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Integrating Resilience Planning in Distribution System Planning

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Table of Contents

List of Figures

List of Tables

Acronyms and Abbreviations

ALCRI	Annual log cost resilience index
ALEC	Average log event cost
AMI	Advanced Metering Infrastructure
APCo	Appalachian Power Company
BCA	Benefit-cost analysis
BCR	Benefit-cost ratio
CAIDI	Customer Average Interruption Duration Index
CELID	Customers Experiencing Long Interruption Durations
CEMI	Customers Experiencing Multiple Interruptions
CI	Customer interruptions
CM	Continued Momentum
CMI	Customer minutes interrupted
ComEd	Commonwealth Edison
ConEd	Consolidated Edison
CPUC	California Public Utilities Commission
DSP	Distribution system plan
FEMA	Federal Emergency Management Agency
GER	Grid-edge resource
GIS	Geographic Information System
HCA	Hosting capacity analysis
HECO	Hawaiian Electric Company
ICE	Interruption Cost Estimate
IDSP	Integrated distribution system planning
IEEE	Institute of Electrical and Electronics Engineers
IGP	Integrated Grid Plan
IOU	Investor-Owned Utility
LG&E and KU	Louisville Gas & Electric and Kentucky Utilities Company
MAIFI	Momentary Average Interruption Frequency Index
MED	Major Event Day
MERT	Major event restoration time
MODA	Multi-objective decision analysis
NJBPU	New Jersey Board of Public Utilities
NPV	Net present value
NWA	Non-wires alternative
O&M	Operations and Maintenance
OG&E	Oklahoma Gas & Electric
PG&E	Pacific Gas & Electric
PIP	Productivity Improvement Plan
POET	Power Outage Economics Tool
PSCo	Public Service Company of Colorado
PUC	Public Utilities Commission
RROI	Risk return on investment
RSE	Risk spend efficiency
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCE	Southern California Edison
SPC	System Performance Contribution
T&D	Transmission and distribution
TECO	Tampa Electric Company
VSE	Value spend efficiency
WMP	Wildfire mitigation plan
WPC	Worst performing circuits

Executive Summary

Electric utilities and regulators face a pivotal challenge. Increasing frequency and severity of storms, freezes, floods, heat waves, and wildfires threaten grid infrastructure, with power outages occurring more often, lasting longer, and having greater impacts. At the same time, electricity rates have risen substantially in recent years, and utilities are increasing system capacity in response to peak load growth.

Advances in electricity system planning can better evaluate and prioritize solutions to mitigate natural hazards and physical threats and keep electricity rates affordable. Currently, 16 states require utilities to file resilience plans for regulatory review through a process that is separate from distribution system plans (DSPs) required in about half of U.S. states. Integration of these siloed processes can effectively balance resilience against other fundamental grid objectives such as affordability, reliability, safety, and serving new loads. By integrating threat-based resilience planning with broader distribution system planning, utilities can optimize investments and address multiple grid needs simultaneously.

Lawrence Berkeley National Laboratory (LBNL) analyzed emerging utility practices and case studies across the country to develop a framework for integration of resilience and distribution planning processes. The framework aims to improve planning efficiency, cost-effectiveness of grid expenditures, and balancing of planning objectives. The framework includes 7 key integration points between resilience and distribution planning processes (Figure ES - 1).

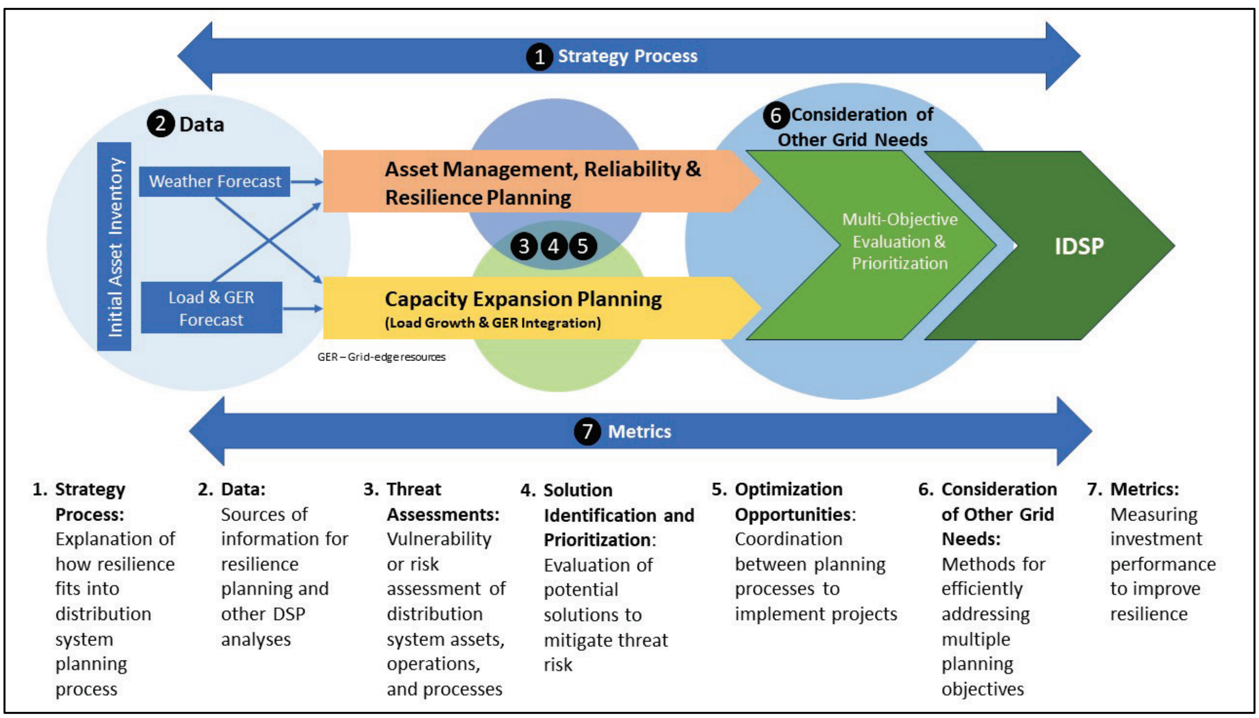

Figure ES - 1. Integration framework and key integration points

At a high level, distribution system planning includes 2 overarching processes that assess the adequacy of the existing system and any needed changes to existing physical infrastructure, operational capabilities, and operations and maintenance (O&M):

1. *Asset management, reliability, and resilience planning* – This process assesses existing physical infrastructure, potential new assets, and O&M practices to ensure reliable and resilient electricity service by proactively addressing failure threats.
2. *Capacity expansion planning* – This process determines new infrastructure needed to ensure the distribution system can integrate and serve existing and additional customer load and grid-edge resources (GERs) over the planning horizon under changing operating conditions.

The 7 integration points indicate ways that utilities can incorporate resilience into each process. LBNL reviewed DSPs and interviewed subject matter experts to identify emerging best integration practices. Table ES - 1 summarizes these practices, which can serve as a guide toward more holistic planning and investment strategies.

The report reviews three practical examples of how utilities have integrated distribution system and resilience planning processes: pole hardening programs at DTE Electric (Michigan) and Pepco DC (District of Columbia) and microgrid planning in New Jersey. The examples illustrate how utilities can balance immediate resilience gaps with long-term distribution system needs, such as aligning routine pole replacements with necessary capacity upgrades, and how states can design programs for microgrids and other GERs, like storage, with the goal of deferring capital-intensive infrastructure expansions. The report also identifies opportunities for future research.

Table ES - 1. Emerging best practices for integrating resilience in distribution system planning

Integration Point	Emerging Best Practices
Strategy Process	• Provide a clear definition of resilience and assigned roles and responsibilities within the utility • Explain how resilience currently fits into a utility's distribution system planning process and how its role is expected to evolve over time • Specify the objectives that the utility will use to assess and prioritize planned resilience expenditures and provide a roadmap for achieving these objectives
Data	• Use consistent data sources and scenarios across planning functions • Document data sources and assumptions • Plan for anticipated extreme weather conditions • Leverage advanced sensing technologies to improve situational awareness and accelerate restoration
Threat Assessments	• Assess the impact of threats to existing planning processes • Leverage existing reliability planning processes and analyses to assess threats
Solution Identification and Prioritization	• Conduct initial cost-effectiveness screening and then prioritize resilience investments in order to facilitate their integration into the broader distribution system planning process • Use tradeoff curves or similar forms of data visualization to help utility and regulatory decision-makers identify optimal levels of investments • Make explicit connections with distribution system planning when resilience planning occurs through other means
Optimization Opportunities	• Integrate resilience-prioritized hardening investments into traditional distribution planning and capacity upgrade cycles to reduce costs and customer impact • Coordinate implementation of projects for maintaining and improving the existing physical system with expanding grid capacity to meet new customer needs • Balance immediate reliability and resilience gaps with longer-term, systemic grid needs
Consideration of Other Grid Needs	• Explore frameworks for comparing risk reduction across multiple planning objectives, including resilience • Evaluate alternatives to traditional infrastructure upgrades to reduce costs and mitigate grid resilience risks • Involve stakeholders in selecting and weighting planning criteria
Metrics	• Collect and analyze power interruption data with as much geographic granularity as possible • Determine baselines for key metrics to measure the performance of grid investments • Test new metrics for assessing grid resilience

1. Introduction

Electric utilities are facing more frequent and severe threats to distribution infrastructure, such as wind, ice, floods, heat waves, and wildfires, leading to more frequent and longer power outages, with major weather-related events accounting for a disproportionate share (DOE, 2008; Shield et al., 2021). States and utilities are aiming to improve resilience to threats posed by earthquakes and physical threats,[1] while balancing the needs of customers for affordable and reliable electricity.

Energy affordability also is a key issue, with some U.S. states experiencing rapid increases in electricity prices in recent years, particularly in the residential sector. A recent LBNL study found that key drivers of utility rate increases are investments in the distribution system and grid resilience (Wiser et al., 2025a; Wiser et al., 2026).

Utility spending on distribution-related capital expenditures increased by approximately 50% from 2019 to 2023—a rate significantly outpacing inflation (Forrester et al., 2024). These expenditures are primarily for refurbishing or replacing legacy infrastructure rather than servicing new load. Resilience expenditures related to natural hazards are another major driver in some regions, for both proactive and reactive investments. Proactive investments have had the greatest impact in Western states, where utilities are making investments to mitigate risks of wildfire as well as harden infrastructure against storms. Reactive investments have had the greatest impacts in East and Gulf coast states, where utilities have had to make extensive repairs after storms and hurricanes (Wiser et al., 2025b).

However, efforts to conduct resilience planning are often siloed from other distribution planning processes, and balancing resilience against other objectives can be challenging. Utilities face issues in transitioning from siloed to integrated processes, including organizational change management, data integration, and operational considerations. In addition, objectives and methodologies for grid resilience and distribution system planning may not align. Distribution planning includes additional objectives such as asset health, reliability, safety, accommodating customer GERs,[2] regulatory and legislative compliance, and meeting capacity needs for new loads. By integrating threat-based resilience planning with distribution system planning, utilities can support affordability goals by optimizing investment strategies that address multiple grid needs.

This study addresses the need to transition from siloed resilience planning to an integrated process that jointly identifies and prioritizes grid solutions and implements them efficiently to deliver reliable and resilient local grids at lower cost to ratepayers. The report:

- Presents a framework that states and utilities can use to advance affordability and grid performance by integrating resilience into broader distribution system planning
- Identifies emerging best practices within this framework

[1] Utilities also are working to build resilience against cyber-threats, out of scope for this study.

[2] GERs—also called distributed energy resources—are resources sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid (NARUC, 2016).

- Analyzes case studies that illustrate how integrated resilience and distribution system planning makes the overall process more efficient and effective

The report focuses on integration of resilience planning and distribution system planning. Previous and ongoing work address integrated system planning more broadly, but do not focus explicitly on resilience planning.[3]

1.1 Background and Definitions

Electric distribution system planning focuses on "…designing, managing, and maintaining lower-voltage networks that connect end users to the larger power system" (ESIG, 2025). Utilities use the process to determine distribution system needs, identify and assess possible solutions, and prioritize and select projects to meet system needs.

Distribution system planning has evolved to include a number of components, including establishing planning goals and objectives, engaging stakeholders, collecting baseline distribution system information, forecasting customer loads and GERs, developing planning scenarios, analyzing load and GER hosting capacity at specific locations, assessing grid capacity needs, analyzing non-wires alternatives (NWAs) for meeting certain types of grid needs, conducting reliability and resilience analyses, and developing an implementation plan (Schwartz et al., 2024; Murphy et al., 2025). Distribution system planning covers several time horizons: operational planning addresses the current year, annual distribution system planning covers a near-term horizon of 1–2 years, and the longer-term utility capital plan generally looks out 5–10 years into the future.

Integrated Distribution System Planning (IDSP) is a holistic approach to distribution system planning that leverages multi-objective decision analysis (MODA) to identify investments that address more than one planning need. Figure 1.1 is an IDSP flowchart, including reliability and resilience analysis as key elements for determining comprehensive distribution system needs and expenditures.

Reliability is "the ability to maintain the delivery of electric services to customers in the face of routine uncertainty in operating conditions" (GMLC, 2020). It is typically assessed using metrics defined in IEEE 1366 standard. The analysis focuses on the average annual frequency and duration of power outages (such as SAIFI and SAIDI[4]), as well as other key performance indicators applied to specific feeders, utility operational regions, and utility service territories.

Resilience focuses on grid performance during extreme events far beyond normal operating conditions. It is "the ability 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" (GMLC, 2020).

[3] For example, see Shipley, J., et al. (2024), *Review of Literature and Utility Commission Proceedings Relevant to Integrated System Planning*; Energy Systems Integration Group (2025), "Integrated Planning"; Relf et al. (forthcoming), *Effectively Considering the Distribution System in Integrated Resource Plans*.
[4] System Average Interruption Duration Index and System Average Interruption Frequency Index.

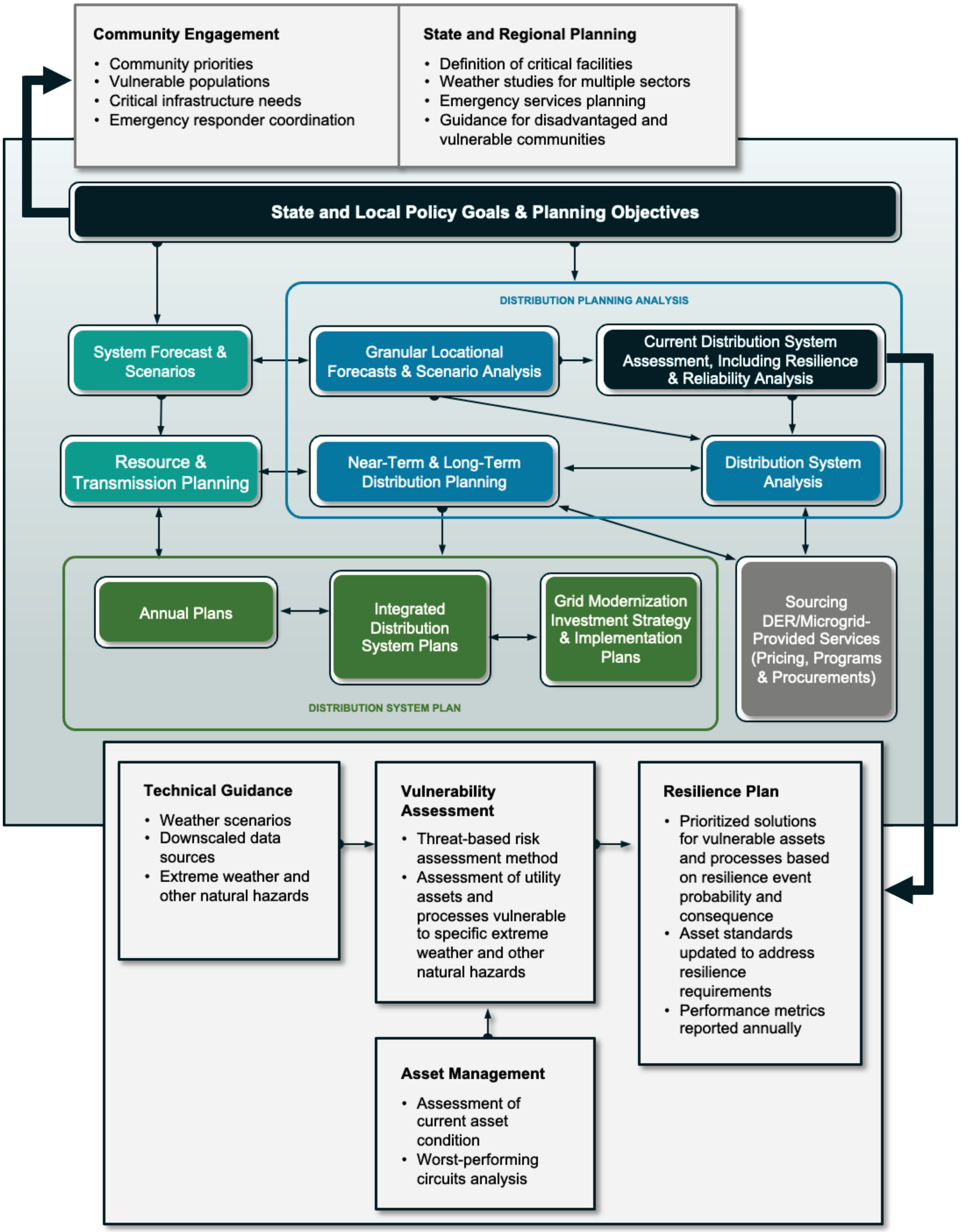

Figure 1.1. Resilience planning in the context of Integrated Distribution System Planning

Source: Adapted from [Schellenberg and Schwartz (2024)](#)

To address escalating environmental and physical risks, utilities are adopting more comprehensive resilience planning. For instance, the increased frequency of wildfires in the Western U.S. has led some states to require utilities to file Wildfire Mitigation Plans (WMPs) every one to three years. On the heels of Hurricanes Irma (2017) and Michael (2018), Florida passed a law in 2019 requiring public utilities to file storm protection plans in response to increasingly intense hurricane seasons and destructive storms. Utilities can realize planning, operational, and implementation efficiencies by integrating these resilience planning efforts into a broader IDSP framework. This alignment allows utilities to unify data and methodologies across multiple objectives, ensuring that capital investments are prioritized efficiently, unintentional planning and implementation redundancies are eliminated, and resilience strategies are synchronized with other goals—such as grid modernization—that may be on different timeframes.

A number of studies address state and utility approaches to distribution system planning. Schwartz et al. (2024) review legislative and regulatory requirements for electric distribution system planning. Murphy et al. (2025) examine data, metrics, and analyses for distribution system planning. Recent studies also examine approaches and frameworks for grid resilience planning (EPRI, 2023; Leddy et al., 2023; Watson et al., 2014). Several national organizations have released resilience planning guides for states and utilities (NARUC, 2025; NARUC, 2026; SEPA, 2024; SEPA and NRECA, 2024; APPA, 2025a; APPA, 2025b). Keen et al. assess current practices in distribution utility resilience planning for wildfires (2023a) and hurricanes and non-winter storms (2023b). Schellenberg and Schwartz (2024) review state resilience planning requirements and provide a standard template that states and utilities can adapt for grid resilience plans. Collins et al. (2025) detail grid resilience data, metrics, and analyses that utilities use—and state regulators can request—for resilience planning.

In recent years, a few studies have begun to examine integration of resilience planning and distribution system planning. For example, De Martini et al. (2022) outline an Integrated Resilient Distribution Planning process, which highlights the relationships between resilience and other planning objectives for more effective and coordinated grid investments. The approach combines risk-based engineering analysis with economic evaluation to identify system needs and select optimal solutions from utility capital and operational solutions and third-party options. The study builds on an earlier DOE guidebook for distribution system planning (De Martini & Taft, 2020). The Smart Electric Power Alliance (SEPA) (2025) identifies key trends in utility resilience and distribution system planning filings, provides recommendations for incorporating resilience in distribution system planning, and develops utility case studies.[5,6]

[5] ESIG (2025) reviews the integration of generation, transmission, and distribution system planning processes and identifies the limitations of optimizing distribution system capacity expansion models for myriad objectives—including resilience—but does not focus specifically on integrating resilience planning in distribution system planning.
[6] LBNL is conducting a study on integration of distribution system planning (e.g., GER program design and implementation) and operations (e.g., day-ahead dispatch) to identify challenges and potential solutions.

This study builds on these earlier efforts by reviewing 50 utility DSPs (see the Appendix), conducting more detailed analysis of 22 plans that considered resilience needs and expenditures explicitly, and developing a framework and typology for integrating resilience planning and distribution system planning. This study identifies emerging best practices based on these plans and on interviews with subject matter experts at four utilities: Avangrid, Commonwealth Edison, National Grid, and Southern California Edison. By systematically reviewing utility DSPs to identify specific points of integration, the current study seeks to bridge the gap between theoretical frameworks and the practical implementation of resilience planning within the distribution planning domain.

1.2 Summary of Methods

This study reviewed plans filed by investor-owned utilities (IOUs), as state legislatures or public utility commissions (PUCs) may require these utilities to submit planning information publicly in regulatory proceedings.[7] As of January 2026, 31 states and 3 other U.S. jurisdictions require utilities to submit DSPs, resilience plans, or both. Other utilities may voluntarily submit a DSP as part of a rate case to support prudence in spending and justify cost recovery.

To inform the integration framework and identify examples of leading practices, LBNL first reviewed 50 DSPs from across the U.S. (see the Appendix) and then selected a sample of 22 geographically diverse plans across 16 jurisdictions (Figure 1.2)[8] using the following criteria.

- Date of plan filing: Plans filed in 2021 or later
- Type of DSP: Diverse set of plans that includes at least one of the following types:
    - Grid modernization plan: Provides a technology roadmap for capital investments and other expenditures that meet state objectives
    - Grid needs assessment: Identifies specific grid deficiencies from the output of distribution system analysis
    - Integrated resource plan (IRP): Details utility plans for bulk power systems (generation and transmission), focusing on plans that include elements of distribution system planning
    - Integrated distribution system plan: Takes a systematic and objectives-based approach to long-term investment strategies, coordinated with bulk power system planning where relevant
- Type of state requirements: At least 3 plans from states representing each of the following categories—(1) require a DSP only, (2) require both a DSP and a resilience plan, and (3) do not have requirements for either a DSP or resilience plan[9]
- Robust discussion of resilience: Integrate resilience into some part of the distribution system planning process

[7] Planning practices for municipal utilities and rural electric cooperatives may be determined by their governing board. A state legislature may mandate plans to be filed by all utilities, regardless of ownership type. For example, Maine and Utah coops must file resilience plans.
[8] LBNL tracks DSP requirements and filings and regularly updates the database. This study leveraged that database for DSP filings.
[9] See Chapter 2 for a discussion of state requirements.

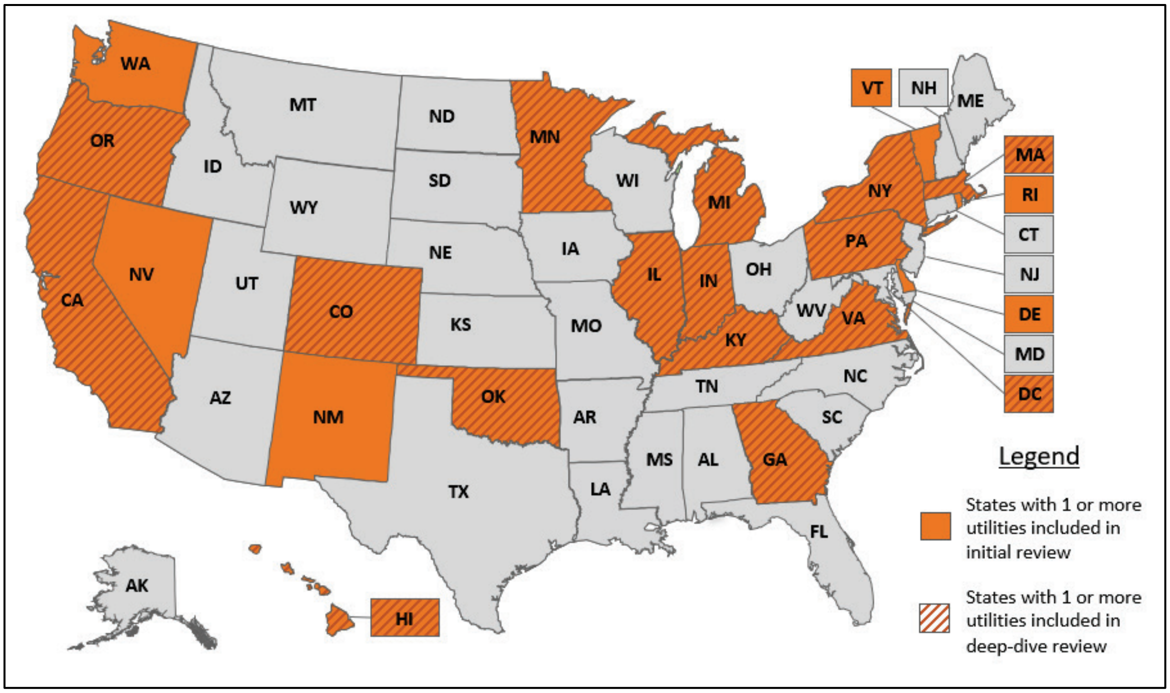

Figure 1.2. States with plans examined during initial and deep-dive review phases

Table 1.1 lists the DSPs included in the review by state, plan name, and utility, with hyperlinks to the utility filings. Nineteen utilities submitted the plans to comply with state requirements (see Chapter 2) and 3 utilities (Georgia Power, LG&E and KU, and OG&E) submitted plans as part of rate cases.

Table 1.1. Plans reviewed for deep-dive analysis

State	Plan Name	Utility Plans Reviewed
California	Grid Needs Assessment, Distribution Deferral Opportunity Report[10]	Southern California Edison (SCE) (2024) Pacific Gas & Electric (PG&E) (2024)
Colorado	Distribution System Plan	Public Service Company of Colorado (PSCo) (2024)
District of Columbia	Annual Consolidated Report	Pepco (2025)
Georgia	Rate case filing	Georgia Power (2022)
Hawaii	Integrated Grid Plan	Hawaiian Electric Company (HECO) (2023)
Illinois	Multi-Year Integrated Grid Plan	Ameren Illinois (2024) Commonwealth Edison (ComEd) (2024)
Indiana	6-Year Electric Plan	Duke Energy (2024)
Kentucky	Rate case filing	Louisville Gas & Electric and Kentucky Utilities Company (LG&E and KU) (2025)

[10] The Distribution Deferral Opportunity Report was renamed the Distribution Upgrade Project Report beginning with the 2025-2026 Distribution Planning Process cycle, per Decision D.24-10-030.

State	Plan Name	Utility Plans Reviewed
Massachusetts	Electric Sector Modernization Plan	Eversource (2024) National Grid (2024)
Michigan	Distribution Grid Plan	DTE Electric (2023)
Michigan	Electric Distribution Infrastructure Investment Plan (EDIIP)	Consumers Energy (2023)
Minnesota	Integrated Distribution Plan	Northern States Power Company (2023)
New York	Distributed System Implementation Plan	Consolidated Edison (ConEd) (2023c)
Oklahoma	Rate case filing	Oklahoma Gas & Electric (OG&E) (2021)
Oregon	Distribution System Plan	Portland General Electric (PGE) (2024)
Pennsylvania	Distribution System Plan	UGI Utilities (UGI) (2024)
	Long-Term Infrastructure Improvement Plan	PECO Energy Company (PECO) (2024)
Virginia	Integrated Resource Plan	Dominion (2024) - Part 1/2 and Part 2/2 Appalachian (2022) - Part 1/3, Part 2/3, and Part 3/3

LBNL selected 3 case studies to illustrate components of integrated planning processes. Two of the case studies are for utilities with plans for pole hardening: DTE Electric and Pepco DC. Utilities can harden poles to withstand severe weather, such as high wind speeds. Pole replacement is also an opportunity to upgrade other distribution system assets or increase capacity at the same time, lowering the cost of such improvements. The third case study is planning in New Jersey related to microgrids. Microgrids can improve resilience by providing a source of power during grid outages—particularly to critical and essential facilities and shared community resources. Microgrids also allow utilities to achieve other planning objectives, such as reducing peak demand through energy storage technologies and grid-interactive loads.

The remainder of this report is organized as follows:

- Chapter 2 reviews state requirements for DSP and, often separate, resilience plans and where the requirements are integrated.
- Chapter 3 introduces a framework and typology to organize the points of integration between resilience planning and distribution system planning.
- Chapter 4 reviews how utilities are integrating resilience in distribution system planning for each of the 7 points of the integration framework.
- Chapter 5 presents 3 case studies for integrating resilience planning in distribution system planning: pole hardening at DTE Electric (Michigan) and Pepco (District of Columbia); and microgrids in New Jersey.
- Chapter 6 summarizes emerging practices and opportunities for future research related to integrating resilience and distribution system planning.

2. State Requirements for Distribution System Planning and Resilience Planning

This chapter reviews state requirements (Section 2.1) and regulatory frameworks (Section 2.2) for distribution system planning and resilience planning, with examples of integrated state requirements.[11]

While all electric utilities conduct distribution system planning and many conduct resilience planning, the level of transparency for the public—and the detail of planning documents—depend on the ownership, governance, and regulatory framework under which the utility operates and the level of resources devoted. Most of the plans reviewed for this study were filed in a DSP or resilience plan proceeding. In states without requirements, the study includes information submitted by utilities in rate cases.

2.1 State requirements

A growing number of states are establishing requirements for electric utilities to file DSPs and grid resilience plans to improve regulatory oversight. Some states require multiple plan filings for specific topics. For example, Pennsylvania requires a DSP, a GER plan, and a transmission and distribution (T&D) improvement plan.

Figure 2.1 shows the types of requirements in each jurisdiction:

- Fifteen states[12] and the District of Columbia (shaded green) require regulated utilities to file one or more types of DSPs,[13] but no separate resilience plan. Three of these states require utilities to include a threat assessment as part of the DSP filings (CO, MA, MI—shaded dark green).
- Eight states require regulated utilities to separately file at least one type of DSP and at least one resilience plan (CA, CT, HI, ME, NV, NY, OR, WA—shaded blue).
- Eight states and the City of New Orleans[14] require regulated utilities to file a resilience plan, but no DSP (AZ, FL, ID, MT, NJ, New Orleans, TX, UT, WY—shaded yellow).

States shaded gray do not have explicit requirements to file DSPs or resilience plans, but utilities may file planning information as part of general rate case testimony.

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[11] Jurisdictions that require regulated utilities to file resilience or distribution system plans, or both, may issue guidelines instead of rules that govern the content of those plans.
[12] CO, DE, IL, IN, MA, MD, MI, MN, NH, NM, PA, RI, VA, VT, WI
[13] Types of DSPs may include distribution system plans, grid modernization plans, high -GER- future plans, integrated grid plans (IGP), and T&D improvement plans.
[14] New Orleans is the only city in the U.S. that regulates an IOU — Entergy New Orleans, a subsidiary of Entergy. (The District of Columbia regulates Pepco DC, but is a federal district.)

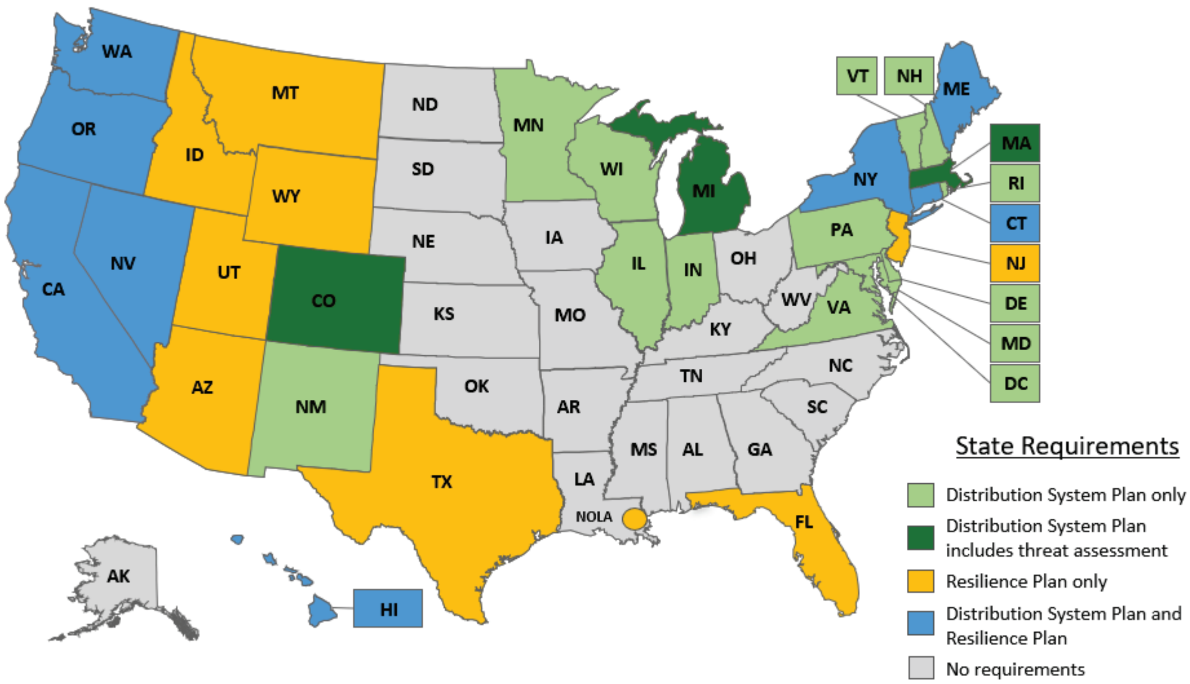

Figure 2.1. State requirements for distribution system planning and resilience planning

Table 2.1 includes links to more information about the specific requirements,[15] including the types of DSPs required, which may include DSPs, grid modernization plans, high-GER-future plans, integrated grid plans (IGP), and T&D improvement plans. Types of resilience documents include vulnerability assessments, adaptation plans, natural disaster protection plans, storm protection plans, and wildfire mitigation plans. States may require that resilience plans address a range of hazards, or they may focus on specific events such as storms (CT, FL, MI, LA-New Orleans) and wildfires (AZ, ID, MT, NV, OR, UT, WA, WY).[16]

[15] LBNL updates a database of state distribution system planning requirements and filings. PNNL updates a database of utility WMPs.

[16] Table 2.1 does not include states with voluntary filing guidelines only—e.g., New Jersey's Infrastructure Investment Program and North Dakota's Wildfire Mitigation Plan.

Table 2.1. State requirements for distribution system planning and resilience planning

State	DSP Requirements		Resilience Planning Requirements
	Type of Plan	Resilience Included	Type of Plan
Arizona			▸ Wildfire Mitigation Plan
California	▸ Distribution System Plan ▸ High GER Future ▸ Grid Modernization Plan		▸ Climate Change Vulnerability Assessment ▸ Wildfire Mitigation Plan
Colorado		▸ Distribution System Plan	▸ Wildfire Mitigation Plan (voluntary)
Connecticut	▸ Distribution System Plan		▸ Resilience Plan
Delaware	▸ Distribution System Plan		
District of Columbia	▸ Distribution System Plan		
Florida			▸ Storm Protection Plan
Hawaii	▸ Integrated Grid Plan		▸ Natural Hazard Mitigation Plan ▸ Wildfire Mitigation Plan
Idaho			▸ Wildfire Mitigation Plan
Illinois	▸ Integrated Grid Plan		
Indiana	▸ T&D Improvement Plan		
Louisiana (only New Orleans)			▸ System Resiliency and Storm Hardening Plan
Maine	▸ Integrated Grid Plan		▸ Climate Protection Plan
Maryland	▸ Electric System Plan		▸ Resilience Plan (required but not filed)
Massachusetts*	▸ T&D Improvement Plan ▸ Distribution System Plan	▸ Electric-sector Modernization Plan	
Michigan		▸ Distribution System Plan (filing guidelines)	
Minnesota	▸ Distribution System Plan ▸ Grid Modernization Plan		
Montana			▸ Wildfire Mitigation Plan
Nevada	▸ Grid-edge Resources Plan		▸ Natural Disaster Protection Plan
New Hampshire	▸ Integrated Grid Plan		
New Mexico	▸ Distribution System Plan ▸ Grid Modernization Plan		
New York	▸ Distribution System Plan		▸ Climate Change Vulnerability Study ▸ Climate Change Resilience Plan
Oregon	▸ Distribution System Plan		▸ Wildfire Mitigation Plan
Pennsylvania	▸ Distribution System Plan ▸ Grid-edge Resources Plan ▸ T&D Improvement Plan		
Puerto Rico	▸ Distribution System Plan ▸ T&D Improvement Plan		
Rhode Island	▸ Grid Modernization Plan ▸ T&D Improvement Plan		
Texas			▸ T&D Resiliency Plan (voluntary) ▸ Wildfire Mitigation Plan
Utah			▸ Wildland Fire Protection Plan
Vermont	▸ Integrated Grid Plan		
Virginia	▸ Grid Modernization Plan		
Washington	▸ Grid-edge Resources Plan		▸ Wildfire Mitigation Plan
Wyoming			▸ Wildfire Mitigation Plan

*Utilities will also file Climate Vulnerability Resilience Plans in Massachusetts, but they are not a state requirement.

The middle column of Table 2.1 indicates that three states require resilience planning in DSP requirements: Colorado, Massachusetts, and Michigan. Requirements in each of these states incorporate resilience in a slightly different manner.

- Colorado's DSP process requires an analysis of risks posed by natural disasters, such as wildfires, floods, severe storms, and a narrative assessment of the efforts the utility is taking to increase resilience on a substation-by-substation basis. The Colorado PUC also directed utilities to include a discussion of existing and proposed pilots or programs aimed at increasing resilience and reliability using microgrids or other technology.
- The Massachusetts state legislature enacted requirements for modernization plans that must describe distribution system improvements that increase reliability and strengthen grid resiliency against weather and disaster-related risks. The legislature also required utilities to assess the suitability of new technologies, such as energy storage and requisite metering and telemetry, to meet forecasted resilience needs.
- The Michigan PSC directed utilities to consider wind speeds, storm frequency, and storm intensity in metrics[17] and to anticipate the occurrence of storms to determine necessary measures to improve system performance during extreme weather events. The Commission also directed regulated utilities to file a report that, among other things, describes how current vegetation management and grid hardening efforts have contributed to reliability performance, a description of planned investments in reliability and resilience on the worst performing circuits, and a summary of efforts to address outages and system reliability discussed in filed distribution plans.

> **State Energy Security Plans**
>
> States develop State Energy Security Plans to receive federal funds from the State Energy Program. The plans serve as a foundation for state resilience planning by addressing physical and cybersecurity threats and vulnerabilities and identifying key risks and investment priorities (NASEO & LBNL, 2023). Utilities can aim to align their resilience plans with methods, data sources, and priorities in their respective State Energy Security Plans (Schellenberg & Schwartz, 2024). In addition, all states prepare FEMA-approved hazard mitigation plans to maintain eligibility for FEMA Hazard Mitigation Assistance.

States may adopt other requirements that advance integration of distribution and resilience planning. For example, the California PUC outlined steps to refine the Distribution Planning and Execution Process, including incorporating wildfire mitigation costs into cost estimates for future capacity upgrades.[18] The PUC also required utilities to use the same long-term weather projection scenarios for planning, investment and operational purposes.[19] The Hawaii Integrated Grid Planning process included a Resilience Working Group, which prepared a report that summarizes resilience planning components such as determining planning objectives and metrics, identifying and prioritizing threats, and developing reference cases for threat scenarios.

[17] September 8, 2022 Order in MPSC Case No. U-20147, p. 55.
[18] Decision 24-10-030.
[19] Decision 19-10-054.

States may require that utilities coordinate across different plans. Schwartz et al. (2024) review the coordination of IDSP with various planning processes, including resilience, and identify actions that states can take to harmonize activities across different processes (Figure 2.2).

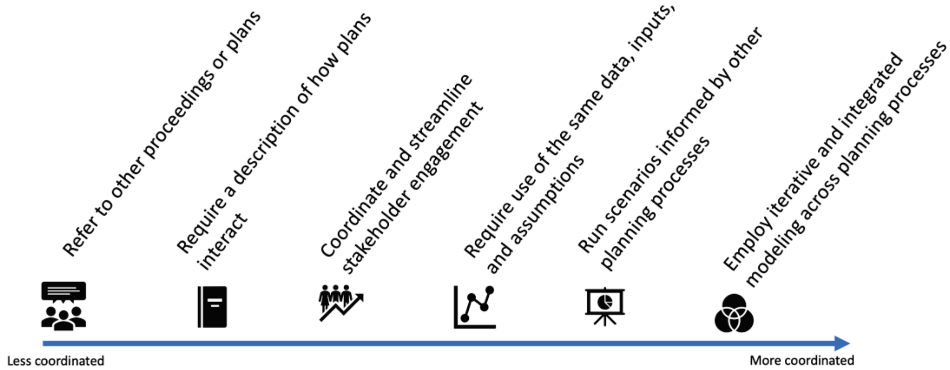

Figure 2.2. Levels of coordination between distribution system and other planning processes

Source: Schwartz et al. 2024

Finally, states may conduct studies that yield utility planning inputs or guide utility planning efforts. For example, Massachusetts developed a statewide hazard mitigation and adaptation plan, first published in 2018 and updated in 2023 (Commonwealth of Massachusetts, 2023). For utility planners, the study provides design standards for gray-sky and black-sky conditions.[20] When a utility proposes a grid hardening project, they can reference the plan's precipitation and wind speed projections to help justify the prudence of their investment to the Department of Public Utilities.[21]

2.2 Regulatory Frameworks for DSP and Resilience Planning

Typically, regulators do not “approve” DSPs or resilience plans, but rather “accept” them as compliant strategic guides.[22] In subsequent rate cases, utilities demonstrate the consistency of their spending with the accepted DSP or resilience plan—or provide a clear rationale for any strategic shifts (Schwartz et al., 2025). For example, in Oregon, regulators use the DSP as a tool for measuring the prudence of a utility’s investment during a general rate case.[23] If a utility asks to recover costs in a rate case for a distribution project that was not included in the DSP, it faces a higher burden of proof to explain why the project is necessary. In jurisdictions where plans are “approved,” this approval is distinct from approval for cost recovery.

[20] Gray- sky conditions occur when the grid is experiencing heightened stress from moderate to severe weather that does not reach the level of a catastrophic disaster or major event (black- sky conditions).
[21] For examples of ways that state energy offices can support distribution system planning, see Murphy et al. 2023.
[22] In jurisdictions where PUCs “approve” DSPs, this approval is distinct from authorizing ratepayer funds for specific projects. For example, HECO (2023) requests PUC approval of its IGP, but it must still seek specific PUC approval to commit funds and projects remain subject to a subsequent prudence review before the utility can recover costs.
[23] Order No. 24-421, Docket UM 2005.

Having an accepted or approved plan can yield certain advantages for a utility—depending on the jurisdiction. For example, states such as Texas and Arizona provide liability limitations for utilities that have a WMP in place and are in compliance with the plan. In addition, while submitting T&D resilience plans is voluntary in Texas, the PUCT can approve expedited recovery of costs aligned with an approved plan through a rate rider, outside of a general rate case.

Utility rate case filings provide information on spending plans for distribution systems and resilience. In a rate case proceeding, the utility aims to demonstrate that its capital investments are "used and useful" and costs are prudently incurred.[24] Such a determination is necessary for the regulator to issue an order authorizing a revenue requirement that allows the utility to recover these costs through tariffs. Table 2.2 summarizes the differences between planning proceedings and rate cases in terms of their primary focus, time horizon, metric of success, and outcome.

Table 2.2. Comparison of rate cases and planning proceedings for regulated utilities

	Planning Proceeding	Rate Case
Primary focus	Strategic and technical, focused on utility plans for capital investments and operation and maintenance of the grid	Financial, focused on determining utility's revenue requirement and setting retail rates
Time horizon	Near-term and long-term, including details of infrastructure needs over the next 5 to 10+ years	Near-term—Set retail rates until the next cost recovery proceeding for expenditures
Metric of success	Ability of plan to achieve utility and state objectives	Determination that costs were prudently incurred
Outcome	Accepted or approved strategy document that guides future spending decisions; supports revenue requested in subsequent rate case(s) for related projects	Order setting authorized revenue requirement and tariffs

[24] Used and useful indicates that the asset is providing service and that without the asset, costs would be higher or the service level lower (RAP, 2016). Prudence reviews have traditionally been retrospective and involve the PUC determining whether the utility implemented the asset as proposed, followed sound management practices, and incurred costs that were reasonable.

3. Integration Framework and Typology

LBNL's detailed review of 22 DSPs revealed the various ways that utilities may incorporate resilience planning in distribution system planning. Using information gathered from the review, LBNL developed a framework for describing these integration points and a typology for defining each point (Figure 3.1). The diagram highlights the two overarching planning processes within distribution system planning: (1) asset management, reliability, and resilience planning and (2) capacity expansion planning. This section first reviews the component elements of the framework diagram, then discusses the integration points—numbered 1 to 7 in the figure.

