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Effectively Considering the Distribution System in Integrated Resource Plans

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Table of Contents

List of Figures

List of Tables

Acronyms and Abbreviations

BPS	**Bulk power system**
CEM	Capacity expansion model
DER	Distributed energy resource
DOE	Department of Energy
DSP	Distribution system plan
FERC	Federal Energy Regulatory Commission
GER	Grid-edge resource (also called DER)
HCA	Hosting capacity analysis
IRP	Integrated resource plan
ISO	Independent system operator
ISP	Integrated system planning
MW	Megawatt
PSC	Public Service Commission
PUC	Public Utility Commission
RTO	Regional transmission organization
T&D	Transmission and distribution

Executive Summary

Distribution spending by investor-owned utilities (IOUs) grew nationally by 6% per year since 2014 — four times faster than the prior two decades — and many utilities are planning for significantly higher spending through 2030.[1] Costs for generation and transmission also are increasing significantly.[2] Utilities across the country have for decades filed integrated resource plans (IRPs) for bulk power system assets, but there has been less visibility into distribution system spending. By considering certain aspects of the distribution system, IRPs can provide greater insight into how planned expenditures at the distribution level could cost-effectively serve both local grid and bulk power system needs.

This report aims to support public utility commissions (PUCs), utilities, State Energy Offices, state utility consumer offices, and other stakeholders to improve electric utility planning processes by identifying a range of tactical approaches to consider distribution system planning (DSP) elements in IRP to meet electricity needs at least cost.

States and utilities across the country, with varying regulatory and market frameworks, are taking meaningful steps to integrate distribution system elements in IRP, aiming to optimize grid investments, reduce utility costs and customer bills, and improve plan transparency and credibility. IRP also can serve as a vehicle for elevating the most impactful elements of distribution planning for stakeholder review and input, particularly in jurisdictions without DSP filing requirements that make that information publicly available.

While IRP and DSP address different levels of the electricity system and use different planning techniques, there are key linkages between the two types of plans:

- Using consistent forecasts, including for loads, grid-edge resources (GERs),[3] and other variables to plan for a unified vision of the future
- Assessing whether distribution system resources can help serve bulk power system needs at lower cost and, at the same time, considering local grid benefits
- Analyzing the capability of the distribution system to accommodate GERs identified as least-cost resources in IRP.

Implementing these practices requires more sophisticated analyses; communication between utility planners, the PUC, and stakeholders; and the utility's commitment to change management to support staff implementing new planning techniques. The following table summarizes leading practices to help overcome these challenges and realize the potential value of considering distribution system elements in IRP.[4]

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[1] Wiser et al., 2026a.
[2] Wiser et al., 2026b.
[3] Also called distributed energy resources.
[4] The Conclusions section of the report includes an expanded checklist tool that utilities, PUCs, and stakeholders can use to assess and improve current practices.

Regulatory & Institutional Alignment
☑ Develop regulatory frameworks for integrated or coordinated system planning
☑ Align utility regulatory guidance for IRP and distribution system planning (e.g., specify expectations for consistent forecasts and scenarios)
☑ Develop a roadmap to improve practices over time and establish a common vision
Aligned Timelines & Horizons
☑ Sequence planning cycles so distribution insights (e.g., available hosting capacity) feed into IRP decisions on time, and vice versa (e.g., quantity of GERs selected in IRP)
Stakeholder Engagement & Transparency
☑ Share scenarios, assumptions, and results openly with PUCs and stakeholders to solicit input on consistency
☑ Incorporate stakeholder input from various forums into unified forecast assumptions, scenario design, and review processes
Common Data & Assumptions
☑ Establish unified methodologies, associated load and GER forecasts, and adoption scenarios across IRP and distribution planning
☑ Maintain a unified integrated data set in an accessible repository for sharing inputs and results
Disaggregated Distribution Forecasting
☑ Align IRP and feeder and substation-level distribution forecasts through a reconciliation method to capture both local and bulk system needs
Hosting Capacity & Deliverability
☑ Assess results of hosting capacity and GER deliverability studies in the IRP process to determine whether pathways exist for GERs to deliver services identified in IRP
☑ Publish hosting capacity maps/tools to guide developer siting decisions for procurements coming out of IRPs
Convergent vs. Divergent Value Analysis
☑ Screen all eligible identified electricity system needs for cost-effective non-wires alternatives
☑ Identify when, where, and how GERs provide simultaneous (convergent) benefits to bulk power and distribution needs and evaluate these potential solutions in more detail
☑ Flag cases where GERs help one level of the electricity system but not the other (divergent) and determine possible mitigations
Bulk Power & Distribution System Resource Co-Optimization
☑ Use technology-neutral procurements
☑ Include GERs as a selectable resource in IRPs and use technology-neutral methodologies for performance accreditation to allow GERs to contribute to resource adequacy assessments
☑ Incorporate findings from coordinated planning into procurement processes and validate planning assumptions for cost and performance based on procurements

1. Introduction

Electric utilities plan their systems to reliably and safely meet future needs at least cost and risk, considering uncertainties. With significant projected load growth, aging infrastructure, rapid technological advances, and increasingly severe and frequent weather events, effective planning is critical to guide utility decision-making for cost-effective investments to meet planning criteria and objectives.

Electricity planning is evolving. Utilities have long used planning frameworks developed for a power system characterized by relatively predictable demand, centralized generation, and one-way power flows. Today's grid is more dynamic. It must serve rapidly growing residential, commercial and industrial loads, new types of large loads such as data centers, accommodate growing shares of GERs such as storage,[5] and maintain reliability as electricity system assets age. Planning processes are adapting to capture the spatial, temporal, and operational complexity of evolving electricity systems.

Planning processes vary based on the type of utility and market structure in which they operate. IRP, conducted largely by vertically integrated utilities, is a "roadmap for meeting forecasted electricity demand over a specified future period, historically focused on the bulk power system [BPS]."[6] Distribution system planning (DSP) "focuses on designing, managing, and maintaining lower-voltage networks that connect end users to the larger power system."[7]

In most jurisdictions, IRP and DSP are conducted separately, on different timelines, and with distinct methods, tools, assumptions, and regulatory requirements. Increasingly, utilities and states recognize that coordinated planning across bulk power and distribution systems produces more robust and useful plans.[8] Consideration of DSP elements within IRP is growing in importance for several reasons — increased siting of distributed generation and storage co-located with loads, significant investments to manage existing distribution systems (asset replacement, safety, reliability, and resilience), and expanded bulk and distribution level capacity needs to address the impacts of economic growth, including large new loads.[9] This report details how considering distribution system elements in IRP provides value to utilities and regulatory processes. Based on a review of a variety of utility approaches, the report offers a range of actions to take to realize that value.

1.1 Study Motivation and Scope

U.S. utilities are responding to rapid changes in electricity systems, including loads that are

[5] GERs are assets, such as gas generators, solar, wind, and energy storage, sited close to utility customers that can provide all or some of their immediate power needs and reduce demand or provide supply to satisfy the energy, capacity, or ancillary service needs (adapted from National Association of Regulatory Utility Commissioners [NARUC], 2016).
[6] Biewald et al., 2024.
[7] Energy Systems Integration Group (ESIG), 2025.
[8] See additional resources at https://www.naruc.org/committees/task-forces-working-groups/retired-task-forces/task-force-on-comprehensive-electricity-planning/resources-for-action/; NARUC – National Association of State Energy Officials (NASEO), 2021a; NARUC-NASEO, ND.
[9] Wiser et al., 2026a.

growing at rates not seen in decades,[10] increased risk from severe weather, and growing customer technology adoption. At the same time, utility investments are facing increased scrutiny from PUCs, customers, and other stakeholders to keep electricity rates in check. Planning processes lie squarely at this intersection by providing visibility into how utilities expect to meet future needs at least-cost, considering various constraints, risks, and uncertainties.

Incorporating elements of DSP in IRP can improve utility planning outcomes, including electricity affordability and reliability. Coordination across the planning domains can enable utilities to better anticipate localized load growth, evaluate bulk system impacts of distribution-level assets, improve valuation and utilization of GERs, and optimize electricity system investments. Robust least-cost planning requires consideration of all system needs to build a system that achieves multiple objectives.

IRP is a prominent and well-established utility planning process that also can serve as a vehicle for elevating the most impactful elements of distribution planning for stakeholder review and input, including:

- Administrative and process coordination
- Load and GER forecasting
- Scenario and sensitivity analysis
- Distribution grid optimization (i.e., improving load factor — the ratio of average load to peak load — and effective GER utilization and integration)
- Integrated system analysis.

However, coordinating bulk power and distribution system planning is an emerging area and complex exercise. Utilities and PUCs need more tangible information on the value of investing in planning coordination and how to begin or improve this practice. They also can consider issues that may arise when planning processes are not coordinated. For example, IRP may identify distributed generation co-located with loads as part of the utility's preferred resource portfolio without considering the cost of distribution system upgrades that may be needed. Conversely, IRP models may not consider potential local grid benefits of distributed generation and storage and fail to select cost-effective resources connected to distribution systems.

Effective tactics for considering distribution planning elements in IRP are adaptable to diverse regulatory frameworks, electricity market structures, available energy resources, state and utility objectives, and existing planning practices across the country.[11] This report aims to help PUCs, utilities, and stakeholders identify where coordination provides the greatest value and what approaches are most feasible in particular contexts.

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[10] Wiser et al., 2026b.

[11] For example, Salt River Project (SRP) is not regulated by a public utility commission but conducts integrated system planning. See a detailed case study on SRP here: https://eta.lbl.gov/publications/effectively-considering-distribution.

While all jurisdictions can benefit from improved planning coordination, the value of integrating distribution planning elements in IRP is particularly strong where:

- Utilities do not have formal DSP requirements and can integrate key DSP elements into the IRP to fill gaps.
- The jurisdiction requires both IRP and DSP filings, but may benefit from improved coordination, such as through structured data exchange, shared scenarios and assumptions, and iterative modeling approaches.
- Utilities are experiencing rapid growth in loads or GERs, or both, and can use integrated planning to effectively align electricity infrastructure investments with changing customer demands and contributions.
- Jurisdictions are seeking methods to identify more holistic and optimized investment strategies.

Some utilities are moving towards an Integrated System Planning (ISP) approach that considers generation, transmission, distribution, and customer resources and needs together. Other utilities conduct IRP and DSP separately, then coordinate the processes by feeding information back and forth across proceedings.[12]

Because the report addresses ways to incorporate distribution planning elements in IRP, it may be most immediately applicable to jurisdictions that have oversight over both distribution and bulk power systems — those with vertically integrated utilities. However, the information is also relevant for entities with some authority over bulk system planning, those that coordinate various plans across stakeholders, and those that incorporate the results of IRPs in other plans, such as wholesale market operators.[13]

Integrated

IRP and DSP are conducted as part of the same planning process, or DSP is substantively embedded within IRP processes

Coordinated

IRP and DSP are conducted separately, with key bridges between each process

This research does not cover transmission planning as a standalone process; it considers transmission planning only to the extent that it is included within an IRP.[14] IRPs can consider transmission needs and solutions in multiple ways. Utility modelers can represent transmission as a static system that creates practical limitations on generation siting and operations, or

[12] Detailed case studies accompanying this report provide examples of both types of planning approaches.
[13] This report does not focus on restructured markets, but readers may draw on the diverse examples provided throughout, including New York's Coordinated Grid Planning process discussed in section 3.4.2 and the Vermont case study available here, to assess similarities and differences in approaches and how they may apply.
[14] Transmission planning is performed at various levels, from a single utility to regional and interregional planning involving federal regulation and, in some areas, Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs).

capacity expansion models may include transmission projects as investment candidates to help identify the optimal future transmission system design in consideration of generation needs.[15]

1.2 Methodology

Lawrence Berkeley National Laboratory used a variety of methods to identify states and utilities that are incorporating DSP elements in IRP processes, delineate common and leading practices, and describe information gaps, challenges, and tactics to achieve desired planning outcomes.

The authors identified a list of foundational contributions to the field, including academic research, industry white papers, reports, and other documents (Appendix B). A resulting annotated bibliography synthesized findings to identify common challenges and assess early examples of coordinated or integrated planning across electricity system domains. Findings informed questions for subject matter expert interviews (Appendix C) and helped identify key case studies.[16]

Researchers also reviewed relevant state regulatory requirements and utility IRP and DSP filings to assess implementation of planning coordination across multiple jurisdictions, selected to capture a range of planning maturity and regulatory environments. The analysis focused on identifying:

- Formal requirements or guidance for IRP–DSP coordination (e.g., statutory language, commission orders, or regulatory rules)
- Shared analytical components between IRPs and DSPs, including load forecasting, scenario development, GER valuation, and need assessments
- Evidence of feedback loops — how distribution-level insights are used to inform resource planning, and vice versa.

Research also included semi-structured interviews with representatives of utilities, PUCs, and industry organizations. Interviews gathered practitioner perspectives on the current state of IRP–DSP coordination, including organizational processes, technical integration, data sharing, and regulatory drivers or constraints. Interviews augmented literature review findings, informed case study development, and supported analysis of regulatory documents and utility filings. Leveraging all of these findings, the report provides tactics to support utilities and PUCs pursuing integration of distribution planning elements in resource planning for bulk power systems.

1.3 Utility Planning Processes

In order to understand how to better consider elements of DSP as part of IRP or other long-term planning for bulk power systems, it is helpful to have a foundational understanding of the objectives and methods of IRP and similarities, differences, and key touchpoints with DSP.

[15] ESIG, 2025.
[16] Case studies are available at https://eta.lbl.gov/publications/effectively-considering-distribution.

IRP has been the core mechanism for long-term decision-making by vertically integrated utilities for the bulk power system, guiding utility resource investments to meet projected system needs. The typical planning horizon is 10 to 20 years. In some jurisdictions, it is longer.[17]

DSP typically addresses reliability and capacity expansion needs for the local delivery grid. Planning encompasses immediate operational needs, short-term action planning, near-term asset investment decisions, and longer-term capital planning up to 10 years into the future (Figure 1).

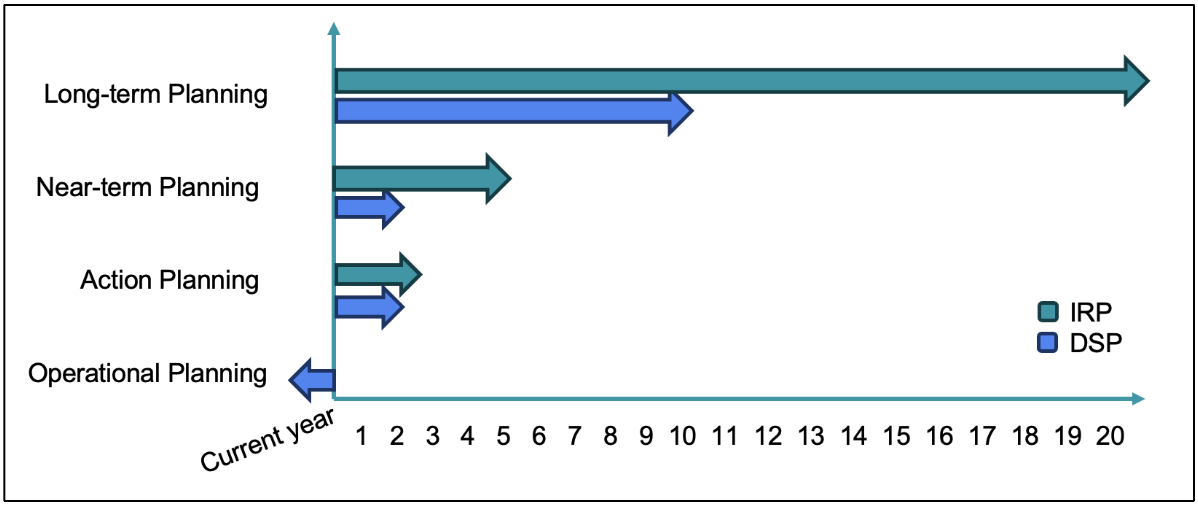

Figure 1. IRP and DSP Planning Horizons (Sources: Adapted and expanded from U.S. DOE, 2020, and Biewald et al., 2024)

These planning processes have historically operated in isolation given the significant differences in how the BPS and distribution systems function. The BPS is electrically connected to the distribution system at substations, where electricity is stepped down in voltage by transformers and delivered to customer premises via distribution system equipment. This interface was originally designed only for one-way power flows, from utility-scale generation to customers, but increasingly experiences bi-directional flows from generation and storage connected to distribution systems. Growth of such GERs, new and rapidly growing customer loads, and technological advancements have created an increasingly two-way and dynamic grid wherein distribution-level insights about load growth, distribution system hosting capacity[18] for loads and local generation, and grid reliability inform long-term bulk resource choices. Conversely, decisions made at the bulk system level can affect distribution system operations and investments. These trends have blurred the lines between planning domains and led PUCs and utilities to pursue coordinated planning approaches.[19]

[17] Biewald et al., 2024.
[18] Hosting capacity determines the amount of load or GERs that can interconnect at a specific point on the grid without infrastructure upgrades or adversely impacting power quality or reliability under existing control and protection systems.
[19] ESIG, 2025.

Some jurisdictions and utilities are going beyond coordination by pursuing ISP. While ISP is still relatively uncommon, its emergence reflects a recognition that siloed planning processes are not the best way to address emerging energy system challenges.[20]

1.3.1 IRP Overview

IRP identifies least-cost, least-risk portfolios of resources to meet projected bulk system needs. The objective is to evaluate plausible futures for the utility system, identify portfolios that can meet demand reliably and affordably, and provide PUCs and stakeholders with transparent information on costs, risks, and trade-offs.[21] Today, most regulated utilities are required to file IRPs regularly with state commissions, typically every 3–5 years (Figure 2).[22] IRP employs a variety of analyses and a suite of modeling tools (Figure 3).

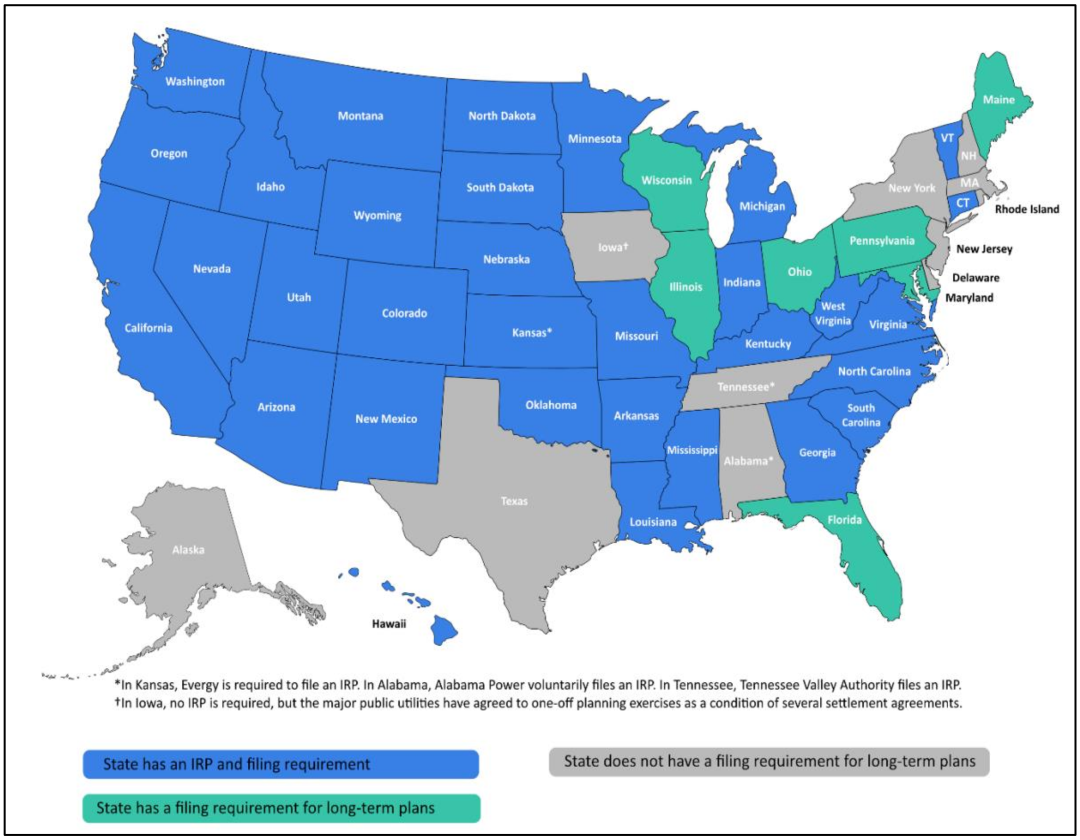

Figure 2. States with Integrated Resource Planning or Similar Processes (as of November 2024) (Biewald et al. 2024)[23]

[20] Burdick et al., 2024.
[21] Biewald et al., 2024.
[22] Ibid.
[23] Alaska recently adopted a multi-utility IRP requirement. New York requires a Coordinated Grid Planning Process that could be considered a form of bulk system planning.

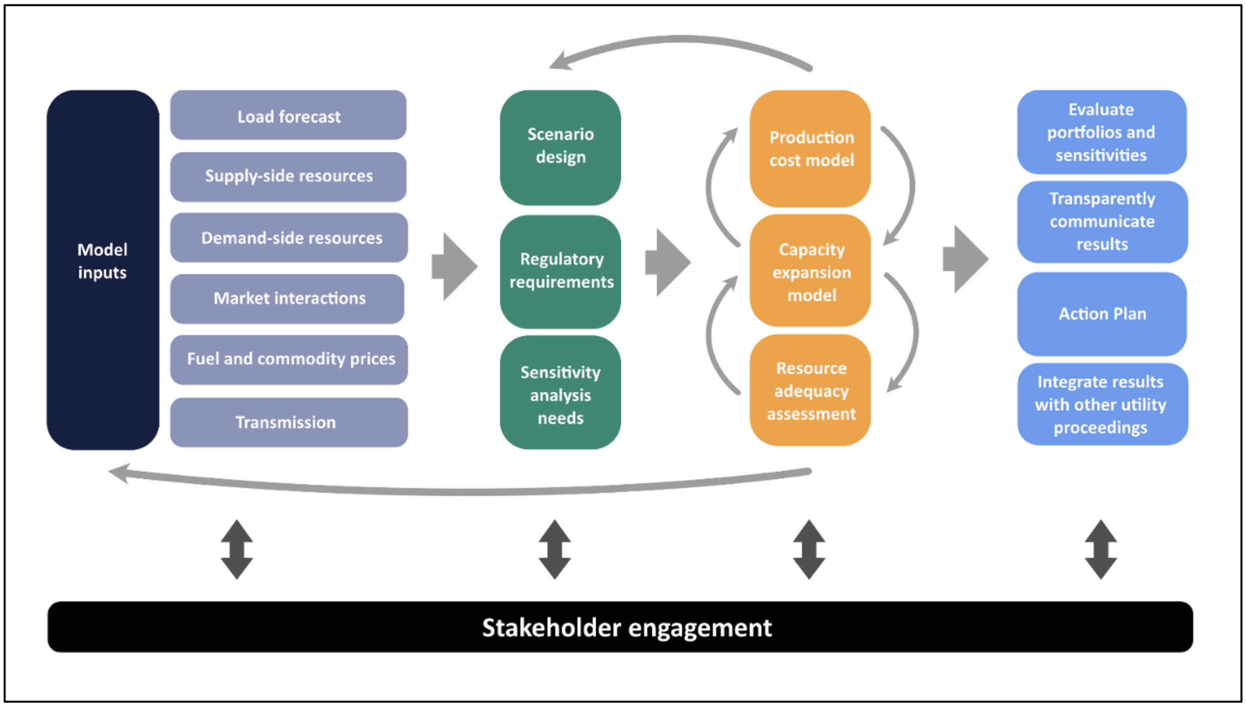

Figure 3. Typical IRP Process (Biewald et al., 2024)

IRP analyses typically include the following processes.

- **Load forecasting:** Load forecasting is the foundation for IRP, serving as an input to production cost, capacity expansion, and resource adequacy assessments. IRP load forecasts are typically done at the zonal level (aggregated to system level), and assess peak demand and energy use by customer segment (e.g., residential, commercial, industrial). Leading practices include forecasting locational GER adoption, hourly GER and load flexibility shapes, and planning for large load growth such as data centers (also called "spot loads").[24]
- **Capacity expansion modeling:** Portfolio optimization models that minimize system costs (capital, fixed and variable operations and maintenance [O&M], fuel) to meet future needs. They determine optimal portfolios of utility-scale generation, storage, and sometimes selected GERs and transmission. These models usually develop portfolios for a 10-20 year period (and in some cases, a longer timeframe), with snapshots of representative intervals or full annual chronological runs. Outputs include investment and retirement decisions, long-term resource mixes, cost projections, and other metrics aligned with planning objectives.[25]
- **Production cost modeling:** Also known as unit commitment and economic dispatch, production cost models simulate chronological system operations at hourly or sub-hourly intervals. They optimize resource (generation and storage) dispatch, unit commitment, and ancillary service provision, minimizing system costs (fuel, O&M,

[24] Biewald et al., 2024.
[25] ESIG, 2025.

startup/shutdown) to meet demand. Outputs include dispatch schedules, locational marginal prices, production and operating costs, congestion patterns, and system operational performance metrics. Together, capacity expansion and production cost models provide cost and unit commitment information for planners to align investment strategies with future operations.

- **Resource adequacy assessment models:** These probabilistic models evaluate the likelihood that the system can balance supply and demand and produce modeling runs across a wide range of weather and operational conditions. This results in thousands of years of simulated operations to calculate resource adequacy metrics, typically using capacity expansion model portfolios as inputs. Outputs include loss-of-load expectation, expected unserved energy, loss-of-load hours, and characterizations of resource adequacy risk periods.
- **Risk and sensitivity analyses:** These analyses stress-test portfolio robustness across uncertain futures such as load growth rates, fuel prices, weather-driven variability, GER adoption, and potential changes in regulations. Outputs include ranges of system costs, identification of common investments across scenarios (least-regret actions), and reliability outcomes.[26]

IRP filings typically include a preferred resource portfolio and alternative portfolios, along with associated cost, reliability projections, and other metrics. Many jurisdictions require an action plan, which translates the long-term resource strategy into concrete near-term steps such as procurement schedules, specific requests for proposals, and program designs.[27,28]

Bulk Power Resource Procurement

Procurement translates the utility's preferred IRP portfolio into actual investments. The IRP informs the general type, quantity, and timing of resources needed, while procurement decisions typically occur separately and follow their own requirements. However, explicit alignment between planning and procurement contributes to solicitations that are directly tied to validated IRP assumptions and system needs (Biewald et al., 2024).

Procurement can be a key bridge between IRP and DSP, because it is the mechanism through which utilities acquire solutions capable of meeting electricity system needs at the bulk power or distribution system level (Kahrl and Schwartz, 2021).

1.3.2 IRP and DSP Similarities and Differences

IRPs emerged in the late 1970s and 1980s.[29] DSP filing requirements began far more recently, starting in 2013.[30] While adoption is growing rapidly, fewer states require regulated utilities to file DSPs compared to IRPs.

[26] Ibid.
[27] Ibid.
[28] Wilson and Biewald, 2013.
[29] Kahrl et al., 2016.
[30] Homer et al., 2017.

Historically, distribution planning focused narrowly on forecasting demand growth and identifying upgrades for grid assets such as feeders, service transformers, and substations to maintain reliability. Today, however, DSP has expanded in many jurisdictions into a more complex, transparent, and participatory process that may address grid modernization (e.g., a technology enablement roadmap), resilience, and coordination with bulk system planning or other planning processes.[31]

Still, distribution planning varies in scope, sophistication, and name across the country. For example, Transmission and Distribution (T&D) Improvement Plans are a type of DSP focused narrowly on near-term investments to meet reliability needs, with expedited cost recovery for approved elements. On the other end of the spectrum, integrated distribution planning uses a systematic approach to satisfy customer service expectations and state and utility objectives for grid reliability, resilience, safety, operational efficiency, and GER integration and utilization. Appendix A provides additional details on current DSP practices. Twenty-two states, Puerto Rico, and the District of Columbia require regulated utilities to file some type of distribution system plan (Figure 4).[32]

Figure 4. State DSP Planning Practices (LBNL, 2026)

Table 1 summarizes key differences between DSP and IRP. While they have steps and analyses in common, these planning processes are designed to answer different questions, and many modeling tools and methodologies differ.

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[31] Schwartz et al., 2024.
[32] See LBNL's online catalog of [State Electric Distribution System Planning Practices](#).

Table 1. Comparison of IRP and DSP Processes

Element	IRP	DSP
Question answered	What is the least-cost, least-risk mix of resources needed to meet long-term electricity demand?	What investments and other actions are necessary for the utility to design, maintain, and manage the low-voltage network to maintain deliverability and reliability?
Filing frequency	Every 3-5 years	Every 2-5 years
Planning Horizon	10-20+ years	5-10 years
Load Forecasting	Aggregated system-level (or zonal) demand by customer segment for each hour of the year	Localized, disaggregated peak loads — up to 8,760 hourly forecasts
Common Modeling Approaches	● Capacity expansion models ● Resource adequacy models ● Production cost models	● Power flow simulations ● Short-circuit / fault modeling
Typical Plan Outputs	● Load/resource balance ● Preferred resource portfolio* ● Near-term action plan ● Alternative resource portfolios ● System costs ● Resource adequacy metrics focused on long-term reliability	● Grid needs assessment ● Near-term action plan ● Long-term capital plan ● Day-to-day reliability metrics such as system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI)
Other Differences	● More commonly uses scenario analysis ● Relatively more agnostic to resource locations, subject to transmission constraints ● Formal filing requirements are common	● Scenario analysis is an emerging practice ● Focused on location-specific needs ● While formal filing requirements for regulated utilities are growing, they are less common compared to IRP

*The preferred resource plan also could be considered a long-term capital plan. IRP and DSP use different terminology for final outputs and cover different time horizons.

2. The Value Proposition for Incorporating Distribution Planning Elements in IRP

Utility distribution system investments are rising in many regions, driving rate increases (Figure 5 and Figure 6) at a time when affordability is top of mind.

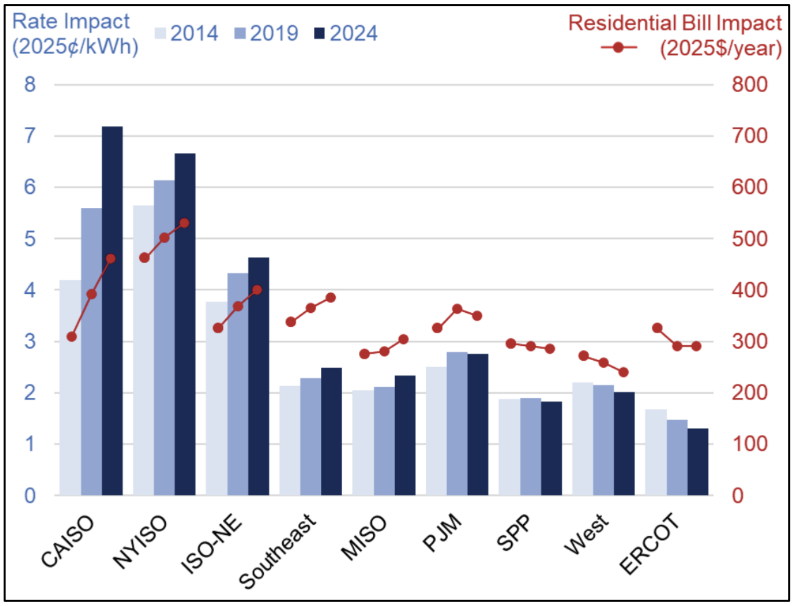

Figure 5. Approximate Rate and Bill Impacts of Distribution Costs (Wiser et al., 2026a)[33]

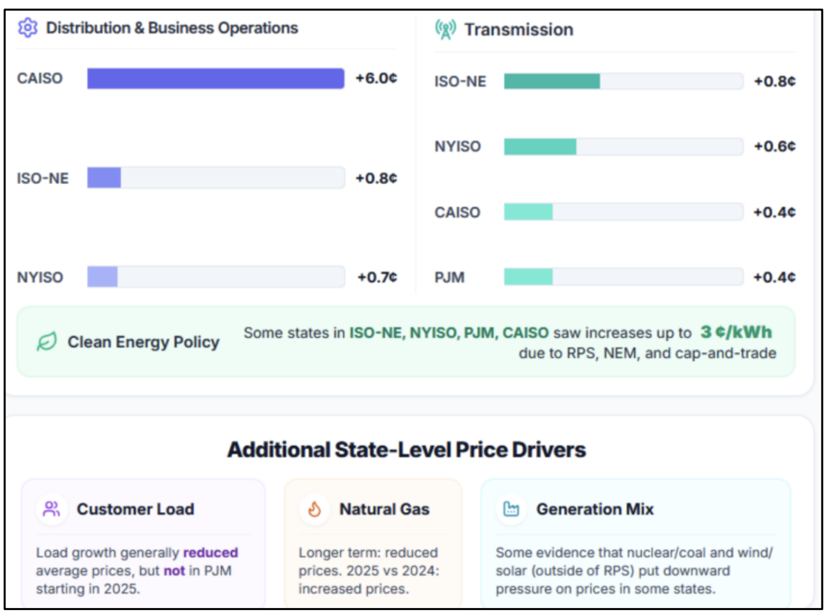

Figure 6. Primary Drivers of Inflation-Adjusted Price Increases, 2019-2025 (Wiser et al., 2026b)

[33] Values are 3-year rolling averages. Estimates are rough approximations of rate impacts. Includes distribution CapEx and infrastructure-related O&M; business operations, insurance, billing and other functions that may be allocated to "distribution" are not included.

These trends have led to a paradigm shift for DSP at some utilities and PUCs, extending beyond an engineering- and reliability-focused exercise. Interviews for this study revealed that in jurisdictions where utilities are subject to least-cost planning statutes, bulk power system planners increasingly are looking at the distribution system for potential resource solutions. In other cases, PUCs and stakeholders are driving forces, requesting greater DSP visibility.

In addition, distribution-connected resources influence the type, timing, and amount of bulk system resources needed. This increasingly requires consideration of distribution planning elements in IRP.

2.1 Benefits of Incorporating Distribution Planning Elements in IRP

Coordinating across various types of electric planning processes can create numerous benefits:[34]

- Harmonized plan results and reduced conflicts between separate plans through use of consistent inputs and methods[35]
- More accurate identification of grid needs by capturing all relevant factors that may influence the system
- Cost savings realized by reconciling forecasts to more accurately assess investment needs and all possible alternatives to meet them
- Increased understanding, transparency, and credibility of plan results
- Higher quality information provided to planners and decisions makers if stakeholder engagement is coordinated across different planning processes
- Administrative efficiencies realized by applying knowledge from multiple planning processes across workstreams.

Assessing the benefits of integration specifically between IRP and DSP processes is nascent. However, limited findings note reduced transmission losses, improved reliability and resilience, and improved deployment of GERs as non-wires alternatives (NWAs) or bulk power system resources.[36] The value of coordinated planning can be challenging to quantify. Subject matter expert interviews, detailed below, support the hypothesis that coordination leads to improved utility plans that serve customers and state and utility objectives more effectively.

2.1.1 Improved Planning Outcomes

Consideration of distribution system elements in IRP optimizes grid investments. This is the most commonly cited value proposition, identified by over half of interviewees across a variety of organization types and geographic areas. Making better use of existing infrastructure, or avoiding or reducing the need for new or upgraded equipment, reduces costs and may provide other benefits such as reduced outages to enable safe construction. For example, when considering distribution asset health, utilities may identify opportunities to create additional hosting capacity at the same time. This is the case in New York, where developers

[34] See Appendix B; Schwartz et al., 2024.
[35] Regulatory review of proposed investments can be challenging when plan results differ.
[36] Burdick et al., 2024.

may request hosting capacity additions in conjunction with planned utility construction projects.[37] In general, considering distribution-level resources and constraints allows planners to optimize the system by providing greater visibility into holistic electricity needs based on the amount, timing, and location of electricity demand and the solutions available to serve that demand and meet other grid needs.

More robust planning can help utilities build in the most effective manner. For example, IRP that spreads a load forecast across broad geographic zones somewhat evenly ("peanut butter approach") risks missing large loads that may materialize in specific areas on the sub-transmission level. Such practices also may lead to suboptimal siting and sizing of generation and associated transmission.

DSP provides a more granular picture of where new loads are expected. That can improve quantification of resource needs in constrained corridors and strategic siting of generation and storage close to loads to reduce line losses and associated costs. Such insights may help utilities meet overall electricity system needs at a lower cost than traditional upgrades or new infrastructure. Operational strategies also help realize these benefits, such as strategically flexing storage or load on the distribution system at peak times to reduce the need both for bulk power and distribution system upgrades.

Optimized planning reduces electricity system costs and improves electricity affordability. The benefits noted above have potential to reduce overall system costs by improving information on the location, amount, and timing of resources needed. In addition, greater visibility into equipment loading patterns and specific planning violations through technologies such as advanced distribution management systems and GER management systems can help planners reduce overly conservative assumptions used to maintain reliability. For example, distribution-level visibility into actual storage charging behavior may reveal that more charging occurs off-peak than the utility assumed, allowing planners to increase available load hosting capacity.

Greater system visibility also improves insight into more cost-effective locations for generator interconnection and can provide more accurate information in the utility resource procurement process (e.g., timing of resource needs and siting insights). Improved distribution system visibility also improves situational awareness for wildfire and other costly grid threats.[38]

2.1.2 Improved Transparency and Trust

Consideration of distribution system elements in IRP improves plan credibility. PUCs and participants in utility planning proceedings increasingly want to understand how planning affects utility decision making, including capital investments. Several utility interviewees noted that IRP is an important communication tool for PUCs and stakeholders. Including elements of DSP in IRP improves planning transparency and builds trust because stakeholders view the

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[37] NY PSC, 2021.
[38] For additional information on the intersection of distribution system planning and resilience, see https://emp.lbl.gov/publications/integrating-resilience-planning.

utility's IRP as more thorough and reliable. Bulk system planners also are better able to answer stakeholder and PUC questions after analyzing distribution system trends like customer adoption of new technologies.

Coordination across plans reduces the possibility that results are in conflict and better harmonizes outcomes. When multiple plans demonstrate a grid need, the justification for investments is stronger — similar to how utilities select a preferred portfolio that includes resources the capacity expansion model selects across multiple scenarios. Showing how distribution-level investments enable better IRP outcomes further validates planned investments.

Coordinated plans provide greater insight into distribution expenditures that may drive rate increases. This can be particularly helpful for investments in distribution-level situational awareness and management infrastructure. For example, utilities invest in advanced distribution management systems (ADMS), advanced metering infrastructure (AMI), GER management systems, and other technologies to help monitor, operate, and manage the local grid, improving day-to-day reliability and resilience to severe weather and physical and cyber threats. PUCs are more likely to support these types of investments when applications include clear linkages with state priorities and electricity planning processes, strong cost-effectiveness and alternatives analysis, and clear prioritization of potential investments.[39] Demonstrating how investments create value for both the distribution and bulk power systems can help meet these criteria. For example, Hawaiian Electric's Integrated Grid Plan discusses how planned investments in grid modernization technologies such as ADMS are critical to managing a portfolio of resources where GERs contribute meaningfully to system needs.[40]

Coordinated planning reduces utility functional silos. Interviewees emphasized the value of conversations across planning teams to share learnings, elevate the importance of DSP across the utility, and begin to standardize integrated planning techniques into business-as-usual practices. Planners build their expertise and capabilities by collaborating with one another, working through challenges, practicing new techniques, and improving processes over time. Placing all planning functions under a single business unit within the utility breaks down planning silos and provides decision-makers with better information that improves planning outcomes. PUCs and stakeholders also may build expertise in new areas, improving regulatory review of utility investment decisions.[41]

2.2 Challenges to Incorporating Distribution Planning Elements in IRP

The literature consistently points to three types of challenges associated with integrating across two or more types of electric system plans:

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[39] Schwartz and Mims Frick, 2024; For additional information on regulatory treatment of grid modernization investments, see Mims Frick, Schwartz, and Sandonato, 2025.
[40] Hawaiian Electric, 2023.
[41] For example, in 2021, certain PUC participants in the NARUC-NASEO Comprehensive Electricity Planning Task Force committed to actions to advance integrated planning. Many of these states continue to pursue emerging planning techniques (NARUC, 2021c).

- Institutional silos within utilities and PUCs between resource, transmission, and distribution planning functions
- Data gaps, analytical limitations, and increased modeling complexity to accommodate granular distribution system inputs in typically systemwide IRP analysis
    - For example, incorporating forecasts for customer storage adoption with sufficient spatial and temporal granularity and conducting sufficiently detailed analyses to accurately identify and evaluate potentially less costly alternatives for both distribution and bulk power system services
- Addressing uncertainties stemming from rapid changes in technologies, load profiles, and large loads, including higher risks of stranded assets

The following interview findings corroborate these issues and illuminate additional challenges and limitations specifically related to including distribution system elements in IRP.

2.2.1 Analytical Challenges

Data marshalling is resource-intensive. Distribution-level sensors, communications equipment, and AMI produce vast amounts of data that can improve IRP forecasts and other key planning inputs. But reaping these benefits requires investment and experienced staff to set up data sharing systems, clean up data, translate locationally- and temporally- granular data for use in less granular IRP analyses, and keep data up to date in a useful format.

Modeling capabilities remain a genuine constraint. Interviewees agreed that, in practice, no single model can fully co-optimize grid investment decisions across bulk, distribution, and customer levels. This is in part because the transmission and distribution systems differ fundamentally in the physics being solved (balanced positive-sequence transmission power flow versus unbalanced three-phase distribution power flow), in temporal resolution requirements, and in scale. For example, a distribution system can have an order-of-magnitude more nodes than the upstream transmission model. Even where such linked models exist, computing power remains a binding constraint on their practical use. Data assembly and reconciliation are also often key limiting factors in the quality of distribution planning, with utility planning processes lagging behind both the granularity of available system data and the pace at which new electricity technologies are being deployed in the field.

However, a growing need for analysis that spans traditional simulation boundaries, such as evaluating the impact of distribution-level resources on bulk-power system operation, is driving software developers to make strides. Most notably, co-simulation platforms link separately developed transmission, distribution, which allows simulators to exchange information at runtime to create larger, more complex composite models.

IRP and DSP are designed to answer different questions. IRP addresses systemwide energy and capacity needs, whereas DSP addresses granular locational needs for the local grid. Thus, IRP inherently addresses larger-scale investments, diluting the importance of incorporating distribution system considerations in some cases. For example, planning reserve margins used in IRP subsume variability in local loads and generation. To illustrate, when utilities plan for a data center on the bulk power system, the effort needed to consider aggregated distribution system assets in IRP to meet that need may outweigh the potential value because such assets are unlikely to meet the large resource capacity levels needed.[42]

For these reasons, utilities, PUCs, and stakeholders can consider which DSP elements will have the most meaningful impact on IRP outcomes — as identified in this report — and focus integration efforts in those areas. Among these are growing loads that may change the relative economics of bulk vs. local resource options.[43]

2.2.2 Procedural Challenges

Cross-functional expertise and organizational structures are limited. There are often workarounds for technical challenges, but they require skilled experts with sufficient time and support. It is uncommon for utility planners to have expertise in both bulk power system and distribution system planning. An additional challenge generally is attracting talented utility engineers and planners. These challenges are exacerbated by utility organizational structures that divide planners by system level, with different directors, and the absence of top-down emphasis on planning coordination and skills development. Building expertise across electricity domains requires change management, time, and a willingness to overcome inertia built through many years of working on a single type of planning. Having explicit direction for coordinated planning from utility executive leadership or the utility regulator can help facilitate required business reorganization.

Assessing impacts of planning coordination is challenging. As an emerging area, there are no standard practices for assessing the consistency of results across IRP and DSP. It requires thoughtful analysis by utilities, PUCs, and stakeholders to identify areas of overlap or discrepancies, particularly when plans are filed at different times and when results are applied in a different type of proceeding such as a rate case. There also are no standard outcome-based metrics to quantify the impacts of incorporating distribution planning elements in IRP. In the future, such metrics will align with core desired planning outcomes – reliability and cost. Utilities can begin assessing coordination impacts using metrics developed with PUCs and stakeholders, such as improvements in reliability[44] per dollar invested in both the bulk power and distribution systems, and overall plan costs for scenarios that do and do not consider distribution level-connected resources.

Integrated planning proceedings are more complex. Proceedings covering both bulk and distribution system processes in-depth can be lengthy. The resulting plans may not be as timely as would be ideal, which can reduce their usefulness. It is helpful to recognize when to move through things more quickly and not get bogged down in process or analysis, particularly to

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[42] However, co-location of generation and storage at data centers is an important resource strategy, regardless of whether the large load is connected to the bulk power or distribution system.
[43] Not all utilities have the load growth — or the type of load growth — that supports that value proposition.
[44] Using metrics such as System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI), and Customer Average Interruption Frequency Index (CAIFI).

support effective stakeholder review and understanding.[45]

As states and utilities advance planning capabilities, it is critical to consider the objectives for IRP and DSP, utility context (e.g., types of customers and loads, customer adoption levels of distributed generation and storage, rural vs. urban service areas), the types of processes where value is most likely to be gained from coordination, and tracking successes and lessons learned.

[45] Some experts expressed that spending too much time trying to get every detail associated with IRP analyses exactly right, including highly granular distribution-level inputs and assumptions, may not be necessary when there is a high level of uncertainty around planning for the long-term future.

3. Methods for Incorporating Distribution Planning Elements in IRP

Tactics for incorporating distribution system elements in IRP include administrative and process-oriented practices and analytical coordination practices. Past research provides foundational information on general strategies for coordinating electricity system planning.[46] This study builds on that work by identifying how those strategies apply within specific IRP and DSP processes and by detailing key analytical linkages.

Methods range from light-touch and less complex activities, such as referencing information across proceedings, to analytically sophisticated and resource-intensive methods such as modeling that iterates on findings across electricity system levels.[47] [48] This chapter presents activities along the spectrum to support states and utilities regardless of experience with coordinated planning to date.

3.1 Administrative and Process-Oriented Coordination

Establishing supportive administrative processes is foundational to conducting more complex analyses and coordinated modeling. Without effective management and protocols, the breadth of topics covered can become unruly. Literature and interview findings confirm the importance of these efforts and indicate that relatively simple approaches can help mitigate challenges.

Table 2 describes key tactics for supporting utility personnel and stakeholders in integrated planning processes. Most procedural aspects of coordination involve simple or moderately complex methods that require thoughtful input from project managers. These relatively low-hanging fruits support improved integration of modeling and analysis. For example, PUCs can consider aligning filing cycles so utilities incorporate updated information consistently across planning processes. PUCs in Minnesota and Michigan adjusted filing schedules to encourage synchronized or dovetailed processes.[49]

[46] See, for example, Schwartz et al., 2024 (Chapter 13); ESIG, 2025; De Martini et al., 2022.
[47] Schwartz et al., 2024.
[48] ESIG (2025) describes this spectrum of activities using a “walk-jog-run” framework.
[49] Terwilliger, Northagen, and Dornfeld, 2024.

Table 2. Workforce and Engagement Tactics for Incorporating Distribution Planning Elements in IRP

Tactic	Description	Impact	Level of complexity to implement
Conduct change management to reduce utility staffing silos	• Restructure utility departments so that resource and distribution planners report to the same executive • Support planners in trying new techniques by emphasizing the importance of coordinated planning, providing training and resources (e.g., models), and offering support as challenges arise	• Planners all work toward the same outcomes • Utility executives have better visibility into planning at different levels of the system • Discussion facilitates resolution of discrepancies in assumptions or approaches across planning processes	**Moderate** - This tactic requires utility executive buy-in and commitment to change
Use advisory groups strategically and effectively to engage stakeholders	• Establish advisory group and stakeholder engagement processes with a clear calendar of events • Create streamlined, consistent, and meaningful opportunities for input	• Advisory groups and stakeholders help to vet issues, maintain focus on important topics, and bring new ideas to the table • Regular, candid discussions help avoid the potential for serious planning flaws late in the process	**Moderate** - Simple steps such as clear naming conventions, maintaining public webpages, and clearly stating stakeholder roles are impactful; however, stakeholder engagement is time-intensive and stakeholder needs and ability to contribute vary
Create opportunities to build skills and expertise across stakeholders	• Improve expertise at the nexus of bulk power and distribution systems across utilities, PUCs, utility consumer offices, and other entities through educational sessions and training	• Improved skills and expertise enable proceedings to progress faster by avoiding too much time spent on foundational information or irrelevant topics • Depth of analysis, review, and feedback on utility plans also improve	**Low** - PUCs and utilities can offer educational sessions on integrated planning topics at advisory group meetings; utility engineers can attend trainings and engage with industry peers

Table 3 identifies strategies for managing information systems and proceeding workflows to support integrated planning.

Table 3. Process Management Tactics for Incorporating Distribution Planning Elements in IRP

Tactic	Description	Impact	Level of complexity to implement
Establish robust data management systems and data-sharing provisions	• Marshall data from both IRP and DSP to allow all utility planners easy access to up-to-date and appropriately formatted information that acts as a single source of information • Establish appropriate information sharing protocols for external stakeholders and provide regular updates	• Aligning inputs and assumptions across proceedings or levels of the system reduces conflicts in planning results and outcomes • Using distribution-level data, such as real-time equipment loading, in IRP can improve system utilization and enable less conservative assumptions, reducing utility costs • Data sharing improves transparency and supports better stakeholder engagement	**Moderate to High** - Simple tasks such as providing clear data descriptions, regular updates, and communication about data availability are important; however, converting large quantities of data to useful formats and translating data sets designed for use in a different proceeding is challenging
Manage proceeding calendars to effectively exchange information	• Identify key touchpoints between proceedings and sync milestones so that inputs are available when needed • When it is not possible to align timing, use consistent methodologies to develop data sets and analyses to produce cohesive, if not the same, results • Keep processes separate where appropriate to ensure sufficient depth of analysis and expertise and avoid additional work where not needed • Conduct planning in bite-sized pieces to support forward progress	• Creates meaningful integration by making outputs from distribution planning (e.g., load and storage forecasts, near-term distribution capital investments) available for the IRP process	**Moderate** - Thoughtful calendar management is theoretically simple, but is often challenged by the reality of proceeding delays and changing priorities; depending on the number of regulated utilities, types of proceedings, and complexity, it can be difficult to change existing schedules — both for utility workplans and commission proceedings
Strategically invest in new modeling capabilities	• Identify tradeoffs between costs and benefits for investing in new modeling capabilities, given that no single model currently exists to effectively analyze the full electricity system and thoughtful scenario and trade-off analysis may be sufficient	• Starting with thoughtful approaches and open source models, rather than immediately investing in sophisticated models, allows planners to develop deeper understanding of the process and identify the most pressing modeling and technological needs • Gradual investment also spreads costs for integrated planning over time	**Low** - Use existing models and capabilities and build from that foundation with more sophisticated practices and eventually new models

3.2 Analytical Coordination

At a high-level, DSP can primarily inform IRP through granular load and GER forecasting, planning for the same plausible futures (scenarios), assessing capabilities of distribution-level resources to meet bulk power system needs as well as the incremental value of these resources for local grids, and co-optimizing resources across all levels of the electricity system (e.g., through operation of distribution-connected batteries). In turn, IRP portfolios can identify the quantity and role of distribution-connected resources to help meet bulk power system needs. At a practical level, this breaks down into the following most impactful analytical linkages between IRP and DSP and associated methods for maximizing each connection point.

1. Load and GER forecasting
    - Sequenced planning cycles
    - Aligning IRP and DSP forecasting
2. Scenario planning and sensitivity analysis
3. Distribution grid optimization (i.e., improving distribution load factor and GER utilization and integration)
    - Distribution grid load factor optimization
    - Integration of GER, including:
        - Hosting capacity analysis (HCA)
        - Streamlined interconnection procedures
        - Flexible connection options
        - GER deliverability reviews[50]
4. Integrated system analysis
    - Convergent and divergent value analysis
    - Co-optimizing bulk and distribution-connected resources
    - Coordinated procurement processes

3.2.1 Load and GER Forecasting

Aligning distribution-level forecasts with system-level forecasts for IRP is important to avoid mismatches in inputs and assumptions and results of the analyses. For example, an IRP might assume one trajectory for load growth or adoption of customer-sited generation and storage, while distribution plans assume another — resulting in inconsistent investment signals, inefficient infrastructure deployment, missed NWA opportunities, and potential reliability risks across both the bulk power and distribution systems. Subject matter experts interviewed for this study emphasized forecasting as a key touchpoint between IRP and DSP. In particular, they noted the importance of understanding load variability and coincidence factors — whether timing of peak demand at the local and bulk power levels is aligned or mismatched.

Alignment of system-level (IRP) and distribution-level forecasts is essential to plan all parts of the grid to the same set of plausible future conditions. Using aligned forecasts provides utilities, PUCs, and stakeholders with a coherent, end-to-end picture of future needs to enable:

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[50] Electric utility review of GER aggregations proposed to provide bulk system services for capability, safety, and reliability impacts on the local distribution system.

- Consistent decision-making across bulk power and distribution systems
- Avoidance or reduction of stranded costs from overbuilding
- Identification of least-regrets solutions that benefit both the bulk power system and local distribution grids

However, DSP and IRP forecasting differ in scope, resolution, and the types of information used to develop forecasts. Distribution planning generally focuses on local infrastructure conditions over a five- to 10-year horizon, emphasizing feeder- and substation-level impacts from known customer growth and local planner knowledge. In contrast, IRPs typically evaluate system-wide load and resource needs over a 10–20+ year horizon using more aggregated economic, demographic, and policy-driven assumptions. IRPs commonly incorporate GER impacts in aggregate form at the system level. Representation of GER adoption at a localized geographic level for the distribution system is an emerging area that requires more granular propensity models for customer adoption, hosting capacity information, and circuit-level behavioral assumptions. As a result, some utilities either exclude GER impacts from local forecasts or allocate system-level GER forecasts uniformly across distribution areas without modeling localized adoption dynamics ("peanut butter" approach).

Different DSP and IRP forecasts are not necessarily problematic if they reflect distinct planning needs or risk-management approaches. Transparency for assumptions, methodologies, and uncertainty analyses is needed so that utility planners and PUCs understand why differences exist and can incorporate the best available information into decision-making.

Table 4 summarizes key differences between system- or zonal-level (IRP) and distribution-level (DSP) forecasts.

Table 4. Differences in IRP and DSP Forecasting Techniques

Aspect	IRP	DSP-Level Forecast
Geographic Scope	Zonal representations, typically aggregated to the system level	Specific substations and feeders in a utility's network
Forecast Horizon	Medium-to-long term — 10–20+ years	Near-to-medium term — often 5–10 years
Spatial and Temporal Granularity	System-level peak demand and energy use — zonal if broken down by region; hourly simulations for entire system	Highly granular (e.g., circuit-level peak loads, hourly profiles)
GER Treatment	Aggregate GER impacts may be netted out of load forecast (e.g., onsite generation reduces residential energy consumption), or GERs may be modeled as resources (but with less locational detail than in DSP)	Explicitly models GER adoption;* GERs affect feeder loads or may serve as NWAs

Aspect	IRP	DSP-Level Forecast
Forecast Method	Uses econometric and end-use models for total load across the utility system; uses scenarios and sensitivities to reflect plausible future loads and GER adoption dependent on a variety of factors	Often relies on known customer growth, interconnection requests, and local business-development information; some utilities supplement these approaches with adoption models, spatial analytics, or advanced forecasting techniques if data are available
Addressing Uncertainty	Focuses on macro-level uncertainties — e.g., economic growth, fuel prices, and federal policy changes; scenarios have less spatial detail	Low consideration of uncertainty; less commonly, utilities may use multiple GER adoption scenarios to analyze uncertainty

* Leading practices use 8,760 hourly modeling and GER adoption propensity models (LBNL, 2026), but DSP more commonly allocates a generalized GER adoption forecast uniformly across the utility's service territory.

Leading practices for aligning IRP and distribution forecasts include (1) synchronizing planning cycles; (2) aligning forecasting for IRP and DSP — for example, by using common datasets, disaggregating IRP forecasts, and ensuring that growth of distributed storage assumed in the IRP aligns with expected adoption of this technology across all distribution feeders; and using scenario analysis to assess uncertainties.

Synchronized planning cycles – Timing gaps between IRP and DSP can under-represent fast-moving trends, such as technology adoption or new technological capabilities.[51] While utilities conduct distribution planning internally each year, they typically file updated distribution plans with PUCs (where required) every two to three years — sometimes with narrower annual updates. IRPs typically follow three- to five-year cycles. Utilities may file interim IRP updates focused on changes that have a significant impact on plan outcomes.[52]

Bridging the timing gaps between forecasts used by these planning processes can include using DSP analysis comparing recent GER forecasts to actual operational impacts of GERs. Utilities also may consider phased distribution upgrades that help bridge the gap between nearer-term DSP needs and longer-term IRP needs and manage the uncertainties associated with needs that are farther down the road.[53]

Integrating IRP and DSP Forecasting – The primary methods for aligning IRP forecasts with distribution-level forecasts are to use consistent data sets and assumptions for load and GER

[51] In some cases, GER adoption may be more fully represented in system-level forecasts than in local distribution forecasts. Utilities may apply more conservative assumptions at the feeder level to manage uncertainty in where and when impacts will materialize.
[52] For example, Hawaiian Electric files an annual update to its Integrated Grid Plan that discuss updated planning and modeling assumptions. Hawaii PUC, 2024.
[53] ESIG, 2026.

growth, disaggregate system-level forecasts down to the distribution system level, and aggregate granular distribution forecasts to validate consistency. Utilities can take various approaches to disaggregation, including using historical adoption trends, customer adoption propensity models, allocation methods, regression-based techniques, and machine learning approaches.[54] The approach may vary by component, such as using different allocators for different types of technologies, discussed further below.

“Known” or “spot” distribution loads like new commercial development, including those co-located with generation, impact energy deliverability analysis and related reliability considerations. Forecasters make adjustments for known distribution loads and distributed energy projects. In many cases, distribution and bulk power planners rely on the same underlying information regarding known new loads or large customer developments but apply different modeling assumptions. Distribution planners may assume the full localized peak-load impact at specific substations or feeders to ensure infrastructure reliability, whereas IRP models may smooth or diversify those impacts across the broader system, particularly when evaluating energy consumption or coincident peak demand at an aggregate level. As a result, differences between distribution and system-level forecasts may reflect legitimate differences in modeling objectives and risk treatment.

Interviewees at four utilities offered that discussion between planners and stakeholders is critical, including municipalities and state economic development agencies. Such discussions provide a more comprehensive understanding of the factors driving certain growth assumptions and help planners develop more accurate distribution-level forecasts that feed up to bulk system planners.

In short, alignment across bulk power and distribution system forecasts provides a common foundation for more cost-effective and credible planning. That is why a growing number of states and utilities are adopting requirements and methods to align system-level and distribution-level forecasts, as illustrated in the examples in the following text boxes. Continuous improvement of GER forecasts year over year also is critical. By comparing past forecasts with actual operational data and adjusting forecast methodologies accordingly, planners can avoid overly conservative or aggressive assumptions and provide more confidence that plans will result in least-cost solutions to resource needs.

[54] SCE, 2025.

<u>Examples of Forecasting Alignment Requirements</u>

Nevada - A 2019 Public Utilities Commission of Nevada (PUCN) order on integrating IRP and IDP planning required inclusion of a Distributed Resources Plan (DRP) as part of developing the IRP. The order included the following requirements: *"The net distribution system load and distributed resources forecast will include system, substation, and feeder level net load projections and energy and demand characteristics for all distributed resource types"* (PUCN, 2019).

Maryland - The Maryland Public Service Commission's (MD PSC) 2025 regulations regarding Electric System Planning, focused on integrated distribution planning, include the following forecasting requirements (excerpted):

"B. Considerations Feeding into Types of Projections

> *(2) Level of Granularity. The granularity of information in an electric system plan may vary as described in other sections of this regulation.*
>
> > *(a) As a near-term objective:*
> >
> > > *(i) Information shall be provided in an Electric System Plan at the substation level; and*
> > >
> > > *(ii) Feeder-level information shall be provided as part of the planning process for feeders where there are identified system constraints;*

[…]

D. GER Forecast. An electric system plan shall account for the following considerations for each electric system planning cycle and scenario.

> *(1) Electric companies shall develop separate forecasts for each relevant GER type, including energy efficiency, demand response, distributed generation, energy storage devices, VPPs and managed EV charging-discharging.*
>
> *(2) Electric Companies shall develop hourly GER forecasts.*

E. Load Forecast. Load forecasts shall account for the following considerations for each planning cycle and scenario as follows:

> *(1) Electric companies shall incorporate load impacts of current and future transportation and building electrification based on known information and assumptions; and*
>
> *(2) Electric company distribution-level forecasts in aggregate shall be aligned to a reasonable extent with available electric company developed transmission-level forecasts and with PJM-developed system-level forecasts with an explanation provided in electric system plans for any differences and the associated factors, including differences in assumptions*" (Code of Maryland Regulations, 2025).

California's disaggregation approach provides a detailed example on how system-level and distribution forecasts can be aligned. The state requires IOUs to translate statewide forecasts of electricity demand and GERs into distribution circuit-level projections for grid planning. The process starts with a single forecast data set provided by the California Energy Commission (CEC). The CEC develops a statewide Integrated Energy Policy Report (IEPR) demand forecast that incorporates load growth, energy use intensity improvements and usage reductions, and trends for behind-the-meter GERs.

Utilities use this forecast for IRPs, distribution plans, and resource adequacy assessments, with oversight by the California Public Utilities Commission (CPUC). The California Independent System Operator (CAISO) uses the CEC forecast for transmission planning studies. By using a single forecast dataset, with scenarios designed to address information needs for different use cases, the state ensures that the expected growth of GERs aligns with the growth reflected in system-level capacity needs. This alignment is critical because IRP portfolios (e.g., the number of new power plants required) inform CAISO's grid studies, which in turn influence distribution upgrades. For example, California utilities include CAISO-approved transmission projects that serve GER-deferrable services on publicly available portals for distribution plans to allow users to view attribute data for different grid layers at the same time.[55]

The disaggregation approach starts with the utility's baseline (existing) demand, using historical circuit data. The utility removes anomalies and normalizes the data for weather conditions, providing a foundation for projecting future usage. The utility then allocates the reference system-level forecasts among its distribution circuits. The following description draws from Southern California Edison's (SCE's) disaggregation methodology.[56]

The utility uses the IEPR forecast for load growth and GERs for its service area and allocates the forecast to circuits using econometric modeling that reflects customer sectors, historical usage, and "known load." Known load data represent high-confidence, bottom-up customer requests that are both certain and spatially defined, such as new data centers or fleet charging depots. The load forecasting methodology requires that known loads be mathematically integrated into the forecast by subtracting them from the net IEPR growth forecast for the first planning year. This ensures that the general IEPR growth projections, which are allocated spatially across distribution feeders using models such as LoadSEER, do not double-count growth the utility already accounts for as specific customer commitments.

If aggregated known loads for a given year exceed the generalized IEPR forecast for that period, the excess load amount is carried forward to subsequent years. This carry-over continues until the forecasted IEPR growth is large enough to absorb the cumulative known loads.

Because known loads represent certain, imminent customer demand, they effectively establish

[55] SCE, 2025 at A-58.
[56] See Section 4 of SCE's 2025 Grid Needs Assessment report for the utility's methodology for disaggregating the CEC's IEPR forecasts for GERs (SCE, 2025).

the immediate baseline demand that existing infrastructure must meet. This high level of certainty means that the aggregation of known loads at a specific substation or feeder can immediately trigger a grid need. In other words, a grid need is established if the aggregated known loads, combined with other factors, push the total forecast load above the circuit capacity limit. Known loads have also factored into the demand forecast used for resource and transmission planning.

A stakeholder engagement process with local and tribal governments enables engineers to proactively identify new loads before formal service requests, particularly for "pending loads," which are less certain than known loads. Stakeholder engagement also facilitates assessments of the timing of service requests based on locally-provided information, the progress of development, and institutional knowledge from previous developments.[57]

GERs are more complex to assess, since they can increase or decrease net demand depending on technology and operation. As part of the California disaggregation process, SCE applies a set of tailored methods to the IEPR service area forecast for each major GER category (see text box).[58]

Key assumptions in these forecasts include proportional scaling of adoption, geographic mapping from ZIP codes to circuits, and accuracy of hourly load and GER shapes. Expert review and stakeholder engagement inform the methodology.

After combining load and GER forecasts, the utility calculates net demand for each circuit and substation at hourly resolution. Known projects are layered in. Before declaring capacity shortfalls, planners test whether load can be shifted to neighboring circuits to avoid system upgrades. The final forecasts are stress-tested under various weather conditions, such as a one-in-ten hot year, to ensure grid reliability under extreme scenarios.

In 2024, the CPUC provided guidance to utilities on ways in which DSP forecasts can deviate from the IEPR methodology, recognizing that DSP forecasts require greater temporal and locational granularity than forecasts for IRP. The change allows certain deviations from the IEPR forecasts to better integrate reliable, bottom-up data into DSP, which may mitigate any loss of granularity (e.g., diversified load shapes) associated with disaggregating a system-level forecast. The Commission required the utilities to work with both the CEC and CPUC to "develop proposals for the method and accounting for discrepancies between the system and circuit level."[59]

[57] CPUