SCG 2016).

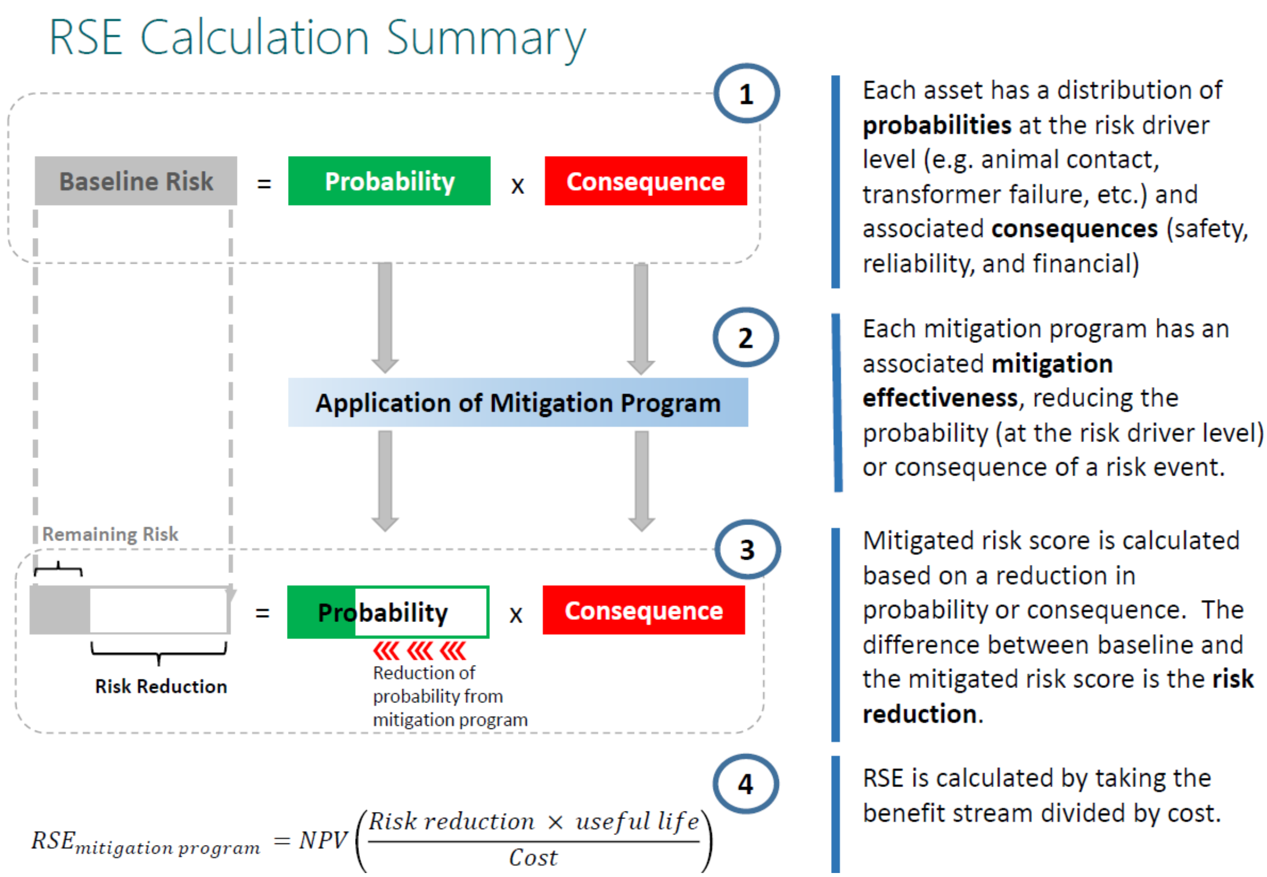


Figure 18. Southern California Edison Risk Spend Efficiency Calculation Method (SCE 2021)

An RSE score is identified for each solution and then used to rank all the solutions to create a prioritized list of solutions within a given budget. The budget reflects the practical considerations of customer rate impacts and utility financial constraints. Applying the simple population at risk weighting method shown to include the outage risk to create a RSE type scoring is presented in Table 13.

In Table 13, the mitigation solutions (A-E) and related cost values came from PG&E's wildfire mitigation plan (PG&E 2022), while the weighted community risk values came from the HRWG Report (HRWG 2020).

Table 13. Example of Weighted Risk Spend Efficiency Analysis (De Martini and Taft 2022)

	Outage Impact Reduction				Risk-Spend Efficiency	
Solution	Weighted Community at Risk	Annual Location Event Probability	Estimated Event Duration (min)	Weighted Avoided Community Interruption (mins)	Solution Cost	RSE Score
A	8000	10%	2160	1,728,000	$2,000,000	0.86
B	5000	20%	2880	2,880,000	$1,000,000	2.88
C	5500	5%	1440	396,000	$500,000	0.79
D	5500	8%	1440	633,600	$250,000	2.53
E	26500	3%	4320	3,434,400	$15,000,000	0.23

Southern California Gas (SoCalGas) Company is required by the California PUC (CPUC) from Order D.16-08-018 to “explicitly include a calculation of risk reduction and a ranking of mitigations based on risk reduction per dollar spent” (CPUC 2016). For the purposes of this section, RSE is a ratio developed to quantify and compare the effectiveness of a mitigation at reducing risk to other mitigations for the same risk. It is synonymous with “risk reduction per dollar spent.” In their Risk Assessment Mitigation Plan, SoCalGas applied an RSE calculation to a set of mitigations or mitigation groupings, then ranked the proposed mitigations in accordance with the RSE result (SCG 2016). These are the steps that SoCalGas followed to calculate the risk reduction for each mitigation:

1. **Group Mitigations for Analysis**: SoCalGas “grouped” the proposed mitigations in one of three ways in order to determine the risk reduction: (1) use the same groupings as shown in the Proposed Risk Mitigation Plan; (2) group the mitigations by current controls or future mitigations as well as similarities in potential drivers, potential consequences, assets, or dependencies (e.g., purchase of software and training on the software); or (3) analyze the proposed mitigations as one group (i.e., to cover a range of activities associated with the risk).
2. **Identify Mitigation Groupings as either Current Controls or Incremental Mitigations**: SoCalGas identified the groupings by either current controls, which refer to controls that are already in place, or incremental mitigations, which refer to significantly new or expanded mitigations.
3. **Identify a Methodology to Quantify the Impact of each Mitigation Grouping**: SoCalGas identified the most pertinent methodology to quantify the potential risk reduction resulting from a mitigation grouping’s impact by considering a spectrum of data, including empirical data to the extent available, supplemented with the knowledge and experience of subject matter experts. Sources of data included existing company data and studies, outputs from data modeling, industry studies, and other third-party data and research.
4. **Calculate the Risk Reduction (change in the risk score)**: Using the methodology in Step 3, SoCalGas determined the change in the risk score by using one of the following two approaches to calculate a potential risk score: (1) for current controls, a potential risk score was calculated that represents the increased risk score if the current control was not in place, and (2) for incremental mitigations, a potential risk score was calculated that represents the new risk score if the incremental mitigation is put into place. Next, SoCalGas calculated the risk reduction by taking the residual risk score and subtracting the potential risk score. For current controls, the analysis assesses how much the risk might increase (i.e., what the potential risk score would be) if that control was removed. For incremental mitigations, the analysis assesses the anticipated reduction of the risk if the new mitigations are implemented. An example that demonstrates the change in risk score for a number of mitigation strategies is provided in Appendix C.

In addition to RSE, a **value spend efficiency** has been proposed to evaluate how certain projects or investments perform relative to multiple planning objectives, including resilience and equity. In value spend efficiency, projects can be prioritized by characterizing the value added in different planning objectives (potentially through ranking or assigning points/value) and dividing that by the cost of the measure to obtain a spend efficiency. Table 14 contains an example of calculating a value spend efficiency for different potential projects based on multiple objectives, including resilience and equity. The planning objectives can be developed through a stakeholder engagement process (De Martini et al. 2022).

Table 14. Illustrative Value Spend Efficiency Calculation (De Martini et al. 2022)

	Planning Objectives Ranked (1-5)									
Specific Projects	**Safety (5)**	**Service Compliance (5)**	**Reliability (3)**	**Resilience (4)**	**Electrification (3)**	**DG/DS Integration (3)**	**Equity (4)**	**Score**	**Cost ($mm)**	**Spend Efficiency (S/C)**
Tree Trimming[1]	5		3	3				11	$2.5	4.4
Undergrounding[2]	3		3	4	1	1	2	14	$5.0	2.8
Pole/Tower Hardening	2	2	3	4			1	15	$2.0	7.5
4kV Voltage Upgrade Conversions	4	4	2	3	3	3	3	22	$10.0	4.5
Substation Breaker Replacement[2]	5	5	3		1	1		15	$2.0	7.5
ADMS		3	3	3	2	3	1	15	$2.5	6.0
Field Automation[2,3]	3	3	3	3		1	2	15	$3.0	5.0
Advanced Metering	1	2	2	1	1	3	1	11	$2.5	4.4

1. Improved reliability & resilience supports greater consumer reliance on electrification
2. If program involves using larger conductor or higher capacity equipment
3. Improved reliability and resilience of grid improves the availability for DER to provide bulk power & grid services

The value spend efficiency calculation can be conducted for alternative measures or combinations of measures to develop an implementation roadmap that reflects the highest value contribution given budget and resource constraints.

5.5 ICE Calculator

ICE Calculator, developed by Lawrence Berkeley National Laboratory (LBNL) and Resource Innovations (formerly Nexant Inc.), is widely used for estimating the customer cost impacts of power interruptions. Customer interruption costs are an important input to the process of conducting value-based reliability planning, which attempts to identify economically efficient strategies "for which the cost of improving reliability is less than or equal to the benefit from the improvement" (Larsen 2021). The ICE Calculator has been used to provide a basis for discussing utility investments with regulators and to assess the economic impacts of power outages.

The ICE Calculator is based on more than 100,000 customer responses from 34 utility-sponsored surveys conducted in the United States between 1989 and 2012. The information used in the ICE Calculator is somewhat dated, with some of the survey responses being over twenty years old. Importantly, the ICE Calculator is not appropriate for estimating costs of widespread, long-duration interruptions and interruptions over 24 hours (Larsen 2021).

Customer cost surveys are less suitable for estimating the impacts of widespread and long-duration power interruptions because respondents may have no past experience to draw upon in estimating the costs they might bear. Customers are also unlikely to be able to have knowledge of indirect costs borne by others, such as cascading economic impacts of power interruptions throughout supply chains. Regional economic modeling in the form of computational general equilibrium modeling may be well-suited for analyzing the costs from widespread and long-duration outages because it can explicitly account for both direct and indirect economic impacts, including adaptive customer behaviors (Baik et al. 2021).

Berkeley Labs is working with ComEd to develop a hybrid resilience valuation approach, called Power Outage Economics Tool, that allows users to estimate direct and indirect impacts of power interruptions under a wide range of scenarios. ComEd uses customer surveys to calculate direct costs of interruptions less than 24 hours in duration. They use regional economic models that integrate:

1. Survey-based techniques to identify mitigating/adaptive behaviors that residential, commercial, industrial, and public sector customers may take to reduce risk before, during, or after a power interruption occurs.
2. Regional economic models that have been calibrated—using survey responses—to assess the full range of economic impacts from power interruptions.

The ICE Calculator is being updated by Berkeley Lab and Resource Innovations through a set of modern interruption cost surveys in coordination with American Electric Power, Dominion Energy, Duke Energy, DTE Energy, Exelon, and National Grid (Homeland Security News Wire 2022).

6.0 Enhanced Reporting to Include Major Events

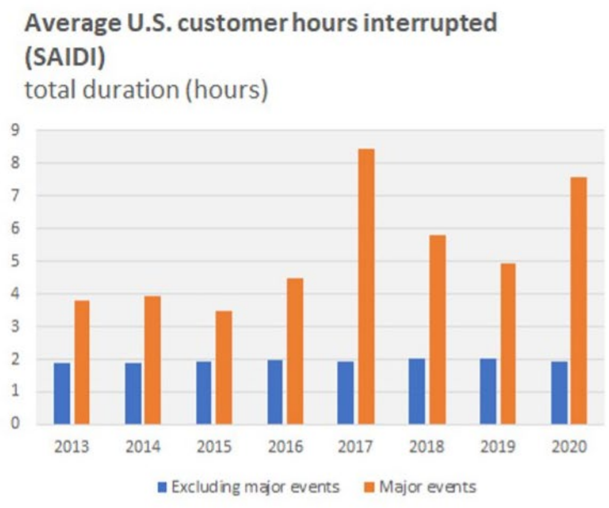
Traditional reliability metrics can be enhanced with customer-focused metrics as described previously. In the review of various reports that have examined reliability and resilience issues over the past several years, many note that current system reliability metrics and standards often exclude major event day or long-term outages. An advancement in reliability metrics would be to include major events as well as shorter-duration events. Major events are days when homes and business are most impacted by outages.

According to IEEE Standards Association (Schwartz 2019), the measures of reliability based on historical outage data like SAIFI and SAIDI are of limited usefulness for measuring resilience:

> *Although classic reliability indices include the effects of routine weather, they exclude so-called black sky conditions, which represent catastrophic storms and other low-frequency or unusual events that can have a high-impact on the functioning of the grid. As a result, reliability measurements do not give us statistical insights on how power systems or networks perform during major outage events.*

To illustrate differences in events with and without major events, Figure 19 shows the average SAIDI and SAIFI numbers for the United States with and without major events published by the US Energy Information Administration. Here, electric power for U.S. customers was interrupted for an average of 8 hours (approx. 500 minutes) in 2017, nearly double the average total duration of interruptions experienced in 2016. More major events such as hurricanes and winter storms occurred in 2017, and the total duration of interruptions caused by major events was longer. Excluding major events, the average duration of interruptions customers experienced was almost identical in 2016 and 2017, at about 2 hours in both years. In 2020, the U.S. experienced a record-breaking number of named tropical cyclones (30), eclipsing the record of 28 set in 2005, the year of Hurricane Katrina. (EIA 2021).

To further capture insight on distribution reliability metrics, IEEE's Distribution Reliability Working Group (DRWG) conducts an annual study whereby company participants (held confidential) voluntarily share their SAIFI, SAIDI, and CAIDI reliability results to assess and compare performance relative to its peers. The DRWG study attempts to identify various factors that may cause differences in reported metrics. According to the DRWG, data may not be directly comparable since data collection and system differences can exist. Companies may not report all forms of outages, due to data collection issues or other reasons (DRWG 2022).



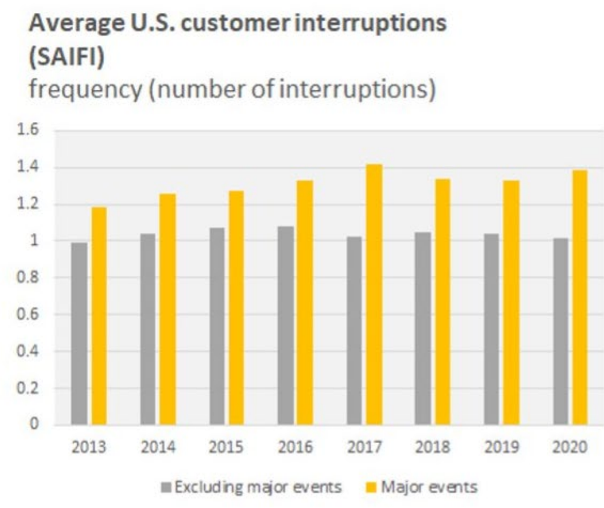


Figure 19. Average U.S. Electricity Customer Interruptions from 2013 to 2020 (Source: EIA)

Some companies, like DTE, report SAIFI, SAIDI, and CAIDI separately for catastrophic storms (where more than 5 percent of customers lose power), non-catastrophic storms, and excluding all storms. The catastrophic storm scenarios are related to resilience (DTE 2021).