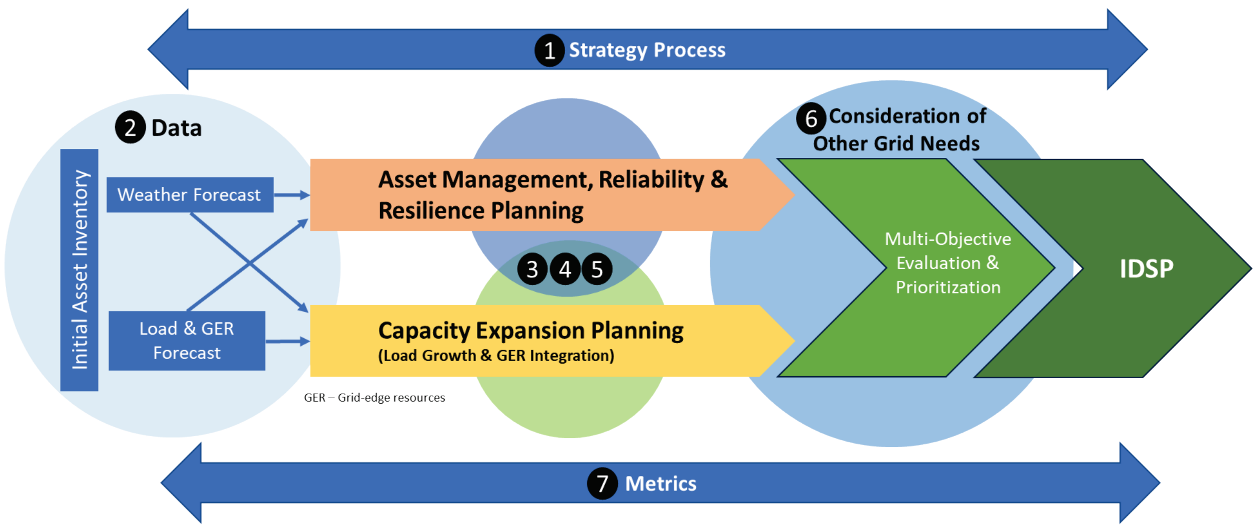

Figure 3.1. Distribution system and resilience planning integration framework

Asset Management, Reliability, and Resilience Planning

The objective of asset management, reliability, and resilience planning, represented in the diagram by the orange chevron, is maintaining and improving the performance of the utility's existing physical grid infrastructure. The process aims to minimize power interruptions by protecting the system from failure and includes both proactive and reactive activities. Proactive activities are longer-term risk mitigation measures such as replacing aging infrastructure, system hardening, and automation to reduce outage restoration time. Reactive activities address recovery from natural disasters and extreme weather and include replacing failed or damaged equipment.

Asset Management

Asset management systematically analyzes the condition and performance of the physical infrastructure used to deliver electricity—based business practices that balance compliance with legal, regulatory, and technical standards with the cost of compliance and the risks of noncompliance—and makes capital and maintenance spending decisions for system safety and reliability. The process establishes a baseline of the distribution system through a complete asset inventory, which serves as the primary system of record by identifying the location, age, and technical specifications of every physical grid component. Engineers evaluate operational performance against historical trends, and conduct benchmarking to compare performance with regional and national averages. The utility also may evaluate the physical integrity of the assets through field inspections, sensor data, and health indexing to determine their remaining useful life. The utility incorporates these findings into an asset management plan, which is a strategic roadmap that prioritizes capital investments and maintenance schedules based on factors such as risk of failure and potential impact on system reliability.

Reliability Analysis

Reliability analysis begins with a historical review, typically relying on standardized metrics promulgated by IEEE, where planners evaluate systemwide indices such as SAIDI and SAIFI over the previous 12-month period. To identify specific issues, the utility conducts a Worst Performing Circuits (WPC) analysis, isolating the circuits that fall below regulatory performance thresholds or system averages. WPC analysis identifies and ranks specific parts of the distribution grid that have provided the lowest level of reliability to customers. While standard reliability reporting of SAIDI and SAIFI metrics measures the average performance of the entire system, WPC analysis focuses on the specific feeders or circuits where customers experience outages far more frequently or for much longer than the average. Table 3.1 provides an example based on SAIFI, CAIDI (Customer Average Interruption Duration Index), and Customer Average Interruption Frequency Index (CAIFI).[25]

Table 3.1. MidAmerican Energy Company - worst performing circuits of 2024 - Illinois District

Index	Number	Index Value	Circuit Identifier	Number of Customers
SAIFI	1	7.6606	13-PU-1	1,647
	2	6.4942	13-40-1	605
CAIDI	1	1212	MOLSECNET	222
	2	781	13-28-1	214
CAIFI	1	7.5732	13-PU-1	1,647
	2	5.3046	13-47-3	646

Source: MidAmerican Energy Company (2025)

Once specific WPCs are identified for further investigation, engineers perform a root cause analysis to determine the reason for the poor performance. The analysis identifies underlying reasons for failures or problems by gathering detailed information about interruptions, examining the data, and determining the fundamental factors that caused the problem, which could be technical, human, organizational, or external (De Martini, 2025). Root cause analysis is imperative for improving the reliability of the electric distribution system by addressing the underlying core performance issues rather than just the symptoms or initiating causes.[26]

[25] While SAIFI measures the average interruption frequency among all customers on a circuit or system, CAIFI measures the average interruption frequency only for customers who experience an interruption.
[26] This type of root cause analysis is distinct from the type that may be triggered after specific outage events of a certain magnitude or duration based on internal or regulatory requirements.

Findings generally culminate in a formal reliability plan, which defines a dual-track investment strategy. One track typically focuses on sustaining target performance through routine maintenance and like-for-like replacements. The second investment track focuses on improving performance for problem circuits.

Resilience Analysis

Utilities conduct resilience analyses in different ways, depending on a number of factors including the specific hazard, the level of integration with other planning processes, and resources devoted by the utility. Resilience planning is a relatively nascent process for electric utilities, so processes continue to evolve.

Resilience planning begins with a hazard assessment to identify and characterize potential threats, such as extreme weather, wildfires, or physical attacks, and their likelihood of occurrence. The data inform a vulnerability assessment, which typically aims to evaluate the susceptibility of systems, communities, assets, and processes to potential harm from identified hazards (Collins et al., 2025). Based on the findings, utilities identify potential resilience solutions, such as hardening measures, advanced technologies, and other strategies to mitigate risks. Utilities prioritize these options using methods that quantify the costs and benefits of risk mitigation and incorporate results into a mitigation plan.

Capacity Expansion Planning

Capacity expansion planning, represented in Figure 3.1 by the yellow chevron, is the strategic process of determining the timing, location, and type of new infrastructure needed to ensure the grid can meet future requirements. It requires the translation of system-level net-load forecasts—driven by macroeconomic trends and state goals—into granular locational forecasts at the substation and feeder levels, including the impacts of electricity load growth and GER adoption. These granular forecasts inform the utility's grid needs assessment, a rigorous engineering analysis that identifies specific locations where projected load growth or bidirectional GER flows will likely violate thermal loading limits, voltage criteria, or protection requirements. Planners aim to avoid power outages or equipment damage from circuits or transformers carrying more power than their ratings dictate. To address these potential capacity deficiencies, utilities evaluate a spectrum of solutions, including both traditional infrastructure upgrades (e.g., conductor replacement) and NWAs and customer-sited resources (De Martini et al., 2022).

Many utilities have already taken steps to align asset management and reliability with the capacity expansion planning process, in part through integrated planning frameworks and state requirements. Resilience planning generally is driven by the same teams responsible for maintaining infrastructure and ensuring system stability. It has emerged as a proactive practice motivated by severe weather events and legislative and regulatory actions and is compelling planners in asset management, reliability, resilience, and capacity planning to work together to integrate a new set of criteria into an already-established decision framework.

Integration Points

The numbered areas in Figure 3.1 indicate key points in the process for integration and illustrate the integration typology—a classification system for discussing ways that utilities integrate resilience planning in distribution system planning.

1. *Strategy Process* - Clear definition of resilience and assigned roles and responsibilities within the utility, as well as an explanation of how resilience fits into the distribution system planning process. This can include details of the resilience strategy, how it is integrated into distribution system planning, and explicit resilience-related planning objectives.
2. *Data* - Sources of information for resilience planning and other DSP analyses. Four sources of data that are particularly important for integration are the utility asset inventory, long-term weather forecasts, load forecasts, and GER forecasts.
3. *Threat Assessments* - Vulnerability or risk assessments of distribution system assets, operations, and processes. The utility incorporates the results into the DSP.
4. *Solution Identification and Prioritization* - Evaluation of potential solutions to mitigate risks of natural or human-caused physical hazards. Screening or ranking potential resilience solutions facilitates subsequent analyses that evaluate the solutions against additional planning objectives.
5. *Optimization Opportunities* - Coordination among planning processes to implement projects. For example, hardening measures can be implemented concurrently with capacity upgrades to avoid successive projects on the same circuit.
6. *Consideration of Other Grid Needs* - Methods for addressing multiple planning objectives. The DSP identifies potential solutions and uses these methods to prioritize solutions across multiple planning objectives.
7. *Metrics* - Measuring investment performance to improve resilience. The DSP identifies metrics and measurement strategies for assessing progress toward realizing resilience objectives.

4. Utility Integration of Resilience in Distribution System Planning

Distribution system planning focuses on accommodating load growth and managing reliability during routine, expected operating conditions, while resilience planning focuses on grid performance during infrequent, extreme events that subject the distribution system to stresses far beyond those normally considered. Utilities conduct distribution system planning on a regular basis, while resilience plans are often triggered in the aftermath of a specific catastrophic condition, such as wildfires or major hurricanes, or pursuant to specific state mandates. Because these planning processes typically have been siloed, the resulting investment strategies often are developed and assessed in isolation. That can lead to redundant capital expenditures and missed opportunities to co-optimize grid upgrades with long-term resilience solutions, as well as multiple, uncoordinated plans submitted to regulators.

Utilities have recently begun to more closely integrate resilience planning in distribution system planning. This chapter reviews the results of LBNL's deep-dive analysis of 22 utility DSPs. For each of the 7 integration points in the framework, this chapter provides:

- *A description of the integration point*, including a definition, its importance, and associated challenges. An "integration point" is common to both resilience planning and distribution system planning—where coordination and alignment could allow planners to meet grid needs more efficiently and thus at a lower cost to ratepayers.
- *Examples of utility integration practices,* organized into 3 approaches in distribution plans to address certain integration points.
    1. **Stated plans for future integration**: As resilience planning and its integration with DSP is relatively nascent, the utility discusses its plans for addressing resilience and integrating the plans in future planning cycles.
    2. **Enhanced reliability analysis**: Utilities, accustomed to performing annual reliability planning, adapt reliability planning methods to resilience. For example, they may leverage WPC and root cause analysis to incorporate the major events they would typically remove from a reliability analysis, in order to determine which circuits to harden and how to prepare them for major events in the future. This category only applies to certain integration points,[27] where utilities can effectively leverage reliability analysis.
    3. **Resilience integration in distribution system plans**: Utilities integrate elements of resilience planning in distribution system planning, and the integration is evident in the filed plans.

The remainder of this chapter reviews examples for each integration point from the reviewed DSPs. The chapter first reviews how the DSPs discuss strategy and different types and sources of data that are applicable to integration. The chapter then turns to integration points focused on analysis: threat assessments, solution identification and prioritization, optimization opportunities, consideration of other grid needs, and metrics.

[27] Threat Assessments, Solution Identification and Prioritization, and Metrics

4.1 Strategy Process

In the context of electric utility planning, a strategy is a high-level roadmap that defines how a utility will align its technical operations, capital investments, and regulatory compliance to meet long-term objectives. Unlike the distribution system plan itself, which lists specific projects and budgets, the strategy establishes the decision-making framework used to set planning objectives, such as complying with state goals, meeting evolving customer expectations, or improving performance during extreme weather events. A clear and comprehensive planning strategy aligns high-level state requirements and planning objectives with granular engineering decisions, ensuring that every capital investment is prioritized and its performance measured based on its ability to deliver against these objectives.

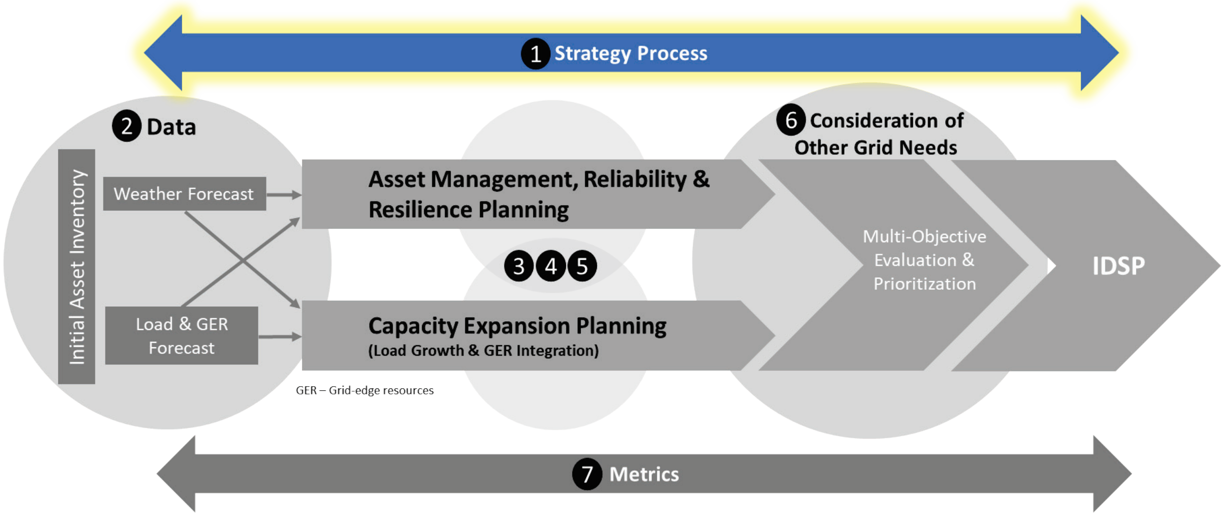

Figure 4.1. Integration framework highlighting strategy process

The 22 utility DSPs reviewed for this study generally describe the overarching strategy for distribution system planning as a transition from traditional, deterministic methods towards approaches that utilize granular data, and scenario or probabilistic analysis, to anticipate the impacts of increasing electricity demand and new technologies (Ameren, 2024; ComEd, 2024; ConEd, 2023c; PGE, 2024).[28]

Utilities are increasingly incorporating resilience as a central planning objective and distinguishing it from traditional reliability. Even in LBNL's initial sample of 50 DSPs, all of the plans mentioned resilience as an objective—including resilience to wildfire, extreme weather, earthquakes, and physical and cyber threats. Some DSPs have entire chapters dedicated to resilience and some cite plans that specifically focus on resilience, such as Consumers

[28] Deterministic planning assumes electricity flows in a single direction from large power plants to customers and does not use data with the locational and temporal detail necessary to understand where and when customers are using and producing energy. Today's grid is far more complex, with two-way power flows, requiring improved data and analysis of uncertainties.

Energy's "Resilient Grid Plan" and Green Mountain Power's "Zero Outages Initiative."

The following examples illustrate resilience becoming a core planning objective:

- “Fundamentally, this Plan is based on the understanding that the elements of distribution planning are related to the core objectives of meeting customer needs through a safer, more reliable, and resilient energy grid” (Indiana & Michigan Power, 2023).
- “Our investments in our distribution system are focused on … preparing for new and increased loads [and] maintaining and enhancing reliability and resilience” (Northern States Power Co., 2024).
- “Integrated planning across the electric and gas networks and the T&D systems will be critical to effective and accurate business planning that ensures reliability, resiliency, and affordability....” (National Grid, 2023).
- “System reliability and resiliency management are central to all four of Ameren Illinois’ grid vision priorities....” (Ameren, 2024).

Dominion's 2024 Integrated Grid Plan (IGP) mentions resilience as a qualitative co-benefit of reliability-driven projects. Some plans cite as an objective integrating threat-based resilience planning into future planning processes, such as PSCo (2024). Figure 4.2 is a graphic adapted from the utility's DSP, reflecting the integration of extreme weather projections into planning processes.

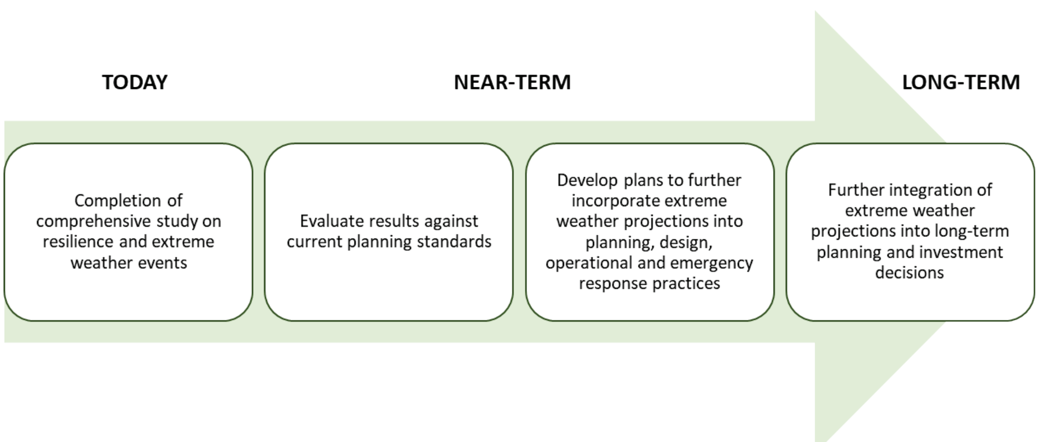

Figure 4.2. PSCo - Incorporation of weather risk into planning

Source: Adapted from [PSCo (2024)]

Consumers Energy (2023) summarizes its overall investment strategy in terms of addressing reliability impacts from increasingly severe weather while continuing to increase grid capacity to accommodate load growth. The utility summarizes the primary purpose of each capital investment (Figure 4.3). The plan reflects an investment strategy driven primarily by increased investments in reliability and to a lesser extent by resilience investments (e.g., undergrounding, fractionalization/circuit segmentation, and automatic transfer recloser loops) and expanding capacity for load growth.

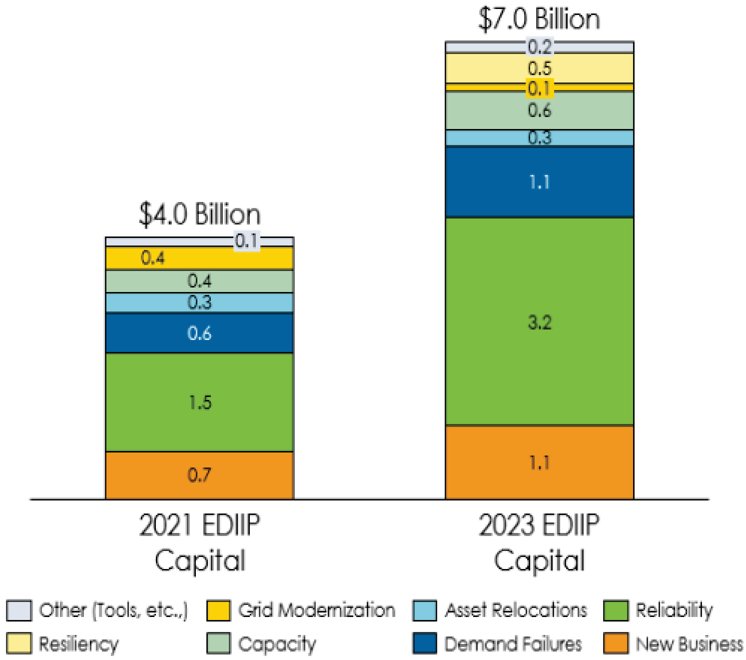

Figure 4.3. Consumers Energy Capital Investment Financial Plan (2024-2028)

Source: [Consumers Energy (2023)]

4.2 Data

This integration point includes data, assumptions, and analyses that feed into the asset management, reliability, and resilience planning process as well as the capacity expansion planning process—and thus are key for resilience integration.[29] Figure 4.4 shows the "Data" integration point highlighted in the resilience integration framework developed for this study. This analytical stage includes three key elements: initial asset inventory and engineering standards, long-term weather forecast, and load and GER forecasts. This sub-section reviews these elements and discusses utility practices for each, including planning scenarios that may incorporate assumptions related to both weather projections and load forecasts. Also addressed are ongoing collection of situational awareness data related to weather, vegetation, asset condition, and outage status, which may feed into both resilience planning and other distribution system planning processes.

[29] See Murphy et al. (2025) for a more detailed review of data, metrics, and analyses in utility DSPs.

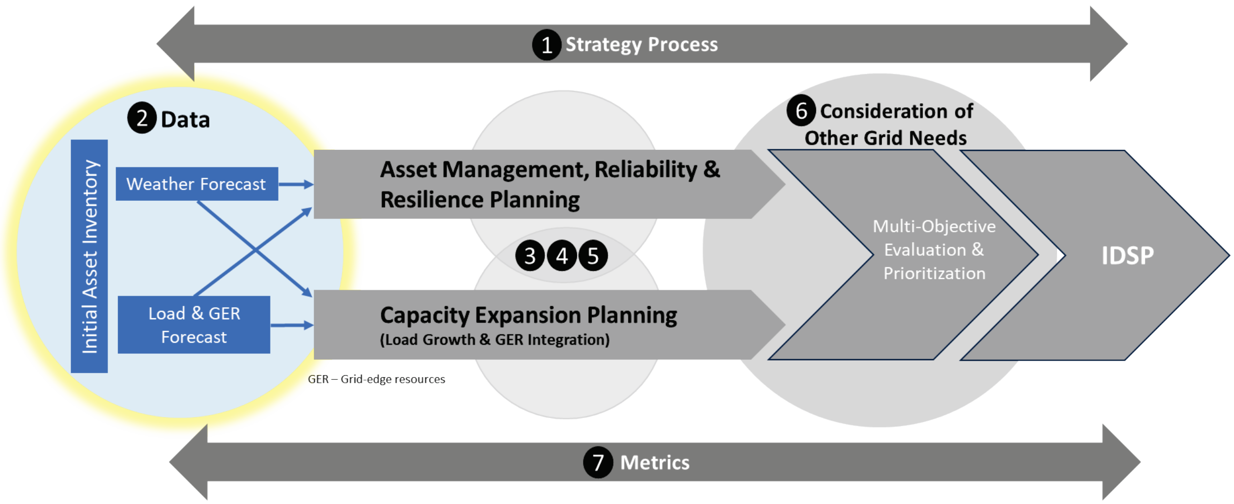

Figure 4.4 Resilience integration framework highlighting data integration point

Initial Asset Inventory and Engineering Standards

The utility's asset inventory and engineering standards are primary data inputs that define the constraints and capabilities of the existing grid. The asset inventory is the system of record, providing planners with physical and geospatial attributes of the distribution system. The engineering standards are the design criteria that ensure planners make investments that are safe, technically sound, and compatible with the current distribution system.

Detailed inventories tell planners the age, material, and condition of every asset in the distribution system. Utilities typically manage these inventories in a geographic information system (GIS) or enterprise asset management system. The inventories inform decision-making about when the utility should replace the asset based on age, condition, or location (e.g., an area expected to experience high winds during storms). For example, Figure 4.5 shows data that PSCo used to inform cutout[30] replacement. Asset management also informs capacity planning by providing information about nameplate ratings of the existing network. The information is vital for planners conducting hosting capacity analyses to determine when thermal and voltage limits would be reached by adding more loads or GERs to the systems.

[30] A cutout, short for "fuse(d) cutout," serves as a combined fuse and switch that protects overhead feeder lines and transformers from damage caused by current surges or overloads.

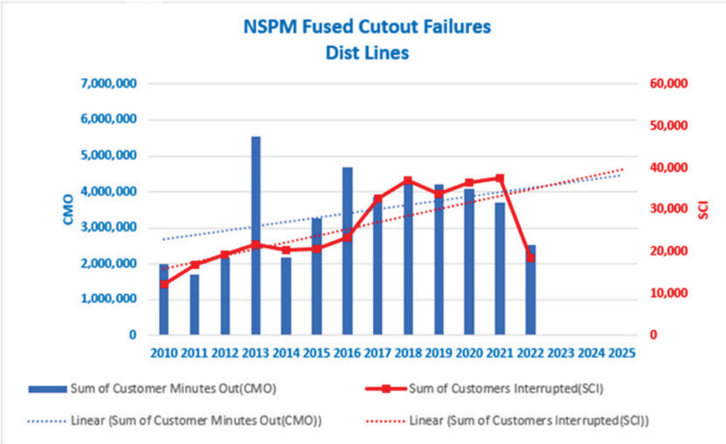

Figure 4.5 Programmatic investment to replace porcelain cutouts

Source: PSCo (2023)

Several DSPs describe a strategic move away from using different asset inventories and toward unified systems. They acknowledge efforts to eliminate disparate, duplicative, and conflicting asset inventories and to maintain asset data quality.

- Ameren Illinois (2024) notes that it has been working on a corporate-wide initiative to establish a single source for all systems and components. The initiative aims to solve the problem of duplicate records and merge data from design, planning, and operations into a single repository. The plan cites benefits that include improved reviews of system health, more accurate results for hosting capacity analysis, and automated model creation and maintenance processes to improve efficiency.
- ConEd (2023c) recognizes the need to consolidate older systems using more current technology that can better aggregate large volumes of disparate information. The utility is implementing an Enterprise GIS to maintain a consolidated mapping and visualization of the system.
- Consumers Energy (2023) notes that it will develop a centralized database of distribution asset data to enable improved integration into platforms for asset health performance analysis and investment strategy.

As utilities transition toward unified systems, they frequently encounter structural and technical barriers to data integration that they work to mitigate or overcome. These barriers are driven primarily by legacy software platforms, proficiency of staff in working with data, and siloed communications networks originally designed for singular, isolated functions. For example, ComEd (2024) reports that managing a geographically overlapping set of networks with incompatible hardware and software components can render grid management inefficient and time-consuming and limit the expansion of situational awareness and grid reliability applications.

Engineering standards dictate the physical requirements for any new equipment. The standards ensure that when a utility adds or replaces a physical asset, it is able to withstand adverse weather conditions to a level that the utility deems appropriate. Utilities may adjust standards to improve system resilience (i.e., harden assets) to account for more severe weather in the future. Each equipment manufacturer maintains its own internal standards and, in many cases, these are informed by (or rely on) standards that industry trade groups define and adopt. In the context of capacity planning, engineering standards can define the contingency requirements for expansion. For example, an N-1 redundancy standard would require a new load to be served such that if one transformer failed, another could pick up the load.

Long-term Weather Forecasts

Severe weather is a major cause of distribution outages in the United States, and distribution failures account for more than 90% of customer outages (Eto et al., 2019). As such, it is a critical planning consideration. Processes for asset management, reliability and resilience planning, as well as capacity planning, rely on long-term weather forecasts as planning inputs. These include assumptions about temperature, average and maximum wind speeds, precipitation, and other variables. For example, ambient temperature data affect heating and cooling needs, which in turn impact local and system peaks and thus capacity planning. The ambient temperature also may impact existing grid infrastructure and performance of assets, such as reducing the capacity of transformers and conductors to deliver power (ComEd, 2024).

The utility industry has traditionally relied on historical weather data to assess asset performance and forecast loads and has used historical weather patterns to estimate future extreme events and peaking conditions. For example, Idaho Power (2022) used a 40-year rolling window of historical temperatures to identify 1-in-20-year extreme events to adjust its peak load forecast. Central Hudson (2023) used historical patterns to weather-normalize its loads for 1-in-2 peaking conditions. Some utilities use historical major storm event databases for resilience planning (TEC, 2022; Oncor, 2024; Entergy, 2023).

The DSPs indicate that utilities are in a transition period regarding how they incorporate weather data into planning processes. Many utilities expect the future to bring more extreme temperatures and intense storms. Thus, projections, rather than historical data, would better represent future conditions. Utilities are subsequently shifting toward using forward-looking, modeled weather data as global weather patterns like temperature and storm intensity change and data become more accessible. For example, ConEd has been incorporating future temperature projections into its demand forecast since 2020 to anticipate hotter conditions (ConEd, 2024). Eversource (2024) is assuming a growing increase in cooling degree days. PGE (2024) is moving away from historical averages and using a linear trend model to reflect changing numbers of heating and cooling degree days.

For future projections of weather variables, some utilities rely on downscaled global projections. These are projections that have been translated from the coarse resolution of global weather models to a finer, more regional or local scale. California IOUs use the same downscaled model data and scenarios in all planning processes that analyze long-term weather impacts, risks, and vulnerability of utility infrastructure systems and operation—as required by the California Public Utilities Commission (CPUC).[31] New York also requires utilities to evaluate

[31] D.24-08-005

assets using specific temperature and sea-level rise projections provided by the state over 10-, 30-, and 50-year timeframes to justify certain capital investments.[32]

Thorough documentation of data sources and explanation of forecasting assumptions are important for regulatory and stakeholder review of planned spending on resilience and other grid needs. Eversource (2024) maps 20 weather variables to each of 5 natural hazards[33] considered in its vulnerability study, as well as to energy demand. The plan provides details on the datasets used to downscale coarse models to granular 6 kilometer-square grids across its service territory. PSCo's (2024) threat assessment includes information on external datasets, projected scenarios, and utility data on assets and processes. These data informed the resilience planning process—including the development of asset risk scores, operational risks, and potential mitigation strategies.

Utilities noted efforts to incorporate weather and risk-related data into a centralized database. PSCo (2024) integrated FEMA flood plain data and wildfire risk zones into its GIS to inform decision-making for equipment installation and upgrades. Figure 4.6 shows projected changes in maximum frozen precipitation amounts by 2050 across Colorado. In interviews for this study, utility experts noted development and planned maintenance of a single database for use by all planning and engineering groups for distribution system projects, instead of myriad databases for individual projects or programs.

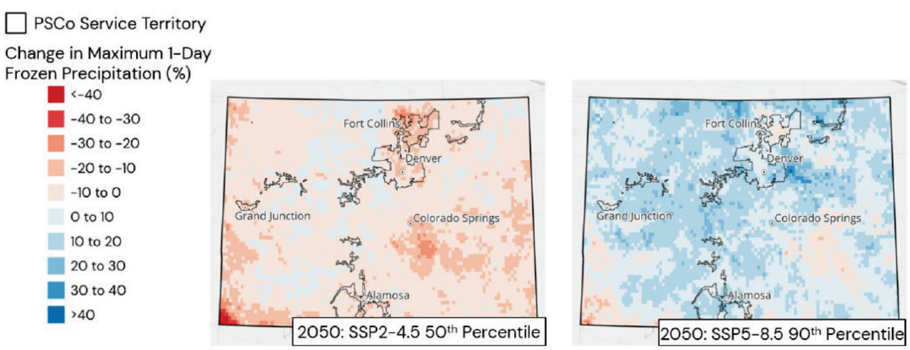

Figure 4.6. PSCo - projected percent change in the maximum 1-day frozen precipitation amounts by 2050 across service territory

Source: PSCo (2024)

Load and GER Forecasts

Load and GER forecasts are key inputs for capacity planning and also are considered in reliability and resilience planning. For example, a transformer operating close to maximum capacity for anticipated load growth would be more likely to fail during a multi-day heatwave than one operating at half capacity. To prioritize grid hardening measures, utilities can layer a hazard map over a granular load forecast to prioritize assets that are both high-risk and highly utilized. These forecasts also can help planners design emergency load shedding measures.

[32] CLCPA / NY PSC Orders – "Grid of the Future" capital investments.
[33] Temperature, precipitation, drought, sea level rise, and storm surge.

For example, if a storm forces a reduction in power, the utility knows how much load it can drop to protect critical facilities like hospitals and water treatment facilities.

Utilities use scenarios for planning processes for both existing physical infrastructure and capacity expansion. Scenarios are self-consistent descriptions of a potential future state used to assess investment decisions against a range of possible future conditions and uncertainties. DSPs show that utilities are aiming to use consistent scenarios across these planning processes. Consumers Energy (2023) uses weather-informed scenarios to forecast changing peak conditions on the distribution system. The alternative scenarios reflect potential future outcomes shaped by assumptions about severe weather and customer technology adoption. Assumptions for severe weather included the highest-impact hazards for the company's service territory, which it deemed to be storm conditions, ice conditions, and extreme heat. Customer technology adoption included grid impacts from projected GERs, heat pumps, and electric vehicles as well as load growth driven by population changes. The scenario modeling results indicate that while the company currently operates under a summer-peaking system, a shift toward winter peaking is likely to occur in the coming decades. As illustrated in Figure 4.7, under a scenario with higher technology adoption (AT), 51% of circuits are projected to become winter-peaking by 2050, compared to 39% under the scenario with lower levels of adoption (CM).

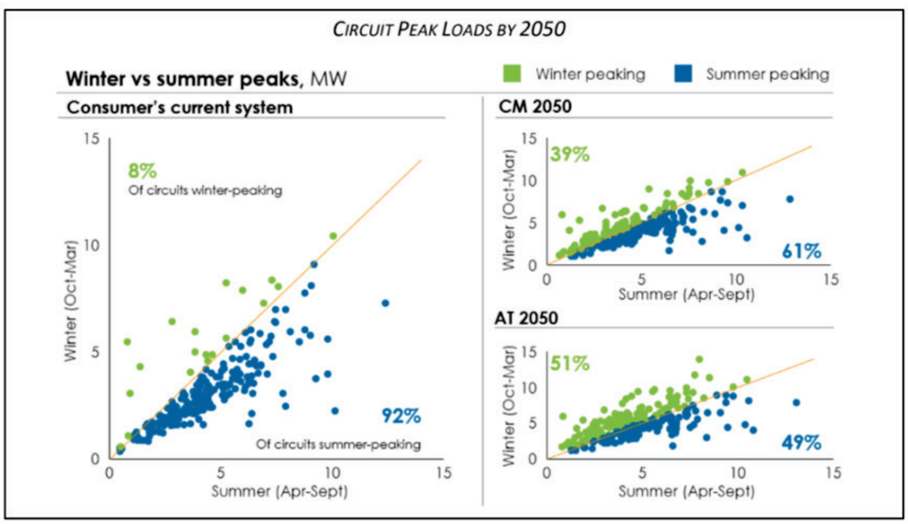

Figure 4.7. Consumer Energy's peak load forecast for different circuits under 2 scenarios

Source: [Consumers Energy (2023)]

Situational Awareness

Utilities are using more advanced technology to collect data for situational awareness. This could be for measuring and monitoring assets, environmental conditions, or restoration status of customers after a major event. One example is light detection and ranging (LiDAR) technology, a sophisticated tool for vegetation management (ComEd, 2024; DTE Electric, 2023; Rhode Island Energy, 2022; PGE, 2024). LiDAR is a remote sensing technology that uses laser light to measure distances and create highly accurate 3D maps of the environment.

This technology is particularly useful in high-risk areas, because it provides three-dimensional data that are difficult or dangerous to acquire through traditional manual inspection.

The DSPs also describe how utilities use drones in conjunction with sensing technology for inspection and data collection for asset management, maintenance, and system assessment (Consumers Energy, 2023; Northern States Power Company, 2023; ComEd, 2025; Ameren Illinois, 2024; Indiana & Michigan Power, 2023). For example, Consumers Energy uses drones and imagery analytics to enhance asset inspection. Figure 4.8 shows the drone imagery. The drones facilitate pole-top condition assessment in comparison to ground-level inspection.

Figure 4.8. Consumers Energy's asset inspection imagery
Drone (left) versus ground (right)

Source: [Consumers Energy (2023)]

Utilities use Advanced Metering Infrastructure (AMI) to obtain information from meters during major outage events. For example, by remotely "pinging" meters, Pepco can instantly verify whether individual customers have regained power, eliminating the need for manual verification through customer calls or truck dispatches. This use of AMI data ensures that field crews are deployed only where restoration work is still needed.

4.3 Threat Assessments

Sections 4.3, 4.4, and 4.5 cover integration points related to the coordination of processes for asset management, reliability and resilience planning, and capacity expansion planning. Figure 4.9 shows the integration framework with the coordination points highlighted (numbers 3, 4, and 5), which correspond to threat assessments (this section), solution identification and prioritization (Section 4.4) and optimization opportunities (Section 4.5).

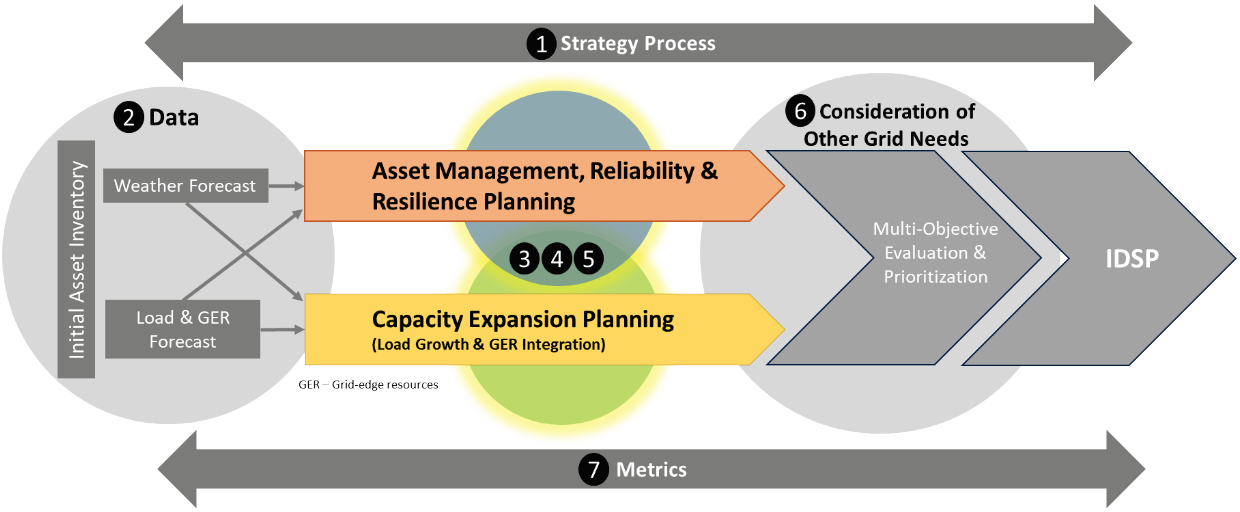

Figure 4.9. Resilience integration framework highlighting coordination points for asset management, reliability and resilience planning, and capacity expansion planning

Threat assessments generally analyze the utility's vulnerability to, or risk from, physical hazards. There is typically a set of unique hazards applicable to a utility service area, and these may be more specific to certain geographic locations within it. Utilities may conduct these assessments as part of the distribution planning process or in a separate proceeding, depending in part on any state requirements (see Section 2.1). Even when conducted in separate proceedings and documented in separate reports, the utility can integrate the threat assessment into the DSP.

Vulnerability and risk assessments have different definitions across utility plans, but generally evaluate the susceptibility of systems, communities, assets, and processes to potential harm from identified hazards. These assessments often focus on understanding key factors such as exposure, sensitivity, and adaptive capacity (Figure 4.10).

- *Exposure* is the degree to which utility assets could face a given hazard, based on location and environmental factors.
- *Sensitivity* is the degree to which an asset could be affected by exposure to climate hazards.
- *Adaptive capacity* mitigates vulnerability and is the ability of systems and people to adjust to potential damage and respond to consequences.

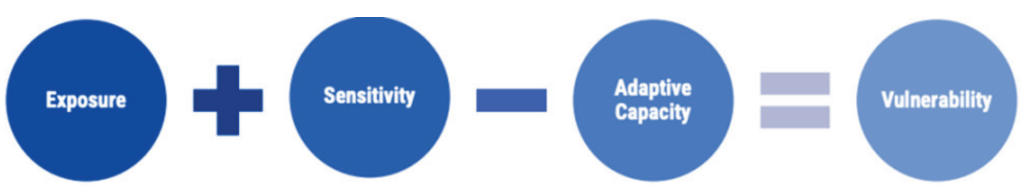

Figure 4.10. Conceptual diagram of vulnerability

Source: [City of Seattle (2023)]

DOE (2024) defines risk as a combination of threat, vulnerability, and consequence (Figure 4.11). The “threat” component typically reflects the probability of the hazard occurring. The “consequence” component is the estimated magnitude of the projected negative outcome.

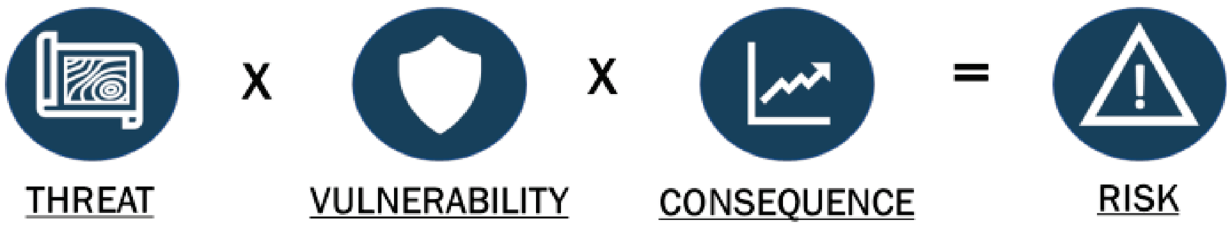

Figure 4.11. DOE risk assessment formula

The remainder of this sub-section reviews utility plans to examine the coordination between threat assessments and distribution system planning. For this integration point (“threat assessments”)—and for the remaining integration points—the spectrum of utility practices refers to the 3 approaches discussed at the beginning of the chapter: (1) stated plans for future integration, (2) enhanced reliability analysis, and (3) resilience integration in distribution system planning.

Spectrum of Utility Practices

Stated Plans for Future Integration

Some utility DSPs indicated plans to integrate threat assessments into future planning processes.

- Ameren Illinois (2024) describes the company's next steps in developing resilience planning capabilities. The utility was pursuing a third-party industry expert to analyze the impact on its grid of natural hazards such as wildfire, flooding, ice storms and vegetation growth. The utility plans to incorporate the results of the threat assessment study into project selection and prioritization in its next filing cycle.
- PSCo (2024) described the integration of asset-level risk assessments into its planning processes as a mid-term goal (2026–2029). Regarding further integration of results, the company stated that it was “still working to comprehensively evaluate the study against current technical standards.”
- Eversource (2024) stated that it planned to use the geographically granular results from its vulnerability study to expand its targeted set of grid vulnerabilities and inform upcoming resilience work.

Enhanced Reliability Analysis

The utility industry has a set of well-established indices for measuring and benchmarking reliability. IEEE Standard 1366-2022 defines these indices. Utilities normally calculate and report standard reliability indices annually, aggregating performance over an entire year. They often rely on a statistically-based method provided in the IEEE standard to segment and treat separately major event days (MEDs). These are the handful of days during the year when reliability impacts are so large that including them would skew year-over-year comparisons of reliability performance.[34] While there is no standard for measuring resilience performance, resilience planning generally comprises events that are larger, statistically speaking, than the vast majority of routine, day-to-day reliability events a utility experiences in any given year. These events can include MEDs, as well as varying levels of severe weather conditions, such as storm categories based on wind speeds.

To assess reliability, utilities typically analyze WPC and conduct root cause analysis. To analyze severe weather threats, some utilities conduct WPC and root cause analysis using interruption data that either include MEDs or focus exclusively on major storms or MEDs, or both. These are major steps toward incorporating resilience in DSPs.

- Florida Power & Light's regulatory reliability metrics exclude MEDs, but its internal planning and vegetation management programs rely on data that include MEDs to properly assess the full impact of hurricanes and tropical storms on feeder performance. The most-impacted circuits during severe storms are often the ones prioritized for hardening and enhanced vegetation clearing (FPL, 2022).
- PG&E faces significant wildfire risk, which is often classified under the MED category. While California's standard regulatory metrics have specific MED exclusions, the company's WMP and associated risk modeling necessitate an analysis of circuits that fail on high-risk, severe weather days. Circuits showing poor performance during high-wind events are often flagged as high-risk WPCs for investment.
- National Grid's WPC analysis considers the full historical performance of feeders, including those frequently damaged by snow, ice, or major coastal storms. Although the regulatory reporting for reliability may exclude MEDs, the feeder health assessment used for prioritizing capital spending incorporates the impact of those severe events to determine where the grid is structurally weakest (National Grid, 2024).
- ConEd computes a "Network Resiliency Index" for selecting WPCs for sectionalization in its Primary Feeder Resiliency program, which aims to mitigate risks associated with projections of increases in extreme heat events (ConEd, 2023b).

Resilience Integration in Distribution System Planning

The most direct way that DSPs integrate threat assessments is to conduct them as part of the distribution planning process. In PSCo (2024), the utility calculated risk scores at the asset level as the product of vulnerability[35] and consequence,[36] where vulnerability was assessed across five natural hazards: extreme heat, frozen precipitation, wind, riverine flooding, and

[34] The IEEE 1366-2012 standard identifies a MED when daily system interruption duration exceeds a threshold "T_{MED}," calculated using five years of historical data. By applying a natural log transformation to the typically skewed data, this method sets T_{MED} at 2.5 standard deviations above the mean to isolate rare, high-impact event days that occur roughly 0.4% of the time.
[35] In this plan, vulnerability = exposure x impact; impact = sensitivity x criticality. The utility evaluated exposure of assets and operations to natural hazards using information from downscaled climate modelling projections. Sensitivity evaluation considered the degree to which each asset is impacted by each type of natural hazard—for example, extreme heat leading to reduced asset capacity. The utility evaluated criticality based on disruption of energy delivery to customers, environmental harm or risks to public and employee safety, and cascading failures affecting downstream assets.
[36] Consequence evaluation includes information on the number of customers—including critical facilities—associated with specific assets and the expected magnitude and duration of outages caused by asset failure.

wildfire. Figure 4.12 illustrates this risk scoring process. Figure 4.13 shows the results of the risk scoring process for substation transformers.

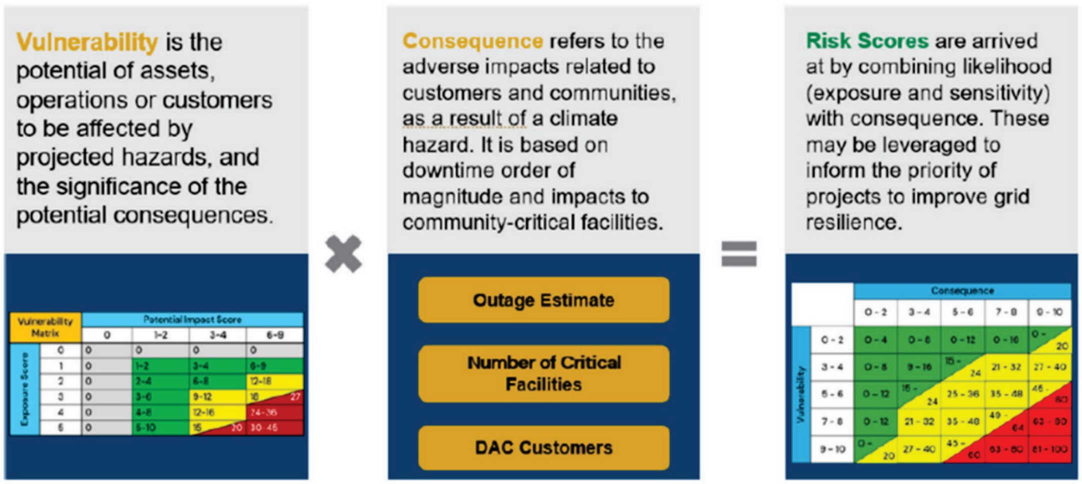

Figure 4.12. Public Service of Colorado - risk scoring process

Source: PSCo (2024)

		Heat		Flood	
Substation	**Consequence Score (out of 10)**	**Vulnerability Score (out of 10)**	**Risk Score (out of 100)**	**Vulnerability Score (out of 10)**	**Risk Score (out of 100)**
G.J.	4.8	2.7	12.9	0	0
A.	4.1	2.1	8.8	0	0
S.	4.1	1.9	7.7	0	0
D.	4.1	1.6	6.6	0	0
R.	4.0	0.3	1.1	0	0
G.	1.5	2.1	3.2	0	0
A.	1.5	1.9	2.7	2.7	6.3
Av.	0.8	1.9	1.5	0	0
L.	0.8	1.9	1.5	0	0
S.	0.7	0.3	0.2	0	0

Figure 4.13. PSCo - heat and flood risk scores for substation transformers

Source: PSCo (2024)

LG&E and KU's Distribution System Hardening and Resiliency Plan (2025)—submitted as part of the company's rate case—describes how the company integrates risk-based assessment into vegetation management programs as part of its broader resilience and reliability strategy. The approach to vegetation management combines cycle-based trimming with additional targeted reliability efforts (e.g., tree removal, corridor widening in areas where trees have had the highest customer impact, and off-cycle trimming). To inform these actions, the company developed a "vegetation risk model" that predicts the likelihood and consequence level of vegetation interference with overhead lines. The overall resilience strategy for vegetation management includes increasing the expenditure levels for both routine trimming and reliability-enhancing activities to reduce the impact of severe weather to the grid.

Utilities also can integrate threat assessments into DSPs by examining the potential impact of threats to operations and processes that are part of DSP—in addition to physical grid assets. Duke Energy assessed the vulnerability of its load forecasting and capacity planning processes—among others—to various weather projections. Figure 4.14 illustrates how the utility used a high, medium, and low risk score for each process area. Duke Energy discovered that projected ambient temperature extremes were not consistent between top-down and circuit-level load forecasting processes and that it had incomplete real-time visibility into substation transformer temperatures for capacity planning. Figure 4.15 shows another example of this approach taken by National Grid (2024). Here, the utility undertook a similar analysis, but used checkmarks to indicate potential impacts to operations and processes by threat, including load forecasting and capacity planning. Both utilities documented these analyses in separate resilience plan filings.

Process Area	Risk Score
Asset Management	High
Load Forecasting	Medium
Capacity Planning	Medium
Reliability Planning	Medium
Emergency Response	Low
Workforce Safety	Low
Vegetation Management	Low

Figure 4.14. 2050 projected vulnerability priority ratings for asset and operations planning groups

Source: Duke Energy (2023)

OPERATIONS AND PLANNING FUNCTIONS	High Temperature	High Winds	Inland Flooding	Ice
Emergency Response	✓	✓	✓	✓
Vegetation Management		✓	✓	✓
Workforce Safety and Methods	✓	✓	✓	✓
Reliability Planning	✓	✓	✓	✓
Load Forecasting	✓			
Capacity Planning	✓			

Figure 4.15. Identified hazards with potential impacts on operations and planning functions

Source: National Grid (2023)

4.4 Solution Identification and Prioritization

Utilities determine which specific resilience solutions to analyze by matching the root causes, severity, and identified vulnerabilities of specific hazards to appropriate mitigation strategies. They often deploy engineering teams to investigate chronic service reliability, failure analysis, and outage drivers which dictate the specific solutions chosen for analysis. For example, ComEd (2024) notes that if its investigations reveal a high frequency of vegetation-caused outages in a specific part of the grid, planners will analyze moving those facilities underground because eliminating ongoing costs of vegetation management makes undergrounding a potentially cost-effective solution. Utilities can use ex-post analysis of resilience mitigation measure effectiveness to predict which solutions may perform well for specific hazards and vulnerabilities (Collins et al., 2025).

Certain state regulations require utilities to evaluate and report on specific measures in grid resilience plans filed with regulators (Schellenberg and Schwartz, 2024). These requirements can include providing a clear justification for why each measure is or is not selected for implementation.

Prioritizing potential resilience solutions involves assigning a value or score to various alternatives. The process allows utilities to screen out alternatives that are not cost-effective. It also facilitates integration of resilience and distribution system planning, as utilities may use the results to represent the resilience criteria in a MODA process, which monetizes or scores the attribute benefits of projects for subsequent prioritization. Prioritization of resilience measures may be the first of multiple prioritization processes, ultimately comparing potential resilience measures with grid projects that have other benefits. The prioritization process may be documented directly in DSPs, or separate resilience plans may be referenced.

Utilities and regulators have honed a set of decision-making methods for deciding whether to make an investment and how to prioritize among alternatives. Cost-effectiveness evaluation is one approach that works well for analyzing potential resilience investments. It assesses the benefits and costs of alternative courses of action and is used to show that the selected path is reasonable and merits cost-recovery. There are 2 key approaches, based on drivers (Figure 4.16) (De Martini et al., 2025).

- *Lowest Reasonable Cost analysis (or “best-fit, least cost”).* This method can be used when the need for a project has already been established. Thus, the analysis does not determine whether benefits outweigh costs; it finds the option that requires the minimum investment needed to comply with specific legal, safety, and/or reliability standards.
- *Benefit-Cost Analysis (BCA).* This method represents all of the costs and benefits of a past or future decision in dollars over a defined time period. Consistency in units makes comparison between costs and benefits straightforward. Decision-makers and stakeholders can readily determine whether and the extent to which benefits outweigh costs.

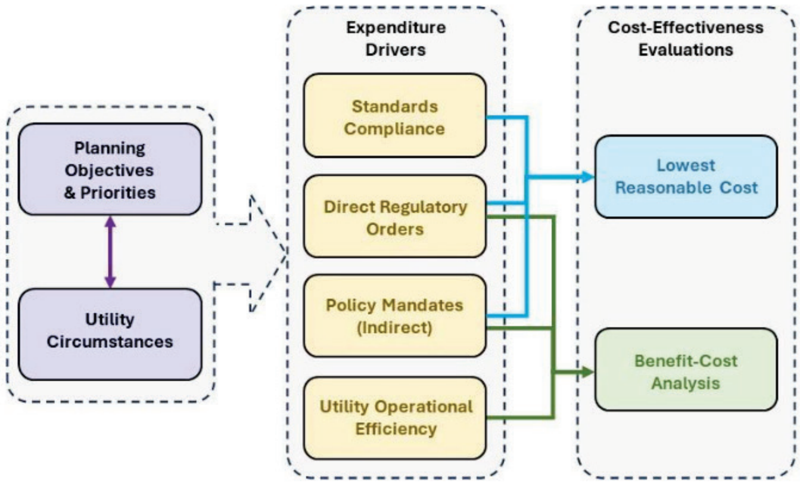

Figure 4.16. Drivers and Cost-Effectiveness Evaluation Methods

Source: [De Martini et al., 2025]

BCA is a quantitative framework for determining the net value of distribution investments over time by weighing their total costs against utility, customer, and societal benefits ([De Martini et al., 2025]). It distinguishes between *direct utility savings*, which are measurable, auditable financial impacts that directly improve a utility's bottom line, and *other savings*, which encompass broader benefits to customers and the general population. These other savings—such as enhanced grid reliability or improved safety—often require estimation and can be more difficult to audit than direct financial outcomes. Nonetheless, they are essential components for assessing the full set of grid investment benefits. BCA can function as a screening tool to ensure that investment benefits outweigh costs—indicated by a positive net present value (NPV) and a benefit-cost ratio (BCR) greater than one. The utility may conduct BCA from multiple perspectives, depending on state requirements.

Other tools to compare multiple alternatives are *risk spend efficiency* (RSE) and *value spend efficiency* (VSE). These methods determine a score for a non-monetized benefit—risk reduction for RSE and a unitless value for VSE—and divide by the cost of the alternative. These approaches generate a normalized efficiency score to prioritize mutually exclusive projects and select more than one for implementation.

The remainder of this section reviews utility practices and cites examples of utilities using these analytical approaches that facilitate their integration in distribution system planning. Each of the examples illustrate how utilities identify, value, and prioritize potential investment alternatives.

Spectrum of Utility Practices

Stated Plans for Future Integration

A number of utilities acknowledged a need for methods to value and prioritize resilience investments.

- HECO (2023) stated that it was focusing on no-regret resilience solutions and proposed developing a method for comparing resilience investments. HECO's IGP indicated that the utility planned to guide future system hardening using defined metrics and BCA once it developed resilience performance targets and quantitative decision-making tools were available.

- ConEd (2024) has conducted extensive resilience planning work, but cited the Joint Utilities' comments that "there currently is no widely recognized and accepted methodology for comparing resiliency investments to customer and regional avoided costs" (Joint Utilities, 2022). The comments stated that the utilities would explore using LBNL's new ICE Calculator 2.0 and other tools for future resilience studies.[37]
- Consumers Energy (2023) cited resilience as a qualitative objective and that the utility was planning to add quantitative scoring in future plans.

Enhanced Reliability Analysis

Using traditional reliability analysis, utilities identify solutions by identifying WPCs, using root cause analysis to determine what is driving poor performance, and assessing the best solution to solve the specific problem. Utilities can use a similar approach for resilience investments.

Eversource (2024) is an example of a utility that used such an approach. Its DSP describes a rules-based method to determine the location of needed grid resilience projects and select the appropriate measure, using reliability metrics that include MEDs (specifically, customer minutes interrupted (CMI) and all-in SAIDI). To begin, the utility analyzed outage data for all major storms in the previous 4 years. The methodology prioritized the highest criticality events (i.e., many customers impacted, multiple events, and long duration events). The utility then performed a root cause analysis, through which it discovered that 25% of major event CMI from 2019-2022 was related to operations of reclosers and breakers.[38] To identify solutions, the utility grouped the impacted zones into 3 tiers of criticality (Table 4.1). The final steps were pairing the highest criticality items with the highest impact solutions and quantifying the impacts of potential resilience solutions on all-in SAIDI.

Table 4.1. Eversource's resilience measure selection criteria

Tier	Criteria	Measure	All-in SAIDI	Cost ($M/mile)
I	Impacted zones with 300,000 or more CMI per event on average	Undergrounding	98%	4
II	Impacted zones with less than 300,000 and more than 150,000 CMI per event on average	Aerial cable	82%	2.2
III	Impacted zones with less than 150,000 average CMI per event—with bare wire	Bare wire to tree wire conversion	50%	1.1
	Impacted zones with less than 150,000 average CMI per event—with insulated wire	Resilience tree work	35%	0.1

Source: Adapted from Eversource (2024)

[37] Comments in 2022 cited limitations of the ICE Calculator 1.0, such as geographical coverage and dated survey data. The utilities note that the ICE Calculator 2.0 (released in 2026) would mitigate these issues.

[38] Reclosers and breakers are automatic protective switches that de-energize circuits when they detect faults, such as short circuits or equipment failures, to prevent system damage and fires. A breaker typically locks open at the substation—de-energizing the circuit until the breaker is manually closed—whereas a recloser tests the line by opening and closing multiple times to clear temporary faults (like fallen branches) without a sustained outage.

Resilience Integration in Distribution System Planning

Reliability and resilience investments are generally capital improvements funded by the utility, with direct benefits to the utility in the form of avoiding the future costs of replacing equipment that could be damaged or costs that would otherwise be incurred to restore power in the event of an interruption. In the first case, an investment to flood-proof a substation would avoid future expenditures to repair or replace substation equipment. In the second case, concrete or composite poles may cost more than wood poles, but they can withstand higher wind speeds—so deploying them can avoid future pole replacement costs after major weather events. Utility expenditures can include customer programs to encourage storage, co-located generation, or microgrids that benefit all ratepayers if the cost is less than the traditional utility solution. During power interruptions, these programs also may provide broader community benefits by powering critical facilities. Typically, utilities pay for a portion of the costs—through a rebate, for example—with the participating customer responsible for the remainder. Several programs are designed this way, such as Pacific Gas & Electric's (PG&E's) reliability/resilience generator-battery rebate program.

Avoided customer interruption costs are a key benefit to customers of reliability and resilience investments. These costs represent the economic burden caused by power interruptions—for residential customers, for example, food spoilage. Utilities can estimate avoided interruption costs for inclusion in BCAs using tools such as LBNL's ICE Calculator.

Understanding the distribution of impacts among customers is an important aspect of using BCA as a decision-making tool for grid investments. Reliability and resilience investments that target certain circuits will not provide benefits to all ratepayers, as avoided customer interruption costs are specific to the customers on the circuits impacted by investments. Thus, a positive NPV alone for an individual project does not indicate that a utility should make an investment; a BCA is an initial screen to identify which potential reliability and resilience solutions merit further consideration as part of overall distribution expenditures.

Tampa Electric (TECO) illustrates an approach for using BCA to plan for storm protection. It prioritizes its 800 distribution circuits based on reliability performance and priority customer count to identify target circuits for improvement using BCRs (TECO, 2022). It assessed reliability performance for both extreme weather and blue-sky days, assigning a higher weighting factor to performance under extreme weather conditions. On the benefits side, the analysis monetized avoided CMI and avoided restoration costs. TECO examined three scenarios: average, high, and extreme storm scenarios (Figure 4.17). The utility selected a budget scenario where the curves leveled out (i.e., marginal benefit of higher spending approached zero).

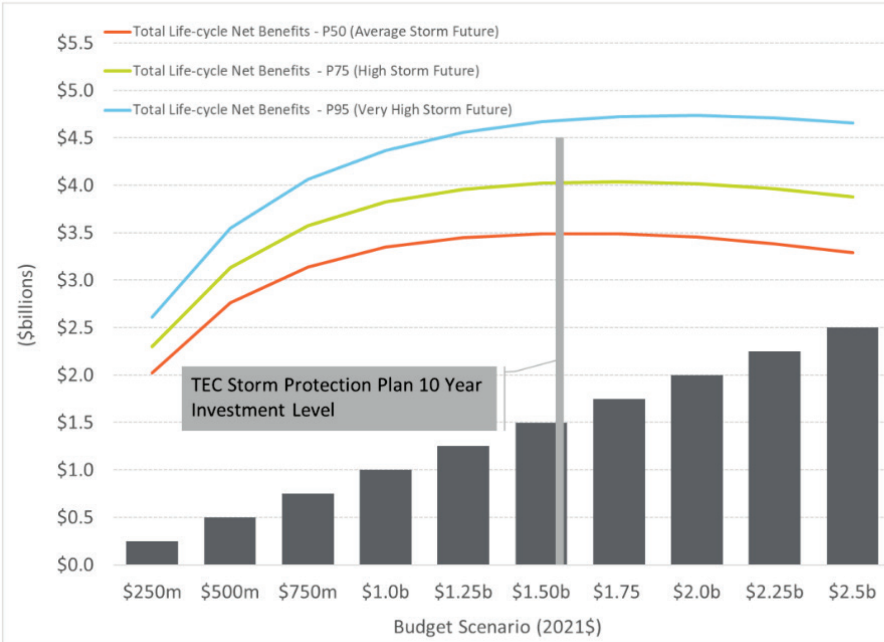

Figure 4.17. TECO - net benefits of storm protection plan across 3 scenarios

Source: [TECO (2022)]

Utilities may approach solution prioritization by analyzing the tradeoff between cost and magnitude of the risk. One way to do so is to trace the RSE curve to see where the marginal risk reduction flattens out for each additional dollar spent. Eversource organized potential mitigation projects on a resilience risk reduction curve, plotting the reduction in all-SAIDI versus the cumulative cost of projects. Figure 4.18 shows the diminishing marginal returns of spending to reduce resilience risks. The plan described the optimal saturation point—when to stop investing—as the place "where the slope of the curve declines," in this case $450 million.

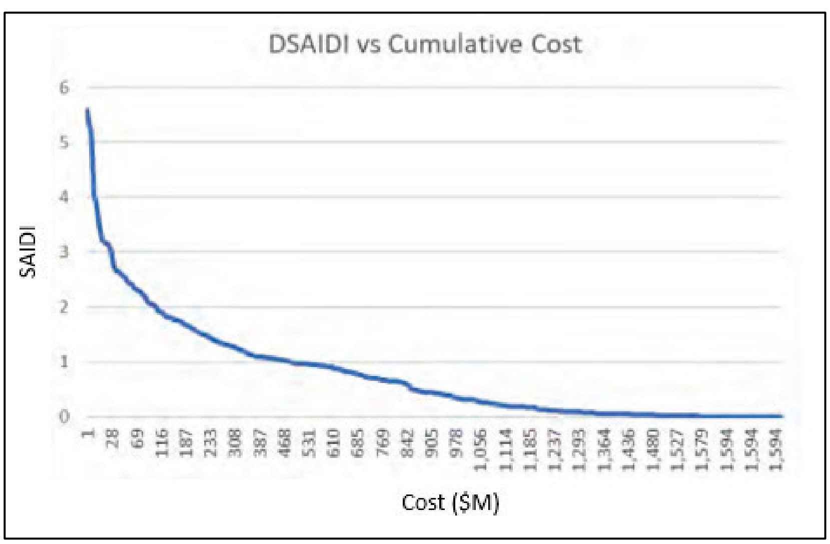

Figure 4.18. Eversource risk spend efficiency curve

Source: [Eversource (2024)]

LG&E and KU (2025) applied a similar approach to determine the appropriate amount of risk reduction spending. The utilities used a Risk Return on Investment model with two key components for each potential solution:

- Numerator: Outage minutes between 2013 and 2023 that would have been avoided if the potential solution had been implemented for all circuits
- Denominator: Cost to implement the potential solution for all remaining circuits

The numerator is determined by an analysis that compares the historical performance of two similar circuits—with and without the solution—to evaluate the all-in SAIDI performance benefit. The denominator is the total annualized cost of implementing the solution (e.g., $/mile undergrounded), including O&M and capital expenditure. Planners determined a final system-level portfolio of solutions by ordering each solution from highest to lowest Risk Return on Investment and establishing resilience performance targets. Figure 4.19 illustrates this process, showing how each solution, encompassing all applicable or prioritized individual circuits, incrementally reduces the system's baseline all-in SAIDI of 244 minutes toward two hypothetical targets: Goal 1, achieving first-quartile performance regionally, and Goal 2, achieving first-quartile performance nationally.

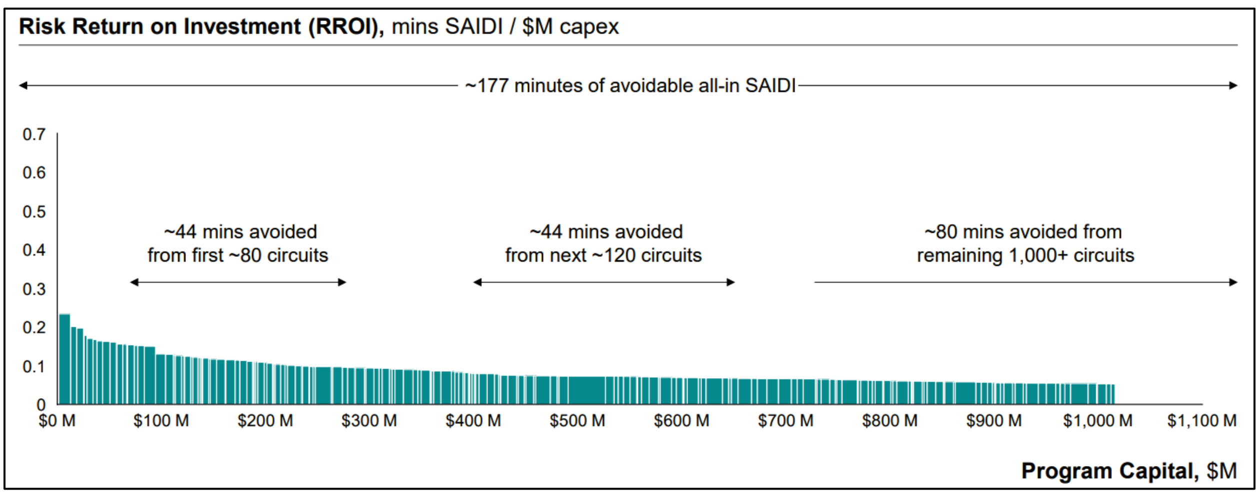

Figure 4.19. LG&E and KU - Risk Return on Investment

Source: LG&E and KU (2025)

PGE's DSP included a section referring to the utility's WMP, where the utility employed a VSE approach to compare pre- and post-mitigation wildfire risk considering additional difficult-to-monetize qualitative impacts. PGE's VSE approach builds on the RSE approach in the WMP by incorporating additional risk impact scores associated with difficult-to-monetize qualitative impacts, such as wildfire impacts on watersheds. The utility used VSE to prioritize investments that achieved the greatest benefit per dollar spent across programs such as vegetation management, system hardening, and Public Safety Power Shutoffs.

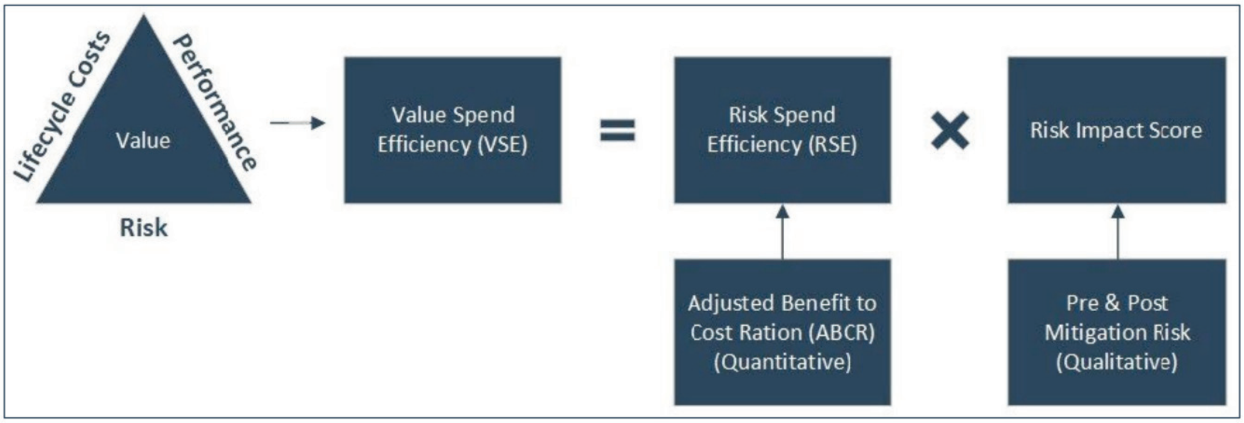

Figure 4.20. PGE's Value Spend Efficiency Model

Source: [PGE Wildfire Mitigation Plan (2024)]

4.5 Optimization Opportunities

Utilities optimize internally to identify opportunities to realize efficiencies for implementing physical grid improvements and expanding capacity. To “optimize” is to find projects that can serve more than one objective, appropriately time implementation, and change or expand projects originally designed to meet one objective so that they can meet other objectives as well. Utilities may undertake projects concurrently on the same circuit or find solutions that would both expand capacity and improve grid performance. For example, upgrading to a higher voltage line may allow more tie-ins with other parts of the grid that already have been upgraded, improving reliability.

Timing is a key consideration for optimizing project implementation across planning processes for improving existing grid infrastructure and expanding capacity. That includes aligning equipment availability, implementation timing, and personnel availability. Balancing longer-term, systemic needs with immediate projects to address local reliability and resilience issues also is important. That often requires two complementary approaches: a long-term plan (e.g., a 10-year horizon) focused on systemic grid needs, and a parallel short-term plan that addresses immediate reliability and resilience gaps. The short-term plan considers solutions like NWAs, temporary distributed generators, or battery storage to defer major capital projects (e.g., capacity expansion or circuit undergrounding) until the long-term solution can be fully implemented. Optimization may also mean not just implementing the quickest fix (e.g., restoring service as quickly as possible), but ensuring long-term objectives are also considered (e.g., accelerating implementation of a large capital project so that it can be included as part of the restoration process). Optimal grid planning and project management require these short- and long-term plans to be carefully integrated and adjusted annually to maximize ratepayer benefits over the entire multi-year decision process (DeMartini et al., 2022).

Spectrum of Utility Practices

Stated Plans for Future Integration

Two examples of utilities citing plans for closer coordination of resilience and capacity expansion projects are Appalachian Power Company (APCo) and PSCo. APCo cited the importance of an integrated approach to transmission, distribution, and generation planning, stating in part that "resilience and safety are enhanced with better visibility over future [transportation load growth] ... and distributed generation at distribution circuit level to allow the planners to plan for multiple load conditions…" (APCo, 2022). PSCo (2024) provided examples of how asset risk scores could be integrated into future distribution system planning processes, such as cross-referencing against the list of assets identified for replacement as part of the maintenance cycle to determine if additional resilience measures or studies should be incorporated into the planned work scope.

Enhanced Reliability Analysis

This approach does not apply to "Optimization Opportunities." Utilities identify ways to simultaneously implement physical grid improvements and expand capacity. The physical grid improvements could be geared toward either reliability or resilience—but the process for optimizing the project plan is the same. For example, a planned capacity expansion project may provide an opportunity to implement additional measures to address blue-sky reliability issues or to harden the grid further to address severe weather.

Resilience Integration in Distribution System Planning

Southern California Edison's (SCE) WMP (2026-28) documents the company's risk score approach for wildfire and explains how it connects to broader grid planning needs. For example, when implementing major wildfire mitigation projects like undergrounding or installing covered conductors, SCE also evaluates whether the same circuits need capacity upgrades due to load growth or other factors, allowing both efforts to be completed together in a coordinated, cost-effective way. This is consistent with the recent CPUC decision requiring utilities to describe their methodology for referencing distribution planning processes when designing projects in other workstreams, such as evaluating capacity upgrades when carrying out wildfire mitigation, to avoid duplication of future grid upgrades (SCE, 2025).

HECO (2023) outlined a strategy to move from its current "baseline" level of resilience to its target level. Figure 4.21 illustrates the planned strategy—with time on the x-axis and an illustrative "level of resilience" on the y-axis. The orange bar at the bottom represents the current level of resilience and the dotted line at the top represents the target level. Near-term system hardening is the dark purple section and future hardening is in lighter purple. Residual risk mitigation solutions driven by the planning process (green) or communities (blue-green) would mitigate risks not fully avoided or prevented by system hardening. For example, the utility plans to implement the North Kohala microgrid prior to a longer-term effort to harden the radial sub-transmission line serving that community. This sequencing allows the microgrid to reduce the impact of planned outages required to construct the hardening project and mitigate unplanned outages in the near term. Once the line is eventually hardened, the microgrid will remain to provide residual risk mitigation.

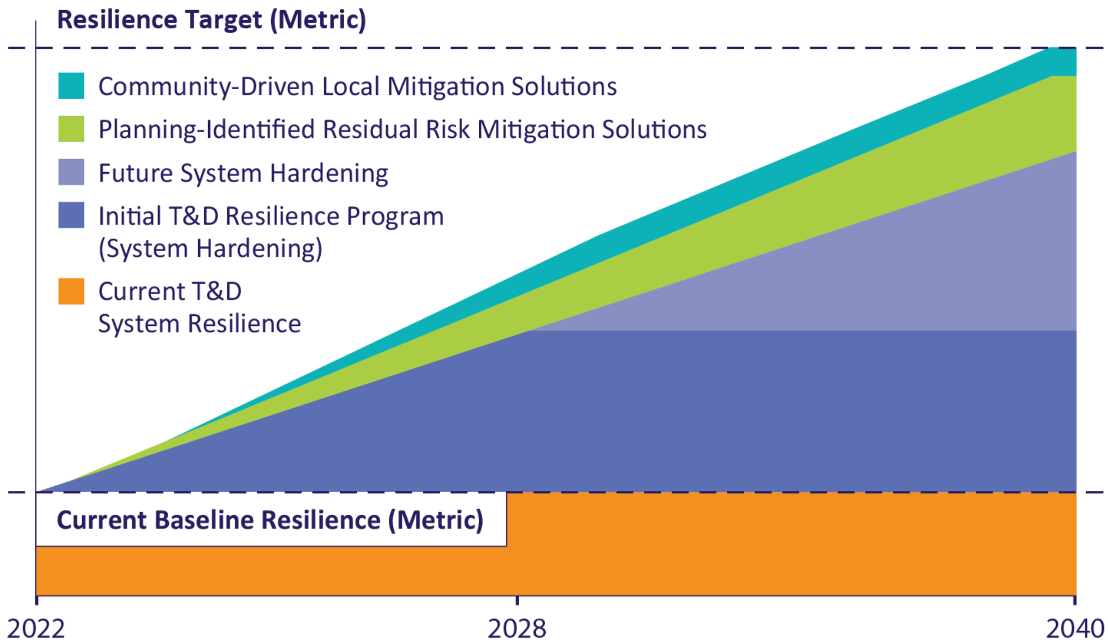

Figure 4.21. HECO - preventive and mitigation solutions to address resilience gap

Source: HECO (2023)

Utility experts interviewed noted the importance of coordination between capacity expansion projects and asset management, reliability, and resilience work to identify optimization opportunities. Some utilities noted specific practices for explicitly promoting coordination. One utility's software flags circuits in the system when any group is looking at conducting work. The flag indicates to other groups that they should coordinate on potential projects. Another utility structured engineering planning groups based on geographic areas, rather than planning processes. These groups are responsible for planning all projects—both infrastructure replacement and capacity expansion—within their areas of responsibility.

4.6 Consideration of Other Grid Needs

Considering other grid needs covers efforts to conduct MODA to balance resilience benefits against other grid planning objectives, such as capacity expansion, public safety, financial risk, reliability, and others. MODA is a prioritization method that utilities use to determine the optimal portfolio of distribution grid expenditures that best meets state objectives, regulatory requirements and customer needs (De Martini et al., 2025). The process involves assessing each proposed, cost-effective solution both quantitatively and qualitatively against weighted planning objectives and their specific metrics. It establishes a framework that helps utilities rank projects to maximize overall value while remaining within financial constraints.

Figure 4.22 shows the integration framework with the "consideration of other grid needs" component highlighted, which includes the process of multi-objective evaluation and prioritization. Utilities use different methods to value and compare criteria to determine which projects they should implement.

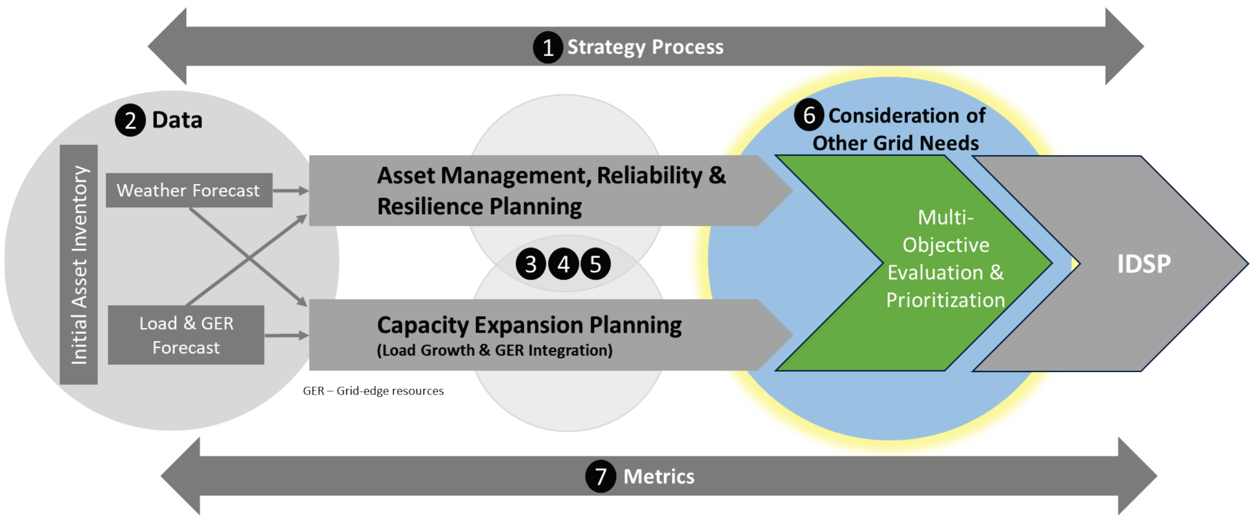

Figure 4.22. Resilience integration framework highlighting consideration of other grid needs

Determining the appropriate valuation method across disparate criteria is challenging—particularly when assessing reliability and resilience investments against capacity expansion investments. Utilities have an obligation to serve new load and new customers, which aligns well with a lowest reasonable cost approach for capacity expansion. BCA works well for reliability and resilience improvement investments, as these investments are generally discretionary, and planners can monetize benefits of fewer or shorter interruptions and avoided costs for restoring power and replacing grid assets. Combining these two methodologies can be challenging, as the BCA yields monetized benefits and lowest reasonable cost analysis does not. Some utilities and third parties have developed models to value reliability and resilience benefits and capacity expansion benefits within the same model, using either a unitless value score or by monetizing the risk of not adequately expanding capacity.

Spectrum of Utility Practices

Stated Plans for Future Integration

The DSPs do not include substantial discussion about future application of value frameworks. However, a number of utilities are part of the IEEE Utility Integrated Planning Task Force that is working to develop an industry consensus value framework and models to help utilities compare investments across multiple objectives (IFS Copperleaf, 2026). The task force aims to develop a consistent multi-objective risk evaluation framework that encompasses resilience among other objectives, such as adequate capacity, public safety, financial considerations, and compliance risk. The effort will consider integration across planning domains, including electric distribution and transmission and gas systems. A working group is developing a set of white papers to document its findings, which the task force aims to use to inform utility risk evaluation practices and tools.

Enhanced Reliability Analysis

This utility practice does not apply to consideration of other grid needs. A MODA may consider reliability and resilience as two separate objectives or combine them together, but the analytical approach is the same.

Resilience Integration in Distribution System Planning

Utilities are increasingly adopting decision analytics and value frameworks to monetize and compare planning criteria—such as reliability, safety, resilience, and environmental impact—on a common economic scale. For instance, Ameren Illinois (2024) and Duke Energy Indiana (2024) use the Copperleaf decision analytics platform to deploy "value models" that calculate project value by monetizing risk mitigation (e.g., safety, regulatory compliance) and financial benefits, converting many non-financial risks into "value units" or dollar equivalents based on the probability and consequence of asset failure. This process ensures allocation of capital to the portfolio of projects that provides the highest total benefit, while staying within budget and resource limits.

DTE Electric uses its Global Prioritization Model to prioritize investments (Figure 4.23). It includes 10 impact dimensions and relevant drivers. Each investment receives a score from 0 to 100 across each dimension based on the ratio of benefits to costs (for most dimensions). The dimensions touch on multiple components of reliability, resilience, and capacity expansion, as well as other criteria such as regulatory compliance and reducing electrical hazards. Each project receives a separate score for reducing outage duration (SAIDI) and frequency (SAIFI). The model also includes major event risk mitigation from substation outage events. To ensure the investment portfolio aligns with strategic imperatives, the scores are adjusted by weighing factors that prioritize safety and reliability. The last column of Figure 4.22 shows the weights. Planners aggregate the weighted scores into a final total, creating a ranked hierarchy where high-scoring initiatives are prioritized for implementation.

Impact Dimension	Drivers	Weight
Reduce Electrical Hazards	• Reduction in wire down events • Reduction in secondary network cable manhole events	3
Overload Relief	• Elimination of overloaded equipment	
SAIDI	• Reduction in duration of outage events	
SAIFI	• Reduction in frequency of outage events	
Regulatory Compliance	• MPSC staff's recommendation (March 30, 2010 report) on utilities' pole inspection program • Docket U-12270 – Service restoration under normal conditions within 8 hours • Docket U-12270 – Service restoration under catastrophic conditions within 60 hours • Docket U-12270 – Service restoration under all conditions within 36 hours • Docket U-12270 – Same circuit repetitive interruption of fewer than five within a 12-month period	2
Major Event Risk	• Reduction in extensive substation outage events that lead to a large amount of stranded load for more than 24 hours	
Capacity Relief	• Elimination of system capacity constraints	
Investment in EJ Communities	• Percent of customers impacted by investment in EJ communities	
O&M Avoidance	• Trouble event reduction and truck roll reduction • Preventive maintenance investment reduction	1
Capital Avoidance	• Trouble event reduction and truck roll reduction • Reduction in capital replacement either during equipment failures or avoided planned capital work	

Figure 4.23. DTE Electric's investment prioritization framework components

Source: DTE Electric (2023)

Another example of balancing multiple objectives is PG&E's planning process, which prioritizes projects across risk reduction objectives related to wildfire, reliability, capacity, public safety, and financial risks. The utility's process consolidates and monetizes asset risk data in a common platform (Copperleaf) separately for each of three electric domains (distribution circuits, substations, and transmission lines). For distribution projects, PG&E normalizes the risk values and aggregates them by asset type, then aggregates them at the distribution circuit level. This circuit-level aggregation enables the utility to manage as a single investment what would otherwise be treated as disparate projects. Figure 4.24 is a snapshot of the planning outputs. The bars are different assets and bar colors represent risk reduction benefit for various criteria.

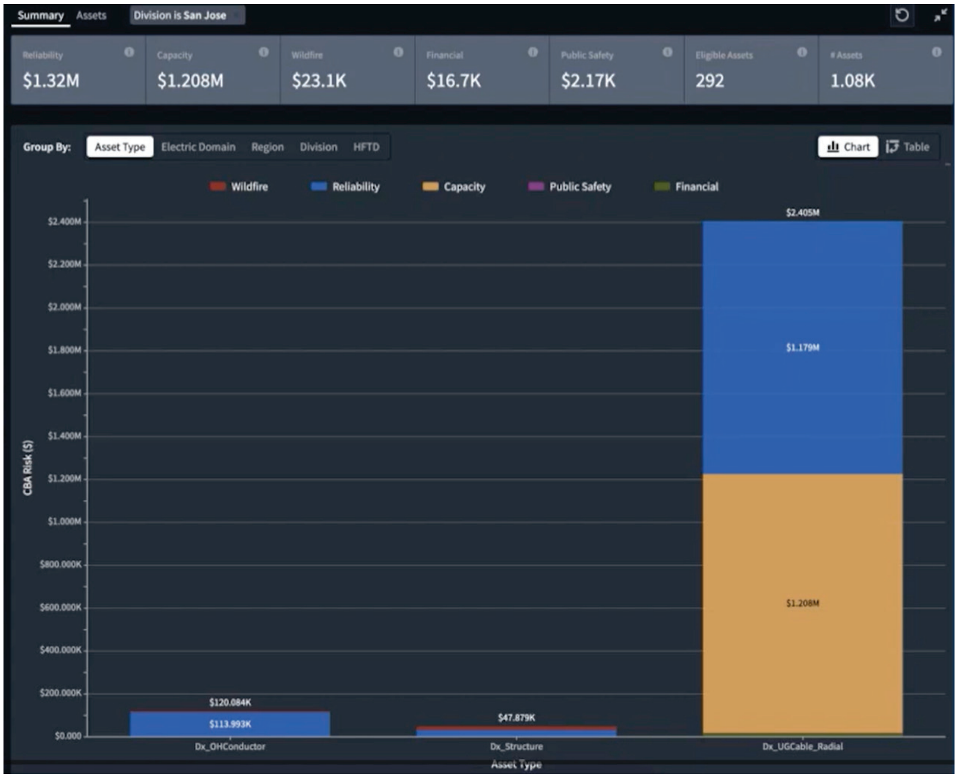

Figure 4.24. PG&E's System Needs Analysis Platform for aggregating monetized asset risks

Source: Energy Central webinar

4.7 Metrics

Utilities and regulators use different types of metrics to measure progress toward achievement of resilience objectives. *Attribute metrics* are characteristics that contribute to or describe the resilience of the utility system and community it serves, such as miles of covered conductor installed, portion of poles that have been hardened, and asset condition. These metrics describe the ability of the system or community to anticipate a hazard, withstand the hazard, adapt to hazard impacts, and recover from the hazard to a normal operating state.

Performance metrics describe the effectiveness of resilience investments by quantifying the extent to which they have reduced the negative impacts of hazard events, such as customer interruptions and restoration costs. Utility resilience measures seek to avoid some or all of the negative impacts that would have occurred without the measures. Performance metrics measure actual results, and thus progress toward achieving resilience objectives.

Figure 4.25 shows the resilience integration framework with the metrics arrow highlighted. Metrics allow planners to set measurable objectives, connecting the utility's strategy to the planning process and outcomes. Utilities that carefully track attribute and performance metrics can connect asset characteristics with outcomes and inform future investment decisions.

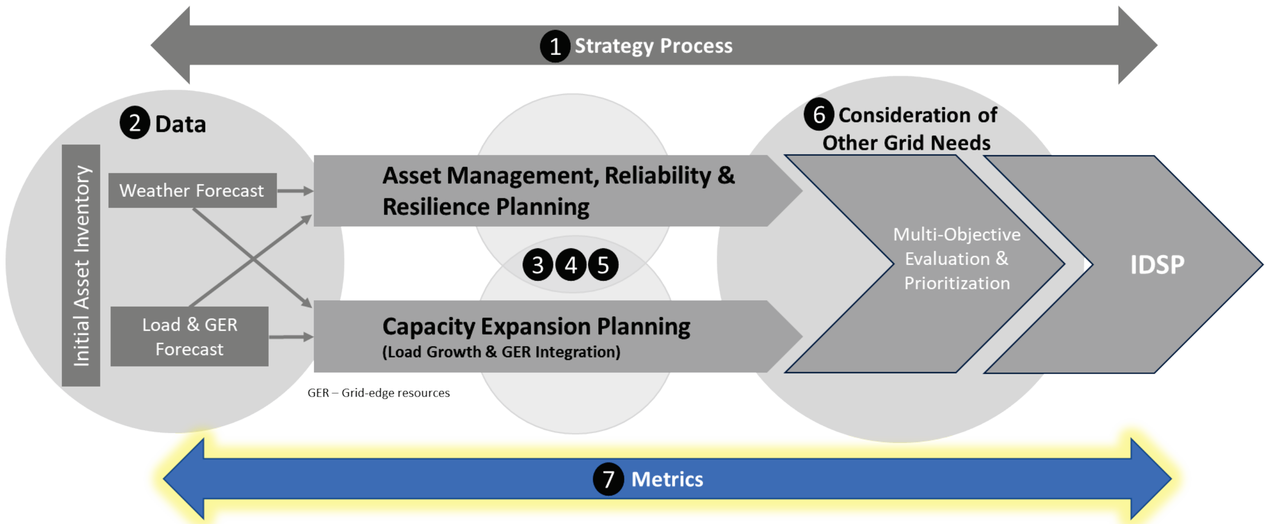

Figure 4.25. Resilience integration framework highlighting metrics

As discussed in Sections 4.3-4.6, utilities are focusing on ways to quantify risk of resilience events[39] as well as risks related to other planning criteria (e.g., safety, capacity). Quantitative measurements of risk—including unitless risk scores—can technically be considered attribute metrics because they describe a characteristic or a condition of the system. For example, if a utility assigns a high-risk score to a circuit because it has older wood poles in a high-wind area, the score is an attribute of the circuit's current state. Functionally, risk scores also can serve as a bridge between attribute and performance metrics, as these scores quantify the potential for failure based on specific traits (e.g., age of equipment, location in a flood zone, or proximity to vegetation). Risk scores can predict performance and be used as evidence to help justify the budget needed to improve future performance.

The utility industry and stakeholders continue to explore ways to best represent performance of resilience measures, given the challenges of characterizing performance for high-impact, low-frequency resilience events (Levy et al., 2025; EPRI, 2025). This section reviews practices observed in filed utility plans and emerging approaches.

Spectrum of Utility Practices

Stated Plans for Future Integration

Utility plans generally define resilience and reliability as distinct but related concepts requiring different measurement approaches. The need for more and better resilience metrics is a topic that utilities, regulators, stakeholders, and researchers have all raised. A number of DSPs noted ongoing efforts to develop metrics and integrate them into the planning process. Several examples are below.

[39] While "resilience event" is commonly used in the electricity industry, there is no standard industry definition. Each jurisdiction or utility develops its own based on hazards in scope. The definition may indicate the range of normal operating conditions as well as the degrees of severity for resilience events (Schellenberg & Schwartz, 2024).

- PGE (2024) acknowledges that further analysis is needed to understand the impact of NWA solutions on resilience.
- ComEd (2024) states that it is considering additional metrics to capture various dimensions of resilience. The utility intends to refine its methodology in future grid plan filings.
- Dominion Energy (2024) is planning to engage with industry leaders (such as IEEE and EPRI) to develop metrics for measuring and assessing grid resilience.
- DTE Electric (2023) and Consumers Energy (2023) note that a Financial Incentives and Disincentives workgroup in Michigan is tasked with developing appropriate metrics for reliability and resilience for the commission's consideration.
- HECO (2023) proposes a structured development process to select or develop resilience performance metrics and define targets that reflect stakeholder values.
- Northern States Power Company (2024) references a PUC order[40] requiring stakeholder engagement for development of resilience metrics: "Xcel shall consult with stakeholders…on the development of a set of evaluation metrics that allow comparison to other resilience offerings."

Enhanced Reliability Analysis

Table 4.2 shows examples of reliability metrics that utilities have adapted for resilience planning by including MEDs. SAIDI, SAIFI, CAIDI, MAIFI are commonly reported. Less-common metrics focus on impacts to customers: the percentage of customers experiencing multiple interruptions (CEMI) and the percentage of customers experiencing long interruption durations (CELID). In contrast, resilience metrics tend to focus on notable events that occur at specific times within a year (e.g., over a day or week).

Table 4.2. Examples of reliability metrics applied to major storms or MEDs to measure resilience in DSPs

Metric Category	Metric Name	Description
Interruption Events	Customer Interruptions (CI)	The number of customers experiencing a sustained interruption over a given time period
	Customer Minutes Interrupted (CMI)	Sum of all customer minutes from sustained interruptions over a given time period
Interruption Frequency	System Average Interruption Frequency Index (SAIFI)	Total number of sustained interruptions that on average customers experiences over a given time period

[40] See RMP Annual Report in Docket No. E002/M-21-694, Dec. 1, 2022

Metric Category	Metric Name	Description
	Momentary Average Interruption Frequency Index (MAIFI)	Total number of momentary interruptions (< 5 minutes) that on average customers experiences over a given time period
Interruption Duration	System Average Interruption Duration Index (SAIDI)	Total number of minutes that on average customers are without power due to sustained interruptions over a given time period
	Customer Average Interruption Duration Index (CAIDI)	The average amount of time customers experiencing a sustained interruption are without power over a given time period
Customer-Focused	Customers Experiencing Multiple Interruptions ($CEMI_n$)	Ratio of customers that experience *n* or more sustained interruptions over a given time period to the total number of customers served
	Customers Experiencing Long Interruption Durations (CELID-t)	Ratio of customers that experience an interruption with a duration longer than or equal to a given time (*t*), over a given time period, to the total number of customers served

Source: Schellenberg and Schwartz (2024); Collins et al. (2025)

Many DSPs use these traditional "system average" reliability metrics as one method for representing resilience performance by including MEDs.[41] One widely recognized issue with this approach is that a single major event can heavily influence the value of the system average metric. This introduces substantial volatility to the year-over-year index values—particularly to SAIDI and CAIDI—reflecting the size of the resilience events and not the level of grid resilience.

Some utilities have separate designations (apart from MEDs) for major events and may apply reliability metrics to these times and locations. For example, Michigan designates "catastrophic conditions" as either severe weather conditions that result in interruptions for 10% or more of customers, or events which result in a local, state, or federal state of emergency declaration.[42] Michigan utilities report performance metrics for normal, gray sky, and catastrophic conditions (DTE, 2023; UPPCO, 2025). Some designations are strictly weather-based and do not depend on the number or percentage of customers experiencing interruptions. For example, California requires utilities to report metrics on high wind warning days as part of WMP reporting. These designations can help to control for weather conditions, and in certain cases can provide information about system performance in gray sky conditions.

[41] For example, Ameren (2024), ComEd (2025), Consumers Energy (2023), DTE (2023), Eversource (2024), LG&E and KU (2025), Pepco (2025), Northern States Power Company (2023)
[42] Mich. Admin. Code R.460.702

Resilience Integration in Distribution System Planning

Utilities use metrics to integrate resilience planning in distribution system planning by performing granular assessments of specific events on specific circuits, exploring ways to incorporate risk reduction into metrics, and developing and applying new metrics and indices for characterizing resilience.

Granular Assessments

Utilities can leverage their outage management systems to perform granular resilience assessments at the circuit or community level, rather than relying on systemwide averages. By isolating specific interruption data—such as cause, customer count, duration, and exact location—planners can evaluate the performance of individual circuits against hazard impacts. This focused approach allows utilities to measure the direct effectiveness of resilience programs by narrowing their analysis to the specific segments of the grid where mitigation measures were implemented. IEEE Standard 1782-2022 provides guidance for collecting, categorizing, and using interruption information. The standard details data elements and practices to maintain consistency and how to compare interruption data both within a utility and across utilities following the standard.

- Pepco (2025) breaks down feeder performance by specific cause codes to help planners tailor resilience interventions to the specific threats facing a circuit. For example, the utility identified one feeder as having 99.78% of its SAIFI driven by "wildlife," suggesting a need for animal guarding rather than storm hardening.

- Consumers Energy’s Forestry Workplan Intelligence & Strategy Engine analyzes historical interruption data specifically for tree-caused incidents and uses machine learning to estimate the circuit-specific performance improvement expected from vegetation management (Consumers Energy, 2023).

Risk Reduction

A number of utilities quantify resilience risk in DSPs, resilience plans, or both. Risk may be characterized as a unitless score or monetized. These measures are used to prioritize investments so that utilities can reduce risk efficiently. Utilities also may use risk scores to reflect the amount of risk inherent in certain parts of the system or to measure risk reductions toward specified outcomes. A number of DSPs contain formal quantifications of risk, and utility resilience plans also include risk scores. These metrics can be applied to reliability planning under blue-sky conditions and to resilience planning under extreme weather conditions. Section 4.4 discusses several examples of risk scores in the context of using RSE for prioritizing projects.

ConEd’s plans provide 2 examples of risk scoring for analyzing resilience. The utility's DSP refers to a vulnerability study that utilizes a probabilistic, risk-based framework to quantify the likelihood and consequences of different long-term weather scenarios across its service territory (ConEd, 2023c). By generating specific risk scores for various asset classes and hazards, the company is able to prioritize critical infrastructure for further analysis and targeted remediation. The utility also developed the Network Resiliency Index, its primary tool to predict the risk of failure by network. The index "…models the relative strength of each network by calculating the probability of failure of multiple associated feeders within a network over time, as caused by individual component failures" (ConEd, 2023b).

New Metrics and Emerging Approaches

Utilities, regulators, and others are developing and experimenting with new resilience-focused metrics for measuring customer interruptions and restoration times, including the following metrics reported in utility plans:

- LG&E and KU (2025) tracks average customer interruptions per major event, which measures how well the distribution system avoids widespread customer outages when exposed to hazards. The utility also tracked 90th percentile customer outage duration, which measures how long it takes to restore 90% of customers in a major event.
- Delmarva (2024) tracks CEMI4R2 and CEMI7R2, which is the portion of customers experiencing at least 4 sustained interruptions per year for 2 consecutive years and 7 sustained interruption per year for 2 consecutive years, respectively.

Researchers and industry groups are working with utilities and regulators to explore new metric frameworks that are not yet tracked in utility plans. These potential resilience metrics aim to address the volatility inherent in retrospective performance metrics for systems subject to high-impact, low-frequency events.

SEPA—in partnership with Baringa—propose a dual-metric framework for measuring realized resilience using a "resistance" and a "recovery" component (Levy et al., 2025).[43] The resistance component is Multi-year SAIFI (MY SAIFI), which uses a 4- to 7-year rolling average of MED-inclusive SAIFI to measure the effectiveness of long-term grid hardening. The multi-year aspect of the measure smooths the volatility from severe weather. The recovery component is Major Event Restoration Time (MERT). It measures the time it takes for a utility to restore power to most of its customers (typically 95%) after a major event.

The aim of the dual-metric framework is to capture how often customers lose power and how long they remain without service.[44] This includes setting multi-year performance targets, adjusting the targets over time, and designing appropriate incentive mechanisms, penalties, and reporting requirements.

The IEEE Distribution Resilience Task Force has developed metrics (currently in draft form) to assess resilience investment performance and recovery effectiveness (IEEE, 2020; IEEE, 2027). The Sustained Interruption Reduction Index (SIRI) calculates CI avoided due to a resilience strategy, such as automation or hardening, and expresses it as a percent of total CI. It thus reflects the portion of customer interruptions prevented by the resilience strategy. The

[43] The report defines "resistance" as "the grid's ability to withstand and minimize the initial impact of a disruptive event" and "recovery" as "the grid's capacity to rapidly restore service and functionality after an interruption."
[44] A forthcoming guidebook by SEPA and Baringa focuses on helping regulators apply these metrics in practice.

restoration effectiveness metric involves a more complex calculation, which combines the effectiveness of utility crews responding to a storm event with customers' interruption experiences (MPSC, 2025). The Michigan Public Service Commission directed Consumers Energy, DTE Electric, and Indiana & Michigan Power to work with Commission staff "to identify and define the data points that would support and serve as inputs to the SIRI and REPAIR metrics"—and, once identified and defined, to report them to the Commission annually (MPSC, 2026).

Ahmad and Dobson (2025) propose risk metrics that can be calculated from a utility's historical outage data and used both to track performance of a utility strategy and potentially to benchmark against other utilities. They designed the System Average Large Event Duration Index (SALEDI) to quantify distribution system resilience by measuring the customer minutes interrupted per customer during large resilience events. Because extreme events exhibit variability and follow heavy-tailed distributions, standard averaging produces erratic indices that require an impractical amount of data to stabilize. SALEDI addresses this problem by applying a logarithmic transformation to the normalized CMI of large events[45] to convert the heavy-tailed data into an exponential distribution. The metric adds the logarithms of these normalized customer minutes over a period of years and divides by the number of years to yield a more stable annual index. SALEDI is designed to act as a complement to SAIDI, the traditional reliability metric. SAIDI tracks routine outages by excluding major events, whereas SALEDI specifically targets extreme events.

LBNL and its partners developed and piloted a prototype Power Outage Economics Tool (POET) for estimating the economic impacts of widespread, long-duration power interruptions (Larsen et al., 2024). POET uses a hybrid valuation approach. It relies on customer surveys for information on household and business customer behaviors for responding to widespread, long-duration power interruptions and uses this information to calibrate a computable general equilibrium model of the regional economy. Key economic impact metrics generated by POET include gross output, which reflects the change in business revenue; gross (regional) domestic product, or the change of the total value of final goods and services generated by the regional economy; and change in household consumption, which is the average lost consumption from the power disruption, or the subsidy to households to make them indifferent to the power disruption.

[45] "Large events" as defined by Ahmad and Dobson (2025) are different than MEDs. They are groups of interruptions that occur within 3 hours of each other. Large events have a lower threshold than MEDs and thus include interruptions from MEDs—as well as additional interruptions.

5. Case Studies

This section applies the resilience integration framework developed for this report to 3 case studies. The case studies cover 2 types of investments:

- *Pole hardening* to withstand resilience events, such as high wind speeds. Pole replacement is an opportunity to upgrade other distribution system assets (e.g., reclosers) at the same time, lowering the cost of such improvements. It also is an opportunity for utilities to balance short-term versus longer-term grid needs. The potential efficiency benefits of integrating planning processes for pole hardening make it an informative case study. Pole hardening can include the following practices:
  - Material upgrades: Transitioning from wood to steel, concrete, ductile iron, fiberglass, or composite materials to prevent snapping and fire damage
  - Structural reinforcement: Adding anchors and storm guys to provide lateral support against high-velocity winds
  - Design modifications: Reducing the distance between poles (span length) to decrease the mechanical stress on individual structures and the conductor wire
  - Pole-top hardening: Upgrading insulators, cross-arms, and fasteners to more robust versions that are less likely to fail and cause cascading outages
  - Alternative cross-arm design: Installing break-away cross-arms designed to snap under stress before the entire pole collapses can help the utility localize damage, reducing repair costs and interruption durations

- Microgrids consist of a group of interconnected loads and generating resources within clearly defined electrical boundaries. From the point of view of the grid, a microgrid acts as a single controllable entity and can connect and disconnect from the grid to operate in grid-connected or island mode. Utilities can support development and implementation of microgrids by administering incentive programs and grants, offering technical and planning assistance, providing data to estimate costs and benefits, partnering with customers or third-party developers, and creating dedicated tariffs that compensate microgrids for the energy and services they provide to the grid.
  - Microgrids offer a versatile alternative to traditional distribution infrastructure by providing localized islanding capabilities and additional benefits such as peak-shaving and relief from capacity constraints.
  - By strategically deploying microgrids, utility planners and governments can ensure that critical facilities, such as hospitals, police and fire stations, and community shelters, remain energized during grid outages caused by extreme weather events.
  - Microgrids can defer or avoid capital expenditures required for new infrastructure.

Implementation of these resilience measures can overlap with other grid needs and therefore other elements of the distribution planning process.

5.1 DTE Electric – Pole Hardening

DTE Electric serves approximately 2.3 million metered customers (with a total population of 5 million) in Southeastern Michigan. The primary natural hazard risks to its distribution system are from high wind and ice storms.

The utility's pole hardening reflects integration of resilience planning in distribution system planning along several points in the integration framework, including strategy process, solution identification and prioritization, consideration of other grid needs, and the use of metrics and ex-post analysis to measure success. This case study walks through the utility's distribution planning process (Figure 5.1) and highlights the applicable integration framework components.

Source: DTE Electric (2023)

Figure 5.1. High-level diagram of DTE Electric's planning process

Strategy Process

DTE Electric used DOE's Modern Distribution Grid framework (DOE, 2017) to assist with the distribution system planning process and conduct a gap analysis of its current system. The utility then examined investments needed, dividing the types of work into four categories: (1) tree trimming, (2) infrastructure resilience and hardening, (3) infrastructure redesign and modernization, and (4) technology and automation. Categories (2) and (3) address resilience and capacity expansion, respectively.

Solution Identification and Prioritization

The infrastructure resilience and hardening category comprises projects and programs to improve grid reliability and resilience in the short term. It addresses the distribution overhead system through the Pole Top Maintenance and Modernization program and 4.8 kV hardening. The focus is on replacement, not capacity upgrades, targeting equipment that is defective, failed inspection, is obsolete, or is nearing the end of its useful life. The program uses a tiered inspection and replacement strategy. Poles under 20 years old receive visual integrity checks; older units undergo physical testing and anti-decay treatments. To improve storm resilience, the utility replaces failed poles with higher-class alternatives that provide more groundline strength and 20% greater wind resistance. Simultaneously, the program replaces defective pole-top components, shifting from wood and porcelain to fiberglass and polymer. By upgrading to these more durable equivalents, the utility reduces equipment failures and customer outages caused by increasingly severe wind gusts and storms.

The infrastructure redesign and modernization category consists of projects that focus on longer-term capacity expansion investments, such as converting the 4.8 kV system[46] to 13.2 kV and upgrading the subtransmission system to increase capacity. These investments replace aging infrastructure, relieve load constraints and convert the 4.8 kV system to a modern, higher-voltage system.

The DTE Electric DSP identified and assessed alternative hardening solutions. For example, Table 5.1 lists the cost and effectiveness of five hardening alternatives for 4.8 kV circuits, comparing average cost per mile with reductions in wire down,[47] SAIFI, and SAIDI. To prioritize projects for capacity expansion, the utility assessed loading constraints and criticality. The load relief prioritization methodology was enhanced in recent years and is now based on five variables: substation equipment overload, substation over firm, circuit equipment overload, strong load growth prospect, and circuit exceeding Distribution Design Order limit, which is a standard that DTE Electric uses to maintain system capacity and operational flexibility.

Table 5.1. DTE Energy 4.8 kV Hardening Alternatives[48]

Program	Avg. Cost per Mile	Wire Down Reduction	SAIFI Reduction	SAIDI Reduction
Arc Wire Only	$191k	-13%	-22%	-36%
4.8kV Hardening	$353k	-26%	-44%	-72%
Pre-Conversion	$1.7M	-90%	-85%	-85%
Conversion	$2.7M	-90%	-85%	-85%
Microgrids	$14.6M	-90%	-95%	-95%

Consideration of other grid needs

DTE Electric inputs the scores for specific criteria from the solution identification and prioritization process into its Global Prioritization Model (discussed in Section 4.6) as part of its capital planning process. The model combines the scores for all criteria as an input for developing the utility's investment strategy. Resilience benefits from pole hardening could be reflected in fewer wire down events, reductions in SAIFI and SAIDI, and avoided capital and O&M from fewer truck rolls. A project that upgrades capacity in addition to hardening poles could have additional benefits of overload relief and capacity relief.

[46] The 4.8 kV portion of DTE’s grid is the oldest part of the system, with elements that are at least 80 years old.
[47] Overhead electrical conductor has broken, fallen from its elevated position, and is either hanging low or lying on the ground.
[48] “Arc Wire Only” refers to removing abandoned wire left from a prior company. “Pre-conversion” includes rebuilding pole tops, replacing poles and transformers as needed, and installing neutral wire. “Conversion” is converting 4.8 kV infrastructure to 13.2 kV.

Metrics

DTE Electric measures results of hardening programs by comparing targeted circuits to a control group of similar unhardened circuits. Using a control group is a means of controlling for weather, adding confidence that changes in metrics before and after project implementation are due to improved grid performance and not simply more favorable weather. Figure 5.2 shows all-weather SAIFI before and after hardening for the hardened circuits and a control group. The program appears to be delivering positive outcomes, as all-weather SAIFI decreased 46% for hardened circuits and increased 26% for the control group (likely due to the impact of more severe weather).

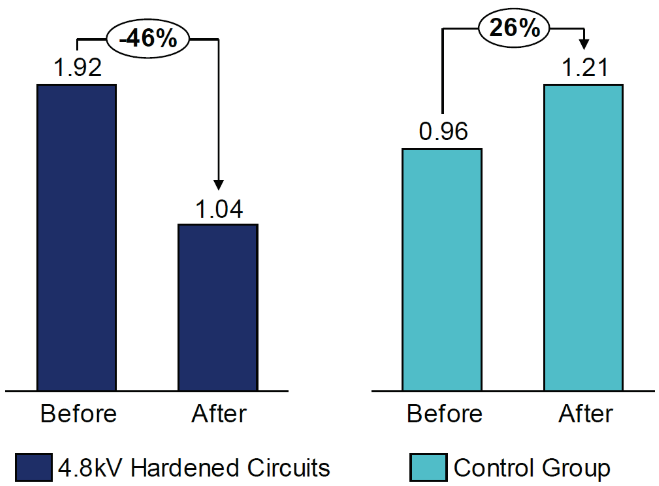

Figure 5.2. All-weather SAIFI before and after hardening

5.2 Pepco DC – Pole Hardening

Pepco DC is a subsidiary of Exelon that provides electric service to about 312,000 metered customers (with a total population of 670,000) across the District of Columbia. The utility faces severe weather risks from summer and winter storms, heat waves, and flooding.

Pepco DC's 2025 Annual Consolidated Report reviews the utility's plans for pole hardening. Similar to DTE Electric, the plans address asset management and reliability and resilience planning as well as capacity expansion planning. The report discusses resilience as an outcome of infrastructure upgrades, consistently citing resilience as the primary anticipated benefit of the planned construction and maintenance. This case study highlights how Pepco DC integrates resilience in distribution system planning at 4 points in the integration framework: strategy process, solution identification and prioritization, optimization opportunities, and metrics.

Strategy Process

The plan breaks down distribution solutions by capacity expansion and system performance, reflecting a strategy to address both types of grid needs and document them in an integrated planning document. The report includes 3 components: system planning, productivity improvement plan (PIP), and priority feeder program. The system planning component addresses existing and future system needs to support load growth cost-effectively. Per regulatory requirements, the PIP reports operating performance of T&D systems and measures to improve reliability. The priority feeder program identifies the most critical 2% of WPCs.

Solution Identification and Prioritization

Pepco's system planning process aims to meet current and future electric system needs, support load growth, and ensure reliable service cost-effectively. Its methodology relies on a 3-step process that involves developing short- and long-range peak load forecasts, analyzing the capabilities of individual distribution components (like feeders and substations) to meet these expected loads, and generating specific system recommendations. These recommendations guide the utility's investment plans, which range from immediate operational measures and load transfers to short- and long-term projects designed to resolve predicted grid issues.

Pepco selects projects for its PIP by focusing on enhancing the operations, performance, and reliability of its transmission and distribution networks. Eligible projects must meet the established criteria of increasing system efficiency by reducing losses, improving overall reliability, or deferring more expensive additions to the electric system. Pepco prioritizes targeted measures such as distribution and substation automation, 4 kV to 13 kV conversions, and priority feeder or neighborhood reliability improvements. Table 5.2 shows illustrative PIP projects. Separately, the utility lists potential solutions in tables of planned upgrades for priority circuits, with individual projects divided into capacity expansion and distribution performance categories.

Table 5.2. Pepco 2024 PIP projects

	$'s in '000s		
Executive Category	**2024 Budget**	**2024 Actuals**	**Variance**
4kV Distribution Substation Automation	$ 172	$ 1,683	$ 1,511
4kV to 13kV Conversion Projects	$ 37,581	$ 22,068	$ (15,513)
Distribution Automation Projects	$ 13,977	$ 11,177	$ (2,800)
Priority Feeder Projects	$ 4,787	$ 6,448	$ 1,660
Neighborhood Reliability Improvement Projects	$ 8,023	$ 9,618	$ 1,596
Grand Total	**$ 64,540**	**$ 50,994**	**$ (13,546)**

Pepco prioritizes WPCs using a method called System Performance Contribution (SPC). The utility calculates an SPC value for each feeder by comparing the feeder outage data to systemwide outage data—specifically, the number of customer interruptions and the number of customer minutes interrupted. The lower the SPC, the worse the circuit performs compared to the entirety of the system with respect to CI (weighted at 75%) and CMI (weighted at 25%).

Optimization Opportunities

The plan identifies ways to optimize the 4 kV to 13 kV conversion program (capacity expansion) with the priority feeder program (reliability/resilience). For example, the plan identifies that one feeder requires a reliability improvement as well as a planned capacity expansion. The utility expects the capacity upgrade to result in better reliability as well as increased capacity to enable GER interconnection and transportation load growth. The utility therefore does not plan to implement a separate reliability improvement investment for this feeder.

Metrics

Pepco collects and examines detailed, feeder-level interruption data by cause and uses the information to perform root cause analysis, prioritize mitigation work, and measure results. Its primary metrics are SAIFI, SAIDI, and CAIDI, focused at the feeder level and sometimes focused by cause (e.g., tree-caused SAIFI). The granularity of interruption data collection allows the utility to hone in on key specific hazard threats and assess solutions to address them.

5.3 New Jersey Board of Public Utilities – Microgrids

Microgrids can offer significant resilience and reliability benefits to customers because of their ability to connect and disconnect from the grid, which enables loads within their circuits to maintain power during utility outage events. Microgrids also have the potential to support the utility grid during normal conditions by providing ancillary services and generation capacity, which can help defer capacity expansion investments. Realizing these benefits requires coordination and expertise to manage bidirectional energy flows and the assets and systems that enable island-mode functionalities.

The New Jersey Board of Public Utilities (NJBPU) categorizes microgrids into three levels with unique regulatory and technical characteristics:

- Level 1: Single building microgrids
- Level 2: Campus-scale microgrids
- Level 3: Community scale or Town Center Microgrid Distributed Energy Resources (TCDER) microgrid

A series of actions in the aftermath of Superstorm Sandy in 2012 led the NJBPU to establish the TCDER Program initiative to improve community and grid resilience during power outages. This program provides funding for municipalities to study the feasibility and design of microgrids capable of serving clusters of critical facilities—such as hospitals, police and fire headquarters, and community shelters—with the primary goal of ensuring operation of community services and shelters during extended grid outages.

During the first phase (2017–2019) of the program, the NJBPU awarded approximately $2 million to 13 public entities to assess potential microgrid locations. Building on those feasibility studies, the ongoing second phase of the program (engineering design) provides incentives for the detailed design of selected projects, helping move them closer to procurement and financing. As of 2026, the NJBPU has awarded approximately $4 million to seven local governments to support engineering designs. However, funding has not been available for construction of these microgrids. Cost allocation, high construction and interconnection costs, an absence of funding, and statutory/regulatory challenges persist.

Strategy Process

New Jersey's electricity market is restructured and regulated utilities are not allowed to own generation assets. The microgrid feasibility studies generally propose models where third parties or the towns themselves own and manage the generating assets. Several municipalities, including Hudson County, Neptune Township, Woodbridge, and Montclair, favored this model. The private third-party entity is responsible for securing the primary capital cost for generation assets (e.g., natural gas-fired combined heat and power plants) and assumes the responsibility for their O&M and fuel costs. Under this arrangement, microgrid customers would pay the privately-owned microgrid company for the energy it supplies, allowing the company to cover O&M costs and recuperate investments in generation assets through long-term contracts with the local governments.

Utilities also play a significant role in microgrid operations. For the 7 projects that advanced to the design phase of the program, utilities would provide and maintain needed upgrades to distribution infrastructure (wires, poles, switches) to accommodate the microgrid and, in most cases, be responsible for managing islanding functions. Where upgrades to the existing infrastructure are necessary to support islanding capabilities, upgrade costs are proposed by the designers to be recovered from ratepayers broadly through retail rates or from microgrid customers through specific tariffs. For example, Highland Park proposes that the utility construct and own the microgrid backbone (conductors and switchgear) as part of the distribution system, recovering costs through standard rate-recovery mechanisms. In contrast, Atlantic City proposes that the utility would adopt a specific "Microgrid Tariff" for microgrid customers. The tariff would preserve a portion of the non-commodity (e.g., distribution) charges and remove the transmission charges, due to the need for only limited assets to deliver power over the distribution system and no need for utilizing high-voltage lines.

Most of the engineering designs indicate that the microgrid projects would not be financially viable without significant subsidies (e.g., government grants, tax credits, and other incentives to offset capital costs). For example, Woodbridge's application states a goal of providing electricity at the current price of utility power, but its final design application acknowledges that it would not be able to meet this goal without grants covering up to 50% of the $27 million project cost.

Solution Identification and Prioritization / Consideration of Other Grid Needs

NJBPU planned to score and evaluate the proposed microgrids for resilience and other grid needs together. NJBPU provided the evaluation criteria for the microgrid feasibility studies to advance from phase I to phase II, including criteria such as resilience, peak demand reduction, and critical facilities support. While the barriers to advancing to construction have been significant, the scoring criteria listed in Table 5.3 illustrate the balanced evaluation approach that NJBPU planned to use.

Table 5.3. NJBPU evaluation criteria for microgrid feasibility studies to advance to Phase II

Evaluation of Applications (100 points total)	
General project characteristics (20 points)	• Overall description • Federal Emergency Management Agency (FEMA) Category III and IV critical facilities included • Community support during grid outages
Technical characteristics (40 points)	• Project readiness • Integration of resources and loads • Communication and control protocols and cyber security measures • Degree of resilience • Incorporation of technologies to reduce air pollution • Ability to reduce peak demand
Financing and business model (40 points)	• Reasonableness of estimated costs • Portion of cost requested from NJBPU • Source of funding for applicant's portion of design cost • Reasonableness of business and financial models proposed • Reasonableness of project cost allocation • Degree of involvement of electricity and gas distribution companies

Source: NJBPU (2021)

For example, the feasibility study for Highland Park emphasized the resilience and public safety benefit of keeping police, fire, and senior housing operational during outages. In evaluating outage reduction benefits, Cape May conducted a simplified analysis using the ICE Calculator to estimate the avoided customer interruption costs that nonresidential customers of a specific feeder would incur from a 10% reduction in SAIFI and SAIDI. The analysis estimated more than $24,000 in benefits over 20 years. Figure 5.3 shows Cape May's forecasted total interruption cost under the modelled scenario compared to the baseline system.

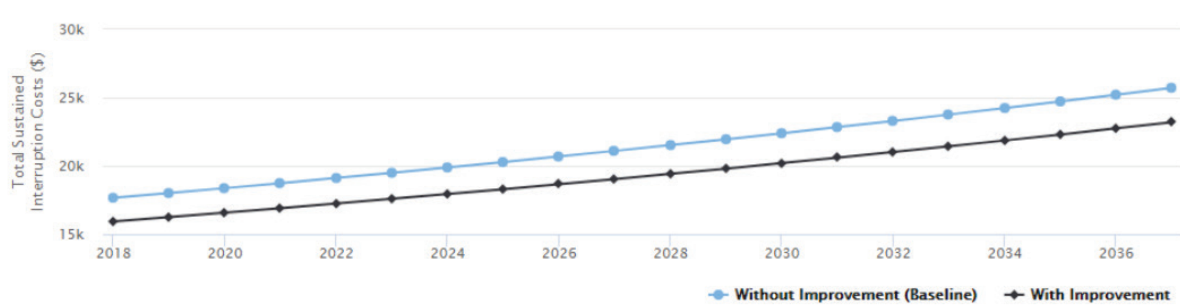

Figure 5.3. Cape May's forecast of total sustained interruption cost using the ICE Calculator

Source: Cape May (2018)

Applications mentioned potential benefits of other grid services, but did not quantify or monetize them. For example, Camden's feasibility study proposes a new microgrid tariff that would account for the value of maintenance and capacity expansion deferrals, in addition to reliability and resilience benefits. Woodbridge's phase 2 application states that quantifying and monetizing expected benefits to the grid more broadly will require involvement by the local utility, including sharing plans for circuit improvement strategies to meet new load requirements that the microgrid may be able to offset and potentially eliminate. Other benefits discussed in applications (Atlantic City and Middletown) include deferring or eliminating distribution capital investments that would be needed to address growing peak loads. Hudson County notes additional system benefits, including local voltage and reactive power support, short-term substation relief, and circuit-level restoration services, potentially delivered through contractual arrangements with the utility.

6. Conclusions

Utilities and states alike have made strides in how they plan for grid resilience and how to integrate that process in distribution system planning. Successful integration can yield more cost-effective spend plans, support a wide range of grid needs, and balance near-term and longer-term objectives. This section summarizes emerging best practices and identifies opportunities for further research to advance integration of resilience and distribution system planning.

6.1 Emerging Best Practices

LBNL's review of DSPs and interviews with utility subject matter experts revealed a number of emerging best practices for integrating resilience in distribution system planning. This section describes these practices for each of the 7 points in the integration framework developed for this study.

Strategy Process

- **Provide a clear definition of resilience and assigned roles and responsibilities within the utility.** A clear definition aligns utilities, regulators, and stakeholders on an overarching vision of resilience and helps utilities set specific objectives. Explicitly assigning roles and responsibilities within the DSP adds clarity and establishes accountability.
- **Explain how resilience currently fits into a utility's distribution system planning process and how its role is expected to evolve over time.** Explicitly define where resilience sits within the broader planning hierarchy, rather than treating it as a separate or add-on function, to ensure it is a foundational objective for distribution system planning.
- **Specify the objectives that the utility will use to assess and prioritize planned resilience expenditures and provide a roadmap for achieving these objectives.** By clearly defining objectives and the milestones that will mark progress toward achieving them, utilities provide regulators and stakeholders with a transparent yardstick to

measure progress and help justify utility decisions. The roadmap also serves as a strategic communication tool to align internal teams.

Data

- **Use consistent data sources and scenarios across planning functions.** Using different datasets from different utility departments is an obstacle to integrated utility planning. Emerging best practices rely on consistent assumptions and scenarios about load growth and GER adoption throughout the entire organization. When distribution engineers and resilience teams rely on the same information, the resulting investment plans are naturally aligned. Standardizing these inputs prevents situations in which a capacity project and a hardening project for the same feeder are based on conflicting assumptions about future conditions.
- **Document data sources and assumptions.** Meticulously documenting all data sources and the specific rationale for each planning assumption supports regulatory transparency and utility justification. Clear documentation facilitates more productive dialogues regarding the balance of risks and costs. It also provides an auditable trail for regulators when assessing the prudence of investments.
- **Plan for anticipated extreme weather conditions.** Shift from relying solely on historical 10-year averages to including predictive modeling that accounts for expected increasingly severe and frequent future weather events. By incorporating downscaled weather data from available long-term weather forecasting models into a utility's own risk models, planners can identify assets that are now, or may be in the future, at high risk for wildfires, flooding, storms, or extreme heat or cold. This forward-looking approach allows the utility to make better decisions today to prepare for hazards that could impact assets over their expected useful lives. An accurate representation of prospective hazard risk enables utilities to better assess tradeoffs between investment costs and post-event savings.
- **Leverage advanced sensing technologies to improve situational awareness and accelerate restoration.** Utilities can use technologies that provide information on natural hazards and physical threats to improve operations and planning. For example, deploying drones for rapid, post-storm inspections not only provides immediate situational awareness, but important asset condition data for planning.

Threat Assessments

- **Assess the impact of threats to existing planning processes.** Including planning processes in threat assessments can identify potential issues that utilities may address to ensure continued effectiveness.
- **Leverage existing reliability planning processes and analyses to assess threats.** Distribution system plans revealed numerous examples of utilities using enhanced reliability analysis to address resilience, which may be particularly useful for smaller utilities. Carvallo and Sanstad (2025) suggest a "reliability-to-resilience" approach where utilities build a resilience planning framework from existing reliability-focused activities. In some situations, extending familiar reliability data, methods, and certain metrics to incorporate resilience outcomes will lead to a more efficient and practical planning

process that may be more easily understood by regulators and stakeholders.

Solution Identification and Prioritization

- **Conduct initial cost-effectiveness screening and then prioritize resilience investments in order to facilitate their integration into the broader distribution system planning process.** Utilities can first use lowest reasonable cost or BCA to determine whether to further assess the investment. To maximize impact, utilities can then employ an RSE metric to rank potential resilience investments. RSE supports the efficient allocation of limited utility funds by maximizing risk reduction. This metric provides a structured basis for comparing expected resilience performance. It also facilitates integration with multi-objective analysis by recognizing that nearly all distribution expenditures contribute to achieving more than one planning objective. Proposed resilience expenditures can then be evaluated in a manner similar to other planned distribution projects in the subsequent cost-effectiveness evaluation and prioritization for all distribution expenditures.
- **Use tradeoff curves or similar forms of data visualization to help utility and regulatory decision-makers identify optimal levels of investments.** Risk reduction versus cost is an example of a tradeoff curve, both represented visually by National Grid (2024) and LG&E and KU (2025). These graphics are helpful for seeing where the tradeoff curves flatten out and the marginal benefits decrease for every extra dollar spent. They also can be effective for building stakeholder support for utility investment decisions.
- **Make explicit connections with distribution system planning when resilience planning occurs through other means.** If the utility values and prioritizes resilience investments in a separate planning process, proceeding, or document (e.g., wildfire mitigation plan), refer explicitly to it in the DSP and leverage the analysis where appropriate. This coordination is helpful for stakeholders reviewing the report and for understanding where other relevant information and analyses may be publicly available.

Optimization Opportunities

- **Integrate resilience-prioritized hardening investments into traditional distribution planning and capacity upgrade cycles to reduce costs and customer impact.** Resilience-focused hardening projects, such as pole replacements or conductor shielding, can be aligned with routine capacity upgrades and maintenance schedules to minimize labor costs and customer disruptions. By identifying opportunities to execute tasks simultaneously, a utility can complete two projects at a lower cost than if the two were performed separately.
- **Coordinate implementation of projects for maintaining and improving the existing physical system with expanding grid capacity to meet new customer needs.** Utility subject matter experts note that any level of coordination is helpful when efforts to harden the grid and expand capacity occur on the same circuit. Even rudimentary coordination can identify opportunities to avoid redundancy and improve efficiency. Planners can then explore ways to add structure and IT tools to make the coordination process more fruitful over time.

- **Balance immediate reliability and resilience gaps with longer-term, systemic grid needs.** Strike a balance between implementing immediate repairs that address current problem areas and making foundational, longer-term investments required for future grid needs. This can mean not simply restoring service as quickly as possible, but accelerating the timing of larger capital projects to include them as part of the restoration process to meet longer-term grid needs and customer demands.

Consideration of Other Grid Needs

- **Explore frameworks for comparing risk reduction across multiple planning objectives, including resilience.** Comprehensive, accurate, and consistent valuation frameworks will help utilities make cost-effective decisions on investments and implement projects efficiently. They provide a quantitative foundation for mitigating risk and can support utility cases for cost recovery of capital and other expenditures.
- **Evaluate alternatives to traditional infrastructure upgrades to reduce costs and mitigate grid resilience risks.** Distributed generation, backup generation, storage, and microgrids are new options utilities can consider that also offer local balancing and islanding capabilities, which traditional wires-only solutions lack. By deploying these non-wires resources strategically, planners can provide power to certain areas—including critical infrastructure—during resilience events. At the same time, these resources can address local capacity constraints without the capital outlays needed for a new feeder or substation.
- **Involve stakeholders in selecting and weighting planning criteria.** Many IRPs for bulk power systems successfully involve stakeholders in selecting and weighting criteria. Stakeholder input builds understanding and support for the plan. Similar approaches can build public support for resilience measures in distribution plans.

Metrics

- **Collect and analyze power interruption data with as much geographic granularity as possible.** Granular data allow planners to perform more precise analysis of interruption causes than what is possible using system-level or even circuit-level averages. Utilities can use this information to help identify effective solutions and deploy them where they are most cost-effective.
- **Determine baselines for key metrics to measure the performance of grid investments.** Developing a better understanding of resilience solutions' effectiveness in the field improves future modeling of expected grid impacts and supports utility proposals for future investments.
- **Test new metrics for assessing grid resilience.** Researchers have developed new resilience metric frameworks that aim to address the challenges in measuring performance during of systems subject to high-impact, low-frequency events (Levy et al., 2025; IEEE, 2020; IEEE, forthcoming; Ahmad & Dobson, 2025). Utilities and regulators can test these new frameworks to determine whether the metrics are useful for measuring performance and to refine the parameters in the metric calculations.

Continuing to develop and refine leading practices in integrating resilience planning in distribution system planning will become increasingly important as state requirements evolve and the magnitude of impacts from severe weather events grows. Utilities currently leading the way demonstrate meaningful efforts to advance an integrated approach across their workforce, data sources, and planning processes. They create an organizational structure that ensures efforts to improve resilience are coordinated with distribution planning. A number of utilities have ongoing, enterprise-level efforts to ensure data consistency and quality. They utilize risk-based approaches to assess the threat of natural hazards to utility assets, processes, and the communities they serve. As valuation methodologies and metrics continue to develop, leading utilities are contributing to industry efforts to transparently value capital investments across multiple attributes and to test new metrics for characterizing resilience and measuring performance. Most of these emerging best practices are transferable to other utilities—even those with less developed capabilities—particularly if the utilities share similar threat profiles and regulatory environments.

6.2 Opportunities for Further Research

The following recommendations describe areas where further research would be particularly useful for utilities and states to further develop and advance methods and processes for integrating resilience and distribution system planning.

- **Assess impacts of state requirements on integrated planning results.** Evaluate the impacts of state requirements on distribution system planning processes and outcomes. Compare states with and without comprehensive planning requirements and determine whether certain requirements lead to more coordinated planning within the utility and stronger engagement with external stakeholders. Examine how specific state requirements influence utility investment priorities, rate case outcomes, and utility expenditures on post-event restoration and recovery versus proactive mitigation.

- **Examine how utilities are assigning value to capacity expansion, resilience, and other planning objectives.** Examine the multi-attribute value models that utilities use in MODA to combine criteria into a single value function. The formulas for quantifying and weighting criteria are generally not disclosed in the DSPs. Collect this information through consultation with utilities and regulators. The details of the value models would be informative for utilities developing their own models or improving their existing models. Focus on the extent to which utilities are standardizing the number and types of qualitative benefits they included, a gap that Ameren Illinois (2024) explicitly identifies as necessary to avoid understating benefits.

- **Explore use of AI and digital twins for planning and tracking metrics.** As utilities move toward AI-enabled operations, examine what capabilities these tools could enable. For example, models might be used to simulate the impact of severe weather events on the grid and predict effectiveness of various investments to avoid interruptions. Assess usefulness of risk reduction metrics from these types of analyses for planning projects and tracking system risks. Also assess their usefulness for measuring past outage avoidance and documenting benefits of recent investments.

- **Accelerate the evolution of design standards to address anticipated threats.** An area for future research involves bridging the gap between high-level forecasted weather data and granular engineering specifications. Examine current utility practices to develop practical and easily replicated methods for downscaling long-term predictive weather models into actionable asset-level criteria, such as wind loading or flood elevation standards. PSCo identified this as a necessary next step following its risk and resilience study. Focus on the lag time between identifying a threat and implementing new design standards, ensuring that infrastructure built today is resilient to weather conditions projected for 2050 and beyond.

- **Assess levels of risk aversion among utilities and stakeholders.** Research can help utilities and regulators define "acceptable" levels of risk. HECO (2023) notes that a system where no customers lose power is not cost-effective, necessitating the establishment of resilience performance targets. Explore different ways to measure and how best to operationalize residual risk. For example, some risks may be better mitigated through infrastructure investment rather than managed through emergency response or insurance.

- **Examine the impact of utility organizational structure on integration.** Evaluate how organizational silos affect the speed and efficacy of grid transformation. Understand when and how centralized planning teams break down barriers to integration. Examine utility workforce development needs to support integrated planning, such as skill sets required for data analytics and project management. Finally, document the influence of different cross-departmental governance structures on the implementation of NWAs and data-sharing initiatives.

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Appendix. Distribution System Plans Included in Initial Review

State	Plan type	Utility
California	Grid Needs Assessment, Distribution Deferral Opportunity Report	SCE (2024)
California	Grid Needs Assessment, Distribution Deferral Opportunity Report	PG&E (2024)
California	Grid Needs Assessment, Distribution Deferral Opportunity Report	SDG&E (2024)
Colorado	Distribution System Plan	PSCo (2024)
Colorado	Distribution System Plan	Black Hills Colorado Electric (2025)
Delaware	Infrastructure, Safety, and Reliability Plan	Delmarva (2024)
Delaware	Long Range Distribution Plan	Delmarva (2022)
District of Columbia	Annual Consolidated Report	Pepco (2025)
Georgia	Rate Case Filing	Georgia Power (2022)
Hawaii	Integrated Grid Plan	HECO (2023)
Illinois	Multi-Year Integrated Grid Plan	Ameren Illinois (2024)
Illinois	Multi-Year Integrated Grid Plan	ComEd (2024)
Indiana	6-Year Electric Plan	Duke Energy (2024)
Indiana	6-Year Electric Plan	Northern Indiana Public Service Company (2024)
Indiana	6-Year Electric Plan	Southern Indiana Gas and Electric Company (2023)
Kentucky	Rate Case Filing	Louisville Gas & Electric and Kentucky Utilities Company (LG&E and KU) (2025)
Massachusetts	Electric Sector Modernization Plan	Unitil (2024)
Massachusetts	Electric Sector Modernization Plan	Eversource (2024)
Massachusetts	Electric Sector Modernization Plan	National Grid (2024)
Michigan	Distribution Grid Plan	DTE Electric (2023)*
Michigan	Electric Distribution Infrastructure Investment Plan	Consumers Energy (2023)
Michigan	Distribution Plan	Indiana & Michigan Power (2023)
Michigan	Distribution Investment and Maintenance Plan	UPPCO (2025)
Michigan	Distribution Plan	Northern States Power Company (2024)
Michigan	Distribution Investment and Maintenance Plan	Alpena Power Company (2024)

State	Plan type	Utility
Minnesota	Integrated Distribution Plan	Northern States Power Company (2023)
Nevada	Distributed Resource Plan	NV Energy (2023)
New Mexico	Grid Modernization Plan	PCSO of NM (2022) - Part 1/2 and Part 2/2
New York	Distributed System Implementation Plan	ConEd (2023)
New York	Distributed System Implementation Plan	National Grid (2023)
New York	Distributed System Implementation Plan	NYSEG (2023)
New York	Distributed System Implementation Plan	Central Hudson (2023)
New York	Distributed System Implementation Plan	Orange & Rockland Utilities (2023)
Oklahoma	Rate Case Filing	OG&E (2021)
Oklahoma	Rate Case Filing	Public Service Company of Oklahoma (2024)
Oregon	Distribution System Plan	PGE (2024)
Oregon	Distribution System Plan	Idaho Power (2022)
Pennsylvania	Long-Term Infrastructure Improvement Plan	UGI (2024)
Pennsylvania	Long-Term Infrastructure Improvement Plan	Philadelphia Electric Company (2024)
Pennsylvania	Long-Term Infrastructure Improvement Plan	Duquesne Light Company (2024)
Pennsylvania	Long-Term Infrastructure Improvement Plan	PPL (2024)
Rhode Island	Grid Modernization Plan	Rhode Island Energy (2022a)
Rhode Island	T&D Improvement Plan	Rhode Island Energy (2022b)
Vermont	Integrated Resource Plan	Green Mountain Power (2024)
Vermont	Integrated Grid Plan	Morrisville (2023)
Vermont	Integrated Grid Plan	Enosburg Falls (2024)
Virginia	Integrated Grid Plan	Dominion (2024) - Part 1/2 and Part 2/2
Virginia	Integrated Grid Plan	Appalachian (2022) - Part 1/3, Part 2/3, and Part 3/3
Washington	Integrated Grid Plan	Avista (2025)
Washington	Integrated Grid Plan	PacifiCorp (2025)

* DTE Electric's 2026 DSP was filed in April 2026.