Title

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State Requirements for Electric Distribution System Planning

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See our companion online catalog of state distribution planning requirements. Additional information is available on Berkeley Lab's Integrated Distribution System Planning website, including an interactive decision framework for integrated distribution system planning, and DOE's Distribution Grid Transformation website.

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Acronyms and Abbreviations

AMI	advanced metering infrastructure
CAIDI	Customer Average Interruption Duration Index
CE	cost-effectiveness
CELID	customers experiencing long interruption duration
CEMI	customers experiencing multiple interruptions
DER	Distributed Energy Resource
DG	distributed generation
DOE	U.S. Department of Energy
DSP	distribution system planning
DSIP	Distributed System Implementation Plan
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
GW	gigawatt
HCA	Hosting capacity analysis
HECO	Hawaiian Electric Company
IDP	Integrated Distribution Plan
IDSP	integrated distribution system planning
IEEE	Institute of Electrical and Electronics Engineers
IGP	Integrated Grid Plan
IRP	integrated resource plan
ISO	Independent System Operator
kW	kilowatt
kWh	kilowatt-hour
MW	megawatt
MWh	megawatt-hour
NWA	non-wires alternative
NWS	non-wires solution
PBR	performance-based regulation
PGE	Portland General Electric
PSC	Public service commission
PUC	Public utility commission
PV	photovoltaic
RFP	request for proposals
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	supervisory control and data acquisition

SCE	Southern California Edison
TEP	transportation electrification plan
TOU	time of use

Executive Summary

Utility distribution systems deliver electricity locally to homes and businesses. Traditionally, utilities sourced power from remote generating facilities and carried it over long-distance, high-voltage transmission systems to local grids. While that is still true today, an array of distributed energy resources (DERs) connected at the distribution level—solar panels, battery storage, electric vehicle (EV) chargers, and demand flexibility technologies like smart thermostats—are now providing energy, load relief, and other grid services. These resources affect planning and operation of distribution systems[1] as well as bulk power systems.[2]

Integrated distribution system planning (IDSP) is a decision framework to enable formulation of long-term investment strategies for local grids, addressing state and local policy goals, objectives, and priorities, consumers' needs, and evolution at the grid edge (Figure ES-1). Ideally, IDSP is coordinated with resource and transmission planning for the bulk power system.

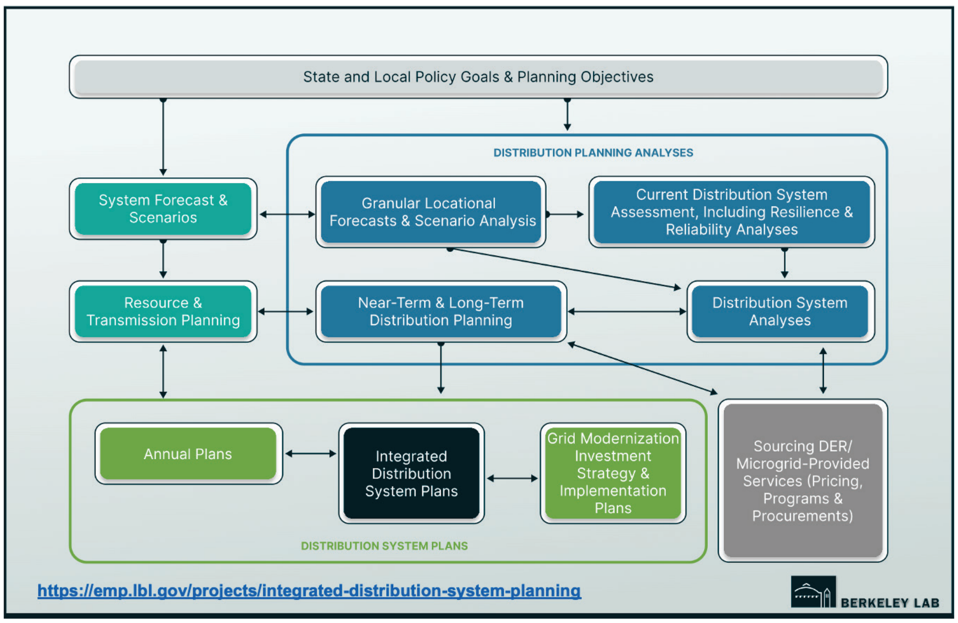

Figure ES-1. Integrated Distribution System Planning Framework

Source: Berkeley Lab

Utilities have conducted distribution system planning since they first began generating and delivering electricity. Over the past decade, 20 states have adopted requirements for regulated electric utilities to file these plans for regulatory and stakeholder review. These plans serve a variety of aims, from improving reliability, to integrating DERs, to modernizing the grid.

[1] See De Martini, P., and L. Schwartz, Distribution System Evolution, 2024; Electric Power Research Institute, *Enabling DER Services in Distribution Operations*, forthcoming.
[2] See Biewald, B. et al., Best Practices in Integrated Resource Planning: A guide for planners developing the electricity resource mix of the future, 2024.

Distribution system planning is increasingly integrated with other utility and state planning processes—for example, for the bulk power system (generation and transmission), DERs, electrification, and state energy plans. Coordination ensures that utilities plan and maintain distribution systems to achieve multiple objectives and priorities at least cost. The extent of coordination ranges from simply referring to other regulatory proceedings and plans to employing iterative and integrated modeling across planning processes (Figure ES-2). The level of coordination required varies by state (Table ES-1).

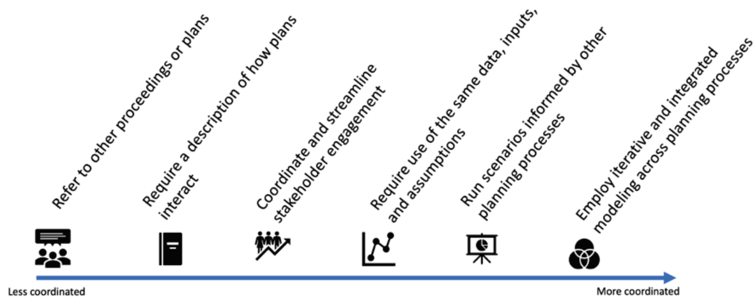

Figure ES-2. Levels of Coordination Across Planning Processes

Table ES-1. Coordinated Plans and Type of Coordination by State

State	Bulk Power (IRP and Transmission)	DERs (including efficiency)	Electrification	Other Related Plans	Highest Level of Coordination
CA	●	●	●	●	
CO	●	●	●	●	
DC				●	
HI	●	●	●	●	
IL	●	●	●	●	
ME	●	●	●	●	
MA	●	●	●	●	
MI	●	●			
MN	●		●	●	
NV	●	●			
NM	●			●	
NH		●		●	
NY	●	●	●	●	
OR	●	●	●	●	
RI		●		●	
VT	●	●	●	●	
VA	●			●	
WA	●	●	●	●	

This report summarizes planning guidance from state legislatures and utility regulators and identifies leading planning practices in the following areas:

- Goals and objectives
- Procedural elements
- Stakeholder engagement
- Forecasting loads and DERs
- Hosting capacity analysis
- Information on the current state of the distribution system
- Grid modernization strategy
- Grid needs assessment
- Non-wires alternatives (NWAs)
- Reliability and resilience analyses
- Equity
- Pilots
- Coordination with other planning processes

An accompanying data visualization and catalog provides interactive maps as well as information and links to state and utility documents.

1. Goals and Objectives

Some 20 states have adopted requirements for distribution system planning for regulated electric utilities through legislation or regulation, or both. Requirements begin with goals and objectives that define long-term, high-level outcomes for grid planning, including core utility functions such as maintaining a safe and reliable distribution system at affordable rates. Goals and objectives also may address specific state policy priorities such as transportation electrification, renewable resources, economic development, and DER integration and utilization.

1.1 Establishing Goals and Objectives

In addition to establishing a high-level vision for grid planning, state — and local — policies may include specific outcomes. For example, Colorado requires distribution system plans that in part create sufficient hosting capacity[3] to support state goals such as increased levels of affordable housing and electrified transportation.

In addition to interpreting in rules and decisions how state policies apply to regulated utilities in the context of distribution planning, public utility commissions (PUCs) may establish their own planning objectives based on the agency's overarching mission and authorities. Stakeholder input is critical when establishing and prioritizing objectives in relation to one another. Stakeholder engagement upfront also helps build buy-in for the planning process.

Effective planning first establishes guiding principles and objectives, rather than leaping to technology choices. Principles are mission-oriented foundations that guide reasoning and decision-making. Objectives are the vision for the desired result with clear scope, timing, and associated metrics. Principles and objectives determine grid capabilities needed, which in turn establish distribution system functionality and system requirements (Figure 1-1). Ultimately, utilities procure equipment, technologies, and services to fill those requirements.

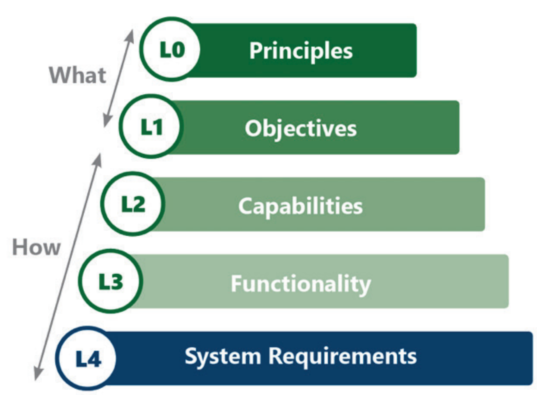

Figure 1-1. Taxonomy of Structures to Organize and Align Distribution System Planning

[3] See Chapter 5.

1.2 Types of Goals and Objectives[4]

1.2.1 Reliability and resilience

Core functions and obligations for utilities include operating a system that is safe and that maintains an acceptable level of reliability. Including these as planning objectives helps ground distribution plans in meeting the utility's basic obligations in conjunction with other state goals. Reliability focuses on the frequency and duration of outages. Resilience is an emerging goal for distribution system planning. While reliability objectives cover day-to-day performance, resilience focuses on preventing and responding to severe events due to natural and human-caused hazards — storms, floods, droughts, extreme temperatures, freezes, hurricanes, sea level rise, wildfires, seismic events, and cyber and physical attacks. When resilience is included as a goal for DSP, it is considered in conjunction with reliability.

Fifteen states (CA, CO, CT, DE, HI, IN, MA, MI, MN, NH, NM, NV, RI, VA, VT) and the District of Columbia have established reliability a distribution system planning (DSP) goal, with five of these states also explicitly citing resilience. For example, Massachusetts statute identifies that utility Electric-Sector Modernization Plans should be designed to improve grid reliability, communications, and resiliency.

Changing grid conditions, such as higher levels of DERs, create new challenges as well as opportunities for maintaining reliability and resilience. Virginia's Clean Economy Act states that "any plan for electric distribution grid transformation projects shall include both measures to facilitate integration of distributed energy resources and measures to enhance physical electric distribution grid reliability and security."

1.2.2 Customer choice and engagement

Ten states (CA, CT, HI, IL, MA, MN, NH, NY, RI, VT) identify customer choice and engagement in energy services as a goal or objective of DSP. For example, the Minnesota PUC's objectives for Integrated Distribution Plans include "Enable greater customer engagement, empowerment, and options for energy services." Among New York's objectives for Distributed System Implementation Plans is to "serve as a source of public information regarding DSP plans and objectives, including specific system needs allowing market participants to identify opportunities." Rhode Island calls for utilities to "prioritize and facilitate increasing customer investment in their facilities … where that investment provides recognizable net benefits." Vermont aims to "empower consumers to manage their energy choices."

1.2.2 Deployment of new technologies and services

Five states (CA, CT, IL, MI, MN) include an DSP objective to accelerate deployment of new technologies and services to optimize grid performance and minimize electricity system costs. For example,

[4] This section relies on Frick, N., et al., "Distribution System Planning: Goals and Objectives," Lawrence Berkeley National Laboratory, April 25, 2023.

Connecticut requires regulated utilities to "investigate the comprehensive and competitive inclusion of electric storage as well as other innovative technologies." Illinois aims to "promote opportunities for third-party investment in nontraditional, grid-related technologies and resources." Minnesota PUC objectives for DSP include "Move toward the creation of efficient, cost-effective, accessible grid platforms for new products and services, with opportunities for adoption of new distributed technologies."

1.2.3 DER adoption and integration

Distributed solar and storage are increasingly attractive to consumers interested in renewable energy sources, controlling electricity costs, and increasing resilience to grid outages. DERs can help utilities to operate their systems more cost-effectively by taking advantage of grid services from resources already deployed. Improved integration may require utility investments in communications and control technologies.

Distribution planning objectives in eight states (CA, CO, HI, IL, MA, MN, OR, VA) and the District of Columbia support DER integration and utilization for grid services. Some of the objectives relate to DER interconnection, including enhancing hosting capacity maps (Maine), proactively identifying necessary grid investments to interconnect new DERs (California), or improving DER interconnection practices (Hawaii). In some states, a major objective for distribution planning is to promote DER adoption. For example, in California, utilities must identify optimal locations for DER deployment, barriers to DER deployment, and necessary spending to integrate cost-effective DERs. Washington requires utilities to assess the potential for DERs to contribute to system needs as part of their Clean Energy Action Plans. The Maine PUC established three priorities for Integrated Grid Planning, one of which is promoting flexible management of customer resources and energy consumption, including "Support integration and utilization of DERs to enable load flexibility and resilience." Hawaii, Washington, and Rhode Island identify as policy priorities fair DER compensation to customers for the grid services they provide.

1.2.4 Other objectives

Several states identified goals and objectives that address other state policies, such as:

- Affordability (CO, CT, DC, IL, MI, RI)
- Equity (CO, IL, MN, OR, WA)
- Stakeholder engagement and transparency (CA, DC, HI, IL, MI, NY, OR)
- Economic development (IL, IN)
- Reducing greenhouse gas (GHG) emissions and supporting a clean energy transition (CO, CT, DC, HI, IL, MA, OR)

As an example, the Connecticut Public Utilities Regulatory Authority's interim decision on its Framework for an Equitable Modern Grid included objectives related to cost-effectiveness in the energy transition and to "advance the ongoing energy affordability dialogue in the State, particularly in underserved communities."

Equity is an emerging priority for electricity system planning. In Minnesota, the Commission ordered Xcel Energy to map reliability and service quality metrics and demographic data to reveal inequities in service quality.[5] In Hawaii, the Commission must balance technical, economic, environmental, and cultural considerations when considering grid modernization investments. As a group of islands, the state also prioritizes a diverse resource portfolio to support energy independence and reliability.

Some states call out the importance of stakeholder engagement and transparency, which also helps promote equitable outcomes by inviting diverse voices into the process. The Michigan Public Service Commission, for example, stated that a "transparent, holistic distribution planning effort is foundational to making informed decisions and spurring collaboration on these complex issues."

In Illinois, grid planning legislation identifies that distribution system expenditures should be evaluated in the context of the state's goals, including whether they create "significant economic development, environmental, and public health benefits in the state." This planning framework recognizes that investments in electric system infrastructure have wide impacts and serve multiple state objectives.

Jurisdictions may explicitly call out GHG reduction as a specific planning objective or discuss environmental issues more holistically. By law, the Public Service Commission of the District of Columbia assesses whether the utility's actions will support achievement of the District's energy and climate change commitments. Oregon, Hawaii, and Illinois similarly link planning to a state emissions reduction goal.

Some states are beginning to call out electrification as DSP objectives. For example, Colorado's DSP rules identify that the Commission will evaluate the plans in light of how they promote progress towards the state's policies, including building and transportation electrification.

Finally, a few states have linked DSP objectives with federal funding available through the Bipartisan Infrastructure Law (BIL) and Inflation Reduction Act (IRA). These laws impact the costs and benefits of different resources that are important to capture in utility planning.[6] Both the Minnesota and Colorado Commissions have ordered regulated utilities to consider the effects of the IRA on distribution system-related plans. In Minnesota, the Commission asked utilities to discuss how they plan to maximize the benefits of available funding.[7]

[5] See Dec. 18, 2020, order in Docket 20-406, in Minnesota PUC's eDockets.
[6] Fitch, T., et al. 2024. Planning to Harness the Inflation Reduction Act. RMI.
[7] See Docket 22-624 in Minnesota PUC's eDockets.

2. Procedural Elements

Statutory or regulatory requirements identify major distribution planning steps, specify a cadence for plan filings, and define time horizons for various plan elements. Requirements also may specify confidentiality provisions, stakeholder engagement activities (see Chapter 3), consideration of plans in cost recovery proceedings, and coordination with other utility plans as well as state plans. In addition, provisions may include a completeness review to determine whether a distribution plan filing includes all required elements. For example, Maine's integrated grid planning statute specifies that the Commission may order the utility to revise the filing to address any deficiencies.

2.1 Filing Frequency

Considerations for setting filing frequency include alignment with utility capital planning processes, workload, timeliness for tracking progress on goals and objectives, and filing cycles for other types of plans.

Recognizing that distribution system needs change rapidly, several states require distribution plan filings every two years:

- Colorado (large utilities file in even years, small utilities file in odd years)
- Connecticut
- Minnesota
- New York
- Oregon (staggered utility filings)[8]

States that require distribution planning within a broad grid planning process, or require distribution-related plans to be filed with other plans (e.g., integrated resource plans), may require full filings every 3–5 years (HI, IL, MA,[9] ME, MI, NV, and VT). States that require less frequent filings may require utilities to submit an annual update or report on a specific portion of the filing — for example:

- California requires an annual Grid Needs Assessment and Distribution Upgrade Project Report.
- Delaware requires an annual distribution Safety, Infrastructure, and Reliability Plan, with long-range plans required every five years.
- District of Columbia requires an annual "consolidated report" for distribution system planning.[10]
- Indiana requires an annual Transmission, Distribution, and Storage System Improvement Charge and Deferrals report.
- Pennsylvania requires annual Asset Optimization Plans.
- Rhode Island requires annual Least-Cost Procurement Plans.

[8] The cadence of plan filings after 2026 will be set in the next guideline revision process or by future Commission order.
[9] Massachusetts utilities also file annual Reliability Reports.
[10] The Public Service Commission of the District of Columbia recently issued a Notice of Inquiry for implementing Integrated Distribution System Planning for electric utilities, FC 1182.

2.2 Planning Horizon

The planning horizon defines the period of study for the plan. Distribution planning requirements across the country are converging on a minimum 10-year planning horizon. Factors in setting the timeframe include construction timelines for substations and other large projects, the planning period for related filings such as integrated resource plans, and state policies such as renewable energy and electrification targets. The California Commission, for example, set the planning horizon in consideration of other state agency and forecasting processes. States also may specify a study period for forecasts or discrete planning elements such as the grid needs assessment.

Plans typically include both a long-term investment plan and near-term action plan. Long-term plans establish the utility's strategy, including a roadmap of capital and maintenance expenditures to address identified grid needs. Near-term plans identify with greater specificity the proposed expenditures to address more immediate grid needs.

Colorado, Hawaii, Michigan, Minnesota, New York, and Oregon require 5-year action plans, while the timeframe in other states is shorter. Action plans often include the following elements:

- Actions, investments, and other expenditures necessary to meet identified grid needs
- Description and justification of how each planned investment supports achievement of the plan's objectives and goals
- Description of how proposed investments interact with other utility plans and programs
- Costs and benefits of proposed expenditures, including customer bill impacts and proposed cost recovery mechanism
- Timeline for proposed investments and actions
- Description of the decision-making framework used for assessing and prioritizing investments and activities
- Proposed pilot programs
- Proposed NWA process

For example, in Colorado, the near-term action plan includes the sequence of events and timing for implementation of NWAs, proposed pilots and programs, major distribution projects determined to be the best option to address grid needs and to cost-effectively interconnect approved and reasonably forecasted Community Solar Gardens capacity, and a system interoperability and communications strategy; costs and plans for NWA evaluation, including acquisition of data; and interaction of planned or proposed investments with utility programs and effects on existing utility programs and tariffs.

2.3 Other Procedural Elements

Requirements may specify other procedural requirements, such as confidentiality provisions, stakeholder engagement, how the Commission will review the filing submission, and relationships with other filings or proceedings.

Typically, regulators allow utilities to apply to file sensitive information under seal according to relevant rules and procedures. For distribution-related filings, the Commission may provide specific guidance with respect to confidentiality provisions such as:

- Level of specificity for hosting capacity maps to provide useful information for developers while protecting customer privacy and security
- Peak demand/capacity by feeder
- Contractual cost terms
- Bidder responses to NWA solicitations
- Proprietary model information

Stakeholder engagement requirements may specify a minimum number of workshops, types of participants, topics to cover, and who will facilitate (see Chapter 3).

Unless otherwise specified in statute, distribution planning is an informational proceeding. In rules or guidance, the Commission may specify how distribution plans interact with rate cases and other proceedings and how the Commission will review distribution plan filings. For example, the Maine Public Utilities Commission stated that "The appropriate time to evaluate the costs of investments associated with the grid plans is when those costs are known and a utility seeks to recover those costs in either distribution or transmission rates." The Commission further specified that approval of an Integrated Grid Plan does not constitute pre-approval of cost recovery of included utility investments or address the prudency of investments and how the utility implements them. At the same time, the Commission stated its intent to provide guidance on near- and long-term investments through Integrated Grid Plan proceedings. Vermont's guidelines state, "Timely review and potential support of the IRP [including required distribution planning provisions] depends on effective and engaged communication from both the utility and the Department during these conversations."

3. Stakeholder Engagement

Stakeholder engagement can improve the quality of information in regulatory proceedings, develop solutions with broad support, build trust among parties, and produce better plans. Of the 20 jurisdictions requiring distribution utilities to file some type of distribution plan, 13 states include provisions for stakeholder engagement (CA, CO, HI, IL, MA, MD, ME, MI, MN,[11] NV, NY, OR, WA).

Requirements for utilities to engage stakeholders may apply in four points in the DSP process: (1) prior to DSP filing, (2) when reporting on DSP implementation, (3) after DSP filing, and (4) when considering changes for future DSP filings (Figure 3-1).

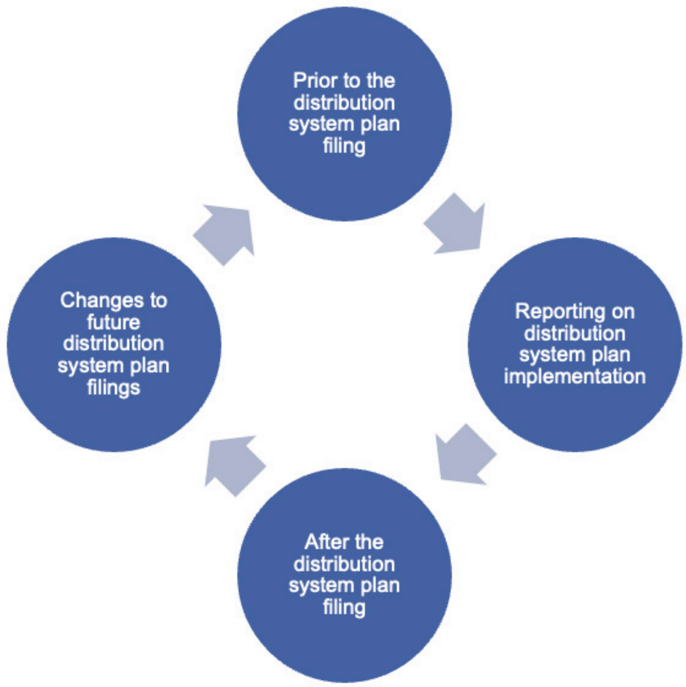

Figure 3-1. When DSP Stakeholder Engagement May Be Required in the DSP Process

The majority of DSP stakeholder engagement requirements focus on the utility sharing information with stakeholders and providing an opportunity to offer feedback before filing the plan (CO, HI, IL, MA, MN, NY, OR, WA). Common actions include specifying the minimum number of stakeholder meetings the utility must hold prior to plan filing (CO, IL, MA, MN, OR),[12] requiring certain topics to be discussed at stakeholder meetings (CO, IL, MN), and establishing working groups (DC, HI, WA).

Several states require that utilities describe their stakeholder engagement process as part of the DSP filing (CA, CO, IL, MN, NY, OR, RI), such as a description of the process, feedback received, and

[11] See Aug. 30, 2018, order in Docket No. E-002/CI-18-251, in Minnesota PUC's eDockets.

[12] State PUCs may also voluntarily host informational workshops as part of the distribution system planning process (MI, OR).

responses to stakeholder comments. In addition to stakeholders participating in formal regulatory proceedings, some states specify requirements for stakeholder engagement after the utility files its DSP, for example, through workshops or additional working group meetings (e.g., CA, MN).

As states gain experience with the DSP process, several have provided regulatory guidance to the utilities to improve DSP stakeholder engagement (e.g., MA, MI, MN,[13] NV).

3.1 Stakeholder engagement during development of DSP regulatory requirements

As with other regulatory proceedings, PUCs engage stakeholders when developing DSP requirements. In most states, this is a PUC-led effort; in some cases, the Commission may direct utilities to propose a DSP process for stakeholder and regulatory review (CA, NY).

3.1.1 California

The CPUC first established Distribution Resources Plan requirements in 2014. In 2021 the CPUC established a Rulemaking to Modernize the Electric Grid for A High DER Future to build on these requirements. As part of the ongoing proceeding, the Commission asked investor-owned utilities to describe their "current Local Planning Engagement processes, forums for outreach to stakeholders, existing challenges, and improvement plans. Include a discussion of how the utility will improve engagement and communication with local and regional planning entities, ensuring that infrastructure planning and additions at the regional and local level are informed by an IOU's DPP [Distribution Planning Process] and vice versa."

3.1.2 Connecticut

The Public Utilities Regulatory Authority (PURA) reopened its investigation IDSP in 2023. The Authority stated that the "proceeding will require the engagement of all Participants and stakeholders to thoroughly vet any IDSP orders and guidance issued… The Authority anticipates that Participants and stakeholders will be able to participate in this reopener docket through engagement opportunities such as: regular Technical Meetings organized around Participant and stakeholder presentations; developing and submitting IDSP proposals; and responding to interrogatories and/or requests for written comment."

3.1.3 District of Columbia

The Public Service Commission's Modernizing the Energy Delivery System for Increased Sustainability proceeding established six working groups to develop recommended actions and next steps on data and information access and alignment, NWAs, rate design, customer impact, microgrids, and pilot projects. The working group submitted recommendations to the PSC on these topics in its final report.

[13] July 31, 2020, Order in Docket No. 19-685, available in Minnesota eDockets.

3.1.4 Maine

State legislation establishing Integrated Grid Planning requirements directed the PUC to initiate a proceeding to identify distribution plan priorities for utility plans. As part of that process, the PUC must hold technical conferences or stakeholder workshops before the filing to identify priorities, assumptions, goals, methods and tools to assist the utilities in developing their grid plan.

3.1.5 Maryland

The Maryland PSC created a working group process to propose DSP requirements, stating that "an important goal of exploring and developing a Maryland-specific Distribution System Planning process is to increase opportunities for early, meaningful stakeholder engagement through increased transparency and coordination."

3.1.6 Minnesota

In 2015, the Commission began a proceeding to consider filing requirements for grid modernization plans required by the state legislature. After holding stakeholder meetings, the Commission issued a report in 2016 defining grid modernization, identifying principles to guide its implementation in Minnesota, and proposing next steps. Later that year, the Commission held a workshop seeking stakeholder input on broader distribution planning efforts. In 2017, the Commission issued and assessed utility and stakeholder responses to a questionnaire[14] designed to collect information about the utilities' distribution planning processes and current plans and ways to improve them. In 2018, the Commission adopted proposed filing requirements, informed by a stakeholder process and parties' comments.

> "Stakeholder input into the iterative process has been a valuable resource in developing appropriate IDP requirements, solidifying planning objectives, clarifying draft language, and making modifications as appropriate." — *Minnesota PUC, August 30, 2018, Order in Docket 18-251*

3.1.7 New York

Prior to the utilities filing their first distribution system improvement plans (DSIPs), New York PSC staff filed a guidance document to identify what content must be included. On the same day, the PSC issued a Notice Inviting Public Comment on the Distributed System Implementation Plan Guidance. The comments received were summarized in the Commission's Order Adopting Distributed System Implementation Plan Guidance.

3.1.8 Oregon

The PUC opened an investigation on DSP in response to a white paper by PUC staff. The Commission approved staff's proposed approach, from developing DSP requirements to completing review of utility plans (Figure 3-2).

[14] April 21, 2017, Order in Docket No. 15-556, available through Minnesota eDockets.

	Pre-Launch	Phase 1: Baselining	Phase 2: Assessment	Phase 3: Refinement
Time-frame	February - March 2019	March 2019 – December 2019	January 2020 – May 2021	June 2021 - ongoing
Goal	Identify the focus of and process for a DSP investigation	• Begin developing a knowledge-base for the major DSP principles • Develop guidelines to evolve the smart-grid report into a robust (initial) distribution system plan	Review the current state of each utility's system, identify near- and long-term needs and next steps to get to optimization	Refine planning process, incorporate additional considerations and requirements

Process	• Staff whitepaper released: Outlines Staff proposal for DSP investigation.
	• Scoping workshop: Stakeholder feedback on Staff proposal i.e., establish whether OPUC has outlined the correct drivers, outcomes, phases, goals and deliverables.
	• Public meeting memo: Staff's final proposal requesting investigation.
		• Workshops: Staff will conduct a series of workshops to establish a baseline understanding of distribution system planning fundamentals, current utility processes, and outstanding distribution planning needs.
		• Draft guidance: Staff releases draft proposal for DSP guidance.
		• Stakeholder comments/ workshop(s) as necessary
		• Revised draft guidance
		• Final comments
		• Public meeting memo: Staff final proposal for DSP guidance.
			• Establish individual utility dockets
			• Utilities file based on Commission guidance (~ 8 months)
			• OPUC and stakeholder engagement process (~ 6 months)
			  ▪ Comments
			  ▪ Workshops
			• Public meeting memo: Staff final recommendations (~April 2021)
				• Continue to implement planning process as directed by Commission
				• Improve and evolve content, process, tools, and methodologies
				• Continue to incorporate evolving policy and operational requirements

Key Objective	Commission order opening investigation	Commission order adopting guidance for utilities to file initial DSPs	Commission orders accepting utilities' initial DSPs and direction to refine DSP process and/or DSP guidance	Commission approval of subsequent utility DSPs as determined during Phase 1 and guidance for refinement of subsequent utility DSPs

Figure 3-2. Development of DSP Guidance in Oregon, With Stakeholder Engagement

Stakeholder engagement is featured prominently in the process. Prior to requesting that the Commission open an investigation, staff held a workshop to gather feedback on its whitepaper. In the "Baselining" phase of the process, staff conducted eight workshops to establish a common understanding of DSP and solicit input from stakeholders on the proposed DSP process, including through a questionnaire to the utilities, third-party administrator of energy efficiency and solar programs, and other stakeholders. Staff used stakeholder input to inform its proposed DSP guidance submitted to the Commission for approval.

3.2 Stakeholder engagement prior to DSP filing

Eight states require regulated utilities to engage stakeholders before they file plans (CO, HI, IL, MA, ME, MN, NY, OR, WA).

3.2.1 Colorado

Distribution system planning regulations require the utility to hold at least one stakeholder meeting three months prior to DSP filing, including to solicit input on future DER programs and pilots, and provide feedback on hosting capacity analysis and online information. The PUC also encouraged the utilities to hold regular, informal stakeholder meetings.

In addition, the utility must make “reasonable efforts” to engage local government and community-based organizations representing disadvantaged communities, and include a description of the stakeholder engagement process in DSP filings.

3.2.2 Hawaii

Hawaii has a robust IGP stakeholder engagement process that includes meetings for technical and non-technical audiences with clear agendas and objectives in advance of the IGP filing, a central location for all IGP documents and analysis, and documentation of how stakeholder feedback is incorporated into IGP work products.

Early in the IGP process, the Commission required the Hawaiian Electric Company, Inc. (Companies) IGP workplan to include details and descriptions of "(1) the proposed Working Groups, including their specific objectives, composition, expected deliverables, and timelines for those deliverables; (2) a specific proposal for how forecasting assumptions, system data, modeling inputs, studies, analyses, meeting summaries, and other data will be shared with the commission and stakeholders throughout the IGP process,” among other requirements.

The Companies’ workplan detailed its stakeholder engagement model. It included broad public engagement, a Stakeholder Council, seven working groups (Forecasting Assumptions, Resilience, Distribution Planning, Standardized Contract, Grid Services, Solution Evaluation and Optimization, Competitive Procurement), and a Technical Advisory Panel (Figure 3-3).

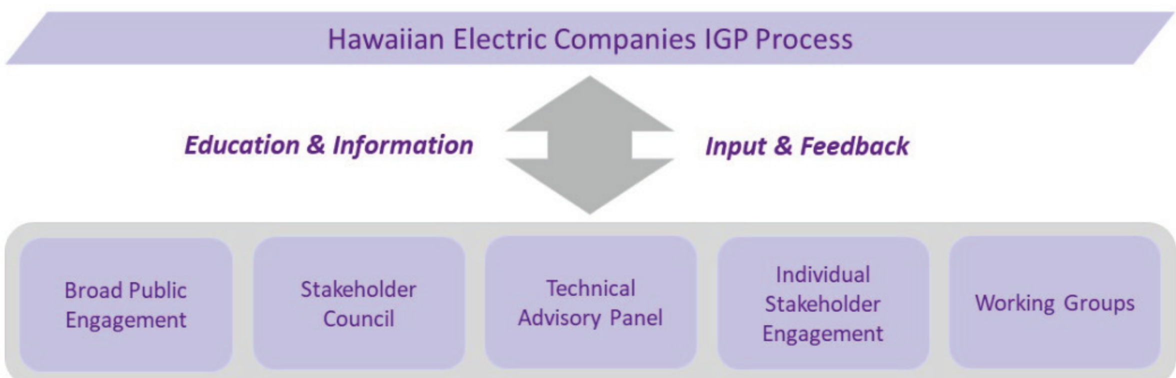

Figure 3-3. Companies IGP Stakeholder Engagement Model

The Stakeholder Council includes representatives from cities, counties, each island, state agencies, partner agencies, and developers, and helps align planning with interests across the islands. Working Groups serve in an advisory capacity and are focused on topics like social and economic resilience, transmission planning, and sourcing and evaluation of contractors. The Technical Advisory Panel consists of experts in energy technologies and engineering who provide an independent source of peer assessment.

"The strength of the Workplan lies in the robust stakeholder engagement model. The Stakeholder Council, the Technical Advisory Panel, and each Working Group has clear objectives, responsibilities, membership, and schedules. But, the Workplan does not presuppose the outcome of each Working Group's discussions — to do so in advance would deny the Working Groups the flexibility they will need to complete their respective tasks. Critically, the Companies have connected the anticipated work products of these groups to specific IGP process gaps. The Workplan proposes mechanisms to enable the flow of information between the different tiers of the Stakeholder Council, Technical Advisory Panel, and Working Groups." — *Hawaii PUC*

Additional Commission guidance suggested refinements to the stakeholder process, including that the Companies provide slides and an agenda prior to meetings, identify clear objectives and outcomes for each meeting, create an opportunity for stakeholders to provide immediate feedback (e.g., an evaluation form), and set up a file sharing method to make information accessible to all stakeholders. In the same order, the Commission also required the Companies to take into account stakeholder feedback in its decision-making and modified the Companies' proposed approach, requiring them to "clearly state how the Companies incorporate stakeholder feedback in the Working Groups' work products" and not simply record stakeholder feedback. The Commission reaffirmed the importance of stakeholder input in subsequent IGP orders.

3.2.3 Illinois

The state's Climate and Equitable Jobs Act established a Multi-Year Integrated Grid Plan process with stakeholder engagement requirements. Each utility must hold at least six workshops and work with an independent facilitator to share specific information with stakeholders, including planned capital investments, as well as data on reliability, resiliency, service quality, and DERs. The utility also must request input from a diverse set of stakeholders, discuss stakeholder proposals to achieve state goals, and educate participants. The Act specified the types of stakeholders that must be included in the process and established a minimum 5-month timeline for stakeholder engagement.

3.2.4 Massachusetts

State law directing utilities to file electric-sector modernization plans require the utilities to conduct technical conferences and hold at least two stakeholder engagement meetings. The law also established a Grid Modernization Advisory Council to improve transparency and stakeholder engagement in grid planning processes.

3.2.5 Maine

The PUC must hold technical conferences or stakeholder workshops before each Integrated Grid Planning filing (every five years) to identify priorities, assumptions, goals, methods and tools to assist the utilities in developing their grid plan.

3.2.6 Minnesota

The PUC directed Xcel Energy to hold at least one stakeholder meeting prior to filing its original plan. Meetings must occur early enough in the process that the utility can obtain and incorporate appropriate public input into its filed plan. In its order on Xcel Energy's 2021 IDP,[15] the Commission required the Company to hold a minimum of four stakeholder meetings to "collaborate with interested parties, obtain input, and generate new ideas around a shared vision of the distribution grid of the future."

The PUC also established topics for which Xcel Energy should seek input during stakeholder meetings, including load and DER forecasts, proposed distribution system investments in the next five years, anticipated capabilities due to these investments, customer benefits from proposed utility actions in the next five years, and consistency with the Commission's specified planning objectives.

3.2.7 New York

The PSC adopted guidance for Distributed System Implementation Plans in 2016, directing that the utilities file a plan and timeline for stakeholder engagement during development of their first plans. The proposed stakeholder engagement strategy filed by the Joint Utilities of New York included launching a [website](#) to facilitate all interested parties to stay up-to-date on DSIP activities and related topics. The stakeholder framework includes an Advisory Group, Engagement Group, and Technical Conferences (Figure 3-4).

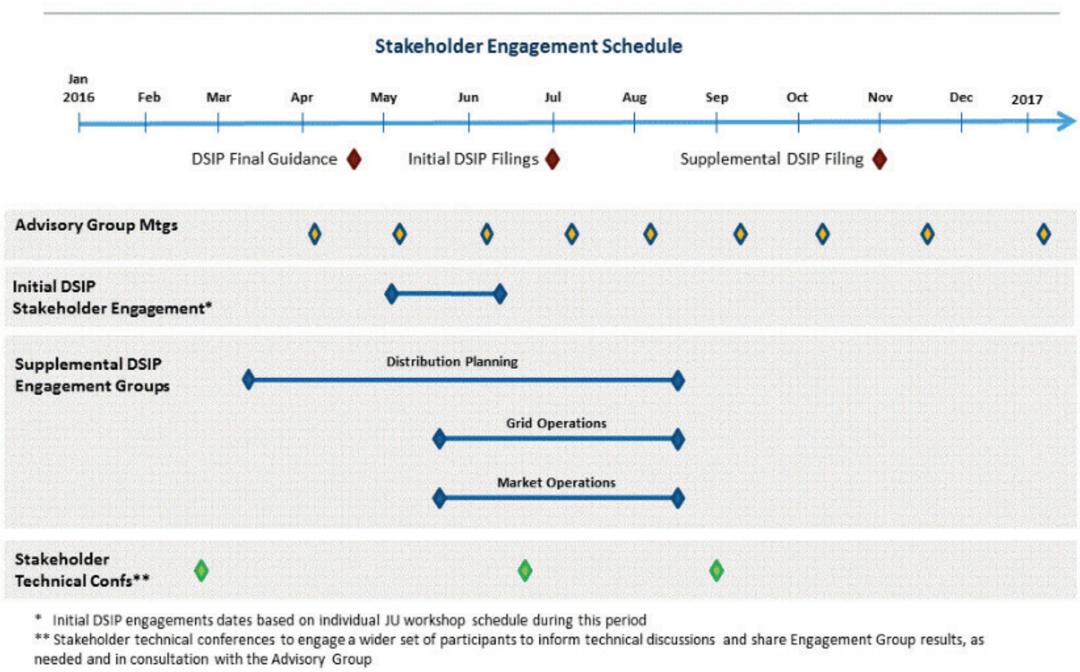

Figure 3-4. New York DSIP Stakeholder Engagement Strategy Schedule

[15] July 26, 2022, Order in Docket 21-694, available in [Minnesota eDockets.](#)

The utilities provide quarterly newsletters on the DSIP website. In its [2023 DSIP guidance], PSC Staff noted that the utilities provide “useful, updated information to stakeholders about expansion of DSP functions and program or market participation opportunities” and recommended that the utilities continue to share information through the website.

Requirements to Report on Stakeholder Engagement in Filed Plans

Several states require utilities to report on stakeholder engagement in filed plans — for example:

- Regulated utilities in **Colorado** must include a description of their stakeholder engagement process.
- In **New York**, PSC Staff guidance for 2023 DSIP filings recommended that each topical section (e.g., integrated planning, forecasting, grid operations, EVs, storage, energy efficiency, and clean heat integration) include information about stakeholder engagement. Specific examples include identifying and characterizing the types of stakeholders engaged in plan development, describing how goals and needs of stakeholders are identified and incorporated in the plan, and explaining how their needs will be met over time.
- In **Illinois**, at the conclusion of required workshops on Multi-Year Integrated Grid Plans, the independent third-party facilitator submits a report to the Commission that describes the “stakeholders, discussions, proposals, and areas of consensus and disagreement from the workshop process.” The rules also specify that stakeholders will have an opportunity to provide comments on the facilitator’s report.
- The **Minnesota** PUC has required Xcel Energy to report on several aspects of stakeholder engagement related to distribution planning. That includes requiring the Company to discuss with stakeholders the inputs and assumptions for hosting capacity analysis and “provide the results of the stakeholder discussion, including an overview of the feedback and suggestions provided by stakeholders, and whether the feedback and suggestions are included in the 2020 HCA Report.”
- **Oregon** requires utilities to prepare a community engagement plan for their plans. The Community Engagement Plan describes the actions the utility will implement to engage communities when developing their non-wires solution proposals. The Plan must include documentation of stakeholder comments and the utility’s response, including comments that were not implemented.
- The least-cost procurement plans, filed with the **Rhode Island** PUC, require the Office of Energy Resources and Energy Efficiency and Resource Management Council include minutes of public meetings and presentations made at Council meetings.

3.2.8 Oregon

The DSP guidelines require the utility to hold at least four workshops prior to filing their plan, at a stage where stakeholders can influence it. In addition, a technical working group led by PUC staff holds regular meetings for stakeholders before and after plan filings to work through technical issues and help keep the planning process on track.

3.2.9 Washington

After reviewing Avista's Clean Energy Implementation Plan required by the state's Clean Energy Transformation Act, the Utilities and Transportation Commission required the utility to start a Distribution Planning Advisory Group. The goals of the group include informing stakeholders about electricity planning, increasing transparency in the planning process, and offering opportunities for stakeholders to provide feedback on materials the utility shares.

3.3 Stakeholder engagement after the DSP is filed

In addition to stakeholders participating in formal regulatory proceedings, some states specify requirements for stakeholder engagement after the utility files its DSP.

For example, in California, the CPUC established the Distribution Planning Advisory Group to advise utilities on selection of distribution deferral opportunities and provide input on development of competitive solicitations for DERs to meet these needs. The CPUC established the composition of the group and required the utilities to include a proposed work plan and agendas in their first distribution deferral opportunities report filing. The Commission also required that meetings include discussion of planning assumptions and grid needs reported in each utility's Grid Needs Assessment, including planned utility investments and candidate deferral opportunities, and candidate prioritization. The group meetings begin after the utilities file their annual opportunities report filing, and they have six weeks to complete their review process. At the completion of their review, the Independent Professional Engineer member of the group submits a report to the utility that must be included in its filing to the CPUC, with recommendations for distribution deferral projects for the year.

In Minnesota, PUC staff can determine if an additional stakeholder meeting is needed after the utility's IDP is filed to gather input.[16]

In Oregon, PUC staff holds ongoing technical workshops and a technical working forum to support collaboration between interested parties.

[16] August 30, 2018, Order in Docket 18-251, available in Minnesota eDockets.

3.4 Stakeholder engagement when considering changes for future DSP filings

As states gain experience with DSP processes, stakeholder engagement is evolving (e.g., HI, MA, MI, MN, NV).

The Hawaii PUC recognized that stakeholder engagement would evolve over time in the Companies' IGP. When reviewing the workplan for the initial IGP, the Commission found the "Companies' approach is reasonable, particularly for this early stage. Given the large number of groups and individuals involved in the IGP process, including the Stakeholder Council, Technical Advisory Panel, each Working Group, and the Parties, the commission expects the Companies to continue to develop and adapt their information sharing methods so that everyone may meaningfully contribute to the IGP process, and benefit from others' contributions." The Hawaii PUC also recognized improvements the Companies made, including more clarity on meeting agendas and goals, identifying specific deliverables, providing opportunities for stakeholders to provide targeted feedback, and coordination among the Working Groups and between the Working Groups and the Companies' efforts in related dockets.

The Massachusetts Grid Modernization Advisory Council provided recommendations on the utilities' draft Electric Sector Modernization Plans, including proposed improvements for stakeholder engagement. Among the recommendations are that the utilities develop goals and clear reporting for metrics of success to measure the efficacy of stakeholder engagement.

In response to the utilities' initial DSP filings, the Michigan PSC stated that "The Commission believes there are significant benefits associated with a comprehensive and forward-looking approach to distribution planning that leverages great Commission and stakeholder input… Open and effective planning processes … will allow the Staff and stakeholders to weigh in on planning assumptions, particularly those that address factors outside the utility's control, such as rooftop solar and electric vehicle adoption." The PSC directed staff to file a report summarizing the stakeholder working group process and provide recommendations to the PSC for the next round of plans. The working group, part of the MI Power Grid initiative, met five times to discuss stakeholder engagement. Staff filed a report with the Commission documenting the feedback and made recommendations for the next round of plan filings.

> "Before reaching a decision on regulatory and policy matters, Administrative Law Judges and Commissioners carefully review and consider the contributions of stakeholders, including formal testimony, comments, and reply comments to the Rulings and Proposed Decisions in a proceeding, keeping in mind the importance of resolving issues in a timely manner. Stakeholders to proceedings, who typically become parties to the proceeding, include the regulated investor-owned utilities, industry trade associations, consumer advocacy groups, non-profit organizations, local governments, and other interested participants. Participation in proceedings by these organizations is critical to ensure that the decisions made are well-informed and provide balanced solutions to the complex regulatory issues before the Commission." — *2022 California PUC Report to the Legislature*

In its order on Xcel Energy's 2021 IDP, the Minnesota PUC required the Company to file a summary of its stakeholder process and a list of next steps prior to filing the 2023 IDP. Xcel Energy held a series of workshops between September 2022 and June 2023, documenting in its report the content and stakeholder feedback. The Company noted several areas where they planned to incorporate feedback in the 2023 IDP, such how to prioritize locations for their Hosting Capacity Program and alternative rate structures to pay for grid upgrades.

Distributed Resource Plan (DRP) regulations in Nevada require NV Energy to file a summary of an informal stakeholder process to discuss recommended improvements to hosting capacity analysis, and for the stakeholder process to occur at least 120 days before the utility files its plan. After reviewing NV Energy's second DRP, the PUC required NV Energy to convene a process within one year to address stakeholder concerns for the explicit purpose of refining and improving future DRPs. Similarly, in 2022 the Commission ordered NV Energy to collaborate with stakeholders to determine the frequency and agenda for meetings addressing intervener concerns related to refining the Locational Net Benefits Analysis in the DRP moving forward. In addition, the PUC required the utility to share the results of its NWA analysis and "explain the factors that led NV Energy to decide to pursue, forgo, or delay decision-making" for all NWAs in its 2023 DRP update and provide stakeholders with an opportunity to provide feedback and recommendations.

3.5 Best practices

Best practices in engaging stakeholders in DSP include the following:

- *Facilitate stakeholder feedback when developing DSP guidance*, for example, when establishing priorities and goals.
- *Provide clear guidance on target stakeholders and roles and responsibilities*. Regulators can clearly articulate who is responsible for stakeholder outreach; planning, hosting, and facilitating meetings; and providing access to information. States can identify specific types of organizations or communities that must be part of the stakeholder engagement process.
- *Provide clear guidance on timing*. Adequate time should be provided for stakeholders to become familiar with the utility's planning process, including assumptions, inputs, analyses, and proposed investments in advance of plan filing. The utility also needs adequate time to incorporate stakeholder feedback into the plan.
- *Require accountability*. States can provide clear guidance to utilities on documenting stakeholder input and how the utility addressed it, including any modifications to assumptions, inputs, or scenarios in the filed plan.
- *Consider working groups to gather subject matter expert feedback*. States or utilities can create working groups, with meetings open to the public, to focus on a specific topic (e.g., hosting capacity analysis). Agendas and materials provided in advance of meetings enable members of the public to decide which meetings they will attend.
- *Create a single, publicly available location for all stakeholder materials*, including large files for data sharing, typically hosted by the utility.

- *Consider ongoing stakeholder engagement*. Some states have ongoing stakeholder engagement for integrated resource planning processes, but it is less common for DSP. Engagement between plan filings provides continuing stakeholder education and opportunities to discuss any needed realignment of utility investments and programs as conditions change.
- *Evolve requirements*. As the DSP process evolves, states can adapt stakeholder engagement to focus on specific topics or bring in additional expertise and perspectives.

4. Forecasting Loads and Distributed Energy Resources

This section describes the range of state requirements for forecasting loads and DERs in DSP, as well as advanced practices.

4.1 Load Forecasting

Load forecasts are a foundational input for DSP. By projecting demand (kilowatts, kW) at specific locations on the distribution system over a 5- to 20-year time frame, utilities can plan infrastructure that meets peak demand and maintains safe operations.

Load forecasts inform the timing, need and type of distribution system investments by identifying system constraints, including capacity shortfalls, power factor and voltage issues, thermal overloads, and mitigation and protection needs. Increasingly, planners need more spatially granular load forecasts. A substation-level forecast, for example, can determine the likely level and timing of a capacity shortfall, but cannot identify what section of the substation area is driving the overload. Forecasts at the feeder-level, or more granular, are needed to determine likely loads driving upgrade needs at a substation.

Load forecasting for DSP traditionally used historical load and trending, weather history, and economic data to estimate peak demand in the future. Increasingly, a singular focus on annual peak demand is not sufficient for grid planning. Load forecasting needs to consider how evolving DER technologies, electrification, more variable loads, changing timing of peak loads, and extreme weather events are changing customer loads. To do so, distribution system planners will need forecasts with high temporal resolution (8,760 hours) for multiple scenarios.

As utility load forecasting practices evolve, states can set expectations for their development and application as they oversee regulated utilities to provide safe, reliable and resilient electricity service.

4.1.1 Distribution Planning Requirements

State requirements for load forecasts vary with respect to time frame, methods, types of load that must be considered, and temporal and geographical granularity.[17]

Time frame. Typically, state requirements specify that load forecasts cover a 5- to 10-year period (CA, CO, DE, IL, MA). States also may set a minimum forecast time frame, such as 6 years in Nevada (NV).

Methods. Some states prescribe approaches for load forecasting, including the use of multiple forecast scenarios (CO, VT), consideration of the impact of state and federal policies (VT), and accounting for DERs. For example, the Colorado Public Utilities Commission requires that utilities develop forecasts under at least two scenarios: load growth associated with existing state policy and an undefined "high"

[17] Some state DSP regulations do not specify load forecasting requirements or all of these elements.

growth scenario (CO). Similarly, Vermont requires that load forecasts account for levels of building and transportation electrification that result from compliance with state climate policy (VT). Several states require that load forecasts account for DER growth (CO, CA, MN, NV, VT, MI). See text box.

Types of load. State DSP requirements may require utilities to consider certain types of loads in their forecasts. For example, in some jurisdictions, regulators require that utilities account for new construction (CO, DC, CA). States are also beginning to require that forecasts include new load from building electrification and EV charging (HI, NY, CO, MN, NV, VT). Vermont specifies that load forecasts account for adoption of cold-climate heat pumps, heat pump water heaters, and “other fuel-switching technologies” that are incremental to requirements for fossil fuel reduction in the state’s renewable energy standards (VT). California specifies service territory targets for economic load growth that must be disaggregated down to substations or below.[18]

Outputs. Load forecast requirements for DSP typically are for “peak” demand. While often undefined, in practice utilities historically planned for a single annual peak hour. Some states provide more specific guidance. For example, Colorado requires utilities to project peak load and peak load growth and differentiate between coincident and non-coincident peaks (CO). Vermont’s requirements specify that utilities forecast peaks for both summer and winter, in addition to forecasting springtime minimum load. That is important for determining how much excess energy from distributed photovoltaics (PV) can be exported to the distribution system (VT).

Geographic granularity. The geographic scope of DSP requirements for load forecasting varies from utility service territories (IL, MI, NV) to specific distribution system infrastructure such as substations (CO, NV, NY), feeders (CA, CO, NV) and line segments (CA). Some states require that utilities provide forecasts at multiple levels, as in CA, CO and NV. In Colorado, the Public Utilities Commission requires forecasts for feeders and substations only when they exceed a risk score threshold or are scheduled for a planned investment (CO). Additionally, load forecasts may be required separately for each customer class (DC).

[18] See the Independent Evaluator report describing this process for San Diego Gas & Electric.

Gross vs. Net Load Forecasts

Gross forecasts represent electricity demand before accounting for the impacts of behind-the-meter generation or other DERs that shed or shift demand. Utilities are increasingly developing net forecasts, which account for demand impacts from DER technologies; e.g., for energy efficiency, demand response and distributed PV.

Some states specifically require that utilities report net load forecasts as part of distribution system plans (NV, MN, CA). Before projecting future load and accounting for different DER scenarios, the utility must first add to the historical data the load avoided by DERs. National Grid, for example, performs this adjustment for PV, energy efficiency, demand response, and storage before it builds a statistical system forecast. The utility then reduces forecasted gross load by the expected levels of DERs to determine the net forecast.

Figure 4-1 from the 2023 Hawaii Electric Integrated Grid Plan illustrates the difference between gross ("Underlying") and net ("Customer Sales") load in its system-level forecast. The net forecast is significantly less than the gross forecast due to load reductions from efficiency and PV. The same logic of adjusting gross load for different levels of DER growth applies to feeder-level forecasts as well.

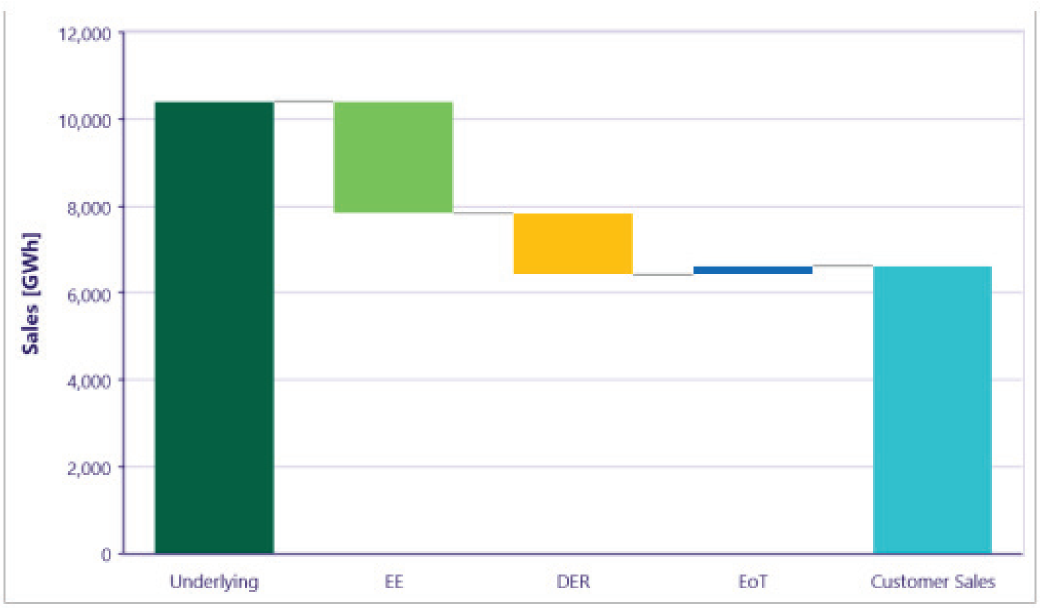

Figure 4-1. Accounting for Impact of DERs in Load Forecasts

EoT – electrification of transportation
Source: 2023 Hawaii Electric Integrated Grid Plan. Figure B-1.

4.2 Load Forecasting

DER forecasts can serve as inputs to other DSP components:

- *Load forecasting:* To estimate load changes due to adoption of DERs over time
- *Hosting capacity analysis:* To identify specific areas of the distribution system with potential high DER growth for evaluation of solar PV, in tandem with other types of DERs, that can be interconnected under existing control and protection systems and without infrastructure upgrades
- *Non-wires alternatives (NWA) analysis and geotargeting DER programs:* To provide trajectories for potential DER deployment and estimates of their load impacts as DERs are considered for grid services at specific locations to defer some types of traditional distribution infrastructure investments

Among state requirements for DER forecasts are outputs, time frames, types of DERs covered, geographic scope, adoption drivers, independent review and technical advisory groups.

Outputs. Requirements for outputs of DER forecasts include estimates of installed capacity (CA), generation (VT), load profiles (MN), changes to peak load (VT) and peak load growth (CO). Other state requirements are more general, such as Massachusetts requiring recent forecasts of DER adoption (MA). Some states require identification of locations of likely DER development (DC, MN).

Time frame. Similar to load forecasts, state requirements for the time frame of DER forecasts range from 5 to 10 years (IL, NV, CA, CO). If not specified, the DER forecast is likely the same time frame as the load forecast or term of the plan.

Types of DERs. Most often, states require forecasts of energy efficiency (CA, CO, DE, MI, NV, VT) and distributed generation such as solar PV (CO, NV, VT, CA, HI). States also require forecasts for demand response (CA, CO, NV), energy storage (CA, CO, HI, NV, VT) and demand flexibility (CO), including managed EV charging (HI, see below). States also may frame types of DERs as open-ended and not constrained to a particular set of technologies (CO).

Geographic granularity. As with load forecasts, DER forecasts may take place at different levels of the distribution system, from feeders (MN, NV) and substations (NV) to systemwide (NV, WA).

Adoption drivers. DSP filing requirements may provide guidance on how DER forecasts consider policy- and market-driven DER growth. For example, Vermont requires that utilities first account for how compliance with the state's renewable energy standards impacts the deployment of behind-the-meter generation and, consequently, peak demand forecasts (VT). This filing guidance also directs regulated utilities to forecast the impact of behind-the-meter generation that is incremental to compliance with the standards (i.e., market-based deployment). In Minnesota, DSP filing requirements specify that utilities consider multiple forms of market-driven DER growth, including individual and aggregated DERs (MN).

Independent review and technical advisory groups. In California, the Commission directs investor-owned utilities to enter into a contract with an Independent Professional Engineer to whom they provide all required data. The engineer verifies and validates that the utilities follow their own processes correctly and that the approaches taken are appropriate and effective.[19] In addition, the engineer verifies and validates the substation and feeder level forecasts produced annually for the DSP. In Hawaii, the Commission directs the utility to meet periodically with a Technical Advisory Panel for independent peer assessment, including input and feedback. The panel vets HECO's load and DER forecasting methods and results.

4.3 Advanced Practices

Hawaiian Electric, National Grid, Southern California Edison and Eversource demonstrate advanced practices in load and DER forecasting. These utilities develop scenario-based forecasts that consider a wide range of DERs, are temporally and geographically granular, and consider electrification.

Hawaiian Electric

In accordance with Hawaii PUC requirements for Hawaiian Electric's 2023 Integrated Grid Plan (IGP), the utility develops "best estimate" forecasts of vehicle electrification, energy efficiency, solar PV with and without battery storage, and distributed wind. Hawaiian Electric then applies these "adjusting layers" to its baseline forecast. For each of the islands it serves, the utility estimates monthly added capacity of PV and wind by rate class across low, base and high scenarios. The scenarios vary DER incentive levels, housing types (single and multifamily) that have rooftop solar, and costs.

As required by the Hawaii PUC, the 2023 Hawaiian Electric IGP also describes EV charging assumptions, including the utility's approach to modeling managed charging. The charging assumptions include estimates of annual energy requirements per light-duty vehicle and electric bus operator and charging profiles for Level 2 and fast chargers in the utility's service territory. For managed charging, Hawaiian Electric finds the charging profile that minimizes costs for drivers under island-specific time-of-use (TOU) rates while meeting state-of-charge requirements for driving (see Figure 4-2).

[19] See the example Independent Professional Engineer report for Southern California Edison, submitted to the California PUC on Nov. 15, 2023. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K913/520913486.PDF.

Figure 4-2. Average Managed EV Charging Profile for O'ahu

Source: Hawaiian Electric Company 2023 Integrated Grid Plan

For energy efficiency, Hawaiian Electric develops a supply curve of bundled measures that differ in their peak impacts, potential energy savings and costs. The utility then integrates these DER layers with customer class, feeder load shapes, and weather data, among other inputs, using the LoadSEER™ model to generate hourly circuit- and transformer-level load profiles. Hawaiian Electric provides this overview of LoadSEER™ in accordance with Hawaii PUC filing requirements.

Hawaiian Electric performs location-based grid needs assessments based on a two-step process. The utility screens substations and circuits for detailed 8,760 analysis that is repeated for each of the load and DER forecast scenarios. Initially, the utility screens substation transformers and circuits to determine if there are violations based on forecasted annual peak demand. If there is insufficient capacity to serve the forecasted demand, the utility performs additional hourly analysis to determine if there is a grid need. Figure 4-3 summarizes the process.

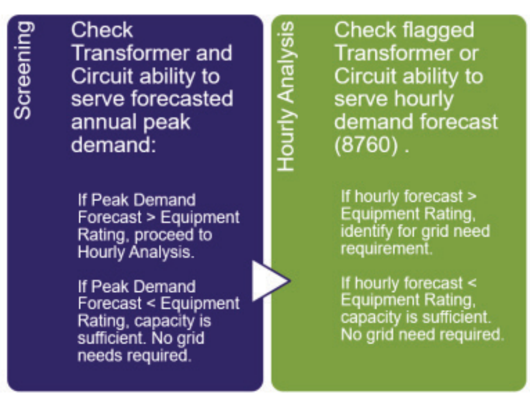

Figure 4-3. Summary of Screening for Hourly Analysis Process Applied for Each Load and DER Forecast Scenario

Source: Hawaiian Electric Company 2023 Integrated Grid Plan

National Grid

In its 2020 Distributed System Implementation Plan (DSIP), National Grid identified areas for improving its forecasting methods, including an assessment of which parcels are likely for solar development and a probabilistic approach to modeling scenarios. Figure 4-4 from the 2020 National Grid DSIP shows a schematic of the parcel-level solar forecast. This bottom-up analysis considers a range of technical and economic parameters to determine project costs and benefits, which it then considers in light of interconnection constraints. In its 2023 DSIP, National Grid used an interconnection analysis tool, GridTwin, to perform the parcel assessment.

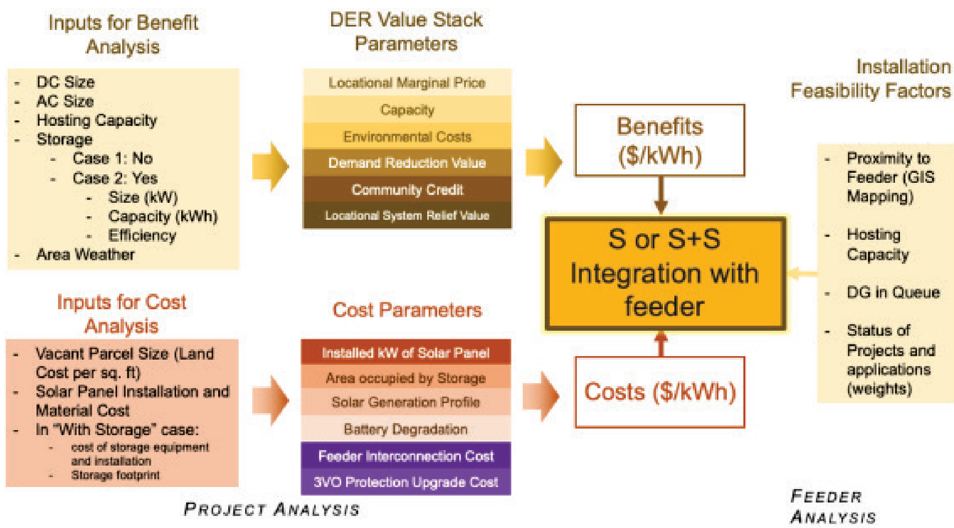

Figure 4-4. Solar and Solar + Storage Module Benefit-Cost Analysis Framework

Source: 2020 National Grid New York Distribution System Implementation Plan

National Grid has also started conducting probabilistic planning in response to New York Department of Public Service staff guidance on DSIPs. Probabilistic forecasting aims to represent the likely variation in load across multiple DER scenarios by weighting each scenario's forecast with probabilities. This approach reduces the number of discrete forecasts by producing a single forecast with a confidence interval that reflects the range of expected load. For its 2023 DSIP, National Grid developed probabilities for low, base case and high deployment for six technology categories: energy efficiency, solar PV, EVs, demand response, energy storage, and electric heat pumps. The utility then forecasted load across each technology-scenario combination to estimate likely ranges of system-level load.

Also in response to New York staff guidance, National Grid details its approach to modeling rooftop PV, EVs and heat pumps in its 2023 DSIP. For rooftop solar, the utility allocates projections of system-level PV to customers based on the likelihood of adoption due to household income and employment, among other factors. National Grid uses a similar method for estimating EV adoption, but at the ZIP code level. For each feeder the utility then applies managed and unmanaged charging profiles to each forecasted EV and allocates the load to home, workplace and public charging using the EVI-PRO Lite tool developed by the National Renewable Energy Laboratory.

National Grid models feeder-level heat pump adoption in three periods through 2050: deployment driven by utility program participation (2023-2027), electrification of delivered fuel heating systems (e.g., fuel oil) (2028-2034), and gradual electrification of natural gas heating through (2035-2050). The utility assumes 30% of homes will retain some fossil fuel heating and use heat pumps as supplemental heat. National Grid then estimates annual heat pump electricity usage from its own programs and allocates that usage by month based on natural gas consumption patterns, distributed across assumed load shapes.

Southern California Edison

California investor-owned utilities allocate utility-wide forecasts from the California Energy Commission for efficiency, solar PV, energy storage, demand response, and TOU rates to distribution circuits. For example, Figure 4-5 illustrates the process for Southern California Edison (SCE) in its Distribution Deferral Opportunities Report. For EVs, the utility uses ZIP code-level propensity models to disaggregate load estimates by location and produces a map showing how distribution circuits relate to ZIP codes. SCE apportions the utility-wide forecast of circuit-level TOU load impacts in proportion to customers on each circuit.

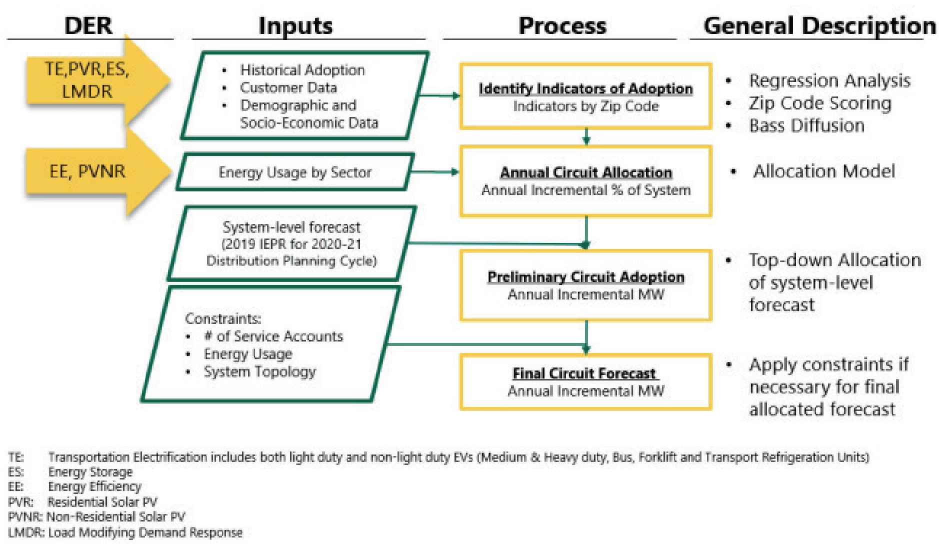

Figure 4-5. SCE's Overall DER Disaggregation Process

Source: 2021 Grid Needs Assessment and Distribution Deferral Opportunity Report

Eversource[20]

For its 2024 Electric Sector Modernization Plan, Eversource performed a 10-year substation-level net peak load forecast. The forecast starts with a weather-normalized, 90/10 gross station peak load[21] used in combination with economic data[22] to determine the trend in load growth relative to economic development. The utility then develops a trend forecast for the next 10 years based on economic projections.

Next, the utility derives a net forecast by adjusting for energy efficiency, solar, EVs, and large customer projects. Eversource-sponsored energy efficiency projections are based on the most readily available three-year plan. Solar projections are developed consistent with historical trends. While installed capacity is expected to rise significantly by 2050, projected total capacity of distributed solar remains the same due to the impact of irradiance on energy output, weather adjustments for time of day, and a 90/10 weather adjustment to ensure that modeled solar output is sufficient to reliably reduce peak forecast (using the 90th percentile irradiance levels during peak load hours). Naturally occurring energy efficiency (reduction in demand due to non-programmatic improvements in end-use efficiency) is captured in the trend forecast. In other words, planning must account for the possibility that solar would not show up when it is needed to reduce station loading. Figure 4-6 shows the resulting weather-normalized, 90/10 net station peak load forecast.

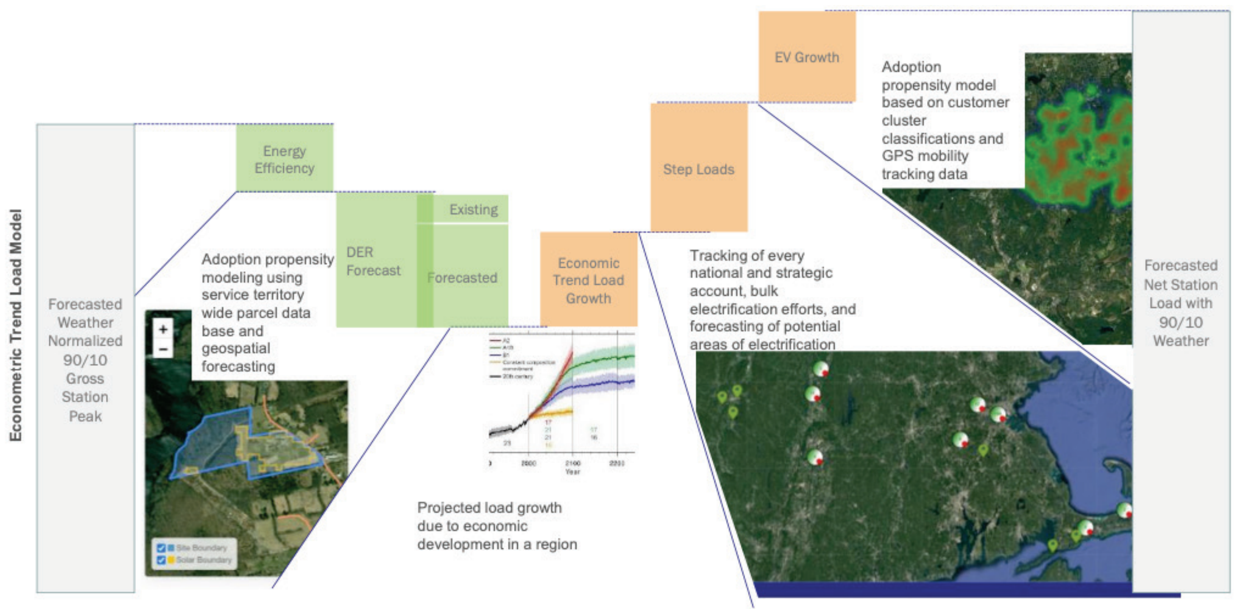

Figure 4-6. DER and Step Load Adjustments to the Econometric Trend Peak Load Forecast at the Substation Level

Source: 2024 Eversource Electric Sector Modernization Plan

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20 Julieta Giraldez, Julieta Energy, drafted this utility example.
21 A 90/10 forecast means a 90% probability of falling short of, and 10% probability of exceeding, the forecast due to weather conditions.
22 Moody's Analytics provides economic data and forecasts at national and subnational levels.

These 10-year net station peak load forecasts inform a 5-year investment plan for 2025-2029. Eversource also includes a longer-term load and DER forecast from 2035-2050, based on an evaluation of policy objectives at the state level. The state-level objectives translate into DERs in the form of total installed solar capacity (gigawatts of distributed generation), number of units of EVs, and electric heat pumps specific to the pathway to net zero emissions and decarbonization initiatives.

Once policy objectives are translated into components of electric demand at a state level, they are broken down by geographic region — typically by ZIP code — using an adoption probability model which informs placement of policy-driven resources across the system. The zip-code level model determines allocation of technology. Within a ZIP code, a bottom-up adoption probability model based on site-specific and customer-level data determines which customer sites adopt DERs in the simulation (Figure 4-7). ZIP code-level of granularity is critical to assess specific impacts of state policies on the distribution system.

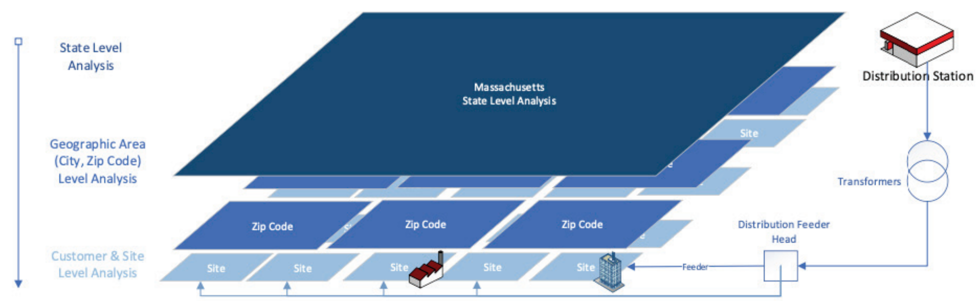

Figure 4-7. Electric Demand Assessment Input and Analysis Layers for Technology Adoption

Source: 2024 Eversource Electric Sector Modernization Plan

Eversource's long-term forecast increases *overall* system electric demand from a 6.1 gigawatt (GW) summer evening peak to a 15.3 GW winter morning peak by 2050. The majority of this 150% increase in electric demand is driven by the electrification of heating needs (about 50%). The remaining drivers are transportation electrification (25%) and "normal" load, absent heating electrification (25%).

At a *subregional* level, the proportion of projected electrification demands between heating and transportation varies. Transportation electrification demand in the Western region of the utility's service territory is expected to be higher relative to Metro Boston, resulting from higher average driving miles and associated charging demand. For heating electrification, demand in the Southeastern region is expected to be higher than in other regions due to a significant amount of commercial square footage and larger homes.

With such significant increases in forecasts of both solar and electrification, above and beyond the 10-year distribution planning horizon, locationally specific growth forecasts and the associated pace of the growth are critical to informing where the bottlenecks will be and by when. Eversource proposes data analytic and forecasting advancements for adoption propensity modeling approaches to deliver locationally specific forecasts.

Eversource also conducted a climate impact study through 2050. As expected, significant increases in summer temperatures are projected. Figure 4-8 shows the 50th and 90th percentiles for daily maximum temperatures in 2050. Eversource is building models to better understand how these impacts will drive up summer cooling load. However, the utility does not expect it to eclipse winter peak load.

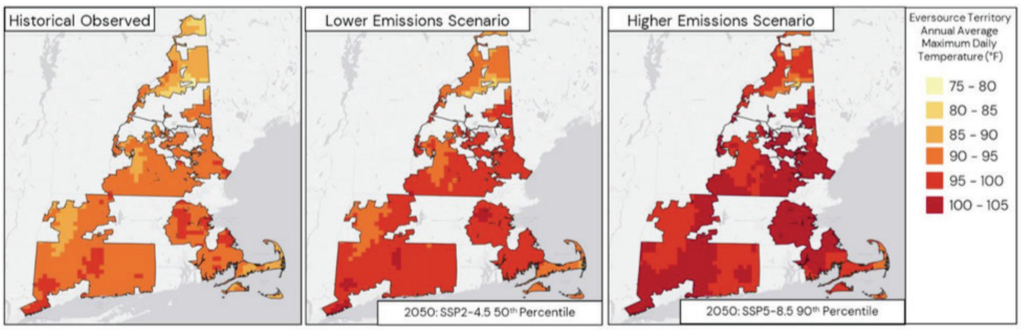

Figure 4-8. Daily Maximum Temperature Increase Projections

Source: 2024 Eversource Electric Sector Modernization Plan

In addition, Eversource projected the annual number of days below the historical 5th percentile daily minimum temperature — minus 5°F — to determine if winter peak load assumptions are likely to hold in a warming climate. Figure 4-9 shows that the number of days below that threshold is reduced. But for now, the utility continues to measure winter peak demand based on that metric. The number of days below the 5th and 10th percentiles of minimum temperatures are projected to decrease by 16.6–27.8 days in Boston by 2050, with less than four days below these thresholds per year remaining in the high greenhouse gas emissions scenario. In the coming years, utilities will likely need to make adjustments to the 90th percentile statistics — adjusting up for warm days and down for cold days, based on climate change models that project changes in temperatures.

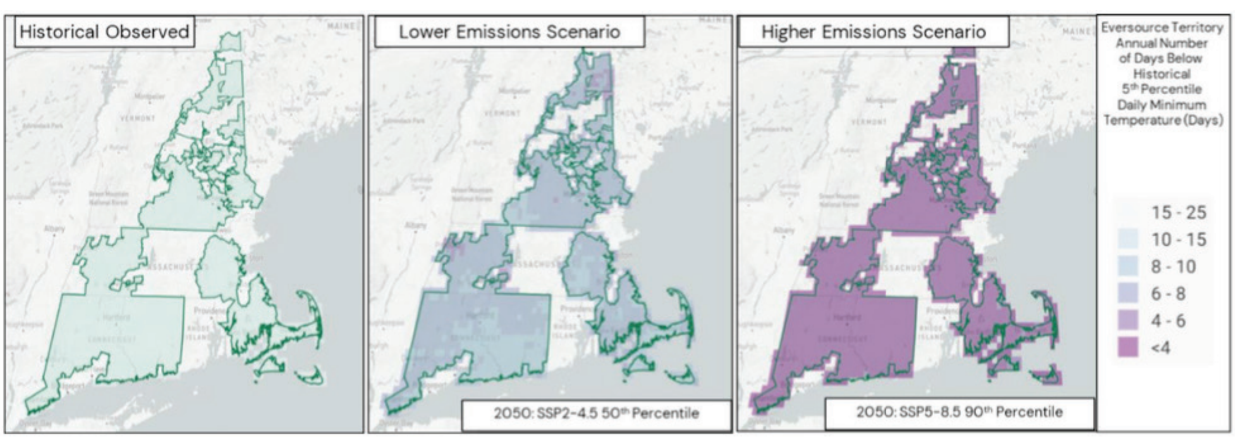

Figure 4-9. Annual Number of Days Below Historical 5th Percentile Daily Minimum Temperature
Source: 2024 Eversource Electric Sector Modernization Plan

In addition, Eversource projected the annual number of days below the historical 5th percentile daily minimum temperature — minus 5 degrees Fahrenheit — to determine if winter peak load assumptions are likely to hold in a warming climate. Figure 4-9 shows that the number of days below that threshold is reduced. But for now, the utility continues to measure winter peak demand based on that metric. The number of days below the 5th and 10th percentiles of minimum temperatures are projected to decrease by 16.6–27.8 days (SSP5-8.5, 90th percentile) in Boston by 2050, with less than 4 days below these thresholds per year remaining in the high greenhouse gas emissions scenario. In the coming years, utilities will likely need to make adjustments to the 90th percentile statistics — adjusting up for warm days and down for cold days, based on climate change models that project changes in temperatures.

5. Hosting Capacity Analysis

Hosting capacity is the DER capacity (in megawatts) that can be interconnected to the distribution system without adversely affecting power quality or reliability under existing control and protection systems, and without infrastructure upgrades. *Hosting capacity analysis* (HCA) is the process of modeling existing grid conditions and simulating power flow at different levels of DER penetration to determine hosting capacity. To simulate power flow, HCA first requires modeling distribution feeders and validating utility load[23] and asset data.[24]

Most often, HCA serves to guide solar PV developers toward sites that are easier and less costly for interconnection. In addition to hosting capacity estimates, the analysis also may provide baseline information on the distribution system, including line voltages and the capacity of currently interconnected DERs, which can aid project developers in evaluating potential sites.[25] Utilities are increasingly using HCA to improve and facilitate interconnection technical screening.[26] In addition, some utilities are using the analysis to improve distribution system planning and to value DERs for programs,[27] procurements and pricing.

5.1 Development guide

As a development guide, HCA supports market-driven DER adoption[28] by identifying parts of the distribution system that can integrate more DERs without adverse effects on the grid or required infrastructure upgrades,[29] resulting in generally lower interconnection costs. The value of HCA as a development guide depends on accuracy and availability of data generated.[30] If utilities do not regularly update and publish results, if underlying data inputs are low quality, or if HCA data are not sufficiently granular, developers will not be able to make informed siting decisions. HCA to guide development of PV and EV charging stations also can help utilities by reducing interconnection requests in areas with high interconnection costs or low hosting capacity, leading to more efficient interconnection studies and queue management.

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[23] Nagarajan, Adarsh, and Yochi Zakai. 2022. "Data Validation for Hosting Capacity Analyses." NREL/TP-6A40-81811, 1863540, MainId:82584. https://doi.org/10.2172/1863540.
[24] Stanfield, Sky, Yochi Zakai, and Matthew McKerley. 2021. "Key Decisions for Hosting Capacity Analyses." Interstate Renewable Energy Council. https://irecusa.org/resources/key-decisions-for-hosting-capacity-analyses/.
[25] Ibid
[26] Ibid
[27] Sigrin, Benjamin, Patrick Dalton, and Debbie Lew. 2020. "Emerging Distribution Planning Analyses." Presented at the Integrated Distribution System Planning Training for Midwest/MISO Region, October 13. https://eta-publications.lbl.gov/sites/default/files/6._emerging_grid_planning_analyses.pdf.
[28] Ibid
[29] Stanfield, Sky, Yochi Zakai, and Matthew McKerley. 2021. "Key Decisions for Hosting Capacity Analyses." Interstate Renewable Energy Council. https://irecusa.org/resources/key-decisions-for-hosting-capacity-analyses/.
[30] Ibid

5.2 Interconnection technical screen

HCA can improve interconnection processes by determining whether detailed studies are necessary and increasing accuracy of existing screening practices.[31] By determining where distribution system upgrades or redesigns will be necessary to accommodate DERs, HCA also can reduce interconnection queue backlogs that slow DER deployment.

Often, interconnection screens rely on rules of thumb, such as capping DER generation capacity at 15% of line section peak load capacity. Instead, HCA can determine whether additional DER capacity will create any issues based on feeder-specific data[32] and either complement existing interconnection screening practices or replace them. A lack of high-quality input data can limit HCA's ability to support interconnection screening.[33]

5.3 Distribution planning tool

HCA can support DSP processes by identifying the location and causes of distribution system constraints, such as overvoltage or thermal violations, and whether upgrades to distribution system components (e.g., regulators) or changes to conservative planning criteria (e.g., overvoltage thresholds) mitigate those constraints. This application of HCA enables utilities to proactively address constraints to DER deployment and consider both physical system upgrades and NWA, such as demand response and storage. The ability of HCA to support DSP depends on the accuracy of the DER forecast.[34]

5.4 Locational benefits analysis

HCA can inform valuation of DERs by providing foundational data and establishing analytical processes necessary for calculation of locational benefits.[35] DER benefits are in part location-specific — for example, the voltage impacts of DERs depend on system impedances and equipment configurations.[36] Avoided line losses also are location-dependent. Locational benefits analysis requires a range of data inputs, including distribution system data and power flow models developed for HCA. However, HCA does not necessarily provide all the data required for calculating locational benefits, such as line losses.

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[31] Stanfield, Sky, Yochi Zakai, and Matthew McKerley. 2021. "Key Decisions for Hosting Capacity Analyses." Interstate Renewable Energy Council. https://irecusa.org/resources/key-decisions-for-hosting-capacity-analyses/.
[32] Ibid
[33] Sigrin, Benjamin, Patrick Dalton, and Debbie Lew. 2020. "Emerging Distribution Planning Analyses." Presented at the Integrated Distribution System Planning Training for Midwest/MISO Region, October 13. https://eta-publications.lbl.gov/sites/default/files/6._emerging_grid_planning_analyses.pdf.
[34] Stanfield, Sky, Yochi Zakai, and Matthew McKerley. 2021. "Key Decisions for Hosting Capacity Analyses." Interstate Renewable Energy Council. https://irecusa.org/resources/key-decisions-for-hosting-capacity-analyses/.
[35] Sigrin, Benjamin, Patrick Dalton, and Debbie Lew. 2020. "Emerging Distribution Planning Analyses." Presented at the Integrated Distribution System Planning Training for Midwest/MISO Region, October 13. https://eta-publications.lbl.gov/sites/default/files/6._emerging_grid_planning_analyses.pdf.
[36] Frick, Natalie, Snuller Price, Lisa Schwartz, Nichole Hanus, and Ben Shapiro. 2021. "Locational Value of Distributed Energy Resources." DOE/LBNL--02012021, 1765585, ark:/13030/qt6hc78827. Berkeley Lab. https://doi.org/10.2172/1765585.