In DTE's Electric Distribution Grid Plan, the company defines resilience as "recovery from a weather-related event that causes power interruptions to at least 5 percent of customers" (DTE 2021). DTE defines catastrophic events as events where greater than 5 percent of customers have interruptions. DTE considers reliability metrics related to catastrophic storms, such as SAIFI, SAIDI, and CAIDI, as the most relevant metrics to understand resilience. DTE also considers the ability to respond to other more localized, high-impact outages, such as major equipment failures, as an important component of resilience (DTE 2021). Many strategic investments being proposed by DTE are designed to address both reliability and resilience. These investments include replacing current overhead equipment with equipment designed to the latest standards, enabling the capability to isolate faults and minimize customer interruptions, and increasing tree trimming. DTE is also proposing mobile fleet investments to respond to localized, high-impact outages.

DTE reports SAIFI, SAIDI, and CAIDI separately for catastrophic storms (where more than 5 percent of customers lose power), non-catastrophic storms, and excluding all storms. The catastrophic storm scenarios are related to resilience. Likewise, in their Washington Clean Energy Implementation Plans, PacifiCorp plans to report on the metrics of SAIDI, SAIFI, and CAIDI at the area level, including and excluding major events (PacifiCorp 2021).

7.0 Practical Considerations of DER Resilience Investments

The ability of community DER measures like solar plus storage and demand response to provide resilience in the face of a grid outage depends on level of service, type of event, presence of enabling equipment, reliable maintence and support, and availability when needed, as described below.

- **Level of service**: This item refers to the level of service desired during a resilience event. If the bulk grid is down, utility customers will lose the full range of energy services they have become accustomed to from the utility. Solar and batteries on a home or business combined with demand response will not likely provide the same level of service customers get from the power grid in a fully functioning state, but could maintain comfort and provide critical support. If a microgrid or community system were designed to provide the same level of service as the full grid, it would be prohibitively expensive. When planning for resilience events and community energy programs, it is important to understand and plan for the level of service that is practical and tolerable. Solar plus storage may be able to adequately support things like cell-phone charging, medical equipment, refrigeration, and a certain level of heating/cooling.
- **Type of extreme event**: The answer to the question of whether demand response increases resilience is "It depends." Demand response does increase the resilience of the bulk system when it provides system flexibility. If the bulk system is bumping up against capacity limits or there is an extreme event stressing the system, demand response can do just what generators do and provide more power to serve load. Demand response gives elasticity in the load, enabling the system to ride through unexpected and/or critical load periods. Demand response gives system operators one more lever to keep the system going during an extreme event. Demand response does not support resilience directly when there is a major ice or wind storm that knocks down a number of distribution lines. Demand response is going to be less or not helpful in that case.
- **Presence of enabling equipment**: Enabling equipment, such as inverters, switches, and controls, is needed to ensure that DERs can provide resilience services during an outage. These items are needed to ensure that all the resources can operate together if the utility system goes down.
- **Reliable maintenance and operations support**: If there is a microgrid at a community center or library, there needs to be reliable operations and maintence of the system. Individual maintenance contracts with a private company or installer can be expensive for a small system or several small systems. People are needed to be able to troubleshoot the systems when they have problems. While inverter troubleshooting can be conducted virtually in many cases because inverters are often cable or Wi-Fi connected, there still needs to be a person on the ground charged with coordinating maintence. If a community contracts with a maintenance company to maintain and operate the systems, there are important questions about whether the maintenance company will be able to get there in a major disaster. Without proper maintenance, the systems may be inoperable and be a large, stranded asset. Some key questions to ask include who will be interacting with this system and how and who will maintain it. One advantage of the utility is that they have line crews on the ground in communities who know how the distribution system work. However, utility workers may also need to be trained to reliably operate and maintain microgrids.
- **Availability when needed**: There are some ways that DERs may adversely impact resilience. A momentary outage lasting only five seconds can knock distributed generation offline. IEEE 1547-2018 requires generation resources to remain offline for five minutes after they have been disconnected. If there are high levels of DERs, such as the 38 percent projected by Energy Information Administration (EIA) by 2050 on the system (EIA 2020), and a utility needs to reconnect customers to the grid, it can stress the system when there is an attempt to reconnect customers to a distribution grid that is now missing 20–40 percent of its generation.

NARUC published reports in 2019 and 2020 on investing in DERs for resilience (NARUC 2019, 2020). Through a series of facilitated workshops with stakeholders from commissions, Regional Transmission Organizations (RTOs), and Federal government, regulators developed a set of eight characteristics of resilient DERs to elaborate on how DERs can counter threats and enhance resilience. The traits include the following (NARUC 2019):

- **Dispatchability**: Resilient DERs can respond to a disruption at any time with little to no advance warning.
- **Islanding Capability**: Resilient DERs can island from the distribution grid and serve load during a broader outage. Enabling switching and other equipment are required to allow for this.
- **Siting at Critical Loads/Locations**: Resilient DERs reside at critical loads or at critical points on the grid (e.g., areas of high residential density).
- **Fuel Security**: Resilient DERs do not rely on the availability of a limited physical fuel to provide power.
- **Quick Ramping**: Resilient DERs are capable of changing output quickly to match rapidly changing load.
- **Grid Services**: Resilient DERs can provide voltage support, frequency response, and other grid services.
- **Decentralization**: Resilient DERs are sized and sited to support a load in the distribution system.
- **Flexibility**: Resilient DERs can be deployed quickly and cheaply (when compared to centralized generation, transmission, and/or distribution) at locations and times where resources are needed.

In the NARUC reports, these eight characteristics were then compared to a set of state regulatory policies and processes: integrated resource planning, hosting capacity analysis, clean peak standards, advance rate design, public purpose microgrids, and state and local resiliency road mapping.

8.0 Conclusions

Reliability and resilience are connected, and investments, if properly planned, can be designed to support both. It would be prohibitively expensive for utilities to attempt to mitigate the impacts of all potential outages. Some of the methods described in this paper can be used to help identify the key threats and their probabilities and consequences, the impacts of different resilience measures in mitigating threats, and ways to engage community members directly and ultimately plan for community survivability when resilience events occur.

It is also important to note that not all communities will experience loss of electricity service in the same way. For some, there will be greater hardship than others. There are analysis and process techniques that can be used to account for different zones of tolerance to utility outages.

Planning for the impact of climate change is critical. There are good models to follow in other states' requirement and utility evaluations. Oregon PUC staff and utilities can learn from those and adapt them to Oregon's specific opportunities and threats.

Existing reliability metrics can be built upon to better address low-frequency, high-impact resilience events and impacts to all customers. As utilities move forward and plan for resilience through measures such as community renewable energy projects, microgrids, and resilience hubs, practical considerations need to be planned for, such as understanding and planning for the needed level of service and ensuring the technical expertise for operations and maintenance to protect investments and provide promised benefits to communities and customers.

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Appendix A

Survey Questions used for Determining Zone of Tolerance following Hurricane Harvey (Esmalian et al. 2021)

Household need for service	Not at all important (= 1) to important (= 5)
Level of preparedness	Not at all prepared (= 1) to over prepared (= 5)
Power-backup or substitute?	No (= 1) or yes (= 2)
Social capital Any relatives or close friends for assistance?	No (= 1) or yes (= 2)
Members of social groups in the community?	No (= 1) or yes (= 2)
Previous experience Experienced previous natural hazards?	No (= 1) or yes (= 2)
Access to reliable information	Never (= 1) to almost always (= 5)
Service expectation	Expected duration of service outages (Number of days)
Social demographic Age	Less than 2 years (= 1) 2−10 years (= 2) 11−17 years (= 3) 18−64 (= 4) 65 years or older (= 5).
Education	Less than high school (= 1), High school graduate or GED (= 2) Trade/technical/vocational training (= 3), Some college (= 4) Two-year degree (= 5) Four-year degree (= 6) Post-graduate level (= 7), and other (= 8)
Household income	Less than $25,000 (= 1), $25,000–$49,999 (= 2), $50,000–$74,999 (= 3), $75,000–$99,999 (= 4), $100,000–$124,999 (= 5), $125,000–$149,999 (= 6), or more than $150,000 (= 7)
Ethnic identity	White (= 0), minority (= 1)
Residence ownership	Nonowner (= 0) Owner (= 1)
Residence type	Multiple units/mobile home (= 1) Single-family home (= 2)
Chronic disease	No (= 1) or yes (= 2)
Difficulty in mobility	No (= 1) or yes (= 2)
Number of years living in Harris County?	Number of years

Appendix B

Examples of Resilience Measures from Past Reports

Table B.1. Electric Grid Investments with Potential Resilience Benefits (Kallay et al. 2021)

Investments	Description	Utility-Side	Customer-Side
Transmission and Distribution System			
Grid Hardening	Pole, wire, transformer, circuit, feeder, and substation upgrades or replacements	X	
Physical Security	Fencing, locks, enclosures, platforms, building extensions, monitoring systems, and alarms, among other investments that protect transmission and distribution system assets	X	
Replacement Parts	Local store of replacement parts that are in high demand and/or difficult to procure on short notice	X	
Physical Spacing and Barriers	Undergrounding, relocation, elevation, and enclosures to prevent threats from jeopardizing critical equipment	X	
Vegetation Management	Tree and brush trimming, removal, and planting of utility-friendly varieties	X	
Generation			
Distributed Energy Resources	Energy efficiency, demand response, load curtailment, electric vehicles, distributed generation, and distributed storage that serve the critical load, reducing the utility resources required to restore that load immediately after a resilience event	X	X
Supplemental Heating and Hot Water Systems	Electric, fossil, solar, or biomass fueled supplemental water and heating systems that provide a secondary or alternate source of water and/or space heating during a resilience event		X
Backup Generation	Diesel and natural gas generators, fuel cells, or renewable energy paired with storage that provide a secondary or alternate source of power during a resilience event		X
Physical Security	Fencing, locks, platforms, building extensions, monitoring systems, and alarms, among other investments that protect generation assets		X
Replacement Parts	Local store of replacement parts that are in high demand and/or difficult to procure on short notice	X	X
Physical Spacing and Barriers	Relocation, elevation, and enclosures to prevent threats from jeopardizing critical equipment	X	X

Investments	Description	Utility-Side	Customer-Side
	Automation & Controls		
Transmission and Distribution Grid Automation and Controls	Advanced distribution management systems (ADMS), flexible AC transmission system (FACTS) devices, geographic information systems (GIS), distribution system supervisory control and data acquisition (DSCADA), outage management systems (OMS), distributed energy resource management systems (DERMS), fault location, isolation and service restoration systems (FLISR), volt-var optimization (VVO), voltage stabilization (for example, SVC STATCOM), and network monitoring devices	X	
Meters	Customer electric meters that provide outage and restoration notification and/or on-demand data (e.g., advanced meter infrastructure (AMI))	X	
Metering Controls	Communication networks and data management systems	X	X
Cyber Protection System Controls	Communications between control centers, cyber system categorization, system security management and controls, electronic security perimeters, configuration change management, and information protection	X	X
	Cross Cutting		
Microgrids	A group of interconnected electricity generators and users operating as part of the larger grid normally, but able to operate in islanded mode during resilience events	X	X
Threat and Vulnerability Assessments	Studies of risks and consequences to inform planning	X	X
Mapping of Hosting Capacity	Electric grid impact evaluation of changes to load	X	X
Critical load identification and prioritization	Definition, list, and restoration sequence for priority customers, load, and the substations and feeders that serve priority customers	X	X
Planning	Facility management planning, community emergency preparedness, cyber and physical system response, restoration, and recovery planning	X	X
Training	Classroom instruction for key staff and practice drills on threat response	X	X
Performance Measurement and Evaluation	Defining and reporting resilience performance metrics	X	X

Table B.2. Resilience Categories, Definitions, Examples, and Benefits (Zamuda et al. 2019)

Category of Resilience Measure	Definition	Example Measures	Benefits
System hardening	-Prevent damage to the electricity system and protect it from extreme weather hazards	-Targeted undergrounding -Floodwalls -Vegetation management -Siting, design and construction -Wetlands restoration	Reduced frequency of interruptions and costs of repairing damaged electricity assets
Physical changes to prevent service interruptions (despite damage)	-Allow the grid to continue to deliver electricity to customers despite damage to its infrastructure	-Microgrids and distributed energy resources -Improved system redundancy -Advanced grid design -Remote communications, monitoring and control technologies -Community energy storage -Demand-side management	Could reduce the frequency/duration of interruptions or if system enhancements required a brief period to allow for power delivery from different source/along different route
Measures to improve recovery time and/or process	-Enable utilities to recover from system damage and interruptions more quickly or more efficiently	-Mutual aid agreements -Damage prediction and response -Increased labor force -Ensuring availability of standby equipment for response	Reduce the duration of interruptions

Appendix C

Example of Evaluating Resilience Improvements from GMLC report (Petit et al. 2020)

Example on evaluating resilience improvements: Consider Superstorm Sandy and the impact it had on power delivery when it made landfall on the evening of October 29, 2012. The day after the storm hit, 8.7 million customers experienced power outages; 90 percent of those customers were in Long Island and over one million of Con Edison's 3.3 million customers were affected. In some areas, the impacts lasted for months.

Consider that a hypothetical utility, Tesla Electric (Tesla), had its operations severely compromised by Superstorm Sandy. Tesla has identified two possible options for enhancing its resilience to future storms. Option A focuses on hardening 20 substations damaged by the storm and whose injury resulted in 80 percent of the lost load. Option B focuses on installing advanced metering infrastructure upgrades that would facilitate a more rapid restoration, but not prevent any actual damage. Both options would also include installation of combined heat and power in critical infrastructure assets, enabling photovoltaic systems to operate in islanded mode.

Tesla chooses to evaluate the options by assessing how each would lessen potential consequences that could occur in the event of future storms. They are interested in consequences to their customers, the community they serve, and themselves.

Specifically, Tesla selects three consequence categories:

- magnitude of power outages that could occur in the event of a future storm
- estimated costs to Tesla for repairing the storm damage and recovering
- the number emergency service assets (e.g., hospitals and police stations) expected to be without power for more than 48 hours.

Option A: $350M	Option B: $250M
• Harden 20 substations that experienced 80% of loads with power outages. • Install CHP for uninterrupted heat and power in 60 critical community assets affected during the storm. • Enable PV systems to operate in islanded mode.	• Install advanced metering infrastructure upgrades to enable remote detection and power restoration. • Install CHP for uninterrupted heat and power in 60 critical community assets affected during the storm. • Enable PV systems to operate in islanded mode.

These consequences establish the resilience metrics that Tesla will use to evaluate the two investment options.

Consequence	Resilience Metric	Units of Measurement	Calculation Process
Outage Magnitude	Cumulative daily power outages.	Customer-days without power	$\sum_{t=1}^{10} x(t)$, where $x(t)$ is the number of customers without power on day t, and $t=1$ is the 1st day of the analysis (October 29, 2012), $t=2$ is the 2nd day, etc.
Recovery Costs	Repair and recovery costs borne by the utility.	$ (dollars)	$\sum_{t=1}^{10} c_{labor}(t) + c_{materials}(t) + c_{parts}(t)$, where $c_{labor}(t)$ is the cost of labor spent on recovery activities on day t, $c_{materials}(t)$ is the cost of materials spent on day t, and $c_{parts}(t)$ is the cost of parts spent on day t.
Community Impact	Emergency service assets without power for more than 48 hours.	# of assets	$h + p + f$, where h, p, and f denote the number of hospitals, police stations, and fire stations, respectively, in Tesla's service region that lost power for more than 48 hours.

Based on projections from the research literature, Tesla estimates the probabilities that Category 1 and Category 2 storm scenarios occurring before 2100 are 33 percent and 17 percent, respectively.

For the two hurricane scenarios, the utility then projects the resulting level of damage on each component in the power system, leveraging their outage management system to characterize the damage inflicted by historical events, like Sandy, for different storm categories**.**

For each critical utility component, the utility can assign a probability, conditional upon each of the two hazard scenarios and the options implemented, that the component will be damaged. The utility then exercises their power flow model in a Monte Carlo simulation.

For the Monte Carlo simulation, the utility performs 100 realizations for Option A and 100 realizations for Option B. The assessment team collects the simulation outputs for the projected outage estimates, costs of recovery, and impacts on critical assets. They use these data to calculate the expected values for each of the resilience metrics. Simulation results describing Tesla Electric's results for each option are shown in the table below.

Option	Disruption	Cumulative Customer-Day Outages (Millions)	Critical Facilities Outages	Cost of Recovery (M$)
A	*Mean*	1.1	1	319
	10th %ile	0.5	0	189
	90th %ile	1.35	8	330
B	*Mean*	1.3	1	450
	10th %ile	1.05	0	300
	90th %ile	1.46	8	500

Option A, even with its higher investment costs, would likely provide greater benefit across all resilience metrics. On average, Option A would save $130M in recovery costs (i.e., $450M − $319M = $131M), helping make up for the larger upfront cost.

Appendix D

Example Risk Spend Efficiency Calculation (SCG 2016)

Example:

Risk: high pressure pipeline failure due to corrosion and material failure of weld or pipe.

Mitigation Strategy: To calculate the RSE, SoCalGas began with the six mitigations in its proposed plan:

1. Qualifications of Pipeline Personnel (Training)
2. Requirements for Corrosion Control
3. Pipeline Integrity (TIMP)
4. Maintenance
5. Operations
6. Pipeline Safety Enhancement Plan.

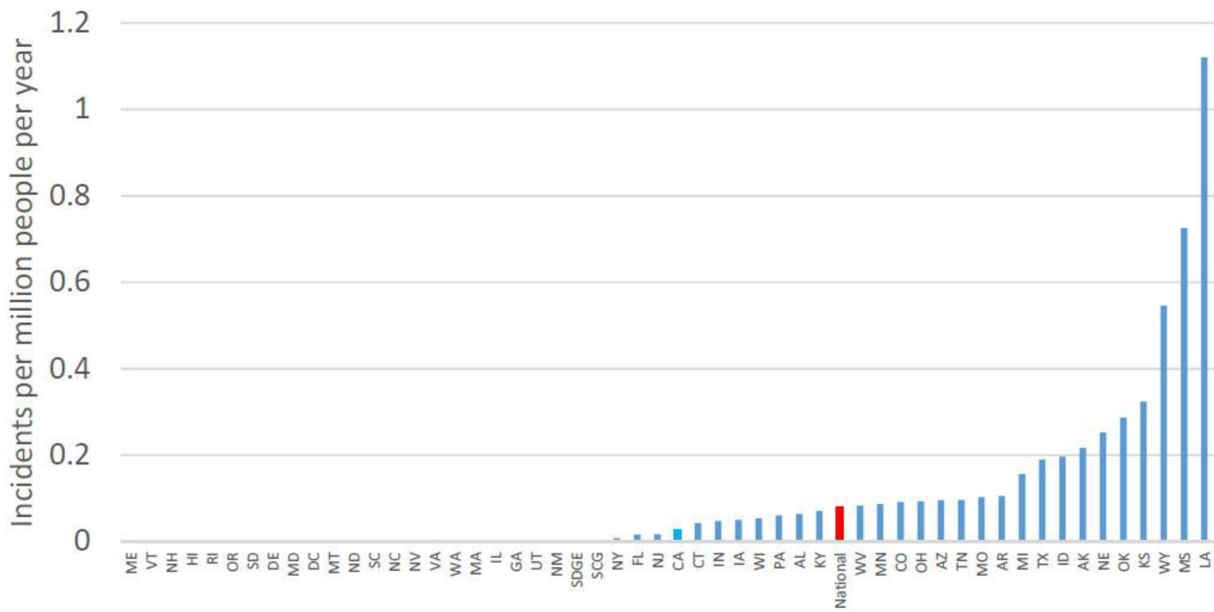
The table below, summarizes SoCalGas's proposed mitigation plan, associated projected ranges of estimated operations and maintenance expenses for 2019, and projected ranges of estimated capital costs for the years 2017–2019.

ID	Mitigation	Potential Risk Drivers Addressed	2017-2019 Capital[25]	2019 O&M	Mitigation Total[26]	GRC Total[27]
1	CFR 192 Subpart M – Maintenance*	• Outside Forces • Equipment • Corrosion	$38,930 - 43,020	$7,690 - 8,500	$46,620 - 51,520	$46,620 - 51,520
2	CFR 192 Subpart N – Qualifications of Pipeline Personnel*	• Incorrect Operations	n/a	400 - 440	400 - 440	400 - 440
3	CFR 192 Subpart I – Requirements for Corrosion Control *	• Corrosion	2,920 - 3,780	520 - 1,140	3,440 - 4,920	3,440 - 4,920
4	CFR 192 Subpart L – Operations*	• Corrosion • Manufacturing • Construction • Equipment • Incorrect Operations	14,280 - 15,780	18,120 - 20,030	32,400 - 35,810	32,400 - 35,810
5	CFR Part 192 Subpart O – Gas Transmission Pipeline Integrity Management*	• Corrosion • Manufacturing • Construction • Equipment • Incorrect Operations	124,920 - 187,120	44,930 - 49,650	169,850 - 236,770	169,850 - 236,770
6	PUC 957 & 958 – PSEP:	• Manufacturing • Construction	365,250 - 608,750	13,500 - 110,000	378,750 - 718,750	133,750 - 321,750

In this example, the chosen mitigation strategy is Transmission Integrity—find the level of possible performance deterioration if these programs did not exist, which would represent the baseline, inherent risk level. It is assumed that should these programs not be funded, then performance would deteriorate to, at best, the pipeline failure incident rate of the worst state in the nation.

SoCalGas is among the entries with zero incidents per million people per year, and the worst-performing state is Louisiana at 1.120 incidents per million people per year (as shown in the figure below). Using SoCalGas' service population of 21.6 million people, the incident rates can be converted to an incident expectation, given by the following calculation:

$$\begin{aligned}
&\mathit{Expected\ Incident\ Rate} = \Delta(\mathit{Incident\ Rate}) * \mathit{Service\ Population} \\
&= (1.120 - 0)\ \mathit{incidents\ per\ million\ people\ per\ year} * 21.6\ \mathit{million\ people} \\
&= 24.2\ \mathit{incidents\ per\ year}
\end{aligned}$$



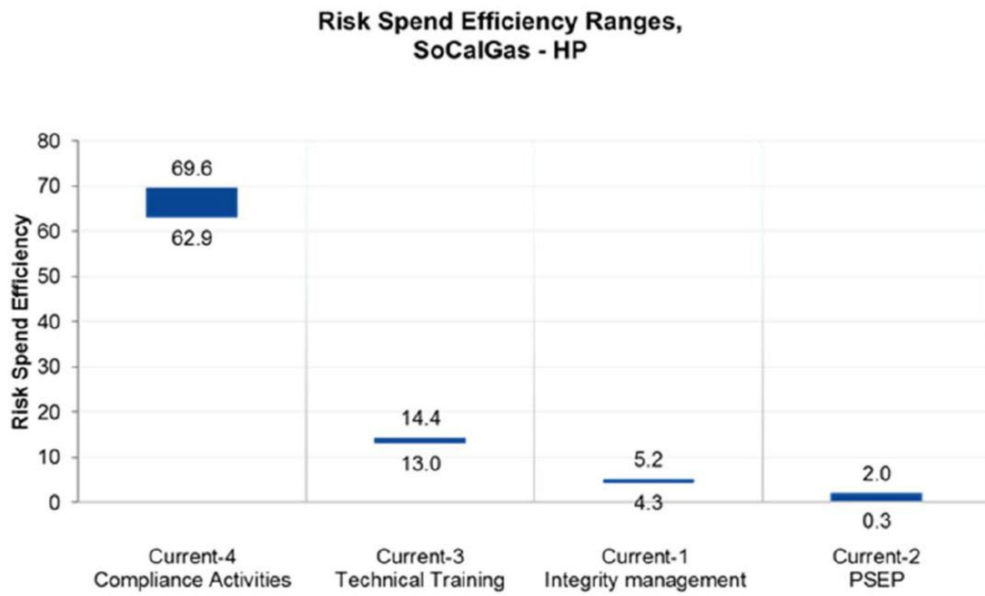
The average number of incidents per year from all causes for the same time period is 1.129 and the proportion of targeted miles being addressed is 43 percent. Putting it all together, the residual risk multiplier is given by the following calculation:

$$\begin{aligned}
&\mathit{Residual\ Risk\ Multiplier} \\
&\qquad = \frac{\mathit{Incident\ Rate\ from\ select\ Causes}}{\mathit{Incident\ Rate\ from\ all\ Causes}} * \mathit{Proportion\ of\ Remediated\ Assets} \\
&\mathit{Residual\ Risk\ Multiplier} = \frac{24.2\ \mathit{incidents\ per\ year}}{1.1\ \mathit{incidents\ per\ year}} * 43\% \\
&\mathit{Residual\ Risk\ Multiplier} = 9.7
\end{aligned}$$

Therefore, if the mitigation is not funded, the projected risk is 9.7 times the current residual risk.

The following figure displays the range of RSEs for each of the SoCalGas High Pressure Pipeline Incident risk mitigation groupings, arrayed in descending order. That is, the more efficient mitigations, in terms of risk reduction per spend, are on the left side of the chart.

$$Risk\ Spend\ Efficiency = \frac{Risk\ Reduction * Number\ of\ Years\ of\ Expected\ Risk\ Reduction}{Total\ Mitigation\ Cost\ (in\ thousands)}$$



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