5.5 State requirements

More than a dozen states require regulated utilities to make HCA maps publicly available.[37] In addition, some utilities publish HCA maps and data on their own accord. The U.S. Department of Energy provides a list of utility maps covering 24 states and the District of Columbia.[38] (See Figure 5-1.) State requirements for HCA differ with respect to types of DERs included, geographic and temporal granularity of the analysis, and how utilities make HCA data accessible. In addition, some states specify particular HCA methods or applications, as well as mitigation analyses.

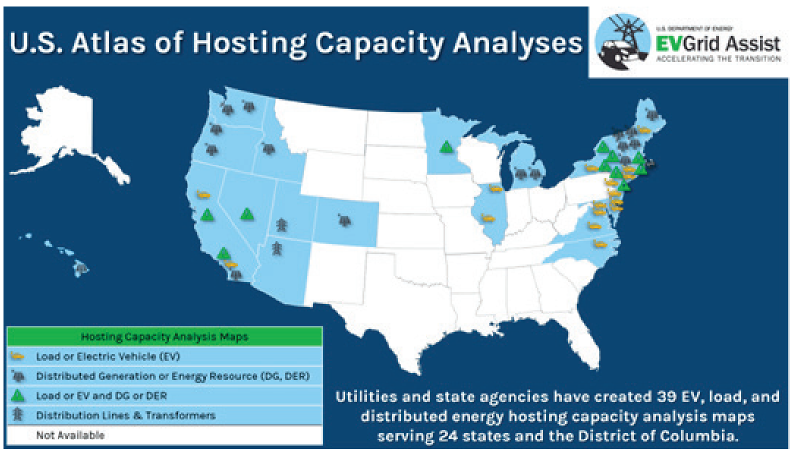

Figure 5-1. States With ≥1 Utility Providing a Public Hosting Capacity Map

Source: Atlas of Electric Distribution System Hosting Capacity Maps (December 2023)

5.5.1 Use cases

Some states identify specific use cases for HCA, which can help target utilities' efforts and stakeholder engagement. For example, the Minnesota PUC expanded HCA use cases over time, beginning with requirements for Xcel Energy to develop an analysis with sufficient detail to serve as a PV development guide and to begin developing HCA as a distribution system planning tool. Most recently, the PUC accepted Xcel Energy's proposal to use HCA in interconnection screens. The California PUC established HCA as tool for DSP interconnection screening and quantifying DER benefits.

5.5.2 Frequency of updates

The hosting capacity of the distribution system can change due to updates in feeder configuration and increases in load and distributed generation. For HCA to remain useful, utilities must regularly update the analysis. Frequency of updates may depend on intended use cases. Interconnection screening, for example, requires an understanding of current grid conditions, so regular updates are critically important. Frequency of updates required for distribution system planning varies by state from annual to quarterly (CO) and monthly (CA, DC, MN[39]).

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[37] NARUC Grid Data Sharing Collaborative. *Grid Data Sharing: Brief Summary of Current State Practices*. 2022.
[38] Atlas of Electric Distribution System Hosting Capacity Maps. https://www.energy.gov/eere/us-atlas-electric-distribution-system-hosting-capacity-maps.
[39] September 15, 2023, Order in Docket No. 22-574, available through Minnesota eDockets.

5.5.3 Types of DERs included

HCA can address a wide range of DERs that modify distribution system load shapes through power generation and demand reduction. Typically, states requiring HCA specify some type of distributed generation, either as a general set of technologies (CO, MN) or by identifying individual technologies, from solar photovoltaics (CA, IL) and wind (CA, NV) to fuel cells (CA) and CHP (CA). States also may require that HCA incorporate demand-side resources such as energy efficiency (CA) and demand response (CA, NV). In addition, states may require that HCA account for energy storage (IL, NV), including non-exporting storage (CO). Increasingly, states are requiring that HCA account for new load from EVs (CA, IL, NV, MN[40]).

5.5.4 DER size

States typically do not specify the size of DERs that are in scope for HCA. Two states, California and Minnesota, are exceptions. The Minnesota PUC interpreted a requirement for HCA on "small-scale distributed generation" in the state's grid modernization law to refer to systems with a capacity less than or equal to 1 megawatt (MW). The California PUC, in contrast, did not set a maximum cap, but stated its assumption that in most cases the nameplate capacity of installed DERs would be less than or equal to 20 MW. In general, public-facing hosting capacity maps are most often used for siting projects between 2 MW and 20 MW, which are more likely to experience high interconnection costs due to required system upgrades to address distribution system constraints.

5.5.5 Level of analysis

States generally do not specify the temporal granularity of HCA but do address the level of infrastructure that is in scope. Requirements range from individual line segments (CA, HI) to higher level zones (MI), though the most common approach is to conduct HCA at the feeder level (CO, VT, MI, MN). States also require substation-level analysis in addition to (MN) or instead of (VT) feeder-level analyses. In practice, states may require that utilities aggregate HCA results at these infrastructure levels or treat them as boundaries within which they conduct more granular (e.g., node-level) analysis. The Minnesota PUC, for example, introduced a requirement for Xcel Energy to report subfeeder results after receiving comments that the utility's feeder-level analysis already produced subfeeder data. Importantly, the geographic level of HCA has implications on the feasibility of some use cases. For example, HCA aggregated at the feeder level can support distribution system planning but not interconnection, because hosting capacity varies within the feeder.[41]

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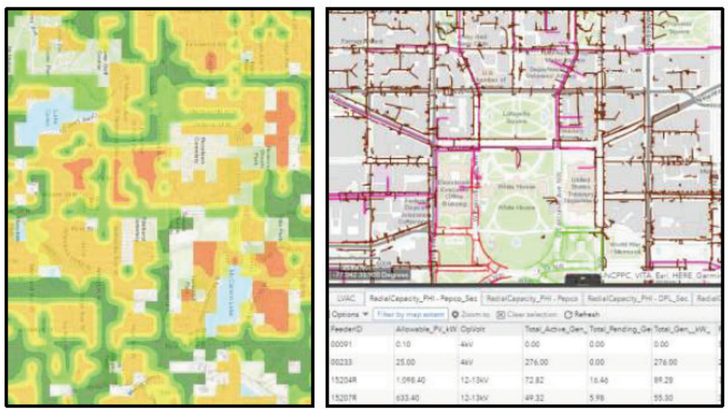
[40] November 9, 2021, Order in Docket No. 20-812, available through Minnesota eDockets

[41] Stanfield, Sky, Yochi Zakai, and Matthew McKerley. 2021. "Key Decisions for Hosting Capacity Analyses." Interstate Renewable Energy Council. https://irecusa.org/resources/key-decisions-for-hosting-capacity-analyses/.

5.5.6 Maps and data

States may require that utilities make the results of HCA available through maps (CO, DC, IL MN, NV, CA). While some states, such as IL and CO, do not specify the level of detail, others do. For example, Michigan implemented a high-level "go/no-go" map as a starting point for HCA performed by Consumers Energy and Detroit Edison, with the goal of refining the maps with data from more detailed analyses in areas with high DER penetration. Requirements may specify that maps show the actual location of lines, as in California, rather than the general area where lines exist, with a buffer zone to hide exact route details (Figure 5-2). Or states may give utilities discretion in determining the granularity of maps. The Minnesota PUC, for example, required that Xcel Energy show individual distribution system lines "to the extent practicable." In the HCA filing that followed this order, the utility declined to increase the granularity of the map due to its concerns about security and customer privacy.



Left: HCA Map with Blurred Distribution Lines from Xcel Energy's HCA | *Source: Xcel Energy, Minnesota*
Right: HCA Map Showing Precise Distribution Line Location | *Source: Pepco, Washington, DC*

Figure 5-2. Granularity of HCA Maps

Source: Interstate Renewable Energy Council (2021).[42]

States also may require that utilities publish the data that underlies HCA maps (CO, NV, MN). Requirements may specify categories or types of data that utilities include. The Minnesota PUC, for example, requires that in addition to hosting capacity, Xcel Energy reports daytime minimum load, peak load, DER installed generation capacity, and queued generation capacity for individual substations and feeders. The Colorado PUC requires that utilities report feeder-level daily daytime minimum load or, if that is not available, daily peak load. Additionally, the PUC requires that utilities provide geospatial data for HCA maps.

5.5.7 Mitigation analysis

States may require that HCA include a mitigation analysis that informs how utilities can reduce hosting capacity constraints. The level of detail in this analysis varies. Colorado, for example, requires that utilities describe how HCA can help identify distribution upgrades that enable greater DER penetration, but does not specify particular analyses. Similarly, Illinois requires that utilities explain how distribution

[42] Interstate Renewable Energy Council. Presentation to New Mexico Public Regulation Commission. 2021.

system investments can affect hosting capacity. These requirements imply, but do not prescribe, mitigation analyses. In contrast, in response to Xcel Energy's 2018 HCA report, for feeders the utility identified as having no hosting capacity, the Minnesota PUC required that the utility report the frequency that hosting capacity constraints occurred, identify mitigation options and costs, and specify how much additional hosting capacity each mitigation option could yield (MN). Similarly, the California PUC requires that utilities identify mitigation options for DER integration issues that result from high DER penetration (CA).

5.5.8 Methods

States typically do not require that utilities use particular methods or software for HCA. California, however, requires that utilities perform "dynamic modeling" that does not include "heuristics" (e.g., past practice of limiting DER generation capacity to 15% peak load in a line section). Additionally, Colorado requires that utilities assess HCA under multiple scenarios that differ in level of DER growth and reliability conditions.

5.6 Best practices

5.6.1 Hawaii

As part of its Integrated Grid Planning process, Hawaiian Electric described its plans for advancing HCA practices. Historically, the utility estimated hosting capacity for the day with minimum annual net load. Updated analysis will estimate hosting capacity in all hours of the year (i.e., 8,760 hours) by modeling hourly DER generation with advanced inverter functionality and accounting for hourly circuit-level load forecasts. The new HCA approach also will include improved modeling parameters such as user-defined ranges for solar system sizes and more informed PV siting. Importantly, Hawaiian Electric will generate probabilistic hosting capacity values based on scenarios that differ in DER penetration, size and location. The utility expects that a probabilistic approach will yield less conservative results than the prior method, increasing estimates of hosting capacity.

Figure 5-3 shows an example of Hawaiian Electric's probabilistic HCA. The load profile illustrates how hosting capacity changes throughout the day over a five-year forecast period in which DER penetration increases. The load shape also reflects hosting capacity at which 5% of simulations trigger violations.

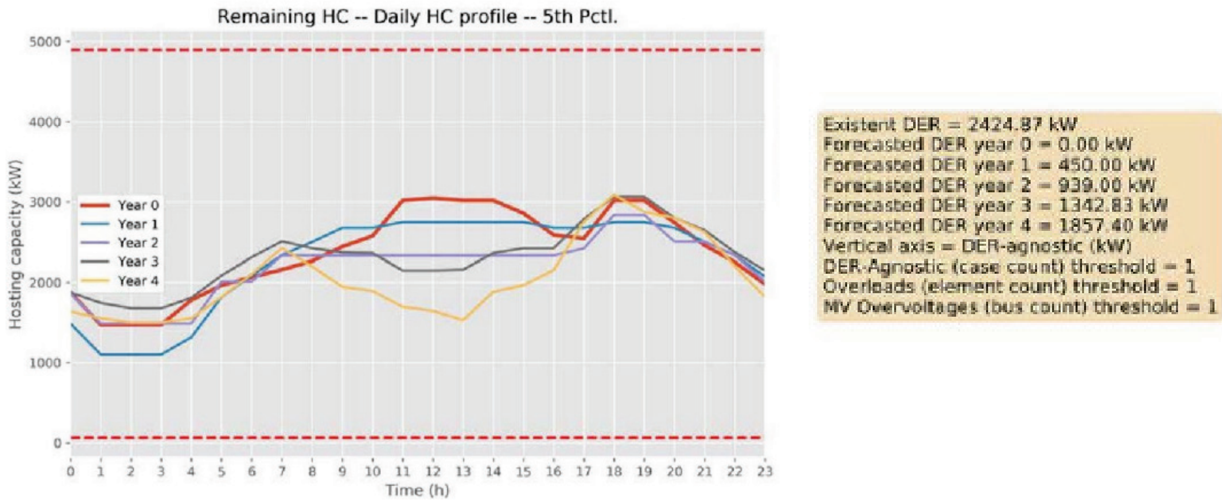


Figure 5-3. Hawaiian Electric Probabilistic Hosting Capacity Profile[43]

5.6.2 Minnesota

Practice in Minnesota demonstrates the value of HCA requirements for mitigation analysis and data quality. In accordance with PUC requirements for its 2019 HCA, Xcel Energy used the EPRI Drive tool to evaluate hosting capacity constraints for 95 feeders that the utility identified as having no hosting capacity in its 2018 study. The utility considered a range of mitigation options for overvoltage and thermal violations, including no-cost adjustments to distributed generation power factors and using no- and low-cost smart inverter functionality. The analysis found that no-cost power factor adjustments could increase hosting capacity by at least 1 MW in 28 feeders. Xcel then assessed additional constraints, including unintentional islanding and reverse power flow, which would require more expensive mitigation. While this analysis was illustrative and considered some mitigation options that Xcel Energy did not employ, such as smart inverter functionality, it demonstrates how mitigation analyses can support targeted and least-cost solutions to hosting capacity constraints.

Xcel also demonstrated how HCA maps (Figure 5-4) can support DER development. In accordance with state requirements, Xcel Energy reports detailed data for multiple nodes within a feeder's footprint, including the specific constraint (e.g., unintentional islanding or thermal discharging) that determines minimum hosting capacity levels. This information can give developers some indication of the costs of mitigating the constraint and whether the location is well suited for DER development.

[43] *Hawaiian Electric Grid Needs Assessment.* Filing F-175806 in Case 2018-0165, November 2021. Figure I-11.

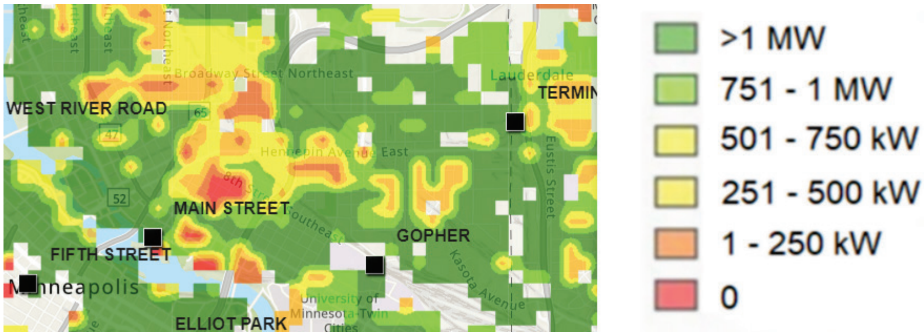


Figure 5-4. Xcel Energy Minnesota Hosting Capacity Map[44]
Source: Xcel Energy. (n.d.)

5.6.3 California

San Diego Gas & Electric (SDG&E) HCA maps allow users to view individual line locations, in contrast to the practice of depicting general areas where lines exist that many utilities follow (Figure 5-5). This level of detail enables electricity customers and developers to identify the feeder that is relevant to the design of a DER project.[45] They can then make design decisions (e.g., installed PV system capacity) that aligns with the feeder. Data on the individual lines can also help customers and developers decide between interconnection points that have different hosting capacity levels.

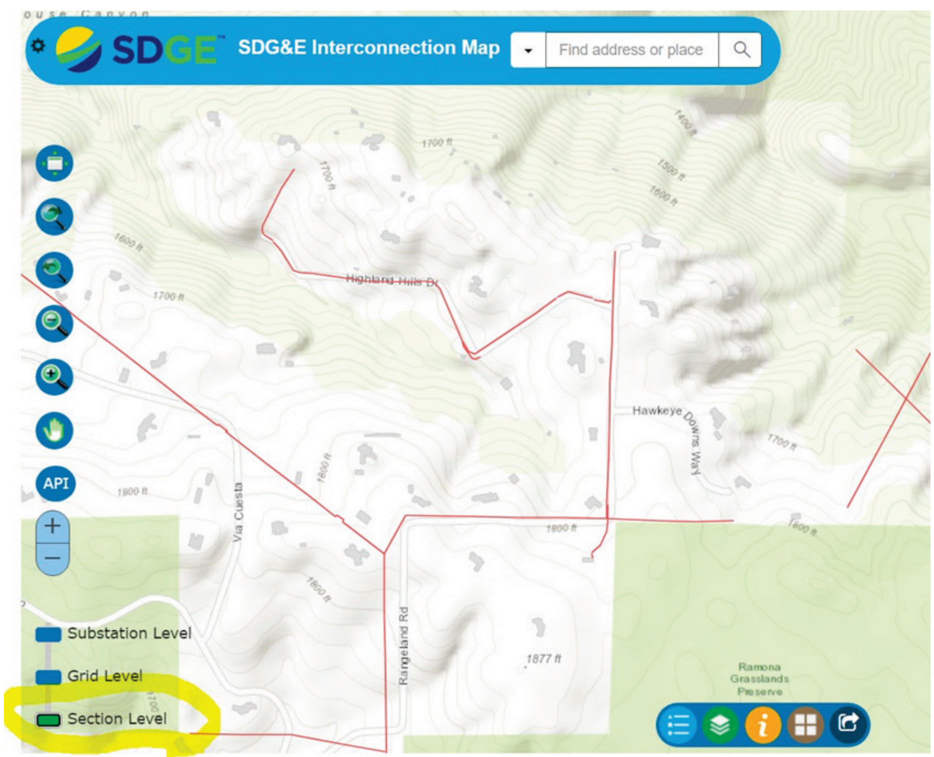


Figure 5-5. Illustrative SDG&E Hosting Capacity Map
Source: San Diego Gas & Electric (2023).

44 Xcel Energy. n.d. "Xcel Energy Minnesota Hosting Capacity Map." https://www.xcelenergy.com/hosting_capacity_map.
45 Stanfield, Sky, Yochi Zakai, and Matthew McKerley. 2021. "Key Decisions for Hosting Capacity Analyses." Interstate Renewable Energy Council. https://irecusa.org/resources/key-decisions-for-hosting-capacity-analyses/.

6. Information on the Current State of the Distribution System

This chapter outlines baseline information that states require regulated utilities to include in DSPs. Baseline information is foundational data about the utility's existing distribution system — physical, financial, and operational — that provides a basis for planning.

6.1 Categories of baseline information requirements

Baseline information requirements for DSP vary by state. Table 6-1 lists seven categories of baseline information required for DSPs in 12 states and the District of Columbia, as classified for this report, along with the level of specificity.[46]

Table 6-1. State Requirements for Baseline Information in Distribution System Planning

Category	CA	CO	DE	DC	IL	MI	MN	NV	NY	OR	PA	VT	VA
Infrastructure	●	●	●	●	●	●	●		●	●	●	●	●
Operational Data	●	●	●	●	•	●	●	○	●	●		●	●
Monitoring Capabilities		●								●			
Management Systems										●			
Financial Data	•	●		●	●	●	●	●	●	●	•		●
DERs	●	●		●	●	●	●	●	●	●		○	●
Annual Reports	●			●					●	●			

Legend:

● Prescriptive and detailed content for baseline information requirement that aligns with the category definition

• Moderate level of detail specified for baseline information requirement

○ Minimal amount of content specified; generally, a high level statement that requires filing of certain categories of data, but with little or no specificity

Following are typical information requirements specified for each of the seven categories:

- **Infrastructure** - Information on physical structure, assets connected to the distribution system, distribution customers served, total system capacity, and total miles of wires. Common examples are average age and age range of assets in each class and life expectancy of assets by technology category. Also included in this category is a description of planning tools (software and methodologies) for analyzing infrastructure.
- **Operational data** - Information describing system operations, including voltage levels and other operating data for distribution system assets. This may include high/low voltage levels for

[46] The names and definitions of categories used in this report may differ from those used by the states. For example, a state may include infrastructure and operational data in a single category called *system data*. Monitoring capabilities also may be listed under system data, rather than as a separate category.

substation transformers, system-level peak demand, and peak demand at more granular levels such as by circuit, substation, town, or operating area levels.

- **Monitoring capabilities** - Information on monitoring and control technologies to help characterize system operations and information and time intervals for which data are available (e.g., outage status).
- **Management systems** - Information on distribution management systems, including advanced control and communication systems, demand response or other DER management systems, and outage management systems. DER management systems leverage smart inverter functionalities built into distributed solar to provide grid support, such as voltage regulation, frequency support, and ride-through capabilities.
- **Financial data** - Information on historical spending for capital investments and other expenditures — e.g., for the past 10 years (as well as projected spending for proposed system upgrades or replacements over the next 5-10 years). Examples of historical spending include expenditures tracked for specific investment categories, operations and maintenance, and interconnection costs for developers and customers.
- **DERs** - Typical information required includes the type and number of net-metered distributed PV systems installed; rated capacity of small generators; total number of EVs, EV charging stations, and battery storage units; and information on demand-side management (also called *demand response* or *demand flexibility*) and energy efficiency programs and pilots. Some states require a map identifying the locations of each small generator interconnected to the grid at the time of filing.
- **Annual reports** - In addition to requiring baseline distribution system information in filed plans, some states require annual reports on topics such as distributed PV and reliability studies, forecasting, distribution system needs, and future investments. For example, utilities may be required to report annually on large distribution projects (greater than 500 kilovolt-ampere [kVA]), distribution system projects added in the prior year, time required for approval of distributed PV interconnection, and total generating capacity of all projects interconnected to the system.

Some of the information required in these categories includes both historical and forecasted data. This chapter focuses on information requirements for the utility's existing distribution system. The Grid Modernization Strategy and Grid Needs Assessment chapters of this report (chapters 7 and 8) address information requirements for forecasted distribution system needs.

6.2 State baseline information requirements

This section discusses baseline information requirements in two groups:

- States with more prescriptive requirements addressing in detail the categories described above
- States with less defined requirements for all or several of these categories

6.2.1 Jurisdictions with more prescriptive baseline information requirements

Example baseline information requirements — for Colorado, District of Columbia, Illinois, Minnesota, and Oregon — are listed below.

Colorado. The PUC outlined baseline information requirements for Distribution System Plans to identify and assess needs on the distribution system. Requirements include providing an overview of infrastructure and operational data and identifying and assessing distribution system needs. Also required is a map of existing (and planned) substations, as well as tabular information about current design capacity and performance of each substation and substation transformer. In addition, the assessment includes the status of advanced metering infrastructure (AMI) deployment. The specific information required includes the following:

- Infrastructure
    - Maximum rated capacity of each substation transformer
    - Peak hourly demand on each substation transformer for the past three years
    - Capacity margin for each substation transformer
    - Advanced functionality capabilities of each substation transformer
    - Number of feeders served by each substation and substation transformer
    - Maximum rated capacity of each feeder
    - Peak hourly demand on each feeder for the past three years
    - Capacity margin for each feeder
    - Percentage of grid availability
    - Minimum daytime load
    - Aggregate miles of underground and overhead wires, categorized by voltage class
    - Monitoring capabilities and data collection on the distribution system, such as substations and feeders for which the utility has real-time supervisory control and data acquisition (SCADA) capability
    - Amount of distributed generation installed on the system (number of systems and nameplate capacity in kilowatts by generator types, organized by substation or feeder)
    - Description of NWA on the system, organized by substation or feeder, including annual cost savings and greenhouse gas emissions reductions
    - Amount and locations of distributed storage installed on the system (number of systems and ratings, measured in kilowatts and kilowatt-hours)
    - Estimated number of EVs
    - Level 2 and direct current fast-charging EV charging stations, organized by substation or feeder
    - Estimated demand flexibility capacity on the system and historic utilization of flexibility capabilities
    - Voltage and power quality data for the past three years
    - Location of highly seasonal circuits
- Monitoring capabilities
    - For substations and feeders for which the utility has real-time SCADA capability
- Financial data

  - Total capital budget for the past three years (and projected for the next five years), broken down by budget category
- DERs
  - Distributed generation, energy storage systems, EVs, microgrids, fuel cells, and demand-side management measures including energy efficiency, demand response, and demand flexibility that are deployed at the distribution grid level, on either the customer or utility side of the meter

District of Columbia. The District of Columbia (D.C.) Public Service Commission established information requirements for data to assess asset condition and maintenance needs for the distribution system. Baseline information requirements for annual report filings include the following:

- Infrastructure
  - Identify underground distribution projects by ward and voltage level (Order 12735).
  - Include justification of projects based on load forecasts, asset age, and condition (Order 16975).
  - Describe the infrastructure maintenance methodology for equipment type or asset group, whether it is reactive, preventive, predictive, and/or reliability-centered (Order 17816).
  - Include a summary table on each substation that details: (Order 20776)
    - Asset condition as part of the Equipment Condition Assessment.
    - Date maintenance was last performed.
    - Outstanding issues to be remediated/fixed.
  - Identify high priority feeders,[47] or the two percent lowest performing feeders as measured by Customer Service and Reliability Standards, provide:
    - A service area map.
    - Outage description.
    - A proposed solution, as well as cost-benefit analysis for maintenance options, revenue impacts, and assessment of past system failures.
  - For any feeder on the Priority Feeder List more than twice provide: (Order 16975)
    - A proposed solution.
    - Outage description and efforts taken to address issue
    - System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), number of interruptions, and number of hours of customer interruptions since feeder has been on the priority list.
    - A feeder service area map
    - Assessment of why past efforts failed.
  - Details on how priority feeder performance changes (Order 21558)
  - 10 years of historical data on high priority feeders (Order 17816)
- Financial data
  - Financial information in the Annual Consolidated Reports covers five years of historical

[47] Potomac Electric Power Company is expected to address issues with priority feeders to prevent the same feeder from appearing on consecutive annual reports.

spending data and five years of forecast spending levels.
    - For the Priority Feeder List, the Annual Consolidated Report includes a discussions of prior years programs and Aggressive Correction Action Programs for priority feeders that are on the list for two or more consecutive years.
- DERs
    - Distributed generation, energy storage, energy efficiency, demand response, and grid software, and controls
- Annual reports - Other information required
    - Comprehensive plan including the planning methodology
    - Disaggregated data concerning priority feeders, load growth, planned spending, and equipment failure by neighborhood
    - Updates on the need for substation additions and enhancements to existing substations from prior plans (i.e., ongoing projects), plus justification for projects, including as applicable, load growth projections and equipment age and condition (Order 16975)

Illinois. Illinois requires a Multi-Year Integrated Grid Plan to be submitted by each utility serving more than 500,000 retail customers. Baseline information requirements are described below.

- System data
    - Description of the utility's distribution system planning process
    - Description of the utility's footprint
        - Length and size of the system – line length by type (overhead, underground)
        - Location of interconnected DERs – type, size, and location
        - Distribution line loss study
        - Substation capacity (kVa)
- Infrastructure
    - Description of current operating conditions of the distribution system presented separately for each operating area, including the following information:
        - Current and expected SAIFI and Customer Average Interruption Duration Index (CAIDI) data for the system
        - Software and data management systems
        - Most recent system load and peak demand forecast for the next 5-10 years
        - DERs, including energy efficiency, that were factored into the forecast
        - Forecasting software currently used and planned software deployments
- Financial data
    - Financial data for the preceding five years
        - Investments tracked by specified categories, operations, and maintenance expenses (and investment and expense estimates for the next five years)
        - Interconnection costs for developers and customers
        - Operation and maintenance
- DERs
    - Data about interconnected DERs

        - Installed nameplate capacity of DERs on the distribution system interconnected in the past year
        - Aggregate DER deployment by type, size, location, and customer class

Minnesota. The Minnesota PUC established an extensive list of baseline information requirements for regulated utilities to report in Integrated Distribution Plans in its February 20, 2019, order on Integrated Distribution Planning (IDP) Requirements. Utilities must file an annual update of the baseline financial data.

- Infrastructure
    - Modeling software currently used and planned software deployments
    - Discussion of how IDP is coordinated with the integrated resource plan (IRP), as well as any modifications
    - Distribution system annual loss percentage for the prior year
    - Maximum hourly coincident load (kW) as measured at the interface between the transmission and distribution system (e.g., using SCADA data)
    - Total distribution substation capacity in kVA
    - Total distribution transformer capacity in kVA, if different from total distribution substation capacity, and the reason for the difference
    - Total miles of overheard distribution wire
    - Total miles of underground distribution wire
    - Total number of distribution customers
- Monitoring capabilities
    - Percentage of substations and feeders with monitoring and control capabilities
    - Summary of existing system visibility and measurement
    - Number of customer meters with AMI/smart meters and those without (and planned AMI investments) and overview of functionality
- Financial data
    - Historical distribution system spending for the past five years by category
        - Age-related replacements and asset renewal
        - System expansion or upgrades for capacity
        - System expansion or upgrades for reliability and power quality
        - New customer projects and new revenue
        - Grid modernization and pilot projects
        - Projects related to local government requirements
        - Metering
    - Historical data from 2018 or earlier related to rate case categories
        - Asset health
        - New business
        - Capacity
        - Fleet, tools, and equipment
        - Grid modernization or pilot projects

- Investments in distribution system upgrades by subset and location
    - Total costs spent on DER generation installation in the prior year by category (application review, responding to inquiries, metering, testing, make ready)
    - Total charges to customers for DER generation installations in the prior year by category (application review, responding to inquiries, metering, testing, make ready)
- DERs
    - Total nameplate kW of DER generation system which completed interconnection in the prior year, by technology type
    - Total number and nameplate kW of existing DER systems interconnected to the distribution grid, when filed, by technology type
    - Total number of EVs in the service territory
    - Total number and capacity of public EV charging stations
    - Number of units and MW/megawatt-hour (MWh) ratings of battery storage
    - MWh saving and peak demand reductions from energy efficiency program spending each year
    - Amount of controllable demand (MW and percent of system peak)
    - Discussion of how DER is considered in load forecasting
    - Discussion of impacts of Institute of Electrical and Electronics Engineers (IEEE) Standard 1547-2018 on IDP (interoperability and advanced inverter functionality)
    - Current DER deployment by type, size, and geographic dispersion
    - Information on areas of existing (or forecasted) high DER penetration, including a definition and rationale for what the company considers “high” DER penetration
    - Information on areas with existing (or forecasted) abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology, including information describing experiences where DER installations have caused operational challenges, such as power quality, voltage, or system overload issues

Oregon. The Oregon PUC established baseline information requirements for DSPs filed by regulated utilities in Order 20-485 in December 2020.[48] DSPs must provide an understanding of (1) the current physical status of the utility distribution system, (2) recent investments in the system, and (3) the level of DERs integrated into the system. Each utility must provide information about infrastructure, monitoring capabilities, management systems, financial data, DERs, and demand response programs (separately from other types of DERs). In addition, utilities must file an annual report.

- Infrastructure
    - A description of currently used baseline and system assessment practices that include:
        - Method and tools used to develop the baseline and assessment
        - Forecasting time horizon(s)
        - Key performance metrics
    - Summary of the number of asset classes and assets in each class, the average age and

[48] Early in the proceeding to establish DSP requirements, the Oregon PUC asked the regulated electric utilities to complete questionnaires about their distribution system — including baseline information — and DSP process. See the questionnaire for utilities, as well as the utilities’ responses in the UM 2005 case file.

age range for the assets in each class, and industry life expectancy of assets in each category
    - Historical distribution system spending for the past five years for:
        - Age-related replacements and asset renewal
        - System expansion or upgrades for capacity
        - System expansion or upgrades for reliability and power quality
        - New customer projects
        - Grid modernization projects
        - Metering
        - Preventative maintenance
- Monitoring capabilities
    - Including description and number of feeders, substations, and monitoring/control technologies currently installed, characterizing the percentage of the system comprised of each technology, the resulting capacity (e.g., remote fault detection or power quality monitoring), and the time intervals of measurements that are available
- Management systems
    - Description of any advanced control and communication system for distribution, DERs, demand response, and outage management
    - Percentage of the system and customers reached with each capability and any utility programs utilizing each capability
- Financial data
    - Historical spending for the past five years
    - Spending categories cover age-related replacements and asset renewal, system expansion/upgrades for capacity and reliability, new customer projects, grid modernization projects, metering, and preventative maintenance
- DERs
    - Description of net metering and small generators detailing total existing facilities by resource type and rated capacity
    - Map identifying locations of each facility type interconnected to the grid at the time of filing
    - Total number of EVs and number
    - Data on charging stations including numbers, sizes, type, ownership, and interconnected feeder over the last five years
- Demand response programs
    - Summary of demand response pilot and established programs, including the number and type of customers participating
    - Seasonal demand response patterns that identify peak demand periods and maximum available capacity to service each customer class
- Annual reports
    - Annual net metering report
    - Annual small generator report

- Annual reliability report. Any descriptions of reliability challenges and opportunities in the DSP should cross-reference underlying data and information contained in the annual reliability report.

6.2.2 States with less defined baseline information requirements

Examples include Michigan, Pennsylvania, Vermont and Virginia.

Michigan. The Michigan Public Service Commission established baseline information requirements for DSPs through a series of orders that began in 2017. In the initial DSP filings, utilities were required to submit a detailed description of distribution system conditions with supporting data, including age of equipment, useful life, ratings, loadings, and other characteristics, as well as reliability metrics. In a 2020 order, the Commission ordered filing of DSPs that included historical information pertaining to outages — SAIDI, SAIFI, CAIDI, customers experiencing multiple interruptions (CEMI), and customers experiencing long interruption duration (CELID).

Pennsylvania. The main vehicle for distribution planning in the state is the Long-Term Infrastructure Implementation Plan that is associated with the Distribution System Improvement Charge. Requirements include baseline information such as types and ages of eligible property for which cost recovery is sought, a general description of the location of the property, and a reasonable estimate of the quantity of eligible property to be improved or repaired. Also required are schedules for planned repair and replacement of eligible property, projected expenditures, and financing means. In addition, regulated utilities must file biennial plans for inspection and maintenance of equipment, including poles, overhead conductors and cables, transformers, switching devices, protective devices, regulators, capacitors and substations.

Vermont. The Vermont Public Service Department requires infrastructure and operational data to be included in an IRP every three years. Infrastructure data includes miles of distribution lines; numbers of substations; a description of each substation including transformer capacity and high- and low-side voltage of transformers; number of feeders; and the length (miles) and number of customers served by each feeder. Plans also describe the utility's current vegetation management program, including budgeted amounts and expended amounts for the last two calendar years and the number of miles trimmed, and proposed vegetation expenditures and miles trimmed for the current year (plus three future years). Each utility's IRP also lists all capital projects completed since the last IRP or in progress.

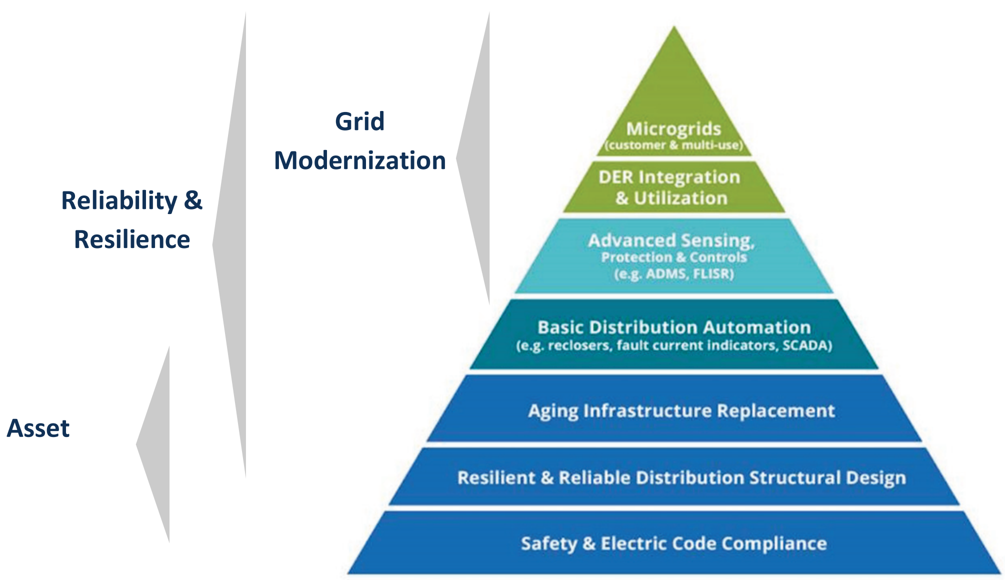
Virginia. In a series of orders beginning in 2019, Virginia established baseline information required for 10-year utility Grid Transformation Plans. Utilities must describe the physical distribution system, main feeder hardening per mile and project, intelligent grid devices, and planned and actual cost for each project connected to the system.

7. Grid Modernization Strategy

Grid modernization is a fundamental component of DSP. In addition to upgrading distribution grid capabilities to achieve traditional objectives like reliability, operational efficiency, and safety, modern grids are needed to meet other state policy goals, including better integration of DERs and decarbonization.[49]

Grid modernization investments span advanced monitor and control technologies (e.g., substation automation and home area networks), communications (e.g., field area networks), applications and systems (e.g., Advanced Distribution Management Systems), data management systems, planning and analytics (e.g., hosting capacity tools and DER interconnection management systems), and customer-facing systems (e.g., DER interconnection portal). These investments must be aligned with traditional asset planning and integrated with other planning objectives and DSP processes (Figure 7-1).[50]

State requirements for grid modernization strategy development and implementation can ensure better alignment of state policy and regulatory goals with utility investments and support the evolution of the distribution system. Ideally, grid modernization strategy development takes place within the DSP process. Where the state legislature requires dedicated grid modernization plans, utility regulators can require they be filed with the DSP or otherwise ensure close coordination.[51]



Source: De Martini

Figure 7-1. Distribution Infrastructure Investment Prioritization Pyramid

49 Baldwin, O'Connell, and Volkmann (2020).
50 DOE (2020).
51 NASEO-NARUC (2023).

7.1 State requirements

State requirements for grid modernization plans vary with respect to the requirement origin, definition, goal, planning horizon, information requirements, technologies, coordination and integration with other planning efforts, cost reasonableness justification, and commission decision and cost recovery process.

7.1.1 Requirement origin

Some state requirements for grid modernization originate at the legislature (California, Massachusetts, Minnesota, New Mexico, and Virginia). Commissions also have authority to require grid modernization plans — either separately or, ideally, as part of DSP. For instance, in 2018, the Rhode Island Public Utilities Commission ordered National Grid to file a grid modernization plan as part of a rate case settlement agreement.

7.1.2 Grid modernization definitions

States define grid modernization by law or regulation. See the "Example Grid Modernization Definitions" text box. Definitions of grid modernization may focus on meeting specific state objectives or types of distribution system projects.

Example Grid Modernization Definitions

California – “A modern grid allows for the integration of distributed energy resources (DERs) while maintaining and improving safety and reliability. A modern grid facilitates the efficient integration of DERs into all stages of distribution system planning and operations to fully utilize the capabilities that the resources offer, without undue cost or delay, allowing markets and customers to more fully realize the value of the resources, to the extent cost-effective to ratepayers, while ensuring equitable access to the benefits of DERs. A modern grid achieves safety and reliability of the grid through technology innovation to the extent that is cost-effective to ratepayers relative to other legacy investments of a less modern character.”

Massachusetts – “The department shall direct each electric company to develop an electric-sector modernization plan to proactively upgrade the distribution and, where applicable, transmission systems to: (i) improve grid reliability, communications and resiliency; (ii) enable increased, timely adoption of renewable energy and distributed energy resources; (iii) promote energy storage and electrification technologies necessary to decarbonize the environment and economy; (iv) prepare for future climate-driven impacts on the transmission and distribution systems; (v) accommodate increased transportation electrification, increased building electrification and other potential future demands on distribution and, where applicable, transmission systems; and (vi) minimize or mitigate impacts on the ratepayers of the commonwealth, thereby helping the commonwealth realize its statewide greenhouse gas emissions limits and sublimits under chapter 21N.”

New Mexico – "[G]rid modernization" means improvements to electric distribution or transmission infrastructure, including related data analytics equipment, that are designed to accommodate or facilitate the integration of renewable electric generation resources with the electric distribution grid or to otherwise enhance electric distribution or transmission grid reliability, grid security, demand response capability, customer service or energy efficiency or conservation […].”

Virginia – "Electric distribution grid transformation project" means a project associated with electric distribution infrastructure, including related data analytics equipment, that is designed to accommodate or facilitate the integration of utility-owned or customer-owned renewable electric generation resources with the utility's electric distribution grid or to otherwise enhance electric distribution grid reliability, electric distribution grid security, customer service, or energy efficiency and conservation, including advanced metering infrastructure; intelligent grid devices for real time system and asset information; automated control systems for electric distribution circuits and substations; communications networks for service meters; intelligent grid devices and other distribution equipment; distribution system hardening projects for circuits, other than the conversion of overhead tap lines to underground service, and substations designed to reduce service outages or service restoration times; physical security measures at key distribution substations; cyber security measures; energy storage systems and microgrids that support circuit-level grid stability, power quality, reliability, or resiliency or provide temporary backup energy supply; electrical facilities and infrastructure necessary to support electric vehicle charging systems; LED street light conversions; and new customer information platforms designed to provide improved customer access, greater service options, and expanded access to energy usage information.”

7.1.3 Grid modernization goals

Grid modernization goals act as the starting point to guide planning efforts, shaping utility investment strategies. State requirements for grid modernization include:

- DER integration (California, Massachusetts, New Mexico, Rhode Island, and Virginia)
- Reliability and security (Massachusetts, Minnesota, New Mexico, Rhode Island, and Virginia)
- Climate impacts preparedness (Massachusetts and Rhode Island)
- Greenhouse gas emissions reductions (New Mexico)
- Support for building and transportation electrification (Massachusetts and Rhode Island)
- Energy efficiency (Minnesota and Rhode Island)
- Minimizing impacts on ratepayers (Massachusetts, New Mexico, Rhode Island)
- Regional energy market integration (New Mexico)
- Integrating renewable energy (New Mexico)
- Consideration of low-income and underserved communities (New Mexico)
- Economic development goals, such as supporting job creation (New Mexico and Rhode Island) and economic competitiveness (Rhode Island)

7.1.4 Grid modernization planning horizon

State requirements may include a specific planning horizon for utilities to apply in their grid modernization planning, such as a 10-year grid modernization vision (California). Alternatively, states may require utilities to consider multiple planning horizons, such as a medium-term and long-term. For example, utilities in Massachusetts, Minnesota, and Rhode Island must consider a 5-year and 10-year perspective in their plans. A longer-term planning horizon also may be established. For example, Massachusetts requires utilities to present a demand assessment through 2050, in addition to a 5- and 10-year planning perspective.

7.1.5 Information requirements

Utilities typically must describe proposed investments and associated capital and operational expenditures. States may require utilities to provide specific information to support proposed investments in grid modernization, such as DER growth scenarios (California, Massachusetts, and Minnesota), hosting capacity analyses (California and Minnesota), locational net benefit analyses (California), internal utility business plans (Minnesota), NWA analysis (Minnesota), and future trends in renewable energy, energy storage and electrification technologies (Massachusetts).

Other examples of information requirements include alternatives to proposed investments (Massachusetts and Minnesota) and alternative financing mechanisms (Massachusetts). States also may require information on the progress of current grid modernization projects (California and Rhode Island) and how existing programs interact with proposed investments (Minnesota). In addition, utilities may be required to provide information on how proposed investments help meet state goals. For instance, Massachusetts and Rhode Island require grid modernization plans to address how the proposed investments support transportation and building electrification.

7.1.6 Grid modernization technologies

States requirements may list specific technologies for utilities to consider when developing grid modernization plans (California, Massachusetts, and New Mexico). For example, Massachusetts provides a list of possible grid modernization investments, including smart inverters, advanced metering, and energy storage. In addition to providing a list of technologies, California provides a framework for utilities to classify their grid modernization technologies considering use cases, system functions and integration challenges.

7.1.7 Coordination and integration with other planning efforts

States may require grid modernization efforts to be integrated with other utility planning efforts. For example, in Minnesota, utilities are required to include the grid modernization plan in their integrated distribution plan. In Virginia, utilities are required to incorporate grid modernization projects in their integrated resource plan.

7.1.8 Cost reasonableness justification

States may require grid modernization plans to justify that investments are reasonable by following specific approaches. For example, regulated utilities in Minnesota must include a cost-benefit analysis for each project proposed to be deployed in the next five years. Rhode Island specifies a benefit-cost framework. Alternatively, in California, the California Public Utilities Commission (CPUC) established that cost reasonableness for grid modernization investments should follow existing standards applied in general rate cases, meaning that utilities must propose the lowest cost approach to meet identified grid modernization needs. In Massachusetts, grid modernization investments must provide net benefits for customers to be approved.

7.1.9 Processes for Commission decisions and cost recovery

Processes for commission decisions on grid modernization investment proposals and cost recovery vary. For example:

- In California, utility grid modernization plans are submitted as part of the general rate case three-year funding cycle.
- In Massachusetts, draft Electric-Sector Modernization Plans must be submitted to the Grid Modernization Advisory Council for review to identify opportunities for improvement. The utility must submit a revised plan to the Department of Public Utilities, identifying the recommendations received, adjustments made, and any unresolved issues. Utilities may include in their electric distribution base rates grid modernization investments that the department considers used and useful.
- In Minnesota, investments to modernize the grid may be certified on June 1 of each even-numbered year. To be certified, projects must be considered in the public interest. Certified projects are later presented to the commission in a rate case and may be approved, rejected, or modified.
- In New Mexico, commission-approved grid modernization investments may be recovered through base rates, a tariff rider, or both.

- In [Rhode Island](), if the commission approves a grid modernization investment that is not already funded by the multi-year rate plan, the multi-year rate plan may be reopened to include the grid modernization investments approved in the distribution rates.
- In [Virginia](), utilities may request a rate adjustment for cost recovery of grid modernization projects once a year.

7.2 Utility practices

7.2.1 National Grid, Massachusetts

A [2022 Massachusetts law]() requires regulated utilities to file Electric-Sector Modernization Plans and established a Grid Modernization Advisory Council to review draft plans and provide recommendations. The utilities submitted their first draft plans in September 2023.

For example, National Grid submitted its [Future Grid Plan](), which defines the scope and scale of actions needed in the next 25 years to enable electrification and mitigate climate change. The plan was presented as the company's commitment "[…] to empowering Massachusetts by building a smarter, stronger, cleaner, and more equitable energy future." As part of its grid modernization strategy, the utility lays out a vision for a modern grid that empowers customers, future-proofs the grid, enables flexibility, and delivers just and equitable outcomes (Figure 7-2). By implementing this strategy, National Grid expects to deliver a modern grid that is ready, reliable, resilient, flexible and efficient.

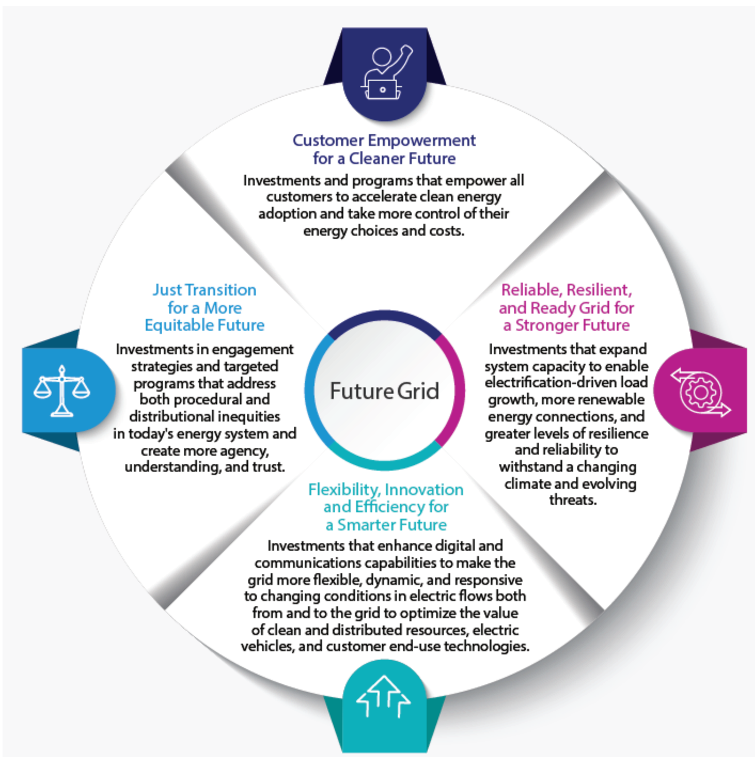


Figure 7-2. National Grid's Future Grid Plan Vision

Source: [National Grid]() at 16

To deliver its grid modernization strategy, National Grid's [Future Grid Plan] proposes more than $2 billion in investments from 2025 to 2029 in network infrastructure, technology and platforms, and customer programs (Figure 7-3). Investments in network infrastructure include upgraded power lines, transformers and substations. The company is considering expanding and upgrading 10 substations and building 3 new substations in the next five years. These investments are driven by building and transportation electrification, which the utility expects to contribute to an increase in peak load of 7% by 2029 and 21% by 2034 compared to 2022. Technology and platforms include investments in monitoring systems to increase operational capabilities and visibility of interconnected devices. Customer programs include demand-side initiatives and pilots to support energy efficiency and cost management.

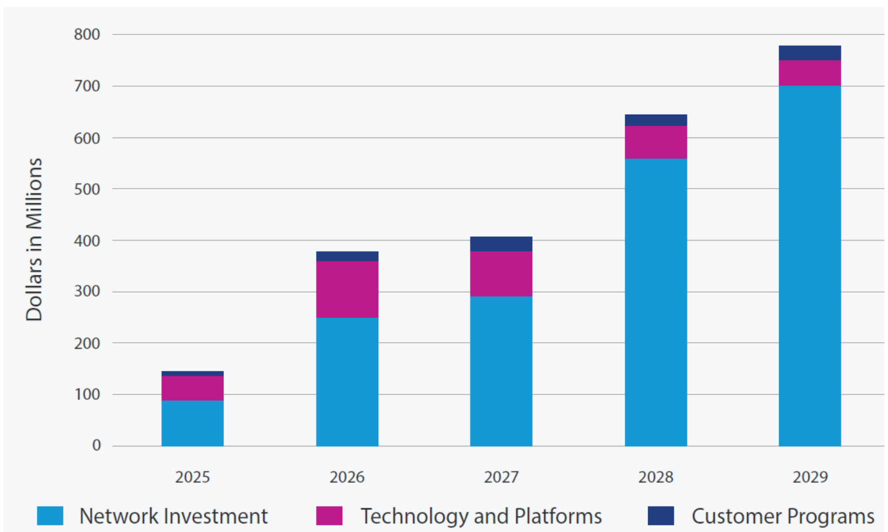


Figure 7-3. National Grid Electric-Sector Modernization Plan Investments Proposed for 2025-2029

Source: National Grid at 12

Through its grid modernization planning process and analysis, National Grid identified that when considering current demand, projected system needs, and existing grid capacity, every region within the company's service territory forecasted demand would exceed current capacity by 2035. For example, Figure 7-4 compares substation load in 2023 and 2035.

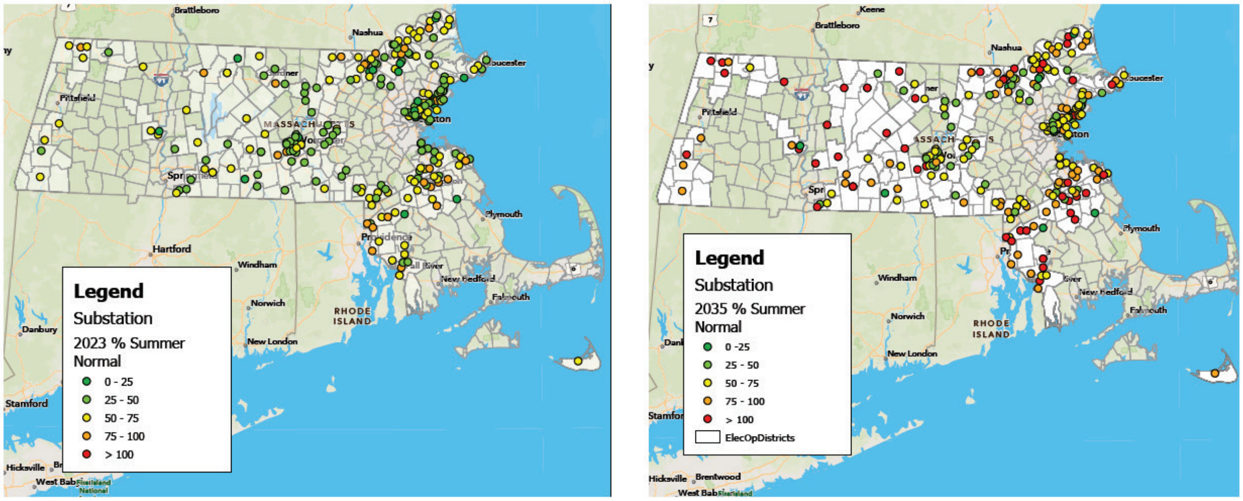


Figure 7-4. National Grid Substation Load Across the System in 2023 (left) and 2035 (right)[52]

Source: National Grid at 24

7.2.2 Xcel Energy, Minnesota

Xcel Energy's grid modernization strategy is focused on maximizing customer value, ensuring a sound distribution business, and maintaining flexibility in the face of evolving technologies and customer expectations. To deliver its strategy, the utility has identified multiple areas of investment, including improvements in grid visibility and controls through investments in advanced distribution system management and fault location, isolation and service restoration. The strategy also includes investments in network technology through Field Area Network infrastructure, two-way communications, and connecting intelligent grid devices and smart meters. Additionally, Xcel Energy describes near-term actions being taken to improve DER integration, including updating interconnection and planning processes as DER penetration increases. By deploying its grid modernization strategy, the utility expects to achieve an interactive and advanced distribution system that provides customers with more readily available and granular data, creates a better interface for customers to control and understand their utility bills, increases customer choice, and manages cost impacts for customers.

Figure 7-5 shows Xcel Energy's grid modernization investments in the near-, medium-, and long-term, including projects in process and potential future investments. For example, near-term projects with regulatory approval include deploying advanced metering infrastructure and developing a deployment and operations strategy to comply with FERC Order 2222. In the near-to-medium term, Xcel Energy plans to implement and integrate a Distributed Energy Resources Management System (DERMS) to support higher levels of DER integration in the distribution system. Medium- to long-term projects include distributed intelligence and implementing processes to meet FERC's order.

[52] https://www.nationalgridus.com/media/pdfs/our-company/massachusetts-grid-modernization/future-grid-full-plan-sept2023.pdf

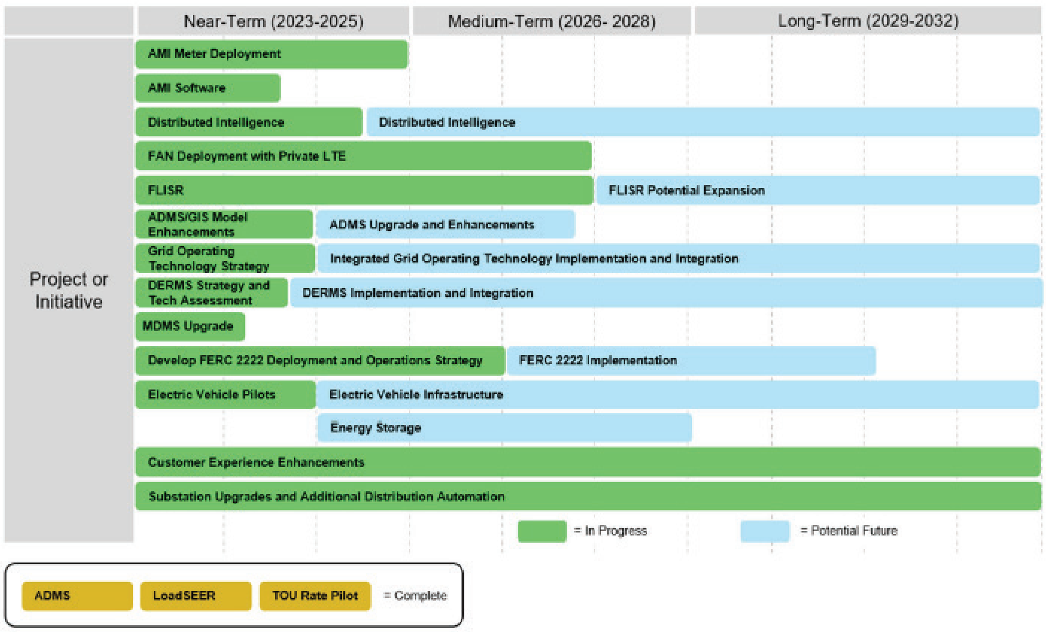


Figure 7-5. Xcel Energy (Minnesota) Grid Modernization Roadmap
Source: Xcel (2013), Figure B1 at 5

Note: AGIS – Advanced Grid Intelligence and Security Initiative, ADMS – Advanced Distribution Management System, GIS – Geographic Information System, AMI – Advanced Metering Infrastructure, FAN – Field Area Network (visibility and control), LTE – Long Term Evolution (also referred to as *4G*), FERC – Federal Energy Regulatory Commission, FLISR – Fault Location, Isolation, and Service Restoration, OMS – Outage Management System, MDMS – Meter Data Management System, DERMS – DER Management System, and TOU – Time-Of-Use. LoadSEER is a software tool from Integral Analytics to manage planning, investments, and risk.

7.3 Best practices

Best practices for state requirements for developing a grid modernization strategy include the following:

- *Integrate the grid modernization strategy with other planning objectives and processes.* Minnesota requires utilities to submit their grid modernization strategy with their IDSPs. The DSP must include a section dedicated to long-term distribution system modernization, developed based on internal business plans and considering knowledge gained during the DSP process.
- *Use a range of planning horizons to develop grid modernization goals for the near, medium, and long term.* Massachusetts requires utilities to develop grid modernization strategies using a 5- and 10-year forecast and a demand assessment through 2050.
- *Develop grid modernization strategies that align with other state goals*. In Rhode Island, utilities must describe how modernizing the distribution grid addresses building heating and transportation electrification. In Rhode Island and New Mexico, grid modernization strategies have to consider the economic competitiveness and job creation benefits of a modern grid.
- *Require a grid modernization roadmap that lays out the utility's investment priorities over time*.

Roadmaps enable commissions and stakeholders to understand how previous, ongoing and future grid investments support strategic components for delivering a modern grid. Figure 7-5, above, is Xcel Energy's roadmap for modernizing its distribution grid in Minnesota.

- *Establish stakeholder engagement processes to provide input into the utility's grid modernization strategy.* Processes should promote diversity of participants and transparency of utility actions resulting from stakeholder input. In Massachusetts, the Grid Modernization Advisory Council reviews draft Electric Sector Modernization Plans. The Council consists of 13 members appointed by the governor, including representatives of low- and middle-income residential customers, environmental justice communities, and the renewable energy and building electrification industries. In their final plans filed with the Department of Public Utilities, utilities must list each of the Council's recommendations with an explanation of why it was adopted, modified or rejected, as well as a list of unresolved issues.
- *Consider alternative investment options and financing mechanisms.* Utilities in Minnesota and Massachusetts must analyze investment alternatives as they develop their grid modernization strategy. Utilities in Massachusetts also must consider alternative financing mechanisms for proposed investments, which may include novel cost allocation methods.
- *Incorporate climate impact assessment and readiness as part of grid modernization efforts.* Massachusetts utilities are required to develop grid modernization strategies that prepare their systems for the impacts of climate-driven reliability events.

8. Grid Needs Assessment

A grid needs assessment (GNA) is an output of distribution system analysis that transparently identifies specific grid deficiencies. Identified grid needs are documented with information such as a description of the deficiency, associated engineering characteristics, and timing of the need. The GNA is the starting point for developing solutions to address each grid need, which may include grid upgrades or NWAs that employ pricing, programs, or procurement.

8.1 State Examples

State requirements for GNA primarily focus on analysis and transparent documentation of the process. For example, Delaware requires utility Long Range Distribution Plans to evaluate "equipment and circuit loading compared to thermal limits, breaker operating capability, asset condition, and safety and environmental issues."

Other states require utilities to clearly link proposed grid investments to identified grid deficiencies. For example, in Rhode Island, utilities must file Three-Year System Reliability Procurement Plans that, in part, assess the ability of an investment to meet specific identified system needs and anticipated reliability, compared to alternatives. The plan must include a description of the specific distribution system need, how it was identified in the system planning process, and when the distribution company expects to procure the reliability investment to meet the need. In Massachusetts, utilities must file Electric-Sector Modernization Plans with 5- and 10-year forecasts and describe current and proposed investments in the electric grid, among other requirements. For example, Eversource's 2024 plan used the forecasts to identify "violations and grid needs in the planning horizon and develop the foundational investments in the ten-year solution set."

This chapter focuses on requirements in other states for utilities to provide transparent documentation of their analysis of distribution system deficiencies.

California

California's Distribution Deferral Investment Framework includes a GNA that occurs after load and DER forecasting and before identifying planned investments and ranking deferral opportunities (Figure 8-1). When developing distribution system resource planning guidelines, the CPUC rejected the California IOUs' proposal to provide a list of distribution deferral opportunities instead of a GNA, stating that "a main purpose of the GNA is to provide transparency into the assumptions and results of the distribution planning process that yield the candidate deferral shortlist, proposed grid modernization investments, and proactive hosting capacity upgrades proposed to accommodate forecast autonomous DER growth."

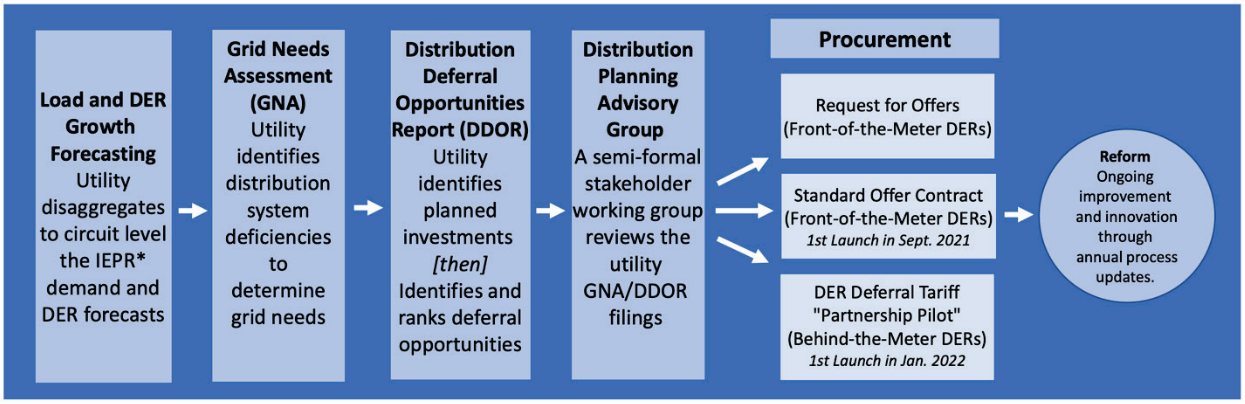


Figure 8-1. Distribution Deferral Investment Framework Overview. *Source: CPUC*

The CPUC requires that "The GNA will present a report of the grid needs that result from the annual distribution planning process. Each grid need shall be characterized by the following attributes:

1. Substation, Circuit, and/or Facility ID: identify the location and system granularity of grid need
2. Distribution service required: capacity, reactive power, voltage, reliability, resiliency, etc.
3. Anticipated season or date by which distribution upgrade must be installed
4. Existing facility/equipment rating: MW, kVA, or other
5. Forecasted percentage deficiency above the existing facility/equipment rating over five years."

Table 8-1 is an excerpt from a 2021 GNA filing that includes these attributes.

Table 8-1. Excerpt From California GNA Spreadsheets. *Source:* CPUC

GNA ID	Substation / Subtransmission Line	Circuit	Distribution Service Requir	Primary Driver of Grid Need	Operating	Deficiency (MW, MVAR, or Vpu)[1] 2021	2022	2023	2024	2025
GNA_2021_309	Valley 'EFG' 500/115 (S)	null	Capacity	Demand Growth	1/29/2026	0.00	0.00	0.00	3.30	9.80
GNA_2021_81	Eisenhower 115/33 (D)	Crossley	Capacity	Demand Growth	6/1/2024	0.00	0.00	0.00	2.87	2.81
GNA_2021_82	El Casco 115/12 (D)	Jonagold	Capacity	Demand Growth	6/1/2024	0.00	0.00	0.00	0.07	0.30
GNA_2021_86	Elizabeth Lake 66/16 (D)	Oboe	Capacity (UCT)	Demand Growth	6/1/2021	0.00	1.80	4.23	1.53	2.22

GNA requirements in California have evolved over time. CPUC 2019 guidance identified additional GNA filing requirements, including a narrative providing an overview of the distribution planning process, a description of steps in the GNA process, process changes since the prior GNA, a description of other details that impact the forecast or could change over time, and an explanation of discrepancies between GNA data and maps. Additional guidance in 2020 addressed several aspects of the Distribution Investment Deferral Framework process, including the GNA. The CPUC required the IOUs to present all grid needs separately and provide forecast data for all feeders (not just those with deficiencies), among other requirements.

Colorado

The Colorado PUC's GNA regulations require the following:

- "(a) The utility shall provide a summary analysis of the energy, capacity, ancillary services, and reliability needs and constraints on a utility's distribution system and solutions to those needs.
- (b) The grid needs assessment shall include an analysis regarding the suitability of non-wires

alternatives to mitigate identified needs and recommendations for the deployment of utility infrastructure upgrade solutions versus the procurement of non-wires alternative solutions to address any identified needs.

- (c) The grid needs assessment shall address existing and forecasted needs over a ten-year planning period that could result in a major distribution grid project."

Utilities also must provide an assessment of critical capacity and reliability needs during the 10-year period, divided into short-term (1-3 year) and long-term (4-10 year) needs; their current plan for investments; and historic (prior three years) and future (next five years) capital budgets. Utilities must use GNA results to identify locations that have sufficient capacity for direct-current fast chargers for EVs and long-term grid needs to avoid or defer distribution system upgrades through "geographically targeted deployment of demand flexibility, demand response and energy efficiency measures."

Hawaii

Early in the IGP process, the Hawaii PUC required the Hawaiian Electric Companies (Companies, HECO) to include in its workplan "the process and timeline for defining and quantifying grid needs (including generation, transmission, and distribution)." The GNA methodology was approved in 2022 and applied in the 2023 IGP filing (Figure 8-2, green box).

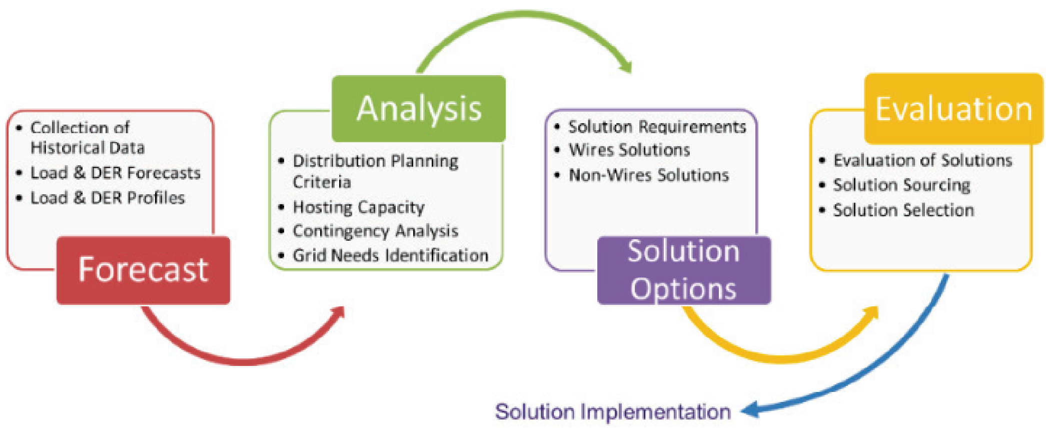


Figure 8-2. Stages of the Distribution Planning Process. *Source: HECO, Location-Based Distribution Grid Needs*

The Companies' divided grid needs into two distribution categories: locational grid needs (to address load growth) and hosting capacity grid needs (to accommodate forecasted DER growth).

Throughout the distribution system planning process, including the locational grid needs analysis, the Companies use their corporate load forecast. It includes layers for underlying growth (i.e., scenarios) to determine substation transformer and circuit demand forecasts. The Companies screen each substation transformer or circuit for planning criteria violations under each load growth scenario. If the demand forecast exceeds the equipment rating during the planning period, the transformer or circuit is advanced to more detailed analysis of hourly grid needs. The output of this granular analysis identifies the timing, capacity, energy, and duration of the grid need (Figure 8-3).

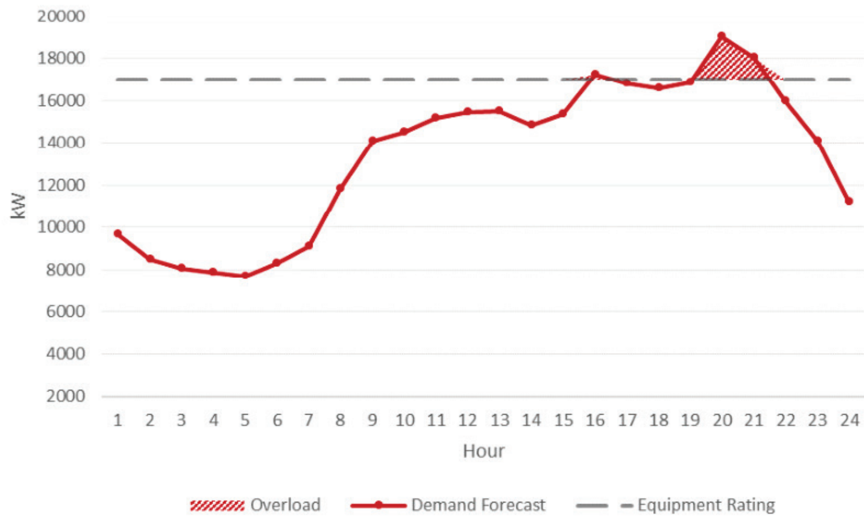


Figure 8-3. Hourly Grid Needs Example. *Source: HECO,* Location-Based Distribution Grid Needs

Following the hourly grid needs analysis, HECO identifies solutions for transformers or circuits that require mitigation. The solution portfolio includes NWAs.

The hosting capacity assessment identifies grid deficiencies based on forecasted DER growth (Figure 8-4). The process begins by determining the total anticipated DERs, comprised of existing DERs and the Companies' forecast of new DERs.

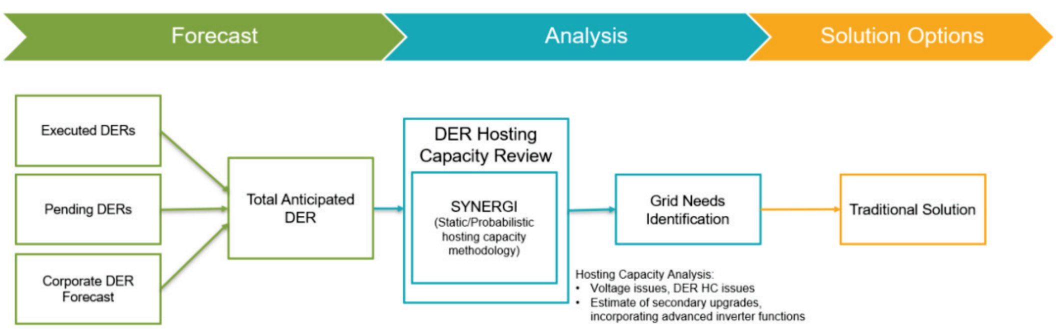


Figure 8-4. Hosting Capacity Grid Needs Identification Stages. *Source: HECO, [Distribution DER Hosting Capacity Grid Needs]*

After developing the DER forecast, the Companies screen each circuit to determine if it can host the forecasted DERs. For circuits with forecasted DER capacity that exceed projected 2025 hosting capacity, HECO conducts stochastic and probabilistic analyses. Analysis results are grouped into three categories: (1) updated hosting capacity is sufficient, (2) updated hosting capacity with modifications does not require infrastructure investment, and (3) the circuit requires additional hosting capacity.

Example Utility Practice

Regulated utilities in Michigan file IDPs under evolving requirements through Commission orders. The Commission does not require explicitly require the utilities to file a GNA. DTE's 2023 Distribution Grid Plan, however, identified gaps to achieving the future state of the grid, following development of load forecast scenarios and assessing the current state of the distribution system. Guided by the DOE's Distribution System Platform Initiative, DTE identified areas where investment is needed most on its grid. The utility grouped the investments into four categories: physical grid infrastructure, observability and controls, analytics and computing platforms, and communications. Proposed investments are organized in the same manner. Figure 8-5 is a conceptual illustration of the status of DTE's grid modernization platform and application layers. The more color in the bars and boxes, the more advanced DTE rates itself in that area. Conversely, a large amount of white space indicates a significant gap.

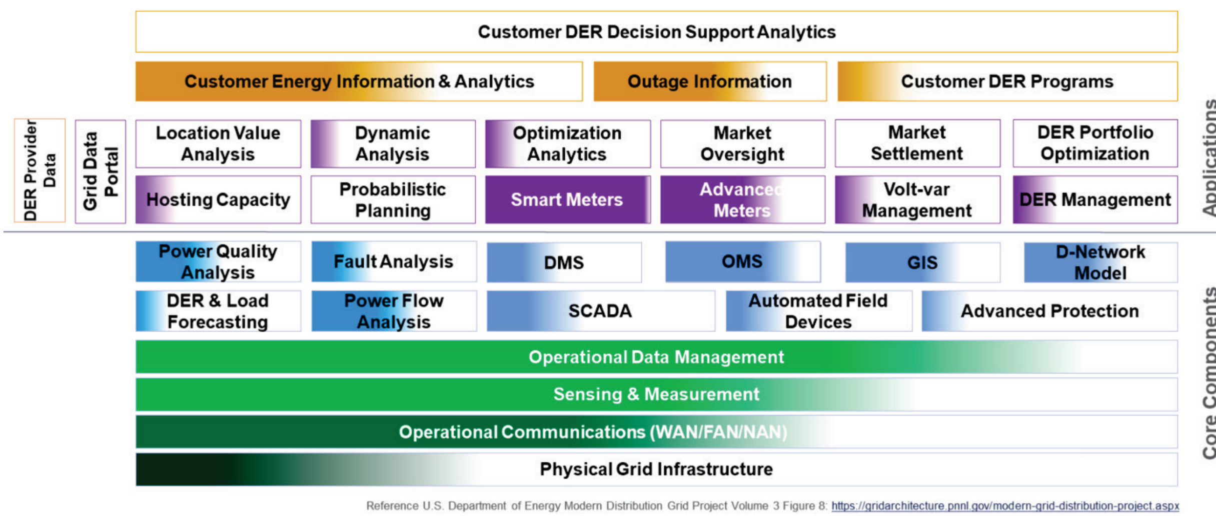


Figure 8-5. Status of DTE's Grid Modernization Platform and Application Layers. *Source:* DTE

Nevada

DSP requirements in Nevada include GNA, defined as "an assessment of the constraints on a utility's electric grid and proposed solutions to those constraints." GNA requirements are broader than identifying grid constraints. They also include analyzing NWA and locational net benefits and recommending utility and third-party NWA investments to address identified constraints. The GNA in NV Energy's 2023 DRP relies on grid constraints identified in the utility's 2023 Capital Plan. The utility identified distribution constraints and capital upgrade projects and provided information for each substation. Reported information includes:

- Constraint type (e.g., thermal, reliability)
- Operational condition (e.g., normal, unplanned contingency)
- Estimated duration, timing, and number of days of deficiency for an average and peak day in 2029

- Estimated maximum deficiency in 2029
- Estimated cost to perform a system upgrade

Oregon

Regulated utilities in Oregon must identify grid needs in distribution system plan filings. The PUC's distribution system planning guidelines state that "Grid needs identification compares the current capabilities of a distribution system and the demands of a system to infer its future need." Figure 8-6 represents the initial distribution system plan requirements for grid needs identification. The utilities' initial plans addressed the Stage 1 requirement. The PUC updated its guidance in November 2024, which will inform documentation for Stage 2 and Stage 3 grid needs identification.

Grid Needs Identification	
Stage 3	Identify grid needs and present a summary of prioritized grid constraints, utilizing prioritization criteria such as community priorities, equity analysis, constraints on DER adoption, and evolving public policy goals.
	Provide new datasets and analysis responsive to OPUC, community inputs and policy evolution.
Stage 2	Develop robust "future state" data needs, including inputs in the following categories:
	Perform equity analysis overlaying customer geographic and socio-economic data relative to system reliability and customer options. Make findings publicly available.
	Needs identification includes results of community needs assessments, DER forecasting, and equity analysis.
	Identify grid modernization needs and present a summary of prioritized grid constraints and opportunities publicly.
Stage 1	Present summary of prioritized grid constraints publicly, including criteria used for prioritization.
	Document process and criteria used to identify grid adequacy and needs. Discuss criteria used to assess reliability and risk, and methods and modeling tools used to identify needs.
2021-2022	2023 and beyond

Figure 8-6. Oregon PUC's Guidance on Grid Needs Identification
Source: Order No. 20-485

PacifiCorp articulated the difference between the "traditional" grid needs identification process and the process outlined in Oregon PUC guidelines for distribution system planning ("DSP") (Figure 8-7).

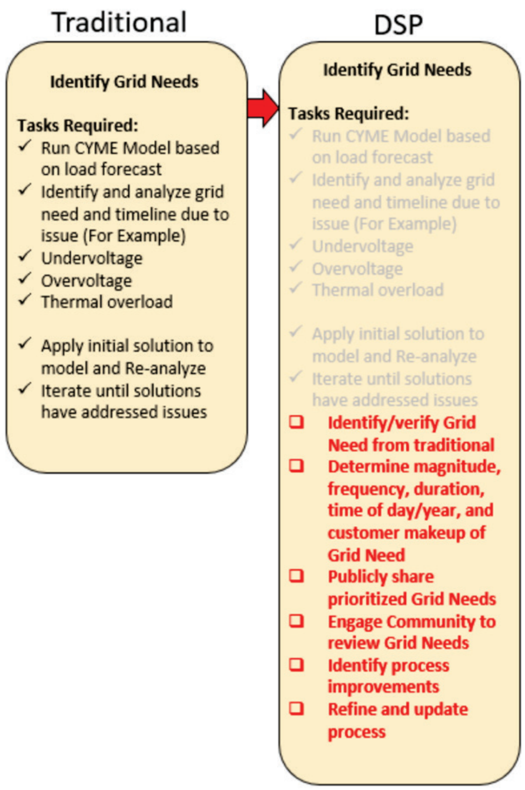


Figure 8-7. Difference in Existing and Initial DSP Guidance
Source: PacifiCorp

A primary difference between the traditional distribution system planning process and the process outlined in the PUC's guidelines is enhanced transparency. The utilities must publicly share its prioritized grid needs and engage community members to review them.

PacifiCorp included lessons learned from performing its grid needs identification, including the following:

- Engineers must have a deeper understanding of the grid need to consider NWAs "For example, to consider an [sic] NWS [non-wires solution], it is insufficient to identify just a peak need (a single data point in the forecast) and building capacity to meet that need. Framing and understanding the need for an NWS requires details around specific times of day, days of year, number of times in a year and overall magnitude and duration of certain needs."
- Grid needs identification must account for generation projects that are in the interconnection process, but are not yet connected to the grid. These additions can significantly impact the grid needs.

Portland General Electric (PGE) developed a ranking matrix to prioritize grid needs for its grid needs identification (Figure 8-8). Based on the results, PGE calculated a score for each substation and circuit and prioritized needs based on the ranking. Each level is a multiplier to weight the results of specific questions that PGE answered for each grid constraint. For example, in Level 5, PGE scored grid needs based on whether the grid upgrade addresses: (1) a safety concern or (2) an upgrade that must be made due to a customer commitment, such as signed minimum load agreements or customer-provided estimates of future load needs that the utility identifies as highly likely. At Level 5, the score is multiplied by five. (The score is multiplied by four at Level 4.) All screening questions and scoring criteria are clearly provided in the plan.

Figure 8-8. Distribution Planning Ranking Matrix
Source: PGE 2022 DSP

8.2 Best Practices

Best practices for states incorporating GNA into DSP requirements include the following:

- *Seek information about the utilities' existing GNA.* Utilities can provide documentation that identifies specific distribution system deficiencies and related characteristics, including timing of need. Regulatory decisions about GNA requirements, including filing and transparent reporting, may be better informed from a deeper understanding of current utility practices. For example, the regulatory commission may ask the utility to present information about GNA practices in a technical workshop or pose formal questions to the utility to understand:
    - Current integration of hosting capacity analysis and DER and load forecasting to identify grid needs
    - Consideration of state and local policies and priorities (e.g., reliability, resilience, DER integration) in the GNA process
    - The relationship between GNA and capital planning processes, including goals, criteria, budget, and timelines
    - How asset management and routine operations and maintenance are separately identified in the GNA
    - Prioritization process for grid investments based on the GNA
- *Emphasize transparency in reporting grid needs.* Regulators can encourage transparent reporting of the GNA process, including assumptions and methods, through policy statements, clear regulations, or required data reporting templates. In addition to specifying what

regulators would like to know, a template also can reduce regulatory staff review time by streamlining the review process. For example, some states require information on all circuits in the GNA; others only require information on deficient circuits.

- *Establish confidentiality provisions for GNA information.* Regulators can specify which data may need to remain confidential, and the process for reviewing utility confidentiality claims, and what information is necessary to allow DER developers to target DER deployment in areas that maximize value to the grid.
- *Request how the utility prioritized grid investments based on the GNA or provide guidance on how to prioritize investments — or both.* Not all utilities that perform a GNA specify how they prioritized resulting investment needs. Understanding the utility's prioritization process is critical, including alignment with state and local goals and priorities.
- *Explore hosting capacity GNA*. States with high levels of DER adoption can consider including a hosting capacity GNA in the distribution system planning process. Understanding such an analysis requires the utility to clearly state its forecasted DER assumptions and how they may impact available hosting capacity.

9. Non-Wires Alternatives

Non-wires alternatives (NWAs — also called *non-wires solutions, or NWS*) are DER options for meeting certain types of distribution (and transmission) system needs — for example, to provide load relief, reduce power interruptions, address voltage issues, enhance resilience, and meet local energy needs. A single large DER, such as a battery, or a portfolio of DERs may be used to meet the specified grid need, as long as they have the necessary technical capabilities.

NWAs have the potential to reduce utility costs by deferring or avoiding infrastructure upgrades. They also offer incremental solutions to grid needs, increasing flexibility and potentially avoiding large upfront costs for potential load growth that may not occur as forecasted.

9.1 State requirements

The District of Columbia and 16 states (CA, CO, CT, DE, HI, IL, MA, ME, MI, MN[53], NV, NY, OR, RI, VA and VT) include NWA analysis in planning requirements (Figure 9-1). Other states are in the process of developing these requirements and may include this analysis as part of the filing requirements (MD).

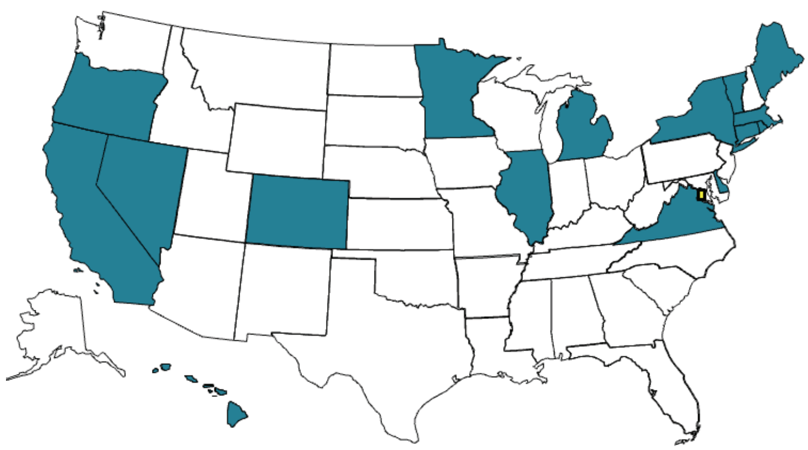


Figure 9-1. States with NWA Analysis Requirements for Distribution System Planning

Source: Berkeley Lab

9.2 NWA process

9.2.1 Overview

NWA identification follows the utility's grid needs assessment to determine the location and timing of constraints on the distribution system (see Chapter 8). The process for performing NWA analysis generally includes four steps (Figure 9-2): (1) identify eligible DER types, (2) determine if the NWA passes the screening criteria, (3) evaluate whether the NWA provides a cost-effective solution to the

[53] August 30, 2018, Order in Docket 18-251, available in Minnesota eDockets

identified grid need, and (4) procure the solution. Cost-effectiveness evaluations for NWAs should capture all intended benefit streams for both DER-based and traditional solutions to ensure that the resulting investment provides an optimal level of benefits considering the cost.

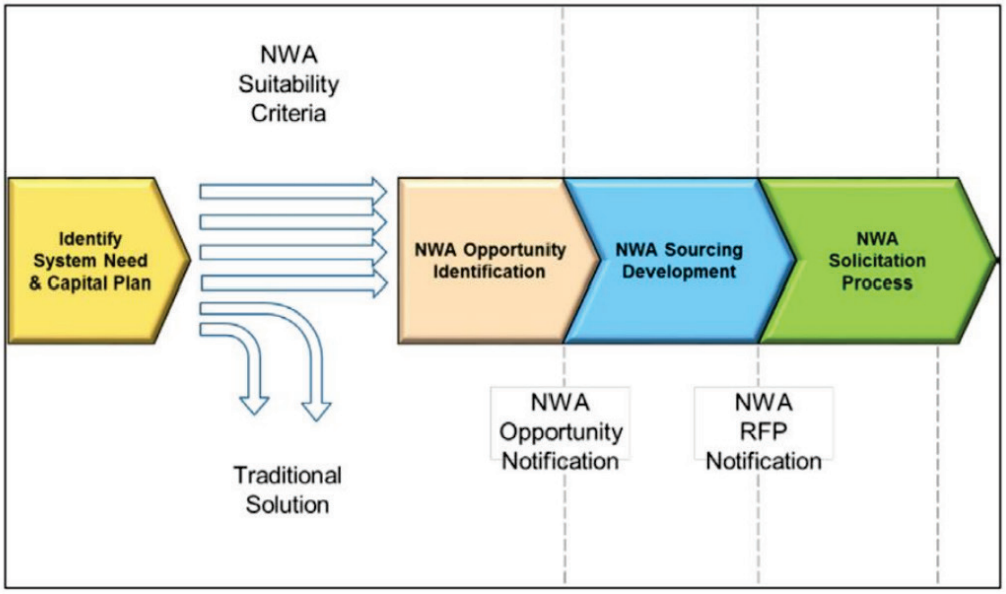


Figure 9-2. NWA Analysis Process

Source: Orange and Rockland Utilities, Distributed System Implementation Plan, June 30, 2023

Typically, the utility issues a request for proposals to solicit bids for NWAs. Where allowed, utilities also may deploy NWAs on their own. Utilities also can geotarget energy efficiency, demand response, time-varying rates, solar, and storage programs to meet local distribution system needs through focused marketing and higher incentive levels.

9.2.2 Eligible Resources

States define eligible NWA resources in the context of DERs, which generally include demand response, distributed generation (including diesel-fired generators), and energy storage. Some state NWA definitions refer to demand flexibility instead of demand response (CO, IL). Fewer states explicitly include energy efficiency as part of the DER definition or separately identify energy efficiency (CA, CO, CT, DC, ME, MI, NV, NY) or EVs (CA, CO, NV) as eligible NWA resources.

For example, the Colorado PUC's DSP regulations state that NWAs can "include one or multiple DER, including but not limited to demand response measures, energy efficiency, energy storage, and distributed generation. NWA projects can include these and other investments individually or in combination to meet the specified need." Further, DERs "may include, but are not limited to, distributed generation, energy storage systems, electric vehicles, microgrids, fuel cells, and demand side management measures including energy efficiency, demand response, and demand flexibility that are deployed at the distribution grid level, on either the customer or utility side of the meter."

Eligible NWAs in Oregon

Portland General Electric defines an NWA as “an investment, strategy, or action intended to defer, reduce or remove the need for a traditional utility solution (such as upgrading a substation or building a new line) in a specific geographical region to an identified distribution system need, such as managing load, generation, reliability, voltage regulation, and/or other wide-ranging distribution system needs.” The utility views NWAs in a comprehensive manner, including time-varying rate design and enabling technologies in addition to commonly included DERs such as energy storage (Figure 9-3).

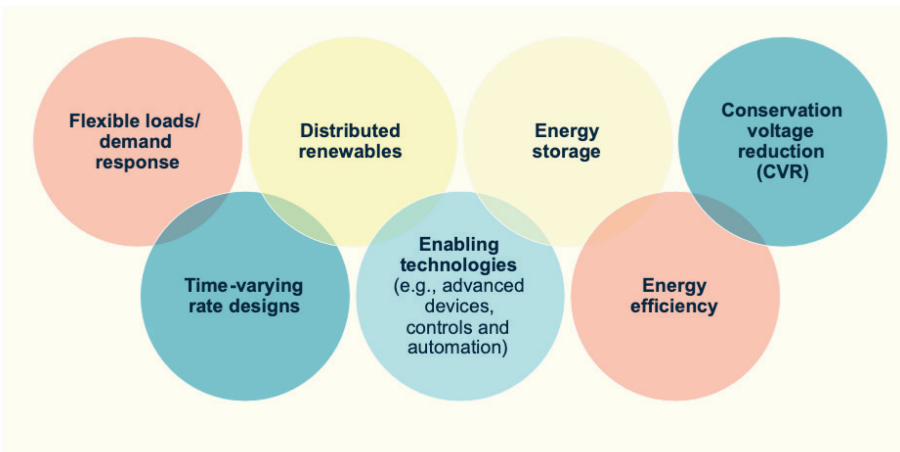


Figure 9-3. Example NWA Actions

Source: PGE Distribution System Plan Part 2

In addition to determining NWA eligibility under statutory or regulatory guidance, specific DER types with the technical capabilities needed to resolve the particular grid constraint must be identified. For projects intended to address load relief, for example, solar PV resources may be an option if the distribution asset experiences high load conditions during daylight hours, but may not be suitable if load reductions are needed at other times. Selecting eligible resources with the right set of technical capabilities is critical to facilitating screening and evaluation for NWA solutions.

9.2.3 Screening Criteria

NWAs are not an appropriate solution for all grid needs. States may specify screening criteria for consideration of NWAs for specific grid needs. The most common screening criteria include:

- Project type (based on grid need)
- Timing of grid need
- Traditional solution cost

9.2.3.1 Project Type

Certain types of traditional utility projects may be specifically excluded from NWA analysis. For example, the NWA analysis process for Hawaiian Electric (HECO) does not include projects that are necessary to comply with public works or other customer requests (e.g., line/pole relocation or undergrounding due to street widening, emergency and preventative equipment and infrastructure replacement, and replacement of damaged or failed equipment). That is because physical construction is needed to meet the needs of these projects. In Minnesota, Xcel Energy identified several project types that are not suitable for NWA based on their analysis experience. These include projects that mitigate risks that exist for over two-thirds of the year (5,840 hours) or in substations with only one transformer. In addition, Xcel does not consider NWA for projects impacting downtown mesh networks or for large customers that are sensitive to outages, like hospitals or nursing homes.

Some states (CA, CO, CT, DE, NV, RI) permit NWAs to address thermal loading or capacity issues and reliability. Three states (CA, CO, NV) consider voltage constraints as grid issues that NWAs can potentially resolve. Other identified grid needs that NWAs may address include performance issues related to asset conditions (DE), power quality (CT), resilience (CA, CT), and distributed resource integration (CT).

9.2.3.2 Timing

Lead time is an important screening criterion for grid needs (Table 9-1). Two states (CT, NY) require utilities to screen projects as part of their NWA analysis based on required minimum lead time. The intent is to allow sufficient time to consider and implement an NWA solution (e.g., 24 months). Currently, 18-24 months is the minimum lead time, with several states selecting 36 months, and 60 months is the maximum lead time.

Absent state requirements specifying minimum lead time for NWA acquisition, utilities in several states (CA, HI, MN, RI) identify a threshold. For example, California investor-owned utilities used a three-year minimum lead time to screen NWA projects in their 2023 Distribution Deferral Opportunity Reports. In Xcel Energy's 2023 IDP for Minnesota, the company used a three-year lead time, but discussed increasing it to five years in a future analysis.

If states choose to include lead time as one of the criteria for NWA analysis, they should consider appropriate timing criteria, availability of utility staff capacity to perform the analysis, NWA bidders' ability to participate in the procurement process given lead time requirements (if applicable), and any supply chain issues. For projects that address thermal loading and capacity issues, it also is important to build in sufficient time to allow for the traditional solution to be constructed if the NWA analysis and procurement process does not yield suitable candidates.

Table 9-1. Example NWA Screening Criteria for Grid Need Lead Time

State/Utility	Criteria		
California	California investor-owned utilities used 36 months in their 2023 Distribution Deferral Opportunity Reports		
Central Hudson, National Grid, O&R, ConEd (NY)	Large project: 36-60 months	Small project: 18-24 months	
Connecticut	Projects where grid service is needed within the calendar year are characterized as "unlikely."		
HECO	Favorable: 24-60 months	Moderate/Uncertain: >60 months	Unfavorable: <24 months
Xcel Energy (MN)	About 36 months		
NYSEG/RG&E (NY)	36 months		
Rhode Island Energy	At least 24 months		

9.2.3.3 Cost

Seven states (CO, CT, DE, HI, MN, NY, RI) use the total cost of the project investment as an NWA project screen. For example, a traditional project must cost more than a certain amount to justify the time and effort required for a utility to perform an NWA analysis and for the project to draw sufficient market interest for development. For example, in Delaware and Rhode Island, traditional utility projects must cost at least $1 million to be considered for NWA analysis, and in Minnesota the cost threshold is at least $2 million. Four of the seven states with a cost screen apply cost tiers (Table 9-2). In Hawaii, HECO created tiered cost screens for its NWA process.

If states choose to include a cost threshold in their NWA screening criteria, consideration of utility size and project size may help inform the appropriate value.

Table 9-2. NWA Cost Screens

<table>
<tr><th>State/Utility</th><th>Tier A</th><th>Tier B</th><th>Tier C</th></tr>
<tr><td>Colorado</td><td>Distribution grid: $2M</td><td colspan="2">"T&D grid": $3M</td></tr>
<tr><td>Connecticut</td><td>Likely: >$1M</td><td>Potential: >$500k<$1M</td><td>Unlikely: >$250k<$500k</td></tr>
<tr><td>Delaware</td><td colspan="3">$ 1M</td></tr>
<tr><td>HECO</td><td>Favorable: $1M+</td><td>Moderate/
Uncertain: $500k-$1M</td><td>Unfavorable: >$500k</td></tr>
<tr><td>Minnesota</td><td colspan="3">$2M</td></tr>
<tr><td>ConEd and O&R (NY)</td><td>Large project: No cost floor</td><td colspan="2">Small project: ≧$450k</td></tr>
<tr><td>Central Hudson (NY)</td><td rowspan="2">Large project: ≧$1M</td><td colspan="2">Small project: ≧$300k</td></tr>
<tr><td>National Grid (NY)</td><td colspan="2">Small project: ≧$500k</td></tr>
<tr><td>Rhode Island</td><td colspan="3">$1M</td></tr>
</table>

9.2.4 Cost-Effectiveness

Typically, NWA solutions must be cost-effective to be selected for implementation. Many utilities use benefit-cost analysis to determine cost-effectiveness. Some jurisdictions, such as the District of Columbia, New York, and Rhode Island, require utilities to file benefit-cost handbooks or models to inform DER developers how the benefit-cost analysis framework will be implemented when evaluating proposed DER projects. In Nevada, the Commission provided guidance on costs and benefits to include in the Locational Net Benefits Analysis.[54]

California investor-owned utilities use three metrics ($/MW-yr, $/MWh-yr, cost of traditional solution) to indicate the likelihood of DERs cost-effectively deferring a traditional solution. Metrics are calculated using an locational net benefits analysis calculator. Table 9-3 is an example of Southern California Edison's project prioritization for Distribution Deferral Opportunity Reports.

[54] Locational net benefits analysis analyzes costs and benefits of DERs to determine their net benefits for a specific location on the distribution system.

Table 9-3. Southern California Edison NWA Project Prioritization

Tier	Project Description	Cost Effectiveness	Forecast Certainty	Market Assessment	Flags
1	New Circuit at Elizabeth Lake Substation	6	1	8	
	New Circuit at El Casco Substation	4	7	1	
	New Circuit at Eisenhower Substation	7	10	3	
2	New Circuit at Farrell Substation	10	5	7	
	Santa Clara-Colonia 66 kV Subtransmission Line Rebuild	5	6	9	
	New Circuit at Gonzales Substation	13	3	10	
	New Circuit at Soquel Substation	9	4	11	
	Saugus-Colossus-Lockheed-Pitchgen 66 kV Subtransmission Line Rebuild	8	8	6	
	Saugus-Elizabeth Lake-MWD Foothill 66 kV Subtransmission Line Rebuild	12	8	5	
	Shawnee Substation Transformer Upgrade	11	10	4	
	Del Valle Substation	3		14	
	Cal City Substation Upgrade	2		15	
3	Alberhill System Project	1	10	2	FLAG
	New Circuit at Kimball Substation	14	2	13	
	New Circuit at Roadway Substation	15	10	12	

Source: SCE (2021).

Several states require NWA analysis but do not specify benefits and costs to be included in the analysis (e.g., DE, MA, MI, ME, MN, VT) or simply state that the NWA must be cost-effective compared to the traditional solution (e.g., IL, RI). In Connecticut, the NWA process monitor workplan includes development of a cost-benefit analysis.

In California, the PUC discussed the importance of considering all deferable costs, including regulatory and permitting costs in the NWA analysis. The state's investor-owned utilities are required to explain any discrepancy in planned investment costs reported in Distribution Deferral Opportunity Reports and general rate cases. The utilities also are required to consider the locational net benefits value for both wired solutions and NWAs based on a 10-year time frame.

Value streams used in benefit-cost analysis for NWAs vary widely. The most commonly used benefits are avoided energy costs and avoided generation, transmission, and distribution capacity costs. In Illinois, utilities must consider the short-term and long-run benefits and costs of DERs including the locational, temporal, and performance-based benefits and costs. In Nevada, utilities must consider reduction or increases in local generation capacity needs, avoided or increased localized investment in distribution infrastructure, reductions or increases in grid safety and reliability benefits, and any other savings or costs distributed resources provide to the grid or impose on customers.

Deferral periods for assumed benefits and costs vary. For example, Xcel Energy assumes five years, while other utilities (e.g., CA) estimate the value for deferring a project for one year. The deferral period is an important factor in the analysis. It drives the size and cost of the NWA solution as well as the magnitude of the financial benefit to the distribution system.

9.2.5 Procurement Options

After a utility determines that the NWA solution is viable, there are two general ways that the solution can be procured: (1) competitive solicitations or (2) utility pricing or programs. Seven jurisdictions (CA, CO, CT, DC, HI, NY, RI) require utilities to use a competitive solicitation process to acquire NWAs. For example, in Colorado, utilities are required to "conduct a technology-neutral competitive solicitation for NWAs to defer, reduce, or avoid the costs of the major distribution grid projects." Connecticut determined that both utilities and non-utilities may submit bids for a NWA solicitation, as did Illinois.

To date, most successful NWA projects are energy storage projects that are awarded through a competitive solicitation, or focused utility programs — often referred to as *geotargeted programs.*

9.2.6 Contingency Plans for Non-Performance

To address the risk that winning NWA bidders or the utility cannot install the DER solutions, or if the DER fails or underperforms, some states require contingency plans. In California, investor-owned utilities must include contingency plans as part of their Distribution Deferral Opportunity Reports (Table 9-4). In its 2023 IGP, HECO cited the potential need for contingency plans in future DSP proceedings.

Table 9-4. Example Contingency Plan for NWA Non-Performance

Scenario	Contingency Plan
DER provider is unable to install DERs according to contract SCE is unable to install DERs to meet the grid need	• Develop short lead time mitigation alternatives that supplement the DER portfolio for total solution, where feasible • If cost-effective solution does not exist, pursue construction of traditional project intended for deferral or short lead time mitigation until ultimate solution can be implemented
DER fails during commissioning, or underperforms during operations and doesn't meet real-time needs of the electric system (based on commissioning and performance verification protocols agreed to in the contract for 3rd party owned DERs)	• Determine emergency limitations if applicable, work with system operations on potential temporary grid reconfiguration, or in worst cases potentially drop load and de-energize customers • Determine reason for DER underperformance • Assess any equipment damage or outage impact • Assess if additional mitigation is required and develop expedited solution options

Source: Southern California Edison's 2023 Grid Needs Assessment and Distribution Deferral Opportunity Report

Examples of Geotargeting DER Programs for Non-Wires Solutions

Consumers Energy, Michigan

The utility developed the Energy Savers Club program (2017–2018) to test the efficacy of using NWAs to reduce load at the Swartz Creek distribution substation. The substation was experiencing high peak loadings due to increases in load growth, and there was sufficient time to explore deferring the substation upgrade with these options.

To reduce load requirements below 80% of maximum summer capacity (i.e., to reduce peak load by 1.4 MW by 2018) — and potentially defer a $1.1 million infrastructure investment, saving customers money — the utility turned to ramping up participation in their energy efficiency and demand response programs in the area served by the substation.

The Energy Savers Club was a uniquely branded marketing campaign to connect commercial and industrial customers to existing energy efficiency programs, and residential customers to existing energy efficiency and demand response (AC Peak Cycling and TOU) programs. The largest savings came from commercial lighting efficiency measures and residential demand response. The pilot tested the role that energy efficiency and demand response programs can play — as potential lower-cost solutions — in managing load and deferring distribution capacity-related investments when targeting specific capacity-constrained geographies.

Xcel Energy, Minnesota

Xcel Energy and the Center for Energy and the Environment began an NWA pilot focused on existing energy efficiency and demand response programs with targeted customer outreach in June 2019 in the cities of Sartell and Sauk Rapids in central Minnesota. The estimated capacity need for the area was 1.5 megavolt-amperes in 2020. The pilot sought to defer or avoid a new transformer and feeder reconfiguration. Field activities were completed in summer 2020.

Among the objectives of the pilot was to offset projected peak demand growth in the target location for a year-by-year reduction in load of 500 kW. Another objective was to test geotargeting demand response as a distribution system resource to assist with local grid management. During the research stage, Xcel Energy and Center for Energy and the Environment found that more than 4,000 residents and businesses in the pilot area already were participating in the utility's demand response programs.

The pilot achieved its goals for both energy efficiency and demand response to meet the stated project needs. At the same time, the utility updated its planning forecast during the pilot, mitigating the need for a distribution upgrade. In addition, a large community solar project was connected in the target area during the pilot period. That significantly changed the load in the local area and provided opportunities to redeploy demand response to mitigate the need for distribution system upgrades to accommodate the solar project.

9.3 Example Utility Practices

Hawaii. When reviewing HECO's Integrated Grid Planning workplan, the Hawaii PUC suggested that utility should "strive to make their non-wires analysis more transparent and thorough." Based on this guidance, HECO developed a three-step approach to analyze NWAs for traditional utility projects identified in the grid needs assessment (Figure 9-4). The results of the assessment are an input to the NWA opportunity screen. This step focuses on quickly and simply determining if the grid need can be met with an NWA ("NWA Qualified Opportunities"), based on technical requirements for transmission and distribution (T&D) opportunities.

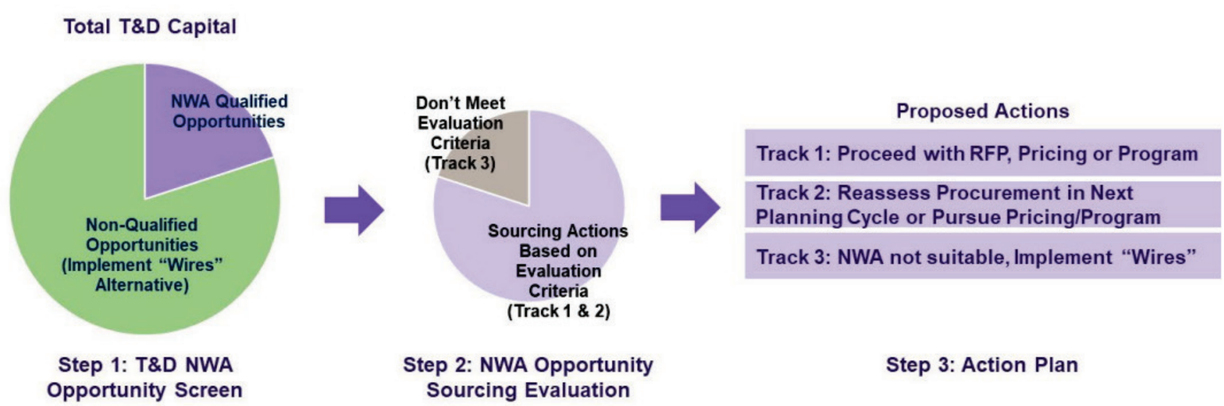


Figure 9-4. NWA Opportunity Evaluation Methodology in Hawaii

Source: *HECO NWA Opportunity Evaluation Methodology*

Next, the company performs an NWA opportunity sourcing evaluation. This step evaluates candidate NWA projects and identifies those with the greatest likelihood of success. The criteria HECO uses are timing of the grid need, performance requirements to meet the grid need, and project economics.

The third step in the process is an action plan. T&D projects are assigned to one of three action plan tracks, which identifies the solution path (Table 9-5).

Table 9-5. HECO's T&D NWA Opportunity Evaluation

Track	Timing	Overall Performance	Economics
1	Favorable	Favorable or Moderate/Uncertain	Favorable
2 (Pricing)	Favorable	Favorable or Moderate/Uncertain	Moderate/Uncertain
2 (Reassess)	Moderate/Uncertain	Favorable or Moderate/Uncertain	
3	One or more are Unfavorable		

Source: HECO NWA Opportunity Evaluation Methodology

The three tracks are:

- *Track 1. Procure NWA opportunities.* The grid need (overall performance) can reasonably be met with an NWA, the projects are greater than $1 million, and the in-service need is within two to five years. These opportunities are primarily procured with competitive solicitations.
- *Track 2. Reassess NWA opportunity.* Track 2 has two options. If the project is more than five years away, or does not have moderate to favorable performance, the company can determine if the project should be reevaluated in the future for procurement. If the project cost costs less than $1 million but more than $500,000, and the in-service need is within two to five years, the company can determine if pricing (e.g., time-varying retail rates) or programs (e.g., for geotargeted energy efficiency, demand flexibility, and storage) can be used to meet the grid need.
- *Track 3. Wired solution*. Grid needs that cannot be met with NWA solutions will be met with traditional wired solutions.

Nevada. Similar to Hawaii, NV Energy identifies all potential T&D system constraints or deficiencies through a grid needs assessment. The company relies on its most recent capital plan and updated information from its distribution planning department to identify candidate projects for NWAs. The company uses a four-step process to determine the viability of an NWA.

First, NV Energy uses NWA suitability criteria to better identify if a planned T&D capital upgrade project may be deferred or eliminated through NWAs. The suitability criteria are divided into two groups: (1) critical suitability criteria and (2) yellow flag suitability criteria (Table 9-6). The criteria are focused on the timing and type of constraint, as well as on siting issues.

Table 9-6. NV Energy NWA Suitability Screening Criteria

Critical Suitability Criteria
Is the constraint anticipated to occur between January 1, 2024 and December 31, 2029?
Is the constraint based upon thermal loading, voltage, or reliability reasons where a reduction in peak demand loading or energy consumption, or load shifting, on the transmission or distribution facilities involved would eliminate or defer the constraint?
Yellow Flag Suitability Criteria
Is the wired solution still within the planning or design stage, with no major equipment on order, received, or installed?
Is it reasonable to assume at this time that local residents would accept a Distributed Energy Resources solution in this area?
Is it reasonable to assume at this time that local government agencies would accept a Distributed Energy Resources solution in this area?
Is it reasonable to assume at this time that there are no environmental concerns which would preclude a Distributed Energy Resources solution in this area?
Is it reasonable to assume at this time that a Distributed Energy Resources solution would be able to be physically located in this area?

Source: NV Energy Distributed Resource Plan, 2023

For NV Energy’s 2023 Distributed Resource Plan, the constraint must be anticipated to occur between January 1, 2024, and December 31, 2029, and must be based on thermal loading, voltage, or reliability. The NWA must reduce peak demand loading or peak demand energy consumption, or shift load, to eliminate or defer the constraint. If the NWA does not meet both critical suitability criteria, it is not a feasible NWA solution for the utility.

Yellow flag suitability criteria include whether major procurement for the “wired solution” has already been initiated, as well as land, environmental permitting, and siting constraints (e.g., safety or customer opposition to NWA technologies) relevant to mitigating the grid need. If an NWA does not meet the yellow flag suitability criteria, it does not necessarily disqualify it as a feasible solution. NV Energy requires the utility analyst to clearly identify a reason to stop the NWA analysis.

The second step in NV Energy’s NWA analysis uses a spreadsheet-based tool. The NWA Screening Analysis tool provides the estimated size and cost of the potential NWA solutions and compares the present worth revenue requirement of the NWA and traditional solution.

NV Energy’s approach to creating an NWA portfolio in the 2023 Distributed Resource Plan is to:

- Identify the amount of existing demand response capacity in the constrained area, and assume that up to 27% of that capacity could be used to reduce the forecasted load via geotargeted demand response programs at no incremental cost.
- Identify the number of distribution transformers and feeders in the specific constraint to establish the cost for conservation voltage reduction.
- Use DER characteristics, costs and benefits to solve for a NWA portfolio that minimizes the present worth of revenue requirement, using a maximum of 5 MW for solar PV and 2% potential loading reduction for incremental energy efficiency and conservation voltage reduction.

Third, NV Energy identifies for additional analysis NWA options with similar estimated costs as the wired alternatives. Fourth, the utility uses a present worth of revenue requirement method for locational net benefits analysis to compare the costs of traditional capital upgrade solutions to the costs and potential system-level and locational benefits of NWA options. The utility uses eight costs and benefits associated with distributed generation in its locational net benefits analysis:

- Avoided energy
- Generation capacity
- Energy arbitrage
- Ancillary services
- Transmission upgrade estimated cost
- Distribution upgrade estimated cost
- Transmission upgrade operation, maintenance, administrative and general expense cost
- T&D losses

NV Energy plans to consider Renewable Portfolio Standard and greenhouse gas emissions benefits in the locational net benefits analysis in the future.

9.4 Best Practices

Best practices in incorporating NWA in DSP include:

- *Requiring an NWA analysis*. While NWA analysis is a best practice for IDP, several states with DSP requirements do not include such an analysis.
- *Establishing clear NWA screening criteria*. Collaboratively developing robust NWA screening criteria can reduce analysis cost and time and more effectively identify the most viable NWA projects. Criteria may include:
    - Clear definition of resources and project types that are eligible for NWA. For example, Colorado provides a clear definition in their distribution system planning regulations.
    - Minimum lead times, taking into consideration utility staff's capacity to perform the analysis, NWA bidders' ability to participate in the procurement process (if applicable), and any supply chain issues. Currently, several utilities are using a minimum lead time of three years.
    - Minimum deferral requirements (e.g., California only requires an NWA to defer a traditional investment for one year).
    - Minimum project cost. Some states and utilities have implemented a tiered cost screen for larger and smaller projects. Most states do not require utilities to pursue projects that are less than $1 million.
- *Specifying standards for cost-effectiveness evaluation*. For example, states can identify the types of benefits and costs and valuation methods utilities should use in NWA analysis. States also can ensure the analysis is transparent and aligns with state policies and goals and analysis of other resources. Several states require a benefit-cost handbook or workbook to promote consistency and transparency.
- *Improving NWA solicitation processes.* Typically, utilities issue a request for proposals to acquire NWAs for specific grid needs, specifying suitability criteria. Among the improvements California is testing are a standard purchase agreement with uniform contract terms and conditions; a price sheet for deferral projects, with DER providers submitting offers at or below the indicated price (simple auction pricing); reducing procurement timelines; and improving aggregation of customer-hosted DERs through new payment structures. The independent evaluator for Xcel Energy's NWA process in Colorado filed a report with the PUC on recommended improvements to the process — among them:
    - Refining NWA suitability criteria
    - Surveying the market to understand current and expected resource capabilities, installation timelines, and costs
    - Combining infrastructure upgrades and NWA resources to more cost-effectively meet the same need as the traditional utility solution
    - Geotargeting existing or modified customer programs, such as energy efficiency, demand response, and managed EV charging programs

- Developing market partnerships and resource portfolios through virtual power plants and energy performance contracting
- Conducting a request for information process with potential bidders to identify potential solutions and costs before issuing a request for proposals.[55]

- *Other paths for NWA implementation.* NWAs may be more successful if there are multiple paths for acquisition. For example, in Hawaii, if NWA screening does not indicate that a competitive solicitation is the best option to procure the solution, the company can determine if pricing (e.g., time-varying retail rates) or programs (e.g., geotargeted energy efficiency, demand flexibility, and storage) can be used to meet the grid need.
- *Contingency planning.* States may wish to include contingency plan requirements to reduce risk associated with NWA projects. For example, California's investor-owned utilities are required to develop a contingency plan for all NWA projects.

[55] DNV. Xcel Energy NWA Independent Evaluator Recommendations for NWA Process Improvements. Sept. 27, 2023.

10. Reliability and Resilience Analyses

Utilities have long planned for reliability of electricity systems. While planning for adequate power supply and associated transmission capacity is part of ensuring reliability, electricity supply shortages are rarely the cause of power outages. The distribution system accounts for more than 90% of all service interruptions, when measured with standard utility metrics for duration and frequency — at least 94% using SAIDI and at least 92% using SAIFI. See Figure 10-1.

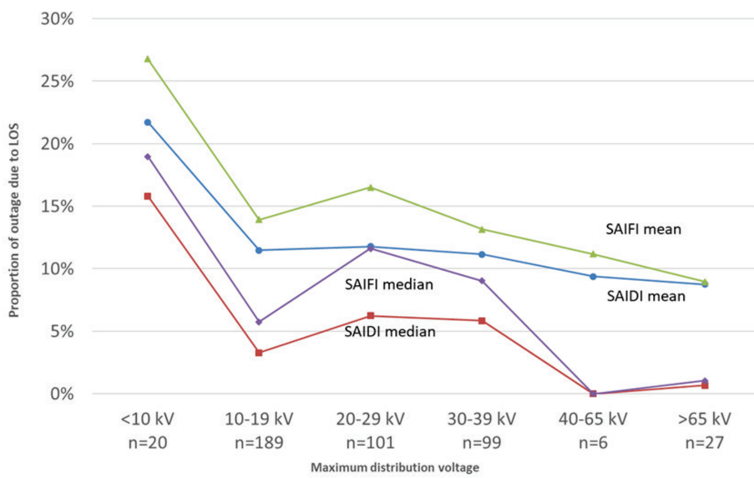


Figure 10-1. Customer-Weighted Proportion of SAIDI and SAIFI Due to Interruptions Originating from the Bulk Power System from 2008 to 2014 for 73 Utilities
Source: Eto et al. (2019).[56]

Berkeley Lab reviewed goals and objectives for distribution system planning in 21 states and the District of Columbia. Of these, 14 jurisdictions have explicit goals or objectives related to reliability and resilience (CA, CT, DC, DE, HI, IN, MA, MI, MN, NM, NV, RI, VA, VT).[57] For example:

- In Colorado, IDP rules specify that the PUC will review and evaluate whether distribution system investments by the regulated utilities support reliability and resilience.
- Nevada requires regulated electric utilities to address reliability benefits in Distributed Resource Plans.
- The first objective of the New Hampshire PUC for a modernized distribution system is to "Improve reliability, resiliency, and operational efficiency."
- The goal of Indiana's grid modernization legislation is to "promote safety, reliability and economic growth by encouraging cost-effective modernization of utility infrastructure."

Table 10-1 lists selected reliability and resilience metrics.[58] A study of electric utility standards in 25 states throughout the country found that SAIDI, SAIFI and CAIDI are the most common indices for

[56] Eto et al. (2019), 717-723.
[57] Frick et al. (2023).
[58] IEEE Standard 1366-2022 is a detailed guide for typical reliability metrics, including calculation methodologies.

measuring performance related to service interruptions and restoration, with requirements to report these metrics annually.[59] Distribution planners also commonly identify the worst-performing circuits for these metrics and focus reliability investments accordingly. For example, Pennsylvania requires utilities to submit an annual reliability report that includes "a list of the major remedial efforts taken to date and planned for circuits that have been on the worst performing 5% of circuits list for a year or more." Increasingly, utilities and regulators evaluate the value of reliability improvements by considering the cost of power interruptions to utility customers using Berkeley Lab's ICE Calculator.[60] [61]

Utilities and regulators increasingly recognize that traditional measures of reliability must be enhanced and complemented in order to more fully characterize or measure resilience, and that new tools and approaches are needed, particularly for assessing performance under extreme weather conditions. While there is no standard practice for measuring resilience performance, utilities, regulators, and industry experts have started to focus on metrics for Major Event Days (MEDs) under varying levels of extreme weather conditions, such as storm categories based on wind speeds.

As Table 10-1 indicates, many resilience metrics are subsets of reliability metrics. *Reliability metrics*, such as SAIFI and SAIDI, are reported on a systemwide basis. States also may require reporting metrics for worst-performing circuits. Still, reporting on impacts of specific days, weather conditions, or customer groups is less common, in part because there are fewer metrics available. *Resilience metrics* focus on specific extreme weather events or storm conditions in general — in some cases, for specific types of vulnerable customers. The IEEE 1366 standard for resilience metrics provides a method for systematically segmenting reliability indices to account separately for large storm events. However, the standard does not discuss outage metrics for specific populations — e.g., critical facilities — though some utilities report SAIDI/SAIFI metrics for geographic regions within a service territory or individual feeders. Because utilities already have data on outage frequency and duration to comply with requirements for reliability metrics, data collection and reporting for many resilience metrics should not be burdensome.

Distribution system planning provides opportunities for utilities and regulators to assess current system capabilities and plan for investments to improve both reliability and resilience.

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59 Public Service Consultants (2020).

60 Interruption Cost Estimate (ICE) Calculator. https://icecalculator.com/home.

61 IEEE Standard 1782-2022 provides an ICE Calculator example to illustrate its common use in the industry.

Definitions

Reliability means "[m]aintain[ing] the delivery of electric services to customers in the face of routine uncertainty in operating conditions." Specifically for utility distribution systems, "measuring reliability focuses on interruptions in the delivery of electricity in sufficient quantities and of sufficient quality to meet electricity users' needs for (or applications of) electricity."*

Resilience 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."**

*Grid Modernization Laboratory Consortium. *Grid Modernization: Metrics Analysis Reference Document*.
**Presidential Policy Directive 21, February 12, 2013

Table 10-1. Selected Performance Metrics for Reliability and Resilience[62]

Metric	Description	Interpretation / Considerations
Reliability		
SAIFI	System Average Interruption Frequency Index	Total number of sustained interruptions that an average customer experiences over some time period
SAIDI	System Average Interruption Duration Index	Total number of minutes that an average customer is without power over some time period
CAIFI	Customer Average Interruption Frequency Index	Average number of interruptions per customer interrupted over some time period
CAIDI	Customer Average Interruption Duration Index	Time required to restore service for an average customer over some time period
MAIFI	Momentary Average Interruption Frequency Index	Total number of momentary interruptions (< 5 minutes) that an average customer experiences over some time period
MED	Major Event Day	Any day with a daily reliability metric that exceeds a statistically-defined threshold based on the previous five years of daily data (e.g., IEEE 1366 standard)

[62] Source: California Public Utilities Commission (2021)[62] and Larsen (2023)[62]

Resilience		
Major Storm-only SAIFI	SAIFI specifically for major storms (or MEDs in general)	Utilities can report these metrics for storm events and on an annual basis by storm category level These metrics also can be specific to life support customers or other types of vulnerable customers and communities
Customers Interrupted (CI)	Total number of customers interrupted for major storms (or MEDs in general)	
Major Storm-only SAIDI	SAIDI specifically for major storms (or MEDs in general)	
Customer Minutes of Interruption (CMI)	Aggregate duration of all customer interruptions for major storms (or MEDs in general)	
Time to Restore X% of Customers	Hours from outage onset time to restore a certain percentage of customers impacted (usually 50%, 90% or 100%)	
% of Customers Restored within 24 Hours of a MED Interruption	Among customers impacted by a MED, the percent that are restored within 24 hours of the outage onset time	
Average Time to Respond to Safety and Critical Infrastructure Needs	Minutes elapsed from time issue is reported to when the utility resolves it	Safety and critical infrastructure needs include blocked roads, downed power lines and other emergency responder priorities
Number of Critical Assets without Power for More than N Hours	Number of critical assets without power for longer than at a chosen time threshold (from one to 24 hours)	Critical assets include substations or feeders that serve critical infrastructure such as hospitals, police stations and water treatment plants
Service Restoration Cost	Total operations and maintenance cost for outage restoration, including external lineworkers from mutual aid agreements	Utilities can report these metrics for specific storm events and on an annual basis by storm category level
Number of Injuries or Deaths	Number of injuries or deaths during storm restoration or due to a lack of electric power	Utilities can report these metrics for utility workers, other emergency responders, or the public at large (due to lack of electric power)
Total Damages ($)	Estimated value of damages due to a lack of electric power during a MED	Utility customers experience substantial outage costs during MEDs

10.1 Comprehensive Efforts to Address Reliability and Resilience

Planning for reliability and resilience are closely connected. Investments and activities that improve resilience will almost certainly improve reliability, and the reverse also is often true. Some states have developed processes and requirements that comprehensively plan for improvements to both reliability and resilience simultaneously. These requirements may be implemented through the IDSP process or a related proceeding.

Massachusetts' 2022 Clean Energy Act directed the Department of Public Utilities (DPU) to require each investor-owned electric distribution company to develop an electric-sector modernization plan to propose discrete investments and alternatives that increase reliability and strengthen system resiliency to address potential weather-related and disaster-related risks (MA). The DPU directed the electric companies to file their first modernization plans by January 29, 2024. The Act also established a Grid Modernization Advisory Council, chaired by the Department of Energy Resources, to review these plans and provide recommendations. Several of the recommendations on the utilities' draft plans address reliability and resilience, focusing on metrics, priorities and climate vulnerability assessments.[63]

In 2021, the Michigan PSC stated that its "focus is on the issues of reliability, resilience, and readiness for … extreme [weather] events."[64] The Commission directed the regulated utilities to file a report that included, among other things, details on how current vegetation management and grid hardening efforts have contributed to reliability performance, a description of planned investments in reliability/resiliency on the worst performing circuits, and a summary of efforts to address outages and system reliability discussed in currently filed distribution plans. While the order occurred outside the formal distribution system planning proceeding, the Commission's efforts to increase transparency in reliability and resilience activities relied extensively on information contained in the utilities' distribution system plans.

In 2022, the PSC ordered Commission staff to develop a web page dedicated to distribution system reliability, customer outages, and storm response and work with utilities to develop a template for filing additional information on distribution reliability, outages and storm response.

In a subsequent 2022 order, the PSC required distribution plans to include forecasted reliability and resilience metrics based on Consumers Energy's 2021-2025 distribution plan (Table 10-2). In addition, the Commission asked the regulated electric utilities to map projections of these metrics to planned system investments to understand anticipated reliability benefits for customers. The PSC also seeks to better understand forecasted resilience performance, with several required metrics related to MEDs, safety and security.

63 Grid Modernization Advisory Council (GMAC) (2023), section 10.

64 The Commission also stated that "ratepayers have a right to expect the utilities to anticipate extreme weather events, to provide a hardened grid that can withstand extreme weather, and to be prepared to restore power expediently with the grid fails." August 25, 2021 order in Case Nos. U-21122 et al. at 3.

Table 10-2. Consumers Energy Historical Performance on DSP Metrics and Expected Future Performance

Reliability	SAIDI (excluding MED)	200	195	170
	SAIFI (excluding MED)	1.02	1.03	0.95
	% of customers with ≥5 interruptions	4.7%	4.7%	<5%
	% of customers with one or more interruption of ≥5 hours	27.7%	27.1%	24.6%
	% of customers restored within 24 hours of a MED interruption	79.6%	74.6%	81.8%
System Cost	Service restoration O&M cost per incident (three-year rolling average; including MED)	$590[1]	$721	$811
	Forestry cost per line-mile cleared	$11.3K (2017-2020)	$10.5K	$13.3K

Source: Michigan Public Service Commission (2022).[65]

In 2022, the Connecticut Public Utilities Regulatory Authority (PURA) established frameworks outside its DSP processes to enhance evaluation of the cost-effectiveness of reliability and resilience investments. In upcoming general rate cases, the regulated utilities must use these frameworks to develop and submit comprehensive evaluations of reliability and resilience program plans to seek PURA approval for cost recovery. The reliability framework requires electric distribution companies to project the incremental SAIDI or SAIFI improvement value associated with specific reliability programs. For the resilience framework, a key justification for program investments is how they address "dark sky" conditions by best reducing long-duration outages for different types of customers.[66] PURA will undertake a comprehensive review of utility plans under the frameworks, including identifying drivers of investments (Table 10-3), considering cost-benefit analyses (Table 10-4), utility assessment of alternatives, and potential rate impacts associated with implementing the frameworks. Cost recovery for reasonable and prudent expenditures associated with the approval of each framework will be included in base distribution rates to be assessed in upcoming general rate cases for each utility.

[65] 2022 Michigan Public Service Commission Order

[66] Dark sky conditions are characterized as rare, but devastating, events that cause widespread damage and are often accompanied by extended service outages.

Table 10-3. PURA Reliability Drivers and Programs

Reliability Driver	Programs
Infrastructure Replacement	Bulk Substation
	Overhead System
	Underground System
	Distribution Transformer
	Pole Replacement
	Other – Unique
Capacity	Peak Load
New Customer Additions[21]	New Customer Load
	New DER Interconnections
Enhancement Programs	System Sectionalization
	Field Sensors
	Wildlife Protection
Maintenance Programs	Inspections
	Surveys
	Vegetation Management

Table 10-4. PURA Benefit-Cost Analysis Minimum Reporting Requirements for Resilience

Resilience Plan	
Program Costs	Capital Expenditures
Assumed SAIDI Reduction	Customer minutes Interrupted
5-Year Resilience Benefit*	Avoided Interruption Costs
	Avoided Storm Restoration Costs
	Avoided VM and Pole Costs
10-Year Resilience Benefit*	Avoided Interruption Costs
	Avoided Storm Restoration Costs
	Avoided VM and Pole Costs
5-Year BCA	
10-Year BCA	

*Benefits should be provided such that they demonstrate a reasonable representation of the uncertainty of storm impact and resulting benefits.

Source: Connecticut PURA (2022).[67]

[67] 2022 Connecticut PURA order establishing reliability and resilience frameworks.

10.2 Treatment of Reliability in IDSP and Similar Proceedings

Improving reliability is a typical objective for distribution system planning processes. For example:

- In Minnesota, the Commission's order[68] establishing IDP filing requirements set out five overarching objectives for distribution system planning, including maintaining and enhancing safety, security, reliability and resilience of the electricity grid at fair and reasonable costs.[69]
- In Oregon, utility distribution system plans must discuss how they will fulfill reliability objectives. Plans must include descriptions of any reliability challenges and opportunities and cross-reference underlying data and information from the Annual Reliability Report. In the Long-term Distribution System Plan, utilities must explain how planned investments will improve reliability, among other goals.
- Colorado's distribution system planning rules require identifying areas of the grid with reliability problems and submitting plans for resolving them.
- Hawaii's Integrated Grid Planning (IGP) process recognizes the need to adapt reliability planning criteria for greater reliance on variable renewable energy resources and energy storage. For the first round of IGP, the Commission accepted Hawaiian Electric's (HECO's) reliability assessment and methodologies but directed the utility to explore improvements to resource adequacy modeling going forward. Specifically, the Commission directed HECO to adopt methodologies that (1) can be transparently derived from other models, such as PLEXOS,[70] (2) incorporate interactive effects between resource types in determining their contributions to system reliability, and (3) use realistic assumptions about variable generators' availability, so as not to unfairly bias resource selection towards firm thermal capacity.[71]
- Virginia allows utilities to file electric distribution grid transformation projects as part of a grid transformation plan.[72] In the final order approving Dominion's latest electric grid transformation plan, the Commission required the company to track and report on the extent to which hardening of primary feeders improved reliability for the specific pool of customers served by those feeders.
- Illinois' Climate and Equitable Jobs Act initiated an Integrated Grid Plan (IGP) process and required utilities to file their first Multi-Year IGP by January 20, 2023. The Act highlighted a need to align "…regulated utility operations, expenditures, and investments with public benefit goals, including safety, reliability, resiliency, affordability, equity, emissions reductions, and expansion of clean distributed energy resources…" Multi-year IGPs must include, among other items, a

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68 In the Matter of Distribution Planning for Xcel Energy, Docket No. E-002/CI-18-251, Order Approving Integrated Distribution Planning Filing Requirements for Xcel Energy (August 30, 2018).

69 Specific filing requirements for IDP were modified by the PUC in subsequent orders in 2019 and 2020. In the Matter of Xcel Energy's 2018 Integrated Distribution Plan, Docket No. E-002/CI-18-251, Order Accepting Report and Amending Requirements (July 16, 2019).
In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request, Docket No. E-002/M-19-666, Order Accepting Integrated Distribution Plan, Modifying Reporting Requirements, and Certifying Certain Grid Modernization Projects (July 23, 2020).

70 PLEXOS is a production cost model commonly used in the electricity industry to simulate generation unit commitment and dispatch in the power system. The Hawaii PUC requires an integrated grid planning process for generation, distribution, and transmission planning.

71 See Hawaii PUC Order 38482 in Docket No. 2018-0165, June 30, 2022, at 27. See HECO's updated IGP, filed May 2023.

72 As part of the annual reporting on these plans, Dominion Energy is required to report on metrics related to reliability including SAIDI and customer minutes of interruption.

long-term distribution system investment plan which must contain detailed explanations of how the planned investments will support these goals.[73]

Many Commissions have historically required utilities to regularly report on reliability performance. In California, for example, utilities file annual electric reliability reports to share recorded average outage duration and frequency, separate and distinct from reliability as it pertains to resource adequacy. Metrics reported include SAIDI, SAIFI, CAIDI and MAIFI.

Reporting on reliability metrics at a more granular level than systemwide is one way regulators are attempting to better understand how customers experience reliability. For example, Colorado requires that DSPs include reporting on reliability metrics (SAIDI and SAIFI at a minimum) for the past three years for each substation.[74] Connecticut requires electric distribution companies to report on a list of metrics that measure the number of customers that have experienced particularly long or frequent interruptions, including:

- Customers Experiencing Multiple Interruptions (CEMI)
- Customers Experiencing Long Interruption Durations (CELID)
- Customers Experiencing Multiple Sustained Interruptions and Momentary Interruptions Events (CEMSMI)
- Customers Experiencing Multiple Momentary Outages (CEMM)

These types of metrics that track the number of customers experiencing particularly low reliability (or resilience) are increasingly common in regulatory reporting. The IEEE 1366 standard defines CEMI, CELID and CEMSMI. Naming conventions and calculation methodologies, however, vary by jurisdiction.

10.3 Treatment of Resilience in IDSP and Related Proceedings

States are increasingly requiring some form of planning and reporting related to resilience. That is in part due to increasing exploitation of utility infrastructure vulnerabilities with more frequent and severe weather events due to climate change. As defined in De Martini et al. (2022), "A threat-based risk assessment involves identifying and prioritizing the scale and scope of resilience threats based on assessing their impacts to specific components of the electricity delivery system and the communities it serves." The assessment identifies specific grid assets that may be vulnerable to different types of hazards and prioritizes improvements to mitigate consequences. Improvements may include capital investments such as undergrounding power lines or changes in business practices such as enhanced vegetation management. Utilities, regulators and stakeholders commonly apply a bowtie method (Figure 10-2) to identify viable resilience solutions.

[73] Climate and Equitable Jobs Act at 724. Ameren's first MYIGP contains a section detailing the company's plans to maintain and enhance reliability and resilience through distribution system investments.
[74] Rule 3539, Security Assessment.

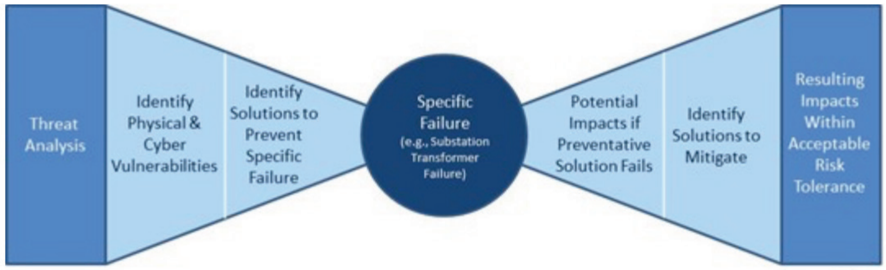

Figure 10-2. Bowtie Resilience Solution Identification Method

Source: De Martini et al. (2022).[75]

For example, Colorado's DSP process requires an analysis of risks by substation posed by natural disasters (such as wildfires, floods, severe storms) and a narrative assessment of the efforts the utility is taking to increase resilience.[76] The Commission also directed the DSP to discuss existing or proposed pilots or programs aimed at increasing resilience and reliability using microgrids or other technology.[77]

Hawaii's initial IGP order did not prescribe resilience planning approaches by the utility. Rather, in its March 2023 IGP report, HECO laid out an action plan for meeting grid needs through 2050, including for resilience. HECO's approach includes developing performance targets and decision-making methods, "no regrets" system hardening investments underway through the Climate Adaptation Transmission and Distribution Resilience Program, and investments to address other risks and needs of customers and communities. In the performance-based ratemaking proceeding, the Hawaii PUC approved a portfolio of scorecards and reported metrics that HECO must make publicly available. Among these are three reported metrics related to resilience:

- Critical Load Reported Metric
- National Incident Management System Certification Reported Metric
- Emergency Response Training Reported Metric

The Hawaii IGP process also included a Resilience Working Group,[78] which prepared a report[79] that summarizes key resilience planning components, including:

- Determining planning objectives and metrics
- Identifying and prioritizing threats
- Developing threat scenario reference cases
- Tiering and prioritization of key customers and infrastructure
- Determining capability gaps and solutions

With respect to resilience planning to address physical and cybersecurity threats, Colorado requires DSPs to include an analysis of cybersecurity threats and efforts the utility is taking to ensure distribution

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75 De Martini et al. 2022. Integrated Resilient Distribution Planning
76 Rule 3539, Security Assessment
77 Rule 3533, Grid Innovation
78 Hawaii IGP Resilience Working Group Documents
79 Siemens (2020).

system security. New York requires Distribution System Implementation Plans to include specific information on cyber security, including (1) utility policies, procedures, and assets that address the security, resilience and recoverability of data stored, (2) processes running in interacting systems and (3) devices owned and operated by third parties.

Some planning processes specifically require utilities to evaluate options for enhancing the resilience of vulnerable, disadvantaged or historically marginalized communities:

- California requires utilities to lead a process of engagement with “disadvantaged vulnerable communities” as the utilities develop their vulnerability assessments (see next section, “Resilience Planning Outside IDSP Processes”) and describe how the utility’s identified mitigation options promote equity. When utilities seek funding to adapt their infrastructure, operations and services to disadvantaged communities, such requests may include mechanisms to promote equity for communities with low adaptive capacity. In determining levels of adaptive capacity, utilities must consult with the communities themselves and other parties.
- California utilities must also develop a resiliency project guide and assist local and tribal governments in navigating the interconnection processes for resiliency projects. The utilities are required to dedicate staff from the distribution planning teams to manage the intake of local and tribal resiliency projects.
- Connecticut requires electric distribution companies to plan for at-risk and vulnerable customers’ resilience to severe weather. The resilience framework requires the companies to consider prioritizing investments that provide benefits to environmental justice and distressed communities.
- Oregon utilities must file a biennial report that describes actions within environmental justice communities intended to improve resilience during adverse conditions or facilitate investments in the distribution system (HB 2021).
- Washington’s performance based regulation proceeding is considering new metrics that utilities would be required to report including the percent of proposed resilience projects in “Named Communities” completed every year.[80]
- In New York, ConEd’s Climate Change Resilience Plan lays out the company’s commitment to equity and providing disadvantaged communities with safe and reliable service. The company has formed an Environmental Justice Working Group to help institutionalize such considerations.

Stakeholder involvement is particularly important for resilience planning:

- HECO relied on a stakeholder working group to inform the resilience strategy for its IGP. The utility used stakeholder input to support the identification of customer needs, policy objectives, forecasts, and assumptions, all of which fed into the IGP analysis. The Resilience Working Group was formed to identify and prioritize resilience threat scenarios, key customer and

[80] “Named Communities” in this proceeding refers to two definitions contained in Washington’s Clean Energy Transformation Act. The Act defined “Highly impacted community” as a community designated by the department of health based on cumulative impact analyses in section 24 of CETA or a community located in census tracts that are fully or partially on “Indian country” and “Vulnerable populations” as communities that experience a disproportionate cumulative risk from environmental burdens.

infrastructure sector capabilities and needs following severe events, and gaps and priorities in grid and customer capabilities following such an event.

- California requires utilities to undertake a multi-step community engagement strategy associated with the vulnerability assessments described above. One year before utilities file their vulnerability assessments they are required to develop and submit a plan describing the community engagement they have undertaken and discussing how they will promote equity in disadvantaged vulnerable communities. One year after filing a vulnerability assessment, the utility must survey these communities and community-based organizations to assess the effectiveness of their outreach and engagement and file the results with the PUC.
- New York utilities must establish a climate resilience working group to inform the development and implementation of their climate change resilience plan, pursuant to Public Service Law §66(29). Consolidated Edison's November 2023 Climate Change Resilience Plan details the stakeholder input process, which built on previous efforts with many organizations participating consistently since 2012.

10.4 Resilience Planning Outside IDSP Processes

States often establish standalone resilience planning requirements that closely align with IDSP.[81] Berkeley Lab identified 12 states with resilience planning requirements outside IDSP processes that regulatory commissions have finalized and are in effect as of June 2024 (see Table 10-5).
The four largest states — California, Texas, Florida and New York — which account for a third of the U.S. population, have set requirements for standalone resilience plan requirements. Most of these plans aim to mitigate adverse consequences related to specific hazards, such as storms (Connecticut and Florida), wildfires (California,[82] Oregon and Utah) and climate change (California, Maine, and New York). Colorado, Louisiana, Nevada, New Jersey, and Texas requirements aim to mitigate a broader range of hazards, including cybersecurity and, for some states, any type of natural disaster. Colorado, Louisiana, and Texas also include physical attacks. States that have not created resilience plan requirements and regulatory processes can adapt the practices of these early adopters, as illustrated by the following examples.

California requires utilities to use the tools, scenarios and data from the Fourth Statewide Climate Change Assessment in all utility planning processes when analyzing climate impacts, risks, and vulnerability of utility infrastructure systems and operations. California utilities also are required to file climate change vulnerability assessments every four years with the CPUC, including an assessment of climate risks to operations and services and options for dealing with vulnerabilities. Southern California Edison filed the first assessment, in 2022. California also requires utilities to provide annual physical security reports which include threat assessments and security plans that identify "critical" assets and propose security mitigation measures.

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81 Alternatively, states can consider including similar resilience planning requirements directly in DSP requirements, as is the case in Michigan and Colorado.

82 The CPUC no longer has responsibility for wildfire safety. A new state agency, the Office of Energy Infrastructure Safety, was formed to oversee Wildfire Mitigation Plans for regulated utilities.

New York utilities are required to file climate change vulnerability studies and climate change resilience plans, informed by the vulnerability studies, with the PSC.[83] Resilience plans must propose storm hardening and resiliency measures for the next 10 years and 20 years and detail how the company will incorporate climate change into its planning, design, operations and emergency response, among other requirements. Figure 10-3 provides a summary of the vulnerability assessment that Consolidated Edison conducted according these requirements. The company's subsequent Climate Change Resilience Plan proposes measures to address these vulnerabilities at a cost of $903 million during the first five years of the plan.

Best practices for prioritizing resilience projects and programs are evolving. Figure 10-4 provides an example from the Tampa Electric Storm Protection Plan, which was developed under the Florida resilience plan requirements. Budget optimization, which estimates the optimal storm protection investment level based on total lifecycle net benefits under various storm scenarios, led to a proposed spend of $1.59 billion over the 10-year plan. Given the high level of investment for proposed resilience spending, these planning processes should be closely integrated with, or constitute a significant component of, DSPs.

83 Public Service Law §66(29)

Table 10-5. Resilience Planning Requirements for Regulated Utilities Outside DSP Processes (in effect as of June 2024)

State	Name of Plan or Legislation	Hazards in Scope	Plan Frequency	Planning Horizon
California	Wildfire Mitigation Plan (Senate Bill 901)	Wildfires	Annual	3 years
California	Climate Change Vulnerability Assessment	Wildfires, extreme heat, extreme storms, drought, subsidence, sea level rise and other climate change hazards	4 years (part of general rate case – GRC)	10–50 years
California	Risk-based Decision-making Framework	All hazards	4 years (part of GRC)	4 years
Colorado	Distribution System Plan	Natural disasters and cyber/physical security threats	2 years	10 years
Connecticut	Resilience Plan	Tropical storms, hurricanes, ice storms	4 years (part of GRC)	10 years
Florida	Storm Protection Plan	Storms	3 years	10 years
Hawaii	Natural Hazard Mitigation Plan	Wildfires, tsunamis, hurricanes, floods, landslides, extreme heat, drought, seismic/volcanic activity	To be determined	5 years
Louisiana (excluding New Orleans)	Grid Resilience Plan	Any low-probability/high-consequence events, including cyber/physical security threats	5 years	10 years
Maine	Climate Change Protection Plan	Expected effects of climate change on utility assets	3 years	10 years
Michigan	Distribution System Plan	Storms	2 years	5 years
Massachusetts (Section 92B)	Electric-sector Modernization Plan (House Bill 5060)	Weather and disaster-related risks	5 years	5–10 years
Nevada	Natural Disaster Protection Plan	Wildfires are primary focus, other natural disasters also covered	3 years	3 years*
New Jersey	Infrastructure Investment Program	Any hazard that impacts safety, reliability, and/or resiliency, including cybersecurity	Voluntary	5 years
New Orleans	System Resiliency and Storm Hardening Plan	Storms	To be determined	5 years
New York	Climate Change Vulnerability Study and Resilience Plan	Increase in severe weather expected from climate change, including stronger storms and more flooding	5 years	10–20 years
Oregon	Wildfire Mitigation Plan	Wildfires	Annual	3 years*
Texas	T&D System Resiliency Plan (House Bill 2555)	Any event involving extreme weather conditions, wildfires, or cyber/physical security threats that poses a material risk to safe and reliable operation of T&D systems	3 years (voluntary)	3 years (minimum)
Utah	Wildland Fire Protection Plan (House Bill 66)	Wildfires	3 years	3 years*

Source: Berkeley Lab, Grid Resilience Plans: State Requirements, Utility Practices, and Utility Plan Template (2024).

* While state requirements do not specify a planning horizon, utilities have filed three-year plans.

	Temperature and Temperature Variable (TV)	Flooding	Wind and Ice
Area and Unit Substations	Primary	Primary	Low
Transmission Substations	Primary	Primary	Low
Overhead Transmission	Primary	Low	Secondary
Overhead Distribution	Secondary	Low	Primary
Underground Transmission	Secondary	Secondary	Low
Underground Distribution	Primary	Secondary	Low
Key Company Facilities	Secondary	Secondary	Low

Figure 10-3. ConEd Climate Change Vulnerability Study (2023) – Summary of Vulnerabilities

Source: ConEd (2023)[84]

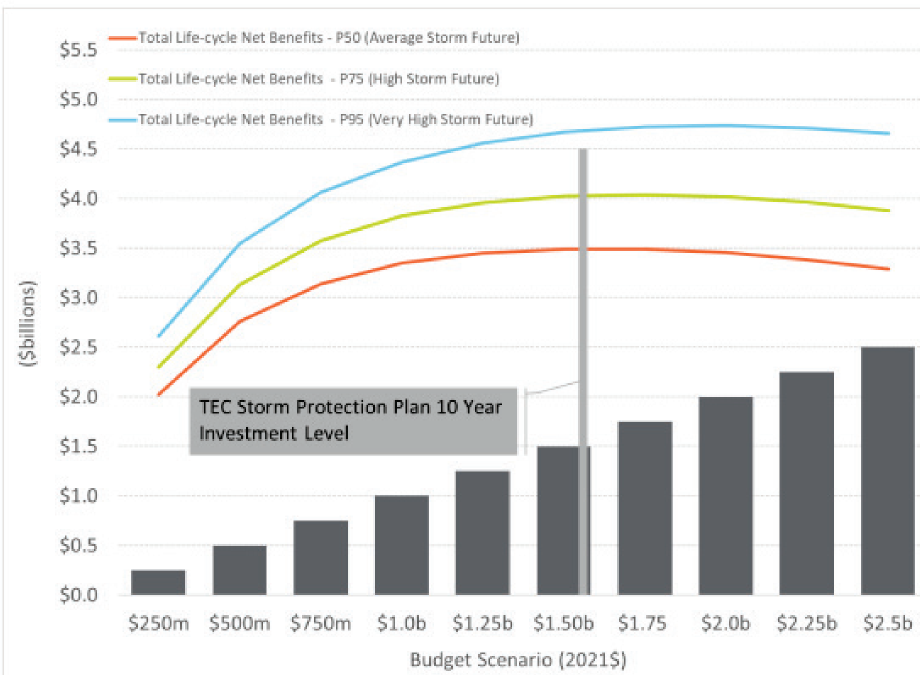

Figure 10-4. Tampa Electric Storm Protection Plan Budget Optimization Results (2022)

Source: Tampa Electric (2022)

For prioritization of risk mitigation investments more broadly, the CPUC required regulated utilities to apply a risk-based decision-making framework as part of the Risk Assessment and Mitigation Phase of the four-year general rate case cycle. PG&E is the first utility to implement this framework, summarized

[84] ConEdison (2023).

in Figure 10-5. The framework adds standardized measures of safety and reliability[85] risks in a new cost-effectiveness framework to prioritize grid solutions as part of the general rate case. This addresses gaps in measurements and impact assessments and ensures consistent metrics across utilities. The framework also ties the community engagement plan to the distribution reliability/resilience plan.

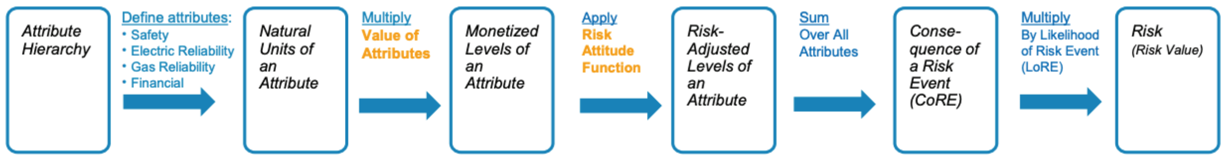

Figure 10-5. PG&E Implementation of CPUC Risk-based Decision-making Framework (2024)
Source: PG&E (2024)[86]

10.5 Best Practices

Best practices in incorporating reliability and resilience in DSP include the following:

- *Reporting more granular reliability metrics.* States have increasingly asked for reliability reporting that goes beyond standard SAIDI, SAIFI and CAIDI indices at a system level. These reports include CEMI, CELID and worst-performing circuit analyses, which aim to track customers that have experienced particularly long or frequent interruptions, as well as MAIFI and CEMM, which aim to track momentary interruptions. As utilities invest in technologies that increase grid visibility as part of IDSP processes, states should require more granular reliability metrics that these technologies enable.
- *Reporting emerging resilience metrics.* Given that traditional measures of reliability are not adequate for measuring resilience, utilities should report emerging metrics for assessing performance under extreme weather conditions (see Table 10-1). Utilities can report many of these metrics for specific storm events, on an annual basis by storm category level and specifically for vulnerable customers, to better assess resilience performance and investment strategies. Metrics for individual catastrophic events should be established, and utilities should provide a narrative summary for each resilience event.
- *Including forecasted reliability and resilience metrics and mapping projections to planned system investments.* While forecasted metrics are subject to uncertainty, particularly for frequency and severity of extreme weather, projections are helpful to understand anticipated benefits customers will experience from improved reliability and resilience. Berkeley Lab's ICE Calculator and other tools can quantify the value of these improvements as part of a benefit-cost analysis.
- *Including a vulnerability assessment to align resilience and IDSP processes.* Vulnerability assessments typically include a matrix that summarizes all hazards relative to assets and operational practices analyzed with a clearly defined vulnerability rating that applies to each

[85] The CPUC decision requires each utility to use the most current version of Berkeley Lab's ICE Calculator to determine a standard dollar valuation of electric reliability risk for the Reliability Attribute. Regarding the impacts of more prolonged outages, staff comments refer to Berkeley Lab's Power Outage Economics Tool (POET) for estimating the impacts of longer duration and consecutive outages, including de-energization events. The utilities are not required to use POET at this time. A study would need to be conducted to provide the necessary data to use the tool.
[86] PG&E (2024).

asset-hazard and practice-hazard pair. Resilience solutions are then identified and prioritized for each asset/practice-hazard pair that the assessment identifies as highly vulnerable.

- *Seeking funding support for reliability and resilience measures in IDSP filings.* Many reliability and resilience measures are eligible for grant funds to offset costs, particularly those included in the federal Infrastructure Investment and Jobs Act (IIJA). DSP filings should identify funding support utilities are seeking for reliability and resilience measures.
- *Developing a common source of statewide climate projections based on expert input.* With increasing frequency and severity of extreme weather events and a general warming trend, historical weather data may lead to misguided investment decisions for resilience planning and other IDSP processes such as load forecasting. In California (Figure 10-5) and New York (Figure 10-6), State Energy Offices worked with climate experts at leading universities in their states to develop extreme weather forecasts for a variety of climate hazards, downscaled for their state. This is a critical step to ensure consistency of data sources and climate scenarios for utilities.
- *Integrating resilience investment priorities with State Energy Security Plans.* These security plans are the foundation of grid investment resilience planning under the IIJA. The plans highlight resilience risks, discuss investment priorities for enhancing the grid, and provide insights into potential priority investments by utilities. Utility resilience plans should align with methods, data sources, and priorities in the State Energy Security Plans.

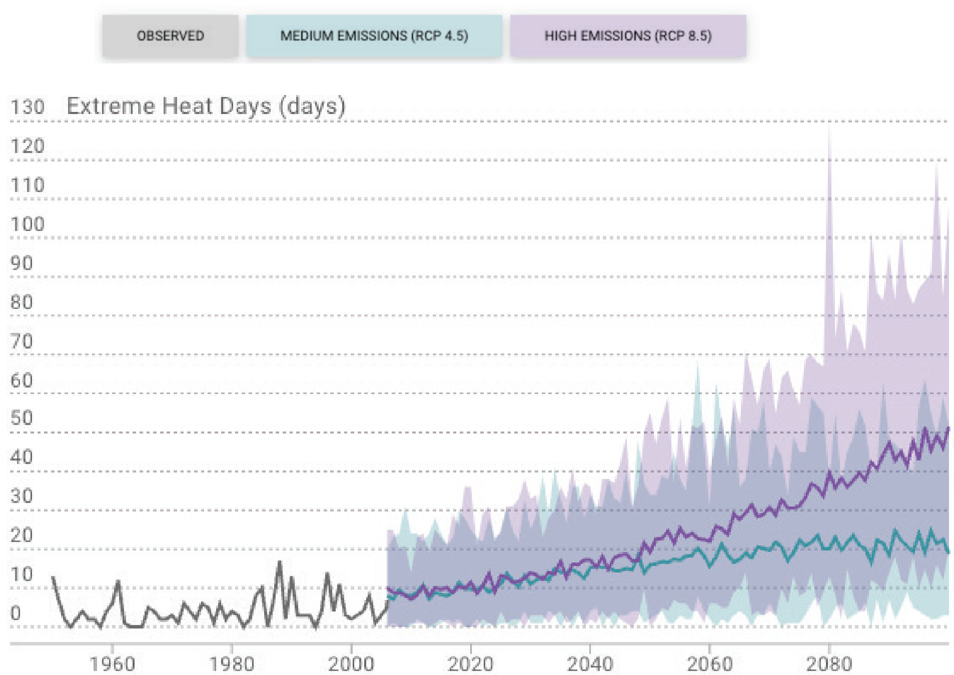

Figure 10-5. Cal-Adapt Forecast of Extreme Heat Days for Downtown Sacramento (ZIP Code 95814)
Source: Cal-Adapt (2024).[87]

[87] Cal-adapt.org Local Climate Change Snapshot for Downtown Sacramento (ZIP Code 95814), retrieved in January 2024 (funding and oversight by the California Energy Commission)

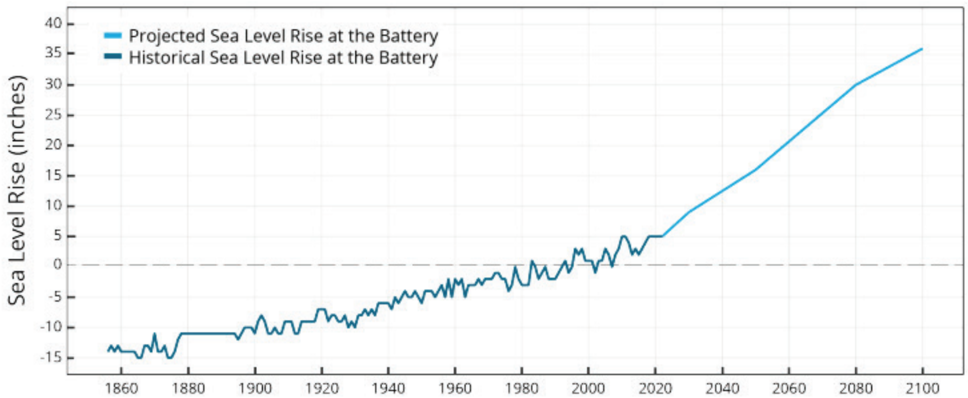

Figure 10-6. Historical and projected sea level rise at the Battery Tide Gauge in New York City
Source: ConEd (2023).[88]

[88] ConEdison (2023) (projections and data provided by the New York State Energy Research and Development Authority in partnership with Columbia University).

11. Equity

States are increasingly requiring utilities to consider energy equity, including distribution of benefits and burdens of grid investments across different customer groups and the potential for targeted infrastructure investments. Energy equity is often described using four core tenets that represent different dimensions: recognition, distributive, procedural, and restorative justice.[89] Strategies to improve energy justice aim to accomplish "the goal of achieving equity in both the social and economic participation in the energy system, while also remediating social, economic, and health burdens on marginalized communities."[90]

Analysis by Berkeley Lab and Pacific Northwest National Laboratory found that over half of U.S. states took action on energy equity between January 2020 and July 2022[91] (Figure 11-1).

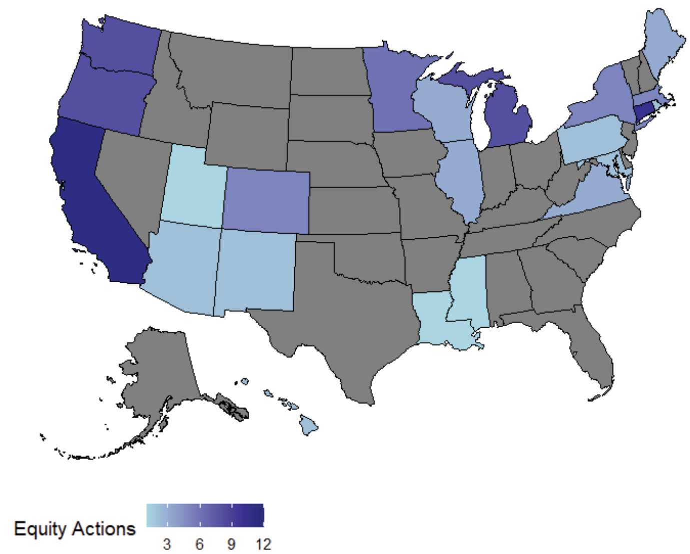

Figure 11-1. States Taking Action on Energy Equity Through Legislation, Regulatory Proceedings and Executive Orders (January 2020-July 2022)

Source: Hanus, N. et al. (2023)[92]

Distribution planning can improve energy equity in many ways. For example, utilities can propose to reduce energy burden by increasing equitable access to cost-saving programs and technologies, including grid-interactive technologies such as smart thermostats. Prioritizing rooftop and community-owned solar, storage, and microgrids in energy justice communities improves access to clean energy technologies, provides opportunities for customers to reduce their electricity bills, and reduces disproportionate environmental burdens resulting from localized use of fossil fuels.[93] Targeted utility

89 Kazimierczuk, et al. (2023).
90 Baker, DeVar, & Prakash (2019), at 5.
91 See Berkeley Lab and Pacific Northwest National Laboratory (2022).
92 Hanus et al. (2023).
93 Farley et al. (2021).

investments also can improve reliability and resilience performance in disadvantaged communities. To date, equity activities and metrics in distribution planning have largely focused on:[94]

1. Affordability, reliability and resilience of electricity,[95]
2. Availability of clean energy transition-enabling technologies, programs and opportunities, and
3. Accessibility of electricity decision-making processes.

11.1 State Requirements

One way that states are beginning to incorporate equity considerations into DSP is through broad statements of goals and objectives that apply to activities of the regulatory commission and electric utilities generally, or DSP specifically. For example:

- Washington's Clean Energy Transformation Act states that the public interest includes the equitable distribution of energy benefits and reduction of burdens to vulnerable populations and highly impacted communities. This goal affects utility planning and programs, including actions relevant to distribution system planning.
- Oregon's Clean Energy Targets bill (HB 2021) created a number of new requirements designed to advance energy equity. In pursuing the state's goal for 100% reduction in greenhouse gases by 2040, utilities are required to engage in "development and equitable implementation of a distribution system plan," among other directives.
- The Hawaii Public Utilities Commission opened an energy equity and justice docket (Docket No. 2022-0250) to investigate how to better integrate equity and justice considerations across its proceedings and for overseeing and regulating public utilities. Hawaiian Electric's 2023 Integrated Grid Plan includes "advance energy equity" as a high-level action. It contains several specific steps the utilities plan to take, including reducing energy burden for low to moderate income customers.
- In the order initiating a proceeding into the utility's climate vulnerability studies and plans, the New York PSC required the plans to include the costs and benefits to the utility and its customers of making proposed improvements, including considerations of equity, with a particular focus on the costs and benefits of undergrounding transmission and distribution lines.
- One of the stated purposes of Colorado's DSP rules is to promote equity with regard to disproportionately impacted communities.
- Illinois' Climate and Equitable Jobs Act (CEJA, SB 2408, 2021) includes equity among the goals for the multi-year integrated grid plans required by the Act. ComEd's *Multi-Year Integrated Grid Plan*, filed in January 2023, includes promoting "greater equity in the transition to clean energy" and assisting historically disadvantaged communities as focus areas.[96]

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94 Parker, Barlow, Eisdorfer, et al. (2023).

95 The Reliability and Resilience chapter of this report discusses state and utility efforts to achieve these objectives for vulnerable, disadvantaged or historically marginalized communities.

96 The Illinois Commerce Commission rejected the plan in its order on Dec. 14, 2023, in case nos. 22-0486/23-0055. The Commission also rejected Ameren's plan. "[T]he Commission's decisions found that both utilities failed to sufficiently incorporate customer affordability into their proposals and their grid plans did not outline how 40 percent of plan benefits will be directed to low-income and environmental justice communities, among other shortcomings." Dec. 14, 2023, Commission news release.

Some states are beginning to require utilities to consider equity when developing action plans and investment strategies and evaluate the effectiveness of their grid plans in addressing equity goals. For example:

- During the grid needs identification steps of DSP, Oregon requires utilities to perform an equity analysis overlaying customer geographic and socioeconomic data relative to system reliability and customer options. In their summary of prioritized grid constraints, utilities must use criteria such as community priorities, equity analysis, constraints on DER adoption, and public policy goals.
- Colorado's DSP rules require utilities to describe how they have incorporated community climate, equity, and resilience goals and priorities into the DSP and action plan.
- Illinois' Climate and Equitable Jobs Act (CEJA) requires multi-year integrated grid plans to contain a description of how the utility is supporting efforts to bring 40% of the benefits from programs, policies and initiatives proposed in the plan to ratepayers in low income and environmental justice communities.[97]
- Maine's integrated grid planning statute requires utilities to include an assessment of the equity and environmental justice impacts of these plans.

A common approach among states seeking to improve distributive energy justice is to enhance disadvantaged communities' and individuals' access to DERs and other clean resources:

- In Connecticut, PURA's opening notice in the docket addressing Energy Storage Pilot Program proposals asked stakeholders to propose how legislatively mandated energy storage pilots can benefit environmental justice, vulnerable and underserved communities.
- HECO's Integrated Grid Plan discusses its shared solar program that gives the surrounding community first priority in subscribing to a solar project. In addition, HECO stated its intent to consider societal impacts such as disadvantaged communities and asset-limited, income-constrained residents when developing microgrid project proposals.
- Illinois's CEJA requires that multi-year integrated grid plans be designed to bring the benefits of grid modernization and clean energy, including DERs, to all retail customers and support efforts to bring at least 40% of those benefits to "equity investment eligible communities."[98]

[97] CEJA at 726.

[98] CEJA defines "equity investment eligible communities" as geographic areas throughout Illinois which would most benefit from equitable investments designed to combat discrimination and foster sustainable economic growth.

- Maryland's Climate Solutions Now Act (SB 528, 2022) directed the Public Service Commission to implement DSP policies that promote 12 state policy goals, including "giving priority to vulnerable communities in the development of distributed energy resources and electric vehicle infrastructure." The Commission has until July 1, 2025, to adopt regulations or issue orders accomplishing the directive. The Commission initiated a work group to undertake a comprehensive examination of DSP and develop a consensus set of Maryland DSP practices.[99]

Promoting Equitable Access to DERs in Connecticut Outside of DSP Processes

The Equitable Energy Efficiency Proceeding and the annual Conservation and Load Management Plan Updates administered by the Department of Energy and Environmental Protection have implications for equitable access to energy efficiency and utility processes. Connecticut's proceeding has eight specific goals related to enhancing equity in energy efficiency program development and delivery.

The 2022-2024 Conservation and Load Management Plan is structured around three priorities, one of which is equity. The utilities propose to meet this priority by developing new equity metrics, increasing marketing to non-English speakers, supporting minority and women-owned vendors, reaching priority communities with education and engagement, and ensuring that energy efficiency workforce opportunities are available to underserved communities.

11.2 Metrics

Regulators are beginning to require utilities to report performance according to new metrics to assess the status of energy equity. Table 11-1 shows metrics that six states are implementing to track energy equity, several of which have implications for DSP. For example, tracking DER investments or total money spent in environmental justice and underserved communities indicates whether distribution system investments should be adjusted to advance equity goals. Tracking organizations engaged in DSP and the nature of outreach to communities helps make transparent utility progress in improving procedural justice. Providing resilience metrics by substation or ZIP code illuminates differences in service quality between historically underserved communities and other neighborhoods, revealing potential areas for targeting future distribution system investments.

[99] See Order No. 90777 on Recommendations of Distribution System Planning Work Group. PC44 and Case No. 9665 (ML 304701), Aug. 24, 2023.

Table 11-1. Energy Equity Metrics Implemented by States[100]

State	Specific metrics identified
CA	• Hours at minimum wage required to pay for essential utility services • Vulnerability index of various communities in California • Ratio of essential utility service charges to non-disposable household income
CT	• "A metric…to track and increase participation in energy efficiency programs among customers that are enrolled in the Matching Payment Program"
IL	• "Equity/affordability"
MA	• "An equity index metric reporting energy efficiency, demand response, heating electrification, and electric vehicle infrastructure investments in environmental justice communities" • Community solar enrollment
OR	• Energy burden • Disconnections for residential customers and disconnections for small commercial customers • Supplier diversity: contract spend for contractors and subcontractors • Organizations engaged and their community representation • Numbers and nature of outreach efforts in energy-burdened communities • EV ownership per capita (per census tract) • Amount of money spent on underserved communities
WA	• Energy burden • Community ownership of resources • Resiliency • Nonenergy benefits • Public health

Source: Hanus, N. et al. (2023)

Minnesota's performance-based regulation (PBR) approach includes several metrics directed at improving equity, including in DSP. They include an equity in reliability metric and a metric for customer service quality under development to measure customer service, including engagement and empowerment. Tracking these metrics by geography or income — or both, as in Minnesota — provides information that can be used to plan future distribution investments and approaches to increase distributive and procedural justice. There also is a metric to track low-income customer participation in utility programs to indicate whether clean DER investments are equitably serving different customer groups.[101] Washington's PBR proceeding is considering several new equity-focused metrics with implications for DSP, including reporting on reliability and resilience metrics for "named communities,"[102] investment spending and spending on NWAs within named communities, and number of customers in named communities enrolled in utility DER programs.

11.3 Stakeholder Involvement and Transparency

States are advancing procedural justice through stakeholder involvement and transparency:

- Oregon's HB 2021 requires utilities to create a Community Benefits and Impacts Advisory Group that must include representatives of energy justice communities and low-income ratepayers. Utilities "may engage" the group on the development and equitable implementation of DSP.

[100] Hanus, et al. (2023).
[101] *Minnesota PUC, Order Establishing Performance Metrics* issued Sept. 18, 2019, Docket No. E-002/CI-17-401, p. 7-8.
[102] "Named Communities" in this proceeding refers to two definitions contained in Washington's Clean Energy Transformation Act. The Act defined "Highly impacted community" as a community designated by the department of health based on cumulative impact analyses in section 24 of the Act, or a community located in census tracts that are fully or partially on "Indian country." "Vulnerable populations" are communities that experience a disproportionate cumulative risk from environmental burdens.

Oregon DSP guidelines require utilities to undertake additional community engagement, including ongoing stakeholder meetings during grid needs assessment, identifying solutions and action planning, and developing pilots, and collaborating with energy justice communities to inform distribution investments in the near-term action plan and implementation of all DSP projects (Figure11-2).

Community Engagement	
Stage 3	Utilities collaborate with CBOs and environmental justice communities so that community needs inform DSP project identification and implementation. "Community needs" could address energy burden, customer choice and resiliency.
Stage 2	Reflecting UM 2005 outreach requirements, utility holds ongoing community stakeholder meetings during grid needs assessment, solution identification, and action planning.
	Utilities and OPUC agree on community goals, project tracking and coordination activities.
	Conduct baseline study to increase detailed knowledge of service territory communities. Engage CBO experts to inform co-created community pilot(s).
	Consult with communities to understand identified needs and opportunities, then seek to co-develop solution options, documenting longer-term needs.
Stage 1	Hold four public pre-filing workshops with stakeholders on Plan development.
	Utilities create a collaborative environment among all interested partners and stakeholders. Utilities document community feedback and utility's responses.
	OPUC prepares accessible educational materials on DSP with consultation from CBOs and utilities.
	Prepare a draft community engagement plan as part of Plan.
	Utilities conduct focused community engagement for planned distribution projects.
	OPUC to host quarterly public workshop and technical forums after Plan filings.
2021-2022	2023 and beyond

Figure 11-2. Oregon Initial DSP Requirements and Expected Evolution for Community Engagement

Source: Oregon Public Utilities Commission (2020).[103]

- As originally envisioned, Xcel Energy's "Resilient Minneapolis Project" would address several aspects of energy equity, including the improvement of focused stakeholder engagement, by working with three Black, Indigenous and People of Color-led organizations; enhancing community resilience; and increasing community-responsive investments in energy infrastructure (see text box). In certifying the project, the Minnesota PUC stated that the proposed investments have the "potential to be transformative within the community."[104]
- California requires utilities to conduct meetings to educate and inform local and tribal governments on vulnerable electric transmission and distribution infrastructure. One of the stated goals of the state's High DER proceeding, the successor to DSP proceedings, is to optimize grid infrastructure investments by facilitating community input about planned developments, DER siting, and resilience needs. In the Scoping Ruling, the Commission asked stakeholders to provide input on what analysis is needed for the Commission to determine how best to improve local engagement in distribution planning.

[103] Oregon PUC UM 2005 DSP Guidelines, December 2020, at 10.
[104] In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan and Request for Certification of Distributed Intelligence and the Resilient Minneapolis Project, Docket No. E-002/M-21-694, Order Accepting 2021 Integrated Distribution System Plan and Certifying the Resilience Minneapolis Project (July 26, 2022) at 10.

- Illinois’ CEJA stated that DSP processes should be made more accessible and transparent and that more inclusive and accessible processes would be in the interests of all of the state's residents. To that end, utilities are required to hold facilitated workshops as part of the integrated grid planning process to encourage diverse participation.
- In Maine, information related to a grid planning filing must be provided in a forum accessible to interested parties, with all relevant data and distribution modeling tools available to interested parties.
- Though not specific to DSP, the Massachusetts Department of Public Utilities opened an inquiry into participation of environmental justice organizations with the intent to enhance the meaningful involvement of all communities. The department’s draft policy states that certain proceedings should receive a heightened level of publication and outreach, and defines three tiers of proceedings. If approved, the draft policy would determine that “Tier 1” proceedings are “major, significant proceedings or those with significant impact on environmental justice communities” and would require extensive outreach in multiple forums.

Resilient Minneapolis Project

In its 2021 IDP,* Xcel Energy proposed the Resilient Minneapolis Project in three locations in partnership with Black, Indigenous, and People of Color-led organizations. The project seeks to make community-responsive investments to improve resilience to crises by protecting against physical threats, such as severe weather, and to increase energy equity in traditionally underserved communities while providing benefits to the distribution grid. The utility proposed to invest in company-owned and operated battery energy storage systems and hardware for islanding switching, microgrid controller, and interconnection.

The company estimated $8.9 million in capital costs. The Commission limited potential cost recovery to $9 million unless Xcel could show that additional costs were reasonable, prudent and beyond the Company's control. The company subsequently filed a request to consider possible budget increases to allow recovery of higher anticipated costs and later requested to withdraw its cost recovery request, citing cost increases of more than 70% largely due to inflation.

In a September 21, 2023, order, the PUC authorized the company's withdrawal request after finding consensus among stakeholders that the project, as initially structured and approved by the Commission, was no longer feasible due to monetary constraints. The Commission instead required Xcel to file a revised project proposal within 180 days with the objective of investing in resilience in the original host communities. Subsequently, Xcel informed the PUC that the company was awarded $9 million in federal funds by the U.S. Department of Energy to complement the project funds approved by the Commission. Xcel has continued to work with the three host sites and the city of Minneapolis to revise the proposal and stated that it will file a revised proposal with the Commission by March 19, 2024.

*July 26, 2022, Order in Docket 21-694, available in Minnesota eDockets

11.4 Best Practices

Best practices in advancing equity in DSP can be described using the four core dimensions listed above: recognition, distributive, procedural, and restorative justice.

Recognition justice is furthered by adopting goals and objectives related to advancing equity; an important first step that many states have taken. Hawaii's docket investigating how to integrate equity and justice considerations across its proceedings stands out for seeking to ensure equity and justice are comprehensively advanced by utilities and the commission.

Best practices in incorporating distributive and procedural justice in DSP include:

- *Developing clear goals and targets to advance equity with accountability.* An example is the Illinois statute that requires at least 40% of the benefits of investments to flow to "equity investment eligible communities." This parallels the national Justice40 goal which states that

40% of the benefits of investments must flow to disadvantaged communities that are "marginalized, underserved, and overburdened by pollution."[105]

- *Requiring utilities to perform equity analysis.* This could include incorporating customer geographic, racial, and socioeconomic information overlaid with reliability and customer options during grid needs assessment and solution identification and prioritization steps, as in Oregon's guidelines.
- *Requiring submitted plans to describe how community and equity goals have been incorporated into the action plan*. Colorado's requirements include this provision.
- *Developing quantifiable metrics.* Metrics can be tracked by geography and income, as directed by the MN PUC, or utilities can track DER investments in environmental justice communities, as in Massachusetts. Such information can be used in DSP to plan equitable future investments.
- *Enhancing meaningful involvement of all communities.* Examples include participation of environmental justice organizations in utility processes, as in Massachusetts, and developing specific requirements for community engagement throughout DSP process steps, as in Oregon. Additional approaches include establishing a designated work group, as in Maryland, or an advisory group, as in Oregon.
- *Developing pilots and programs that serve community needs.* Work directly with traditionally disadvantaged communities to develop pilots and programs that serve community needs while advancing commission goals, as in the Resilience Minneapolis project in Minnesota.
- *Providing intervenor funding for energy justice communities.* The Oregon Legislature, for example, enacted House Bill 2475 (2021) to expand the state's intervenor funding program to provide financial assistance for environmental justice organizations to participate in regulatory proceedings before the Public Utility Commission to represent the interests of low-income residential customers and residential customers that are members of environmental justice communities.

Restorative justice to rectify injustices that have occurred because of previous decision-making, has yet to be explicitly included in DSP processes. Doing so alongside the approaches described above would create a more comprehensive strategy to advance equity.

[105] The White House (n.d.).

12. Pilots

Integrating innovative technologies and services in distribution system planning can support new cost-effective approaches to meeting grid needs and state goals and increase participation of utility customers and third-party service providers in delivering grid solutions.[106] But with greater uncertainty in impact, innovative technologies and services require more evidence with respect to their performance, compared to investments that are well established and deployed at large scale by utilities today.

Experimentation can provide information to improve understanding of how a new technology or service interacts with existing distribution grid assets and operations, assess its value to the grid, and help validate use cases.[107] The electric utility industry often refers to such activities as *pilots* or *demonstration projects.*

Pilots are important for advancing distribution system capabilities. Pilots also can test pricing, programmatic and procurement strategies to enable value streams for DERs.

Pilots are generally limited in scope, scale and time, compared to full-scale deployment. These boundaries contribute to establishing a controlled environment for experimentation and support the process of learning by doing.

Expectations for the outcome of a pilot program also are different from those of a full-scale deployment program. Instead of well-defined outcomes for clearly understood technologies and services, learnings from a pilot may indicate that it was a success and can be considered for deployment at a larger scale or that the pilot failed to achieve its goals and should be ended or reconfigured.[108]

While diverse in scope, most states that require regulated utilities to conduct DSP provide guidance on demonstration projects through pilots. For example, several states are guiding pilots toward understanding how to effectively operate and optimize a distribution system with growing shares of DERs, including building capacity and processes to identify and deploy cost-effective NWAs. Some states require that pilots be developed in collaboration with stakeholders. Most states set requirements on the information utilities must submit on the scope and costs of existing and future pilots. However, few states have established a process to transition from pilots to full-scale deployment of piloted technologies and services.

12.1 Pilot requirements

State requirements for pilots vary with respect to applications and technologies, the content of pilot

106 See National Association of State Utility Consumer Advocates et al. (2022).

107 See Cappers and Spurlock (2020) for further details on the role of pilots for experimentation in the electric utility industry.

108 See Cappers and Spurlock (2020) at 92 for further discussion on the role of learning through pilots and that a failed pilot can still be "used and useful."

proposals and reporting, stakeholder engagement and equity, and the commission approval process.

12.1.1 Pilot applications and technologies

Pilots may focus on demonstrating and understanding DER system impacts, including operation and integration (California, Colorado, and New York), DER costs and benefits (Washington), NWAs (Colorado and Oregon), and hosting capacity analysis (California, Oregon, and New York). Conversely, state requirements may establish pilot exclusions. For instance, pilot proposals associated with providing basic electric service may be excluded (Hawaii, Michigan, and Vermont). States also may exclude from pilots unproven technologies with low technology readiness levels (District of Columbia).

In addition, pilot requirements may serve a state's interest in investigating a specific technology (Indiana, Nevada, and Virginia). Indiana and Nevada, for instance, have established specific requirements for utilities pursuing EV pilots. Similarly, Virginia regulators set requirements for battery storage pilots. Alternatively, states may opt not to direct utilities to a specific technology or application (Massachusetts), or states may indicate technologies and applications of interest for pilots while allowing utilities to consider other options (Colorado).

12.1.2 Content of pilot proposals and reporting

State requirements may specify the information utilities must include in pilot proposals and reporting. For example, regulators may require proposals to include a justification for the pilot project, the proposed scope, and the implementation schedule (Colorado, Michigan, and Rhode Island). Some states explicitly require utilities to describe pilot costs and benefits (Colorado, Minnesota, Michigan, and Vermont).

Some states specify pilot durations. For example, pilots operating under Connecticut's Innovative Energy Solutions Program and Vermont's expedited pilot program may run for up to 18 months. Regulators also may require information on the possibility of a pilot becoming a full-scale deployment program (Colorado, Connecticut, and Massachusetts). Related to pilot scaling, Michigan requires regulated utilities to provide information on expected cost-effectiveness and net benefits for full-scale deployment.

In addition, states may require utilities to report on previously approved pilot projects (Massachusetts, Minnesota, and New York). Some states specify reporting on pilot evaluation criteria and metrics (Colorado, Hawaii, Michigan, and Oregon).

12.1.3 Stakeholder engagement and equity

State requirements may shape how utilities engage stakeholders and integrate equity considerations in pilots. For example, requirements may encourage stakeholder collaboration to inform pilot efforts (Massachusetts), direct utilities to collaborate with third-party service providers when considering pilot projects (Connecticut, Hawaii, and New York), or consider pilot proposals from third parties (Colorado). States also may incorporate equity considerations, requiring utilities to identify and describe pilot impacts on disadvantaged communities (Colorado, Hawaii, Michigan, and New York).

12.1.4 Approval process

State requirements may establish expedited processes for pilot proposals, such as Hawaii, Vermont, and Michigan. In Vermont, utilities can pursue pilots without regulatory approval for proposals that meet eligibility criteria.[109] To be eligible, pilots should: (1) support distributed renewable generation or projects that reduce fossil fuel consumption, or contribute to state goals set in Vermont's Comprehensive Energy plan; (2) last less than 18 months; and (3) not exceed 2% of the municipal company or electric cooperative net assets, or increase cost-of-service by more than 2%.

12.2 Typical pilot practices

Typical pilot practices include requirements for information that utilities should include in pilot proposals and reporting, standards for information-sharing, and increasing transparency for utility pilot activities. Pilot practices in Minnesota and the District of Columbia represent these practices.

12.2.1 Minnesota

Minnesota's pilot requirements apply to large as well as small utilities, including Xcel Energy, Otter Tail Power Co., Minnesota Power, and Dakota Electric Association, focusing on information requirements for pilot proposals and reporting in utility DSP filings. Utilities are required to include the following information in DSPs:

- Historical capital spending information for the past five years of pilot projects
- Planned capital spending information, including project drivers and implementation schedule
- Description of the status of ongoing or new pilot opportunities being considered

Following these requirements, Xcel's 2024-2033 distribution system plan included summaries for ongoing and future pilots being considered. Ongoing pilots, for example, include an EV optimization pilot targeting commercial and residential customers with the objective to manage EV grid impacts by providing incentives for off-peak charging. The pilot provides charging schedules designed to push EV demand outside Xcel's peak hours and stagger charging to avoid a demand spike during off-peak hours. Customers that meet 25% of EV charging needs during their assigned off-peak schedule will receive an annual $50 bill credit.

In Xcel's 2023 rate case, stakeholders proposed a new approach to pilots and asked the Commission to consider a regulatory sandbox approach — a dedicated regulatory process focused on defining and deploying pilot projects efficiently. This is similar to the approach implemented in Connecticut's Innovative Energy Solutions. However, the Commission decided that such an approach was not needed

[109] The PUC "[...] authorizes Vermont municipal and cooperative electric utilities to offer innovative rates and services to their customers as pilot programs, subject to specific limitations and requirements, without first obtaining approval from the Commission." Order Adopting Standards and Procedures for Innovative Rates and Services Offered by Municipal and Cooperative Electric Utilities. https://epuc.vermont.gov/?q=downloadfile/550795/160494 at 1

at this time and instead issued an order encouraging continued stakeholder collaboration.[110]

12.2.2 District of Columbia

The Public Service Commission of the District of Columbia approved a process for pilots as part of an investigation and stakeholder process focused on grid modernization, Modernizing the Energy System for Increased Sustainability. The Commission developed the requirements to support pilots funded through a $21.55 million pilot project fund created as a result of the PHI-Exelon merger. The requirements define eligibility and assessment criteria. Each proposal goes through a two-step screening process. The first step focuses on screening projects for alignment with pilot principles and technology readiness level.[111] Proposals scoring 80 out of 100 move to the second step, which assesses proposals for administrative parameters, technical merit, approach and environmental impacts (Figure 12-1).

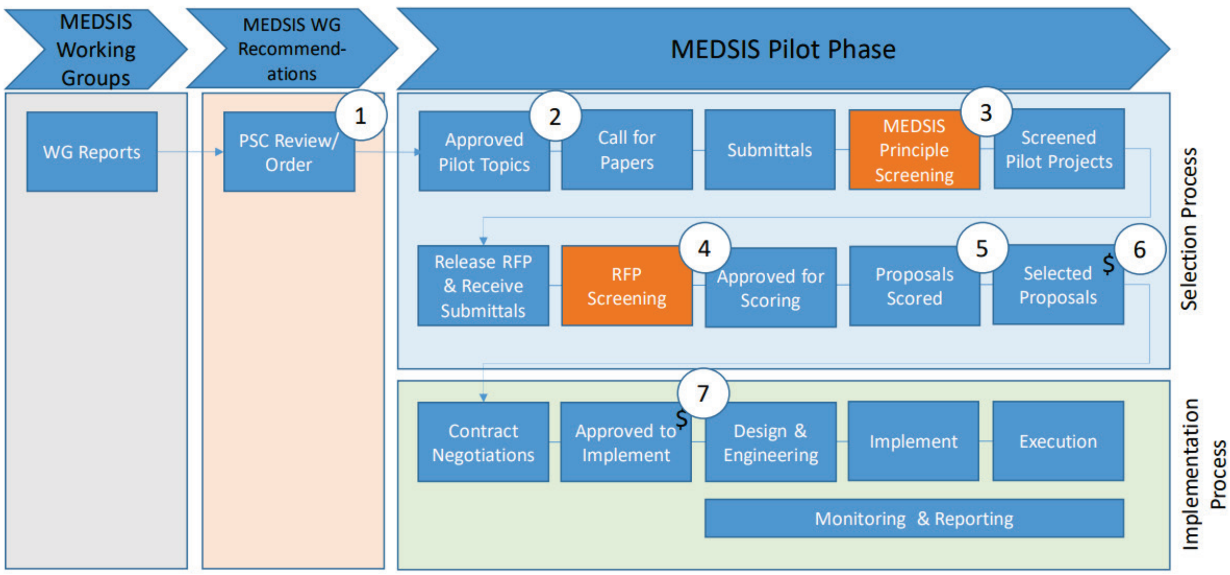

Figure 12-1. Pilot Project Approval Timeline
Source: SEPA (2019), Figure 5.16 at 228.

A "Pilot Projects Governance Board" is responsible for making recommendations to PUC staff on pilots eligible for funding and oversight of implemented pilots. To avoid conflicts of interest, board members must not include stakeholders interested in obtaining pilot funding.

12.3 Best practices

Best practices include establishing a comprehensive set of requirements for utility pilots to shape many of the elements discussed above. Comprehensive requirements create an objective process for pilots to

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110 MN PUC in its order decided that "[...] Xcel must work with interested parties and other utilities as relevant to discuss methods for improving the effectiveness and efficiency of pilot projects, accelerating the timeline for scaling successful pilot programs into full offerings, and increasing innovation in the energy sector, consistent with the public interest." At 163, Order 7/17/2023, Docket E-002/GR-21-630, Available at: https://mn.gov/puc/edockets/.
111 For a detailed scoring template for each step, see SEPA (2019) at 396.

be designed, implemented and contribute to learnings that support identifying opportunities for full-scale deployment of successful projects. Michigan and Oregon employ some of these best practices, described below.

12.3.1 Michigan

Michigan is noteworthy for its efforts to better understand the value of pilots and establish objective criteria for future pilot selection. Regulators recently pursued efforts to assess past experiences with pilot projects and build a more robust framework for future pilot proposals. Commission staff led a survey of Michigan utilities and found that, of the 95 pilots conducted between 2008 and 2019, 36% resulted in a full-scale program, 31% were not pursued beyond the pilot phase, 26% were ongoing projects, and 7% of the projects were identified as "Other." The survey results also indicated that most pilots (67%) required reporting progress to the Commission. This finding signals the importance of an effective regulatory framework to identify pilots that are viable to become full-scale offerings and set an expectation that successful pilots result in that outcome.

A review by Commission staff of utility cases for the same period found that the majority of pilots did not describe specific goals, justify relevance, or include participant selection and sample information.

Building on the outcomes resulting from stakeholder collaboration, the Commission adopted a pilot definition that states, *"A pilot is a limited duration experiment or program to determine the impact of a measure, integrated solution, or new business relationship on one or more outcomes of interest."* The Commission also adopted objective criteria that utilities must provide for each pilot proposal:

- Needs and goals
- Design and evaluation plan
- Costs
- Timeline
- Stakeholder engagement
- Public interest

The Commission clarified that providing all of the information is not a guarantee for project approval, and that missing information on some of the criteria will not result in automatic rejection.

Michigan also improved transparency by developing an online pilot directory with information reported by utilities. The directory allows stakeholders to access pilot details and filter by utility, piloted measure, customer group, and pilot status. Figure 12-2 shows the directory search interface.

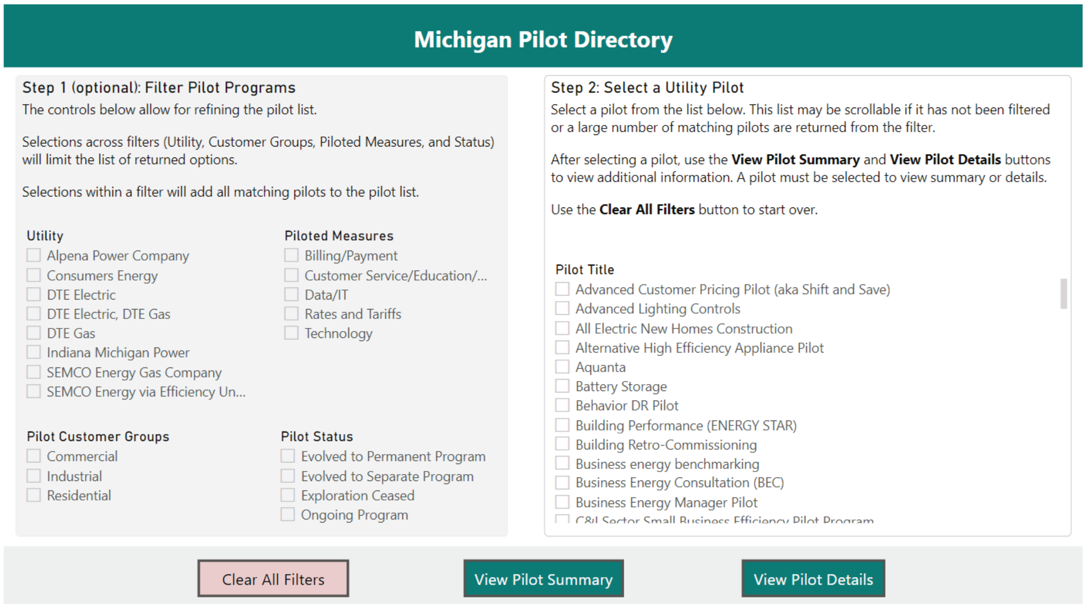

Figure 12-2. Michigan's Pilot Directory Search Interface
Source: MPSC (2024)

12.3.2 Oregon

Oregon DSP requirements specify a comprehensive process to identify and assess pilots for two DER-related applications. First, utilities must include at least two pilot proposals to deploy NWAs instead of traditional grid infrastructure investments. Pilot proposals must be developed in collaboration with community stakeholders to support local community needs. Utilities must conduct additional community meetings during development of pilot projects and file a "Community Engagement Plan" outlining their approach to engaging community representatives.

The DSP action plan must identify relationships and interactions with other investments, such as demand response programs. Specifically, utilities must provide a high-level summary of any demand response pilots and program performance metrics for the past five years. The summary must include participating customers by customer class, winter and summer demand response performance data, maximum available capacity of demand response per customer class and combined total, system peak load, and available capacity of demand response as a percentage of seasonal system load.

Second, utilities opting to pursue hosting capacity analysis pilots to test and deploy new approaches must include the pilot objectives, plan, budget and evaluation methods.

Further, when considering smart grid opportunities,[112] utilities must describe evaluations and

[112] "Smart grid investments are utility investments in technology with two-way communication capability that will (1) improve the control and operation of the utility's transmission or distribution system, and (2) provide consumers information about their electricity use and its cost and enable them to respond to price signals from the utility either by using programmable appliances or by manually managing their energy use." In the matter of Public Utility Commission of Oregon, Consideration for Adoption: Staff Proposed Guidelines for Distribution System Planning. Docket No. UM 2005, Appendix A at 13.

assessments of any smart grid pilot.

For pilot proposals emerging from collaboration with community stakeholders, the utilities must prioritize grid needs of interest to the community, such as local load growth or power quality issues. Proposals must discuss the grid needs identified, alternatives considered, and costs and benefits. Utilities also must set equity goals in collaboration with stakeholders.

Following implementation of these requirements, utilities proposed new pilot projects in their 2022 DSPs.

12.3.2.1 Portland General Electric

Portland General Electric (PGE) identified two potential pilots, targeting: (1) Eastport-Plaza and the Eastport substation transformer and (2) the Dayton-East feeder and Dayton substation transformer. For each pilot, the utility described the grid need, traditional solution, potential NWA solutions, decision-making metrics, and community engagement process. Figure 12-3 provides the details for the Eastport pilot.

NWS candidate: Eastport-Plaza and Eastport WR1	
Scope of grid need	Planning criteria violation on Eastport-Plaza and Eastport WR1
	Violation seen on summer weekdays from 1pm-7pm
	Relief can be provided anywhere along the feeder and partially at the substation
Traditional solution	Substation transformer upgrade and feeder section reconductoring
NWS	Energy efficiency • 5,500,000 kWh/yr annual savings by 2032
	Demand response • 2,166 kW of summer peak demand potential by 2032
	Solar and storage • 2,940 nameplate kW-dc of residential rooftop solar PV • 743 nameplate kW-dc of non-residential rooftop solar PV • 1,000 nameplate kW-dc of Community Solar installations
Decision making metrics	Relief can be provided anywhere along the feeder and partially at the substation
Community engagement	Performed outreach to CBOs through four Community Workshops (see **Section 2.4**)
	Conducted outreach to schools and government partners in the affected area to align plans with existing efforts and potential projects
	Going forward, will conduct detailed community needs assessment for the Eastport area by working directly with CBOs with connections and existing relationships in the area (see the community needs assessment section of **Appendix E**)

Figure 12-3. Eastport Pilot Candidate Summary Details
Source: UM 2005 – PGE's Compliance per Order No. 20-485, Distribution System Plan Part 2, Table 29 at 112.

PGE analyzed two options for NWAs to address grid needs in Eastport and Dayton: (1) a front-of-the-meter utility-scale battery plus some behind-the-meter customer DER adoption and (2) more aggressive customer DER adoption, which reduced the need for a utility-scale battery. After its assessment, PGE proposed to move forward with the second option, which included energy efficiency, load flexibility, and behind-the-meter storage.

Oregon Commission staff supported PGE's proposed solution, while recognizing that the utility's pilot process and proposals can be improved in the future, including additional details on next steps and implementation of proposed solutions. Commission staff also encouraged the utility to complete community engagement activities necessary to meet DSP requirements. Particularly, for the Dayton pilot, PGE did not engage community partners and customers to the same extent as it did for the Eastport pilot proposal. Staff recognized the time constraints leading to that outcome but called on the company to comply with the Commission's requirements for collaborative development of pilot proposals as a way to address identified community needs.

12.3.2.2 PacifiCorp

PacifiCorp identified two pilot locations: Klamath Falls and Pendleton. The utility obtained input from community stakeholders and received pilot proposals from the Farmers Conservation Alliance and the Oregon Solar and Storage Industry Association. Considering grid needs for both locations and stakeholder input, the utility opted to pursue the pilot in Klamath Falls to address overcapacity and low voltage issues. The utility found that not pursuing solutions for this circuit could result in an outage to 45% of customers served by the circuit.

Combining aspects of proposals from different stakeholders, PacifiCorp analyzed two options for NWAs. One option consisted of behind-the-meter solar and storage installed at residential and commercial customer sites, and the second consisted of targeted energy efficiency measures.

Figure 12-4 illustrates how onsite solar plus storage would address the overloaded circuit. PacifiCorp identified the need for 2.44 megawatt-hours (MWh) of storage to address the grid need. Its analysis found that installations at about 300 residential customer sites would be needed to address the grid need, assuming solar PV modules of 10 kW and a battery storage rating of 10 kW/10 kWh.

Alternatively, PacifiCorp found that 4.525 MWh of energy savings could address the grid need with a targeted energy efficiency solution.

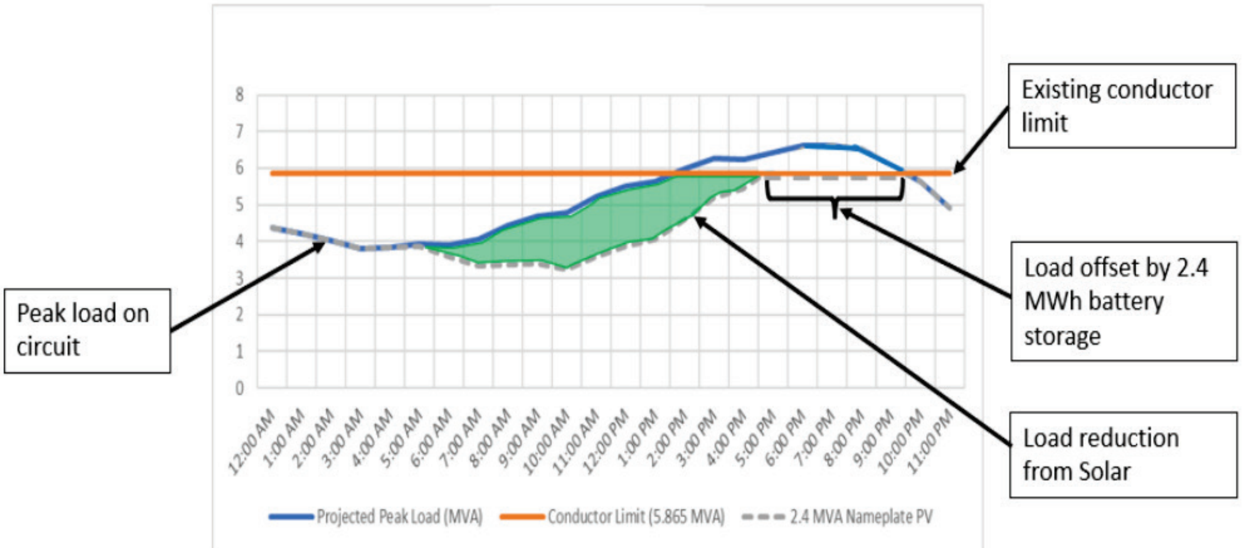

Figure 12-4. Solar Plus Storage Pilot Option Analysis at Residential Customer Sites
Source: PacifiCorp (2022), Figure 50 at 109.

PacifiCorp developed a framework and conducted initial analysis of both alternatives. Figure 12-5 is an overview of the DSP process and the steps the utility followed for NWA pilots:

- Preliminary analysis: High level analysis to confirm grid need and NWA suitability
- Detailed analysis: Detailed review of the local area and examination of potential NWA impacts on the grid need identified
- Identification of options: Development of potential NWA pilots
- Evaluation of proposals: Assessment of proposed pilots — technical feasibility, implementation time, complexity, cost, reliability, customer and community benefits, and cost-benefit analysis

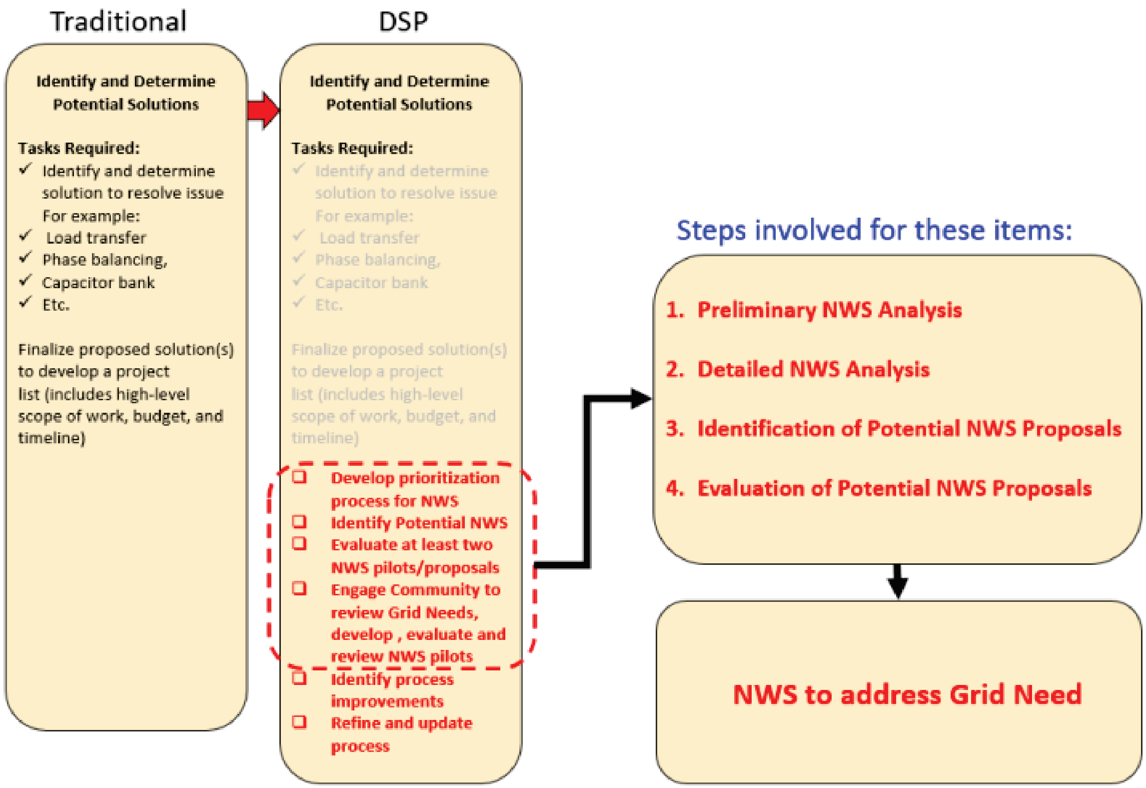

Figure 12-5. Analysis Framework for Pilot Alternatives
Source: PacifiCorp (2022), Figure 43 at 92.

The utility continues to work with the Farmers Conservation Alliance, Oregon Solar and Storage Industry Association, and Energy Trust of Oregon — the third-party energy efficiency administrator — to improve understanding of both options. Tables 12-1 and 12-2 show the utility's preliminary findings for cost-effectiveness for solar plus storage and targeted energy efficiency, respectively. PacifiCorp's cost-effectiveness analysis for the solar plus storage option included consideration of non-quantified energy benefits, such as resiliency, represented as a 10% adder. Oregon Commission staff considered the analysis pioneering work.

Table 12-1. PacifiCorp's Initial Cost-Effectiveness Results, with Optimistic Inputs, for Solar Plus

Benefit Cost Assessment	CE – 5 Year	CE – 10 Year	CE – 20 Year
Utility (UCT)	1.38	2.07	2.70
Customer (PCT)	0.02	0.03	0.05
TRC	0.14	0.23	0.34

With 10% benefit adder	CE – 5 Year	CE – 10 Year	CE – 20 Year
Utility (UCT w/ adder)	1.52	2.27	2.97
Customer (PCT w/ adder)	0.02	0.03	0.05
TRC (w/ adder)	0.15	0.25	0.37

Notes: CE - Cost-effectiveness, UCT - Utility Cost Test, PCT - Participant Cost Test

Source: PacifiCorp (2022), Table 10 at 110.

Table 12-2. PacifiCorp's Initial Cost-Effectiveness Results for Targeted Energy Efficiency

Scenario	Utility Cost Test	Total Resource Cost Test
Business-as-usual	3.1	1.3
Accelerated acquisition (typical measure mix)	2.6	1.2
Accelerated acquisition (targeted measure mix)	3.0	1.4

Source: PacifiCorp (2022), Table 13 at 119.

13. Coordination With Other Planning Processes

Integrated distribution system planning requires consideration of other planning processes — for example, for the bulk power system, DERs, electrification, grid modernization, and resilience to climate change and other threats. Coordination across functional areas is imperative to ensure that utilities plan and construct distribution systems to facilitate achievement of multiple state and local objectives and priorities in a least-cost manner.

This chapter describes the benefits and challenges of effective coordination across planning processes, coordination activities, and example state requirements and utility practices. States can draw from these examples as they establish or update planning requirements.

13.1 Coordination Benefits, Challenges and Activities

Ideally, utilities develop distribution system plans in coordination with any other plan that may influence distribution system needs. Coordinated planning harmonizes traditionally siloed planning processes by aligning inputs, methods and information flows. It ensures that all relevant factors that may influence distribution system needs are considered in a timely manner. Having a holistic picture of all distribution system requirements and available investment alternatives creates efficiencies that can result in cost savings. Coordination ranges from simple alignment across planning processes to complex iterative and integrated modeling efforts (Figure 13-1).

Use of consistent inputs across planning processes increases understanding, transparency and credibility of results. Coordination also increases the ability of stakeholders — both external to the utility and within the utility across functional areas — to participate in proceedings, increasing expert knowledge available to planners and decision-makers. More diverse perspectives improve the quality and depth of information that informs distribution system plans. When stakeholders are better able to understand data and are more familiar with inputs, they also are better equipped to help improve planning inputs, resulting in more robust plans overall.

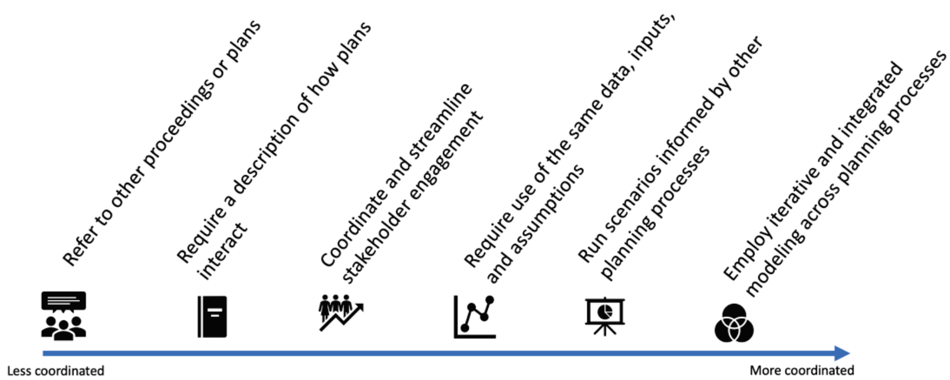

Figure 13-1. Levels of Distribution System Planning Coordination

Traditionally, planning processes have been siloed, which allows planners to address specific areas in great depth but which forgoes these benefits. Siloed planning can also lead to missed opportunities that result in sub--optimally located resources, overbuilt infrastructure, and higher costs overall.[113] Successful coordination requires consistent and sustained attention to what are often lengthy and technically complex proceedings. If not thoughtfully administered, this can create barriers to participation for stakeholders that may have limited bandwidth to meaningfully participate. For example, stakeholders participating because of specialized expertise in a certain area may lose interest or momentum when the proceeding focuses on other areas. In addition, coordination can be time- and resource-intensive, may result in less depth of analysis, and may require significant investments of time by utilities and regulators. The planning process can be managed to reduce these challenges by careful articulation of planning objectives upfront and sequencing and scheduling of workstreams. Staff that work across coordinated planning processes benefit from their knowledge of different proceedings and may realize efficiencies in their work.

Figure 13-1 shows the following actions toward harmonization across different planning processes, in increasing order of coordination:

1. *Refer to other proceedings or plans.* Drawing on information from other proceedings and other types of plans is a simple initial coordination element that can improve the quality of the IDSP. Without any explicit direction by the Commission, the utility, regulatory staff, and stakeholders may proactively refer to data, processes and findings in related proceedings in their IDSP filings to build a more robust decision-making record.
2. *Require a description of how plans interact.* Planning rules may require a narrative overview of how related plans interact with the IDSP. This requirement will yield some information on the utility's efforts to coordinate related plans, but it is still a low level of coordination because it does not require any specific analysis, explicitly define important areas for coordination, or require any particular outcomes from coordination.
3. *Coordinate and streamline stakeholder engagement.* Utilities can explicitly coordinate stakeholder engagement activities such as workshops, technical conferences, and working groups to more efficiently draw on stakeholder expertise across proceedings. For example, intervenors in a relevant proceeding may be invited to participate in an IDSP technical conference, or the utility may convene a single working group to provide expertise on a topic across multiple proceedings. This achieves a moderate level of coordination because stakeholders will contribute to a robust and coordinated record for decision-making using their knowledge of other proceedings.
4. *Require the use of the same data, inputs and assumptions.* Requirements can specify that utilities use the same underlying information across plans such as load forecasts, economic indicators and DER cost assumptions. It may not always be possible to use the same datasets depending on the timing of data releases. However, requirements can specify timelines for refreshing underlying data, inputs and assumptions to ensure data are up to date, while avoiding overly frequent and onerous updates. This mid-level coordination may increase

[113] Burdick et al. (2024).

efficiency across planning activities and help to ensure outcomes of different types of plans are comparable.

5. *Run scenarios informed by other planning processes.* Requirements may explicitly direct utilities to run scenarios aligned with other planning processes or goals, such as decarbonization or DER deployment goals. Requirements may provide direction on how utilities should consider the results of such scenarios and incorporate findings in their final IDSP.
6. *Employ iterative and integrated modeling across planning processes.* This highest level of coordination explicitly requires that inputs and outputs of different planning processes inform one another. This action ensures that the resulting IDSP is consistent with other plans.

Roles and Responsibilities for Coordinated Planning

- *Utilities* – Conduct analyses, file plans and describe how plans are coordinated
- *PUCs* – Establish requirements, conduct technical conferences, and review and approve plans
- *Consumer advocates, state energy offices, third-party service providers, industry representatives and other stakeholders* – Provide market and technical insights and specialized expertise, review plans, suggest improvements and participate in proceedings

13.2 Types of Plans to Coordinate

Each state has different planning requirements and processes that reflect their unique policy priorities and conditions. Vertically integrated utilities necessarily conduct electricity system planning differently than utilities operating in restructured states, as these utilities do not own generating facilities or procure energy under long-term contracts for their customers.[114] Market ownership structure informs which plans may be coordinated and which entities may be involved.[115] This chapter focuses on how to coordinate distribution system planning with other planning processes, but also includes examples where utilities or states are moving to Integrated System Planning, which plans for the generation, transmission, distribution, and DERs and customer-sited resources all in a single process. [116]

In addition, states are increasingly requiring utilities to integrate various types of distribution-related plans. For example, the Minnesota PUC requires Integrated Distribution Plans (IDPs) that incorporate

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[114] Vertically owned utilities that operate in an RTO or ISO region also may plan differently than a utility outside of such regions.

[115] A task force for PUCs and state energy offices developed roadmaps for comprehensive electricity planning across five planning landscape scenarios, including different market structures. The roadmaps are a useful reference for states to build planning processes specific to their environment. See https://www.naruc.org/committees/task-forces-working-groups/retired-task-forces/task-force-on-comprehensive-electricity-planning/resources-for-action/roadmaps/.

[116] Burdick et al. (2024).

statutorily required grid modernization and transportation electrification plans.[117] In contrast, some states require independent regulatory filings for electrification, grid modernization and resilience. Thoughtful coordination is important in such cases because there are more likely to be issues related to siloed personnel and analyses and planning timelines than when the plans are integrated into a single filing.

As another example of increased planning coordination, Nevada requires detailed DER plans to be filed as part of IRPs. But while these DER plans include some common distribution planning elements, they focus on preparing for the impacts of DER growth and maximizing potential DER benefits for utility customers.

States that do not require separate DER, electrification, grid modernization, or other distribution-related plans often have specific requirements for how such elements must be factored into an IDSP. While this is not coordination across separate plans, it still requires coordination across utility functional areas and ensures that utilities are planning for important state or regulatory objectives.

13.2.1 Bulk Power System Plans

Historically, utilities conducted IRPs to determine the amount of generation and demand-side resources needed to serve customer load in a process wholly separate from distribution system planning. Recently, some states and utilities began moving toward planning processes that consider all levels of the grid in conjunction with one another.[118] IRP requires consideration of loads, DERs, generating resources, and transmission throughout the region in which the utility operates — including awareness of RTO or ISO markets — for utilities operating in restructured states.

Coordination of planning for the distribution system and bulk power system — transmission planning and, where relevant, IRP — is important. For example, DERs at the distribution level may help mitigate the need for some generation and transmission investments. At the same time, availability of transmission and generation capacity on the bulk power system can inform the operational deployment of DERs or identify constraints to be addressed in distribution plans.[119] Transmission plans also can provide important information about the potential role of DERs in the event that timelines for transmission build-outs are not expected to meet near-term utility load growth.

However, coordinating distribution planning with bulk power system planning is complex. First, DERs can operate in multiple modes, acting autonomously, providing grid services for utilities, or participating in wholesale markets. The different levels of DER control and visibility across entities requires new approaches to coordination with utilities, RTOs/ISOs, and DER aggregators.[120] Second, transmission is interregional in nature, involving many entities and jurisdictional authorities, including

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[117] Most utilities that file distribution system plans consider DERs in load forecasting, hosting capacity analysis, and non-wires alternatives analysis.
[118] See Berkeley Lab's Interactive Decision Framework for Integrated Distribution System Planning.
[119] Dyson, Swishberg, and Stephan (2023).
[120] Gridworks (2018).

multiple utilities, independent transmission companies, RTOs and ISOs, PUCs, the Federal Energy Regulatory Commission, and organizations involved in stakeholder processes.

As an illustration, different agencies and entities play key roles in California's electricity planning processes. These include a long-term forecast of energy demand produced by the California Energy Commission, (2) a Long Term Procurement Plan proceeding conducted by the PUC, and (3) a Transmission Planning Process performed by the California ISO. These entities have been coordinating their efforts for more than a decade, including through an interagency process-alignment technical team and memorandums of understanding. The plans require translation of datasets for use across various models. For example, energy efficiency and rooftop PV load shapes may be translated from multiple service area level forecasts down to a statewide load bus forecast to be used in power flow modeling.[121] This type of data translation is technical and time-intensive for datasets that can change quickly.[122]

13.2.2 DER Plans

Distribution planning requires detailed understanding of loads and constraints on the distribution system. Circuit-level data build up to substation and feeder level, all of which inform the need to invest in solutions to solve distribution system issues such as capacity shortfalls, thermal constraints, and other planning criteria violations. DERs have significant impact on the timing and amount of load at the circuit level. Plans for energy efficiency and other DERs are often developed separately.

Coordinating DER planning with DSP is critical because DER growth may be a driver of distribution system investments.[123] Conversely, well-sited DERs may mitigate certain distribution system constraints.[124] Customers are increasingly turning to DERs to improve resilience of their homes and businesses and to reduce their electric bills.[125] Grid operators desire increased visibility and control of DERs to reduce challenging operational impacts of unmanaged load and generation on the grid and maximize the grid value of such equipment. For example, Xcel Energy in Colorado has outlined a vision for increased visibility and control of a growing DER fleet aligned with integrated system planning and utility operations (Figure 13-2).

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[121] California Public Utilities Commission, California Energy Commission, and California Independent System Operator (2014); California Public Utilities Commission, California Energy Commission, and California Independent System Operator (2022); California Public Utilities Commission (2024).

[122] For more detail on coordination amongst these agencies, see Burdack et al. (2024).

[123] White, Agrawal, Bohman, et al. (2024).

[124] Heleno et al. (2023).

[125] Gorman, Barbose, Miller, et al. (2023).

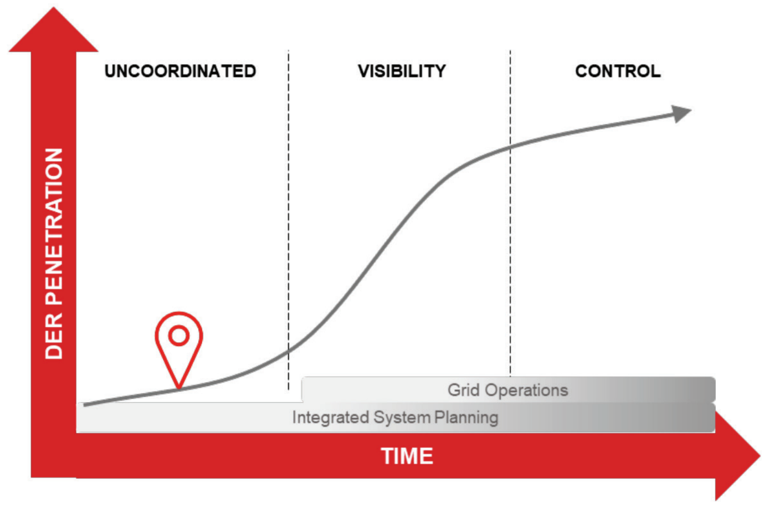

Figure 13-2. Xcel Energy (Colorado) Roadmap for DER Visibility and Control

A well-vetted DER forecast used in distribution system planning, DER planning (when conducted separately), and bulk system planning informs the timing and amount of bidirectional load the system needs to accommodate. The grid needs identified by the DSP also helps inform the value of DER investments and technologies that improve DER visibility and controllability by demonstrating how avoiding or shifting loads or generation can reduce or avoid the need for certain distribution investments. Such values help identify cost-effective investments and inform DER compensation frameworks.

13.2.3 Electrification

Many states have identified electrification goals or initiatives as part of decarbonization targets.[126] Electrification of buildings and transportation are particularly relevant to electric utilities because they must plan to serve the additional load, ideally in a manner that does not exacerbate peak demand issues and is provided at the lowest reasonable cost to customers. With increasing electrification, some states are beginning to move toward integrating electricity and natural gas planning.[127]

Building electrification, such as replacing gas furnaces with electric heat pumps, is a driver of increased electric load that is often coincident with both local and utility system peaks. EV charging also requires significant investment in the distribution system, as charging systems are typically new loads that draw significant power from the grid at inopportune or sporadic times. For example, home EV chargers typically operate when residents arrive home from work, often coincident with system peak demand. Fast chargers can overload transformers and create locational grid constraints.[128]

[126] See Rocky Mountain Institute (2023) and NC Clean Energy Center (2024).
[127] LeBel et al. (2024).
[128] Harper, McAndrews, and Sass Byrnett (2019).

When conducted separately, it is important to coordinate distribution system and electrification planning processes because the impacts of electrification have such strong effects on distribution system needs. States are increasingly requiring utilities to proactively plan for electrification to minimize the negative impacts of increased load, consider EV-specific time-varying rates and managed charging programs, and provide equitable electrification opportunities. When not considered in a standalone filing, many states require that utilities account for the impacts of electrification as part of the DSP, such as in the load forecast.

13.2.4 Plans to Achieve Other State Goals

Each state has its own objectives and priorities that inform regulatory guidance to utilities for various types of planning. In addition to coordinating distribution planning with plans for the bulk power system, DERs, and electrification, many states require utilities to plan for grid modernization and resilience. Well-coordinated, developed, and stakeholder-vetted plans effectively inform general rate cases or cost recovery proceedings, facilitating utility cost recovery of investments necessary to meet multiple state objectives.

Grid modernization plans identify a technology roadmap to ensure grid capabilities are in place to meet objectives and priorities. Example technologies include monitoring equipment and software, smart grid devices that allow for automated two-way system control, and protective devices. These technologies may overlap with those included in DER and resilience plans because they can contribute to DER controllability, situational awareness, and system security. State objectives for grid modernization can drive the need for distribution system planning and investments. Grid modernization plans are often an input to distribution system plans, or utilities may file standalone grid modernization plans.

A growing number of states require regulated utilities to file resilience plans to address one or more hazards, such as climate change.[129] Resilience plans use threat assessments and risk-based planning to identify appropriate mitigations. Such plans may consider approaches such as undergrounding equipment, replacement of wood poles with steel poles, adding technology to improve situational awareness (such as advanced distribution monitoring systems and weather stations), increasing vegetation management, and other measures depending on location-specific hazards. For example, Table 13-1 shows National Grid’s investment plan for physical resilience projects and programs for its New York service area. The utility also included an investment plan for operational resilience projects and programs.[130]

[129] Schellenberg, and Schwartz (2024).

[130] Operational resilience projects and programs include substation transformer specification changes, update transmission structure standards, electric load forecasting, and transmission facility rating methodology changes.

Table 13-1. National Grid's Summary of Identified Physical Resilience Projects and Programs

Physical Project	Mitigated Climate Hazard	Description	FY Start	FY End	Total Cost[23] (Capex)
1. Overhead Distribution and Sub-transmission Line Design Upgrades*	Wind Gusts and Ice	Update distribution line standards to move from Class 3 poles to Class 1 for main lines and poles that carry heavy equipment (approximately 8,000 poles/year) and update sub-transmission line standards to use Class 1 poles for single circuit structures, Class H1 for double circuit structures, and Class H2 for double circuit with distribution underbuilds (approximately 900 poles/year).	2026	2045	$879M
2. Overhead Transmission Line Design Upgrades*	Wind Gusts and Ice	Build T-Lines to withstand 120 mph wind gusts in high wind areas (46 total) by using more steel and larger foundations. Projects include 44–115kV lines and 2–230kV lines (approximately 1,300 circuit miles covered).	2026	2045	$109M
3. Distribution Targeted Undergrounding	Wind Gusts and Ice	Targeted undergrounding of 1–2 miles per year of 3-phase main line in highest wind and icing areas.	2027	2045	$348M
4. Spare Transmission Line Structures	Wind Gusts and Ice	Purchase 10 T-Line spare structures per division (30 total) designed for 120 mph gusts to speed restoration.	2026	2030	$2M
5. Substation Flood Walls	Flooding	Install flood walls at 18 substations in high-risk areas (approximately 17,000 linear feet of flood walls total).	2027	2033	$28M
6. Distribution and Transmission Substation Transformer Specification Upgrades*	Extreme Heat	Update transformer spec from 32°C (90°F) to 35°C (95°F). Current plans include 35 distribution projects (81 transformers) and 24 transmission projects (37 transformers) with installs and replacements.	2026	2031	$25M
*Added scope to existing projects					

Source: Climate Change Resilience Plan, submitted November 21, 2023, to New York Public Service Commission (Case 22-E-0222)

As distribution system planners identify the need for new or upgraded infrastructure for capacity and reliability needs, it is critical to coordinate with resilience planning to identify overlapping needs and associated high-value investments, ensure engineering is done in accordance with best practices for resilience, and minimize costs by avoiding duplication of investments. Such coordination also can help to future-proof the system by minimizing infrastructure sited in vulnerable locations, such as flood-prone areas.

Collaboration with emergency responders, other utilities, and other service providers, such as telecommunications carriers and other pole attachers, is an important area of coordination. Coordinating with emergency responders ensures that hardening investments and infrastructure siting are aligned to minimize impacts to evacuation routes. Coordination with telecommunications companies can help to ensure that poles are not overloaded and that infrastructure is effectively planned such that when a pole is replaced, it can be removed immediately without lingering infrastructure from third parties. Such coordination also can reduce visual impacts of utility infrastructure, increase cost-effectiveness and support affordability goals, and improve safety.

13.2.5 Rate Cases and Cost Recovery Proceedings

States may establish a linkage between the DSP and the utility's rate case or other cost recovery proceedings. It is important to connect these two types of proceedings in order to maximize the usefulness of the DSP and potentially streamline review of proposed distribution system investments. Plans are an important tool for guiding actual utility investments by providing context and support for expenditures. IDSP in particular, demonstrates how the utility has translated its goals and objectives into actions and necessary investments. In particular, the utility's action plan can provide a clear roadmap between the long-term vision for the distribution system and near-term activities. This context and the information in the DSP can help regulators and stakeholders to more effectively and efficiently review proposed expenditures in rate cases.

In order to do this, Commissions can clearly establish their vision for how the DSP will interact with a rate case or other cost recovery proceeding. This can include actions such as describing how the utility can deploy the DSP in rate cases to support proposals, establishing timelines that account for both proceedings, and establishing common objectives and expectations across both proceedings. It is important to consider that Commissions do not typically approve DSPs, indicating that nothing included in the DSP is presumed to be pre-approved. Utilities are likely expected to still provide a robust justification for any proposed investments within the relevant proceeding, including how it aligns with the DSP and whether it deviates from the DSP and if so, why.

Early in the DSP process, the CPUC identified that establishing a clear connection between DSP and general rate cases (GRCs) was an important priority. Over time, the CPUC has refined its guidance. In a 2018 order, the CPUC provided a framework for how Grid Modernization planning could inform GRCs, including:

- Establishing common vocabulary and defining grid modernization and its scope
- Establishing a timeline for grid modernization filings as part of the distribution resources planning process
- Providing guidance on how the Commission would assess the cost-effectiveness of grid modernization investments
- Establishing submission requirements for the grid modernization sections of GRCs

The Minnesota PUC has also explored how to link IDSP with rate cases. In 2023, the Commission sought input on how what decisions it could issue to provide guidance on how the utility should align distribution spending with future rate cases. The Commission also provided guidance in the rate case, stating that "In its next Integrate Distribution Plan (IDP), Xcel must propose and discuss ways for the IDP process to inform financial and cost recovery issues in rate case."[131]

[131] Notice of Comment Period, Docket 23-452, November 17, 2023. Available at: https://mn.gov/puc/edockets/.

13.3 State Requirements

Several states require some form of coordination between distribution system planning and other types of plans (Table 13-1). The table depicts whether there is a requirement in place, either through legislation or Commission decision, order, or rules, that requires some form of coordination of DSP with other plans. DER plans considered both standalone DER plans and energy efficiency or demand-side management plans. The table also assesses what level of coordination is required, aligned with Figure 13-1. The following sections provide more detail on several of these examples.

Table 13-2. The Coordinated Planning Landscape

	Bulk Power System (e.g., IRP and transmission plans)	DER Plans	Electrification Plans	Other Plans (e.g., grid modernization, resilience)	Level of Coordination
CA	x	x	x	x	• Require use of the same inputs
CO	x	x	x	x	• Require use of the same inputs
DC				x	• Refer to other proceedings
HI	x	x	x	x	• Require same inputs • Run scenarios • Iterative modeling
IL	x	x	x	x	• Require a description of how plans interact
ME	x	x	x	x	• Refer to other proceedings • Require use of the same inputs • Run scenarios
MA	x	x	x	x	• Require a description of how plans interact • Coordinated stakeholder engagement
MI	x	x			• Refer to other proceedings, • Require use of the same inputs
MN	x		x	x	• Require same inputs • Run scenarios
NV	x	x			• Require use of the same inputs
NM	x			x	• Require use of the same inputs
NH		x		x	• Require a description of how plans interact
NY	x	x	x	x	• Require use of the same inputs • Coordinated stakeholder engagement • Run scenarios • Iterative modeling
OR	x	x	x	x	• Require a description of how plans interact • Require use of the same inputs • Coordinated stakeholder engagement • Run scenarios

					• Iterative modeling
RI		x		x	• Require description of how plans interact
VT	x	x	x	x	• Require use of the same inputs • Run scenarios • Iterative modeling
VA	x			x	• Require a description of how plans interact
WA	x	x	x	x	• Require use of the same inputs • Run scenarios • Iterative modeling

13.3.1 Hawaii

Hawaii provides lessons on how to effectively integrate planning across the electricity system. The Hawaii PUC adopted an Integrated Grid Planning (IGP) process that harmonizes distribution, transmission and generation planning through iterative modeling. IGP requirements aim to efficiently address state goals such as renewable energy portfolio standards, DER growth and integration, electrification of transportation, affordability and resilience.

Figure 13-3 provides an overview of the steps in the IGP process, as executed by Hawaiian Electric, and illustrates how the steps feed into one another. Importantly, the process begins with development of a single set of inputs and assumptions that feed simultaneously into bulk power system capacity expansion and distribution analyses. The capacity expansion analysis first determines a set of proxy resources that can meet identified grid needs over the planning horizon, then evaluates those proxy resources for resource adequacy and cost on an hourly basis. Hawaiian Electric iterates on each step if the modeling results in violations or unmet planning criteria. The utility uses two models in the distribution analysis step that create hourly circuit- and transformer-level forecasts over the planning horizon and then assesses circuit-level loading, hosting capacity, and possible planning criteria violations. The distribution planning analyses feed into the system security step that evaluates the dynamic stability of the system, allowing for iterative modeling that considers grid needs and solutions at each level of the system.[132]

[132] Hawaiian Electric (2023).

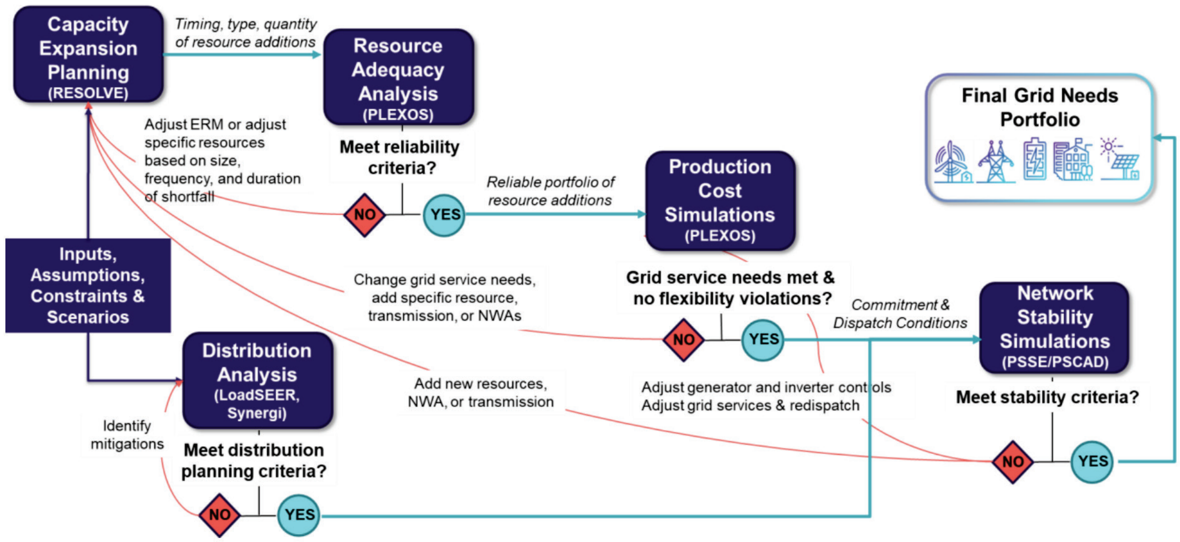

Figure 13-3. Hawaiian Electric's IGP Process

Throughout the process, Hawaiian Electric engages a diverse group of stakeholders. Initially, the IGP proceeding included many working groups, each focused on a specific area such as distribution system planning, forecasts and assumptions, NWAs, procurement and resilience. Over time, the working groups were consolidated. A Stakeholder Technical Working Group focuses on all aspects of IGP.[133] This allowed stakeholders to more effectively engage in the process because there were fewer meetings and they no longer needed to choose where to direct their time and resources.

In 2021, the Hawaii PUC required Hawaiian Electric to closely coordinate between the IGP process and development of next-generation DER programs by requiring the utility to develop and incorporate best estimates for DER tariffs and program values for energy efficiency, other DERs and EVs. For customer-sited solar and storage programs, the utilities' best estimates assumed that energy export values would align with system needs and be controllable by the utility, customers would consume onsite solar energy produced to match their own loads, and the program structure would include an upfront incentive for storage. The Commission also directed Hawaiian Electric to update these assumptions in future rounds of IGP to reflect the actual approved tariffs. In 2022, the Commission required that the utility conduct modeling to inform incentives for next-generation DER programs, drawing from IGP results, particularly that the two proceedings would use some of the same scenarios.[134] For example, both proceedings used the IGP's base case scenario, a scenario in which DER growth is frozen at current levels, and a high fuel forecast scenario. In both proceedings, the Commission expressly required alignment of inputs and assumptions and aimed to reduce duplicative efforts.

[133] Hawaiian Electric also engages the broader public, technical advisors, and key stakeholders. See: https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-and-community-engagement.

[134] Hawaii Public Utilities Commission Order No. 38754, Docket No. 2019-0323, filed December 8, 2022.

The Hawaii PUC also requires coordination of IGP with other relevant dockets and directed the utility to identify critical interrelationships.[135] In response, Hawaiian Electric described how it planned to integrated its Electrification of Transportation Roadmap with IGP, including use of managed and unmanaged charging profiles.[136] The roadmap informed Hawaiian Electric's light-duty EV forecasts, which were further modified based on Commission requirements, to update the data in conjunction with actual charging data and a case study. Figure 13-4 shows the original and revised hourly profiles for light-duty EVs on Oahu for a representative day in 2026. This

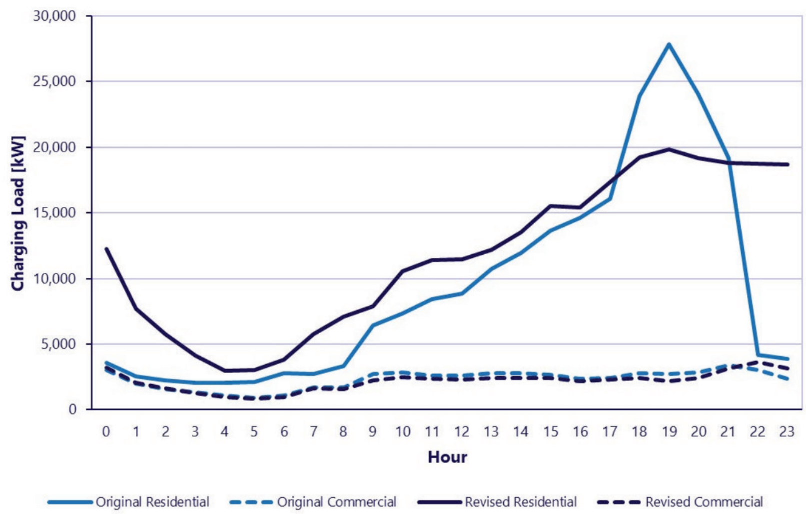

Figure 13-4. Hawaiian Electric EV Charging Profiles, as Revised

Hawaiian Electric's IGP discusses other state goals such as affordability and grid modernization, but these areas are less coordinated in IGP to date. For example, Hawaiian Electric's Final IGP analyzes affordability for typical residential and low-income customers. The analysis shows that typical residential bills are expected to remain relatively flat over the planning horizon, while low-income customers may experience a lower energy burden. Hawaiian Electric also states that the utility's ability to address the reliability and resilience needs in the IGP is dependent on grid modernization investments (addressed in a separate proceeding) that improve distribution operations, such as an advanced distribution management system, cybersecurity monitoring, and field devices like smart reclosers and smart fault current indicators.

13.3.2 Maine

In 2022, Maine enacted an Integrated Grid Planning law that requires large transmission and distribution utilities to file 10-year IGPs. The law specifies multiple areas of coordination across entities, including that the IGP must assess the relationship of the utility's electric system to the regional grid,

135 Hawaii Public Utilities Commission Order No. 36725, Docket No. 2018-0165, filed November 4, 2019.
136 Hawaiian Electric Companies Update to IGP Schedule, Workplan, and Interdependencies with Other Docket, Docket No. 2018-0165, filed May 27, 2020.

incorporate elements of the triennial energy efficiency plan, and incorporate analysis from the state's climate action plan. The law also specifies areas where the plan should consider other state priorities such as greenhouse gas reductions, end-use electrification, DERs and environmental justice.

The Commission issued an order on IGP requirements in July 2024.[137] The Order clarifies that the focus of the proceeding is on distribution system planning because the covered utilities do not own or control generation assets and the Commission does not have jurisdiction over generation or transmission rates. However, the order discusses strategies for coordinating with ISO-New England. Utilities must use the ISO's most recent Capacity, Energy, Loads, and Transmission forecast as the basis for their plans. The annual forecast has a 10-year horizon that considers DER growth and accelerated EV adoption scenarios. Utilities must use this ISO forecast to develop a broad range of modeling scenarios and develop a methodology to disaggregate the forecast from the transmission to the distribution level.

The Commission also requires a narrative description of how each utility's IGP supports achievement of the state's climate goals and specifies planning documents by other entities that can help to inform IGPs. The utilities will file their first IGPs in January 2026.

13.3.3 Indiana

The state's administrative code requires some coordination across planning processes. IRPs must discuss the impacts of distributed generation on load forecasting and generation, transmission, and distribution planning, as well as models used for dynamic simulation of the transmission system, including its interconnectivity with other systems.

For example, Duke Energy Indiana owns generation, transmission and distribution facilities in the state and is part of the Midcontinent ISO (MISO). The utility owns bulk transmission facilities both wholly and jointly with other utilities that have rights to use the system. The utility also is interconnected with seven other local balancing authorities. This landscape means that planning requires significant coordination with many other entities, including through the Reliability*First* Corporation, MISO transmission planning and coordination processes, and meetings and discussions with other entities.[138]

Coordination between the utility and the ISO is critical because of the interdependencies between the two entities regarding load forecasting, capacity needs, rules for DER participation in the wholesale market, and resource adequacy requirements. Additionally, the utility's decisions to purchase generation from the market or invest in its own new resources impacts both transmission and distribution needs.

The utility's transmission requirements are significantly impacted by other entities, in particular when evaluating adequacy for future load growth. The utility uses the same load forecast for transmission

[137] Docket No. 2022-00322: https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2022-00322.
[138] Duke Energy Indiana (2021).

planning as in the rest of the IRP. The forecast considers both rooftop solar and EV growth and incorporates information from a separately approved energy efficiency plan.[139] The utility involves its distribution planning team in the transmission planning process to examine location-specific substation and transformer loading trends and projections. Duke Energy Indiana employs the Reliability*First* Corporation's regional power flow scenarios to ensure that the system will be planned to accommodate expected power transfers.

Duke Energy Indiana's transmission and distribution planning is complex and tightly coordinated with MISO. The utility provides its simulation scenarios and information on its transmission facilities to MISO and participates in MISO's transmission planning and study processes. MISO in turn reviews the utility's proposed plans. The utility states that for its next IRP, it is seeking to improve its consideration of MISO information, such as more granular trade-offs between market purchases and generation investments and MISO resource adequacy constructs.[140]

13.3.4 Washington

Distribution system planning is tightly coordinated with DER planning and IRPs in Washington. The 2019 Clean Energy Transformation Act requires that each electric utility file a Clean Energy Implementation Plan every four years that is consistent with IRP and identifies specific targets for energy efficiency, demand response and renewable energy. The utilities file biennial updates. State law specifies that DERs identified in optional utility DER plans be included in IRPs and that distribution system plans are used as inputs to the IRP. The DER plans in part identify the potential for DERs to serve as NWAs as well as resources for the bulk power system.

The Utilities and Transportation Commission (UTC) also established rules that require IRPs to include DER assessments. These assessments must incorporate energy and non-energy benefits and consider the impact of a variety of DERs on the utility's load and operations. The DER assessments must include conservation, energy efficiency, load management, demand response, DER energy assistance programs, solar, storage and EVs.

The IRP and DER plans also must consider other state priorities such as equity impacts. As implemented by the UTC, utilities must propose to assess and appropriately weight and consider the equitable distribution of customer benefit indicators, such as public health, reduction of burdens, or other non-energy benefits, based on input from an advisory group. Importantly, the state legislature passed the Large Combination Utilities Decarbonization Act in 2024, authorizing the UTC to allow large electric and gas utilities to incorporate these planning requirements into a single integrated system plan.

The UTC's rulemaking process requires streamlining requirements of the Act with previous law, in this case, the Energy Independence Act. The UTC's rulemaking implementing required changes in IRP

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[139] In the IRP, Duke Energy Indiana mentions coordination with its grid modernization plans, which are filed separately. The utility is implementing an integrated volt-var control program that uses devices to optimize voltage on the distribution system. This program is modeled as a resource in the IRP (pages 227–228).

[140] Duke Energy Indiana (2021).

requirements identified overlap with existing reporting requirements and eliminated or consolidated certain requirements. For example, the UTC eliminated semi-annual reporting on distributed generation that included data points such as average system size, system counts, and energy generation in favor of including such information in the IRP process.

Puget Sound Energy (PSE) filed its biennial CEIP update in 2023, including updates to its load forecast, demand-side resource assessment, resource costs and scenarios. The update included forecasts coordinated with other utility plans that reduce the energy efficiency target based on the utility's conservation plan, increased the demand response target by almost fourfold, and kept renewable energy and DER targets relatively the same. The UTC approved the update on March 25, 2024.

In June 2024, the utility issued its Planning Transition Work Plan consistent with the 2024 Act. The work plan bridges the gap between the current planning framework and the upcoming integrated system planning process. The document discusses distribution system investments, including grid modernization advances such as automation tools, electricity capacity upgrades to accommodate EV charging, localized DER grid integration technologies, improved hosting capacity maps and DER siting plans, and targeted pilots to test electrification as an alternative to gas pipelines. PSE filed a request with the UTC on June 5, 2024, to consolidate the next round of IRP and CEIP filings, as allowed by the Large Combination Utilities Decarbonization Act, and PSE anticipates filing its first integrated system plan in 2027.

13.3.5 Minnesota

Minnesota law requires Xcel Energy to file transmission and distribution plans that consider necessary investments for grid modernization, resilience against cyber and physical threats, and energy conservation opportunities. Beginning in 2018,[141] the Commission required regulated utilities to file IDPs that incorporated these requirements and others, including baseline data, hosting capacity information, DER scenario analysis, long-term modernization plans, NWAs, and, more recently, transportation electrification plans (TEPs). Table 13-3 shows how Xcel Energy in Minnesota deploys the same tool or model consistently across multiple phases of the IDP.

[141] Order Approving Integrated Distribution Planning Filing Requirements for Xcel Energy, Docket 18-251, August 30, 2018. For subsequent orders, see https://mn.gov/puc/activities/economic-analysis/planning/idp/.

Table 13-3. Consistent Use of Models and Tools Across Xcel Energy's 2023 IDP

	Planning Process Component						
Tool	Forecast	Risk Analysis	Mitigation Plans	Budget Create	Initiate Construction - EDP Memo	Long-Range Plans	Hosting Capacity
Synergi Electric			X			X	X
LoadSEER	X	X				X	
MS Excel		X		X		X	
CYMCAP		X					
GIS			X			X	X
SCADA	X						
WorkBook		X	X	X	X		
PI Datalink	X						
DRIVE							X

TEP coordination is particularly important in Minnesota, where EV adoption has been growing significantly across the state. The Minnesota Department of Commerce identified that the number of EVs will need to more than double to meet the state's goals to reduce greenhouse gas emissions 50% by 2030 and to net zero by 2050.[142] The Minnesota PUC recognized the importance of coordinating the IDP process with TEP and in 2022 required rate-regulated utilities to combine statutorily required TEPs with IDPs.[143]

The Commission established a number of TEP requirements,[144] including the following:

- Summary of programs, including residential EV charging and fleet and school bus electrification
- Plans for facilitating public charging and awareness of charging availability
- Programs and tariffs to address flexible load, increase charging when renewable energy is available, and reduce metering costs
- Discussion of divestment from fast charging investments over time
- Cost and bill impact data
- Analysis of gaps in fast charging availability, including identification of locations and sizes needed and the utility's role in supporting a cost-effective charging network

[142] Minnesota Department of Commerce – Pollution Control Agency. 2023. Greenhouse Gas Emission in Minnesota 2005-2020. Biennial Report to the Legislature. Greenhouse gas emissions in Minnesota 2005-2020 (state.mn.us).
[143] December 8, 2022, order in Dockets E999/CI-17-879, E002/M-21-694, E015/M-21-390, E017/M-21-612. Also see https://mn.gov/puc/activities/economic-analysis/planning/idp/.
[144] November 1, 2023, Xcel Energy's Integrated Distribution Plan in Docket No. 23-452, available in Minnesota eDockets. See Appendix H1 for a list of requirements and sources.

- Discussion of policy issues related to distribution system upgrades and associated costs
- Breakdown of investments in environmental justice communities

Of particular relevance to integrating multiple planning processes, the Commission required that each utility use the same data and scenarios across its IRP, IDP and TEP and identify any policy issues associated with distribution upgrades for EV programs. In its 2023 IDP, Xcel Energy discusses compliance with this requirement and provides a table showing the consistency of DER forecasts across different tools (Table 13-2). The utility also discusses that it is working toward the Commission's requirement of aligning DER forecasts across IRP and IDP, but that the IRP model updates were not complete in time for the IDP filing. This illustrates a challenge in integrating planning processes that data availability cycles do not always align to ensure perfectly consistent use across proceedings.

Table 13-4. Xcel Energy's alignment of DER forecasts across modeling tools

Forecast	Vintage Reflected in Corporate-Level DER Scenario Modeling	Vintage Used in LoadSEER DER Scenario Modeling
Distributed Solar PV	June 2023	June 2023
Community Solar Gardens	August 2023	August 2023[7]
Distributed Energy Storage	September 2023	2021 IDP
Energy Efficiency	September 2023	Embedded in 2022 Energy Sales & Demand forecast
Demand Response	2022	Embedded in 2022 Energy Sales & Demand forecast
Electric Vehicles	July 2023	2022

The TEP section[145] of Xcel Energy's IDP includes discussion of proactive grid reinforcement projects and possible ways to reduce customer costs for EV programs, such as excluding certain costs in tariffs. For grid reinforcement, the utility identified three major challenges in anticipation of EV growth:

1. The scale and timing of new commercial EV load
2. Non-uniform impacts of new commercial EV load
3. Long and non-uniform lead times for distribution system projects such as feeder and substation capacity upgrades that do not align with shorter lead times for EV projects

The utility indicates that these challenges could delay charging projects, increase costs, result in stranded assets, or result in lost charging opportunities. To help overcome these challenges, the utility is conducting location-specific EV forecasting aligned with scenario planning used in the rest of the IDP and developing pilot programs for EV charging deployment and management. Xcel Energy's IDP filing also discusses challenges with getting approval of proactive distribution system investments in previous general rate cases and decisions in the IDP that will guide future rate case cost recovery.

145 November 1, 2023, Xcel Energy's Integrated Distribution Plan in Docket No. 23-452, available in Minnesota eDockets. See Appendix H.

A briefing paper on the 2023 IDPs discusses whether Xcel's IRP and IDP should be filed on the same schedule to ensure that the utility uses the same inputs and assumptions.[146] While noting its support for procedural and administrative improvements, the utility stated that the two proceedings operate on different planning cycles and cover different planning horizons. PUC staff noted that using consistent methodology is more important. The Commission stated in July 2024 that it would establish a working group on cost allocation and proactive grid upgrades for electrification and DERs. The working group will address how proactive upgrades can be integrated with planned distribution system investments.

13.3.6 Nevada

In 2017 Nevada required that each utility's IRP include a Distributed Resources Plan (DRP). Among other requirements, the DRP must propose ways to coordinate existing programs approved by the Commission and identify any spending necessary to integrate cost-effective DERs into distribution planning.

A 2021 state law required electric utilities to include in IRPs a plan to accelerate transportation electrification. The law requires the Commission to determine if the utility's plan adequately considers whether the proposed investments, incentives, and rate designs improve system efficiency and flexibility, utilize energy at off-peak hours and integrate renewable energy, further private investment in transportation electrification infrastructure in the state, increase the demand for skilled labor, improve education on transportation electrification, and provide value to customers, among other things.

NV Energy filed its first TEP in its 2022 IRP. The utility proposed numerous residential and commercial EV programs and four grid integration programs. The grid integration programs included tariffs, managed charging, systems development, and building codes programs. In 2023, regulators approved three EV programs that had the most evidentiary support related to legislative requirements, citing advancement of customer choice and increasing access to electricity as a fuel. The Commission did not approve the proposed grid integration programs. The Commission anticipated that additional data and information would inform the next TEP, to be filed in conjunction with the combined IRP and DRP.

In 2024, NV Energy filed a triennial IRP that includes a DRP, demand-side plan, and renewable energy and transmission plan.[147] The IRP included a third-party DER market potential study and model dispatchable behind-the-meter load programs for demand response and transportation electrification. The IRP proposes small-scale solar and storage programs to serve as NWAs and support community solar programs. The DRP highlights ways that NV Energy is integrating its organizational activities in light of the energy transition, including harmonizing analytical toolsets for DER valuation and modeling, using technology to integrate DERs into system operations, and creating an Integrated Energy Services

[146] Terwilliger, H., A. Northagen, and T. Dornfeld. 2024. *Staff Briefing Papers*. Docket No. E111/M-23-420; E015/M-23-258; E017/M-23-380; E002/M-23-452. Filed June 20, 2024.
[147] Docket No. 24-05041, filed on May 31, 2024.

department that covers energy efficiency, demand response, clean energy, transportation electrification, and integrated grid planning in order to increase coordination across these areas. The utility files quarterly metrics on transportation electrification, including charging locations, incentives, equitable deployment, number of users, charger uptime and outages, total and time-varying kilowatt-hour usage, charging session time, truck rolls, costs, workforce development, third-party investment and other data.

13.3.7 Colorado

The state's policy goals drive multiple utility planning processes. The alignment in desired outcomes results in the need for coordination across DSP and other plans, such as electrification and DER plans, although these plans are filed separately.

A 2019 law required the Commission to establish rules for DSPs for qualifying retail utilities. The Commission adopted rules in 2021. The utility's plan must describe how energy efficiency, other DERs, and beneficial and other electrification will impact the distribution grid over a 5- and 10-year horizon. Plans also must use the grid needs assessment portion of the DSP to identify where there is sufficient hosting capacity available for EV fast charging equipment and whether vehicle-to-grid programs could serve as NWAs. Utilities may seek cost recovery for transportation electrification planning in their DSP filings.

Public Service Company of Colorado (Xcel Energy) filed its first DSP in 2022, noting the importance of the distribution system to achieving the utility's and state's decarbonization goals.[148] In particular, the company noted that forward-thinking investments to support electrification are important to achieving net zero emissions. The Commission approved a settlement for the DSP in 2023, including a recommendation that the Commission open a proceeding to explore DER and beneficial electrification policy issues. Figures 13-5 and 13-6 show that integration of the DSP with other utility planning processes is fundamental.

[148] May 2, 2022. Public Service of Colorado – DSP Application. Docket No. 22A-0189E. Available at Colorado Public Utilities Commission E-Filings.

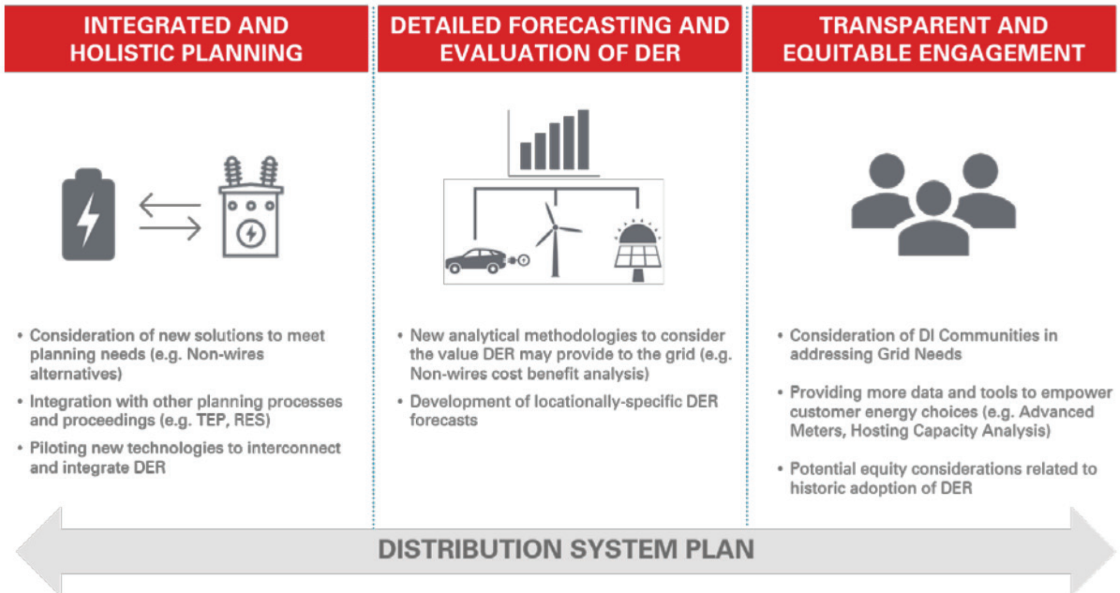

Figure 13-5. Major Themes Included in Public Service Company of Colorado's First DSP[149]

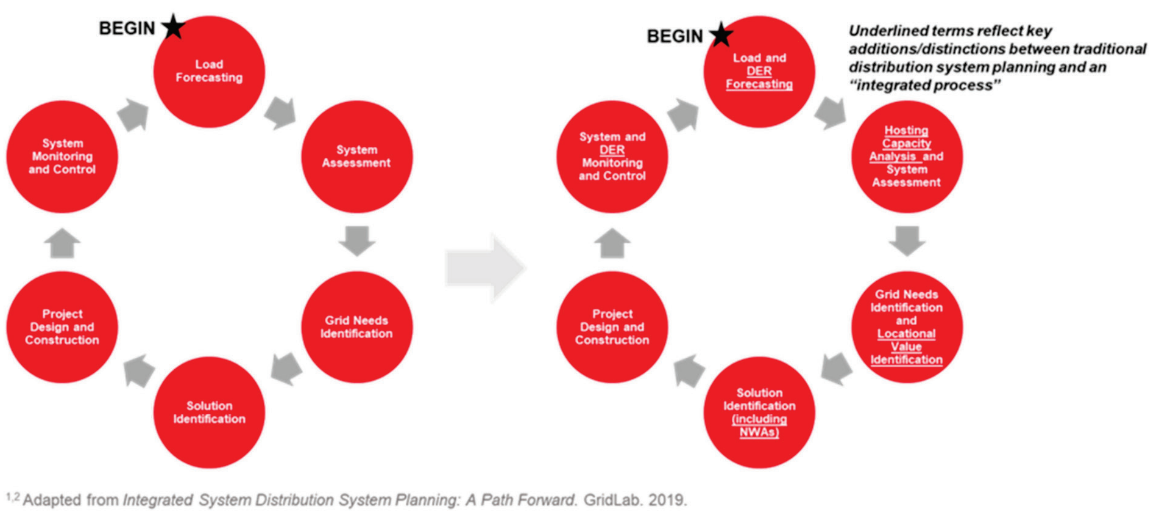

Figure 13-6. Public Service Company of Colorado's Approach to IDSP

In particular, Xcel Energy states that the expansion of DERs and electrification require that the distribution system is:

- designed to a modern standard;
- robust enough to maintain voltage at the proper level;

149 Previously undefined acronyms in the figure: RES - renewable electricity standard; DI - disproportionately impacted. May 2, 2022. Public Service of Colorado – DSP Application. Docket No. 22A-0189E. Available at Colorado Public Utilities Commission E-Filings.

- able to carry required energy; and
- equipped with relay protection schemes as DERs place additional strain on aging facilities.

To increase the plan's transparency and coordination, the DSP includes granular DER forecasts at the feeder level and provides an analysis of eight EV pilots, included in a separate TEP. These pilots align with the DSP's objectives to improve system performance, integrate DERs, minimize system costs, increase system reliability and resilience, and reduce greenhouse gas emissions and renewable energy curtailment.

The Colorado PUC also is undertaking Clean Heat Planning for regulated gas distribution utilities. Xcel Energy, which provides both gas and electric service in the state, filed its first Clean Heat Plan in 2023. The plan included coordination on demonstration projects with state agencies, tribes and local governments. The plan focuses heavily on electrification (Figure 13-7) and will require significant coordination with electric DSP.

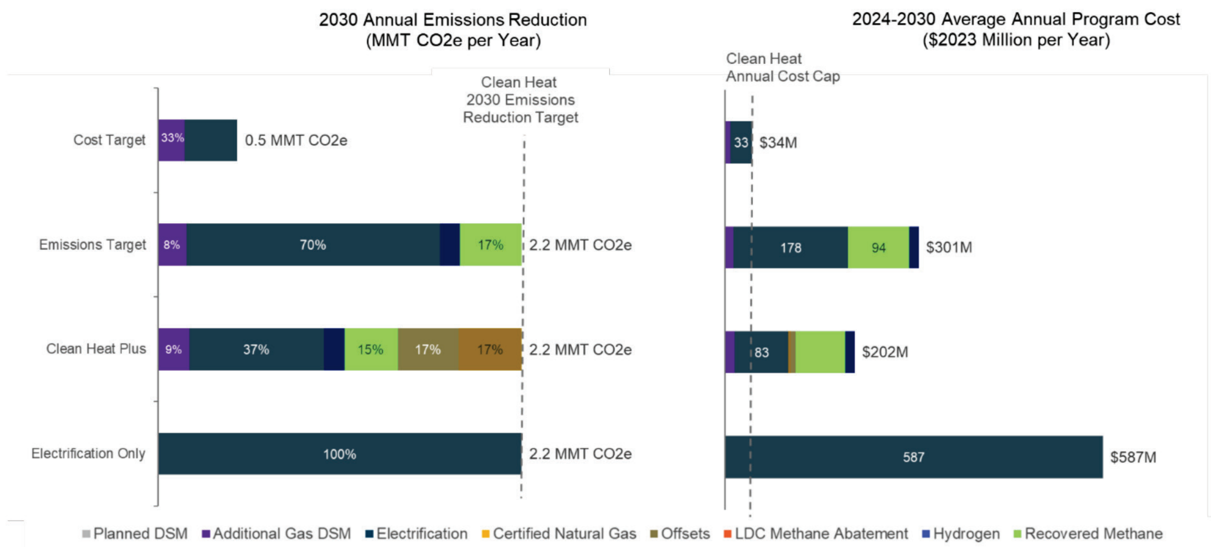

Figure 13-7. Xcel Colorado's Portfolio for Clean Heat Plan Programs

13.3.8 Vermont

The state's regulated electric utilities are required to submit a proposed IRP every three years. The Vermont Department of Public Service provided guidance for developing IRPs, including required elements of transmission and distribution system planning. The guidance highlights the importance of coordinated planning by emphasizing guidance such as the following:

- *Each distribution utility's IRP should describe the process undertaken to facilitate inter-utility coordination relative to transmission planning.*
- *Each distribution utility's IRP should describe the actions taken [to] facilitate inter-utility coordination relative to sub-transmission planning.*

- *The utility's IRP should describe the efforts undertaken to ensure coordination with relevant telephone and cable companies relative to transmission and distribution planning.*
- *An IRP should describe efforts taken to ensure coordination with relevant stakeholders regarding roadside relocation of distribution lines.*

The guidance also emphasizes the impact of coordination on minimizing the visual impacts of distribution lines on the state's scenic landscape. Utilities are directed to work with external stakeholders such as the Department of Forests, Parks and Recreation, Agency of Transportation, local governments, and others to improve the aesthetics of their infrastructure. The guidance also requires coordination with the Department of Forests, Parks and Recreation, other utilities, and the public on vegetation management, resilience and physical and cybersecurity, and public notifications and coordination with other utilities on emergency preparedness and response.

Green Mountain Power's 2021 IRP includes some, but not all of this information, as the Commission's guidance came out following that plan submission. The 2021 IRP includes an integrated vegetation management plan and discusses the physical security of the grid, including information about substations that are in FEMA-designated floodplains. The utility will submit its next IRP in December 2024.

13.4 Best Practices

States that are initiating or modifying distribution system planning requirements can consider lessons learned and emerging practices in other states with respect to coordinated planning:

- Ensure use of consistent datasets, inputs and outputs across planning processes to improve transparency and facilitate participant engagement.
- Establish consistent, meaningful and streamlined opportunities for input from stakeholders with varied areas of expertise and demonstrate how that input has impacted plans and decision-making.
- Consider timing requirements across planning processes and sequence planning processes appropriately, including by limiting or coordinating working group processes to ensure participants have adequate bandwidth to effectively engage with the material and to maintain momentum in their ability and desire to participate.
- Prioritize integration of plans that are most closely aligned and that are more mature over more nascent plans, to maximize the benefits of coordination and to ensure adequate depth of analysis on newer plans.
- When establishing new reporting requirements, assess whether there is opportunity to eliminate, modify or consolidate existing reporting requirements.
- Develop metrics at the outset to determine whether integration across planning processes has delivered on the intended benefits and met the desired outcomes.

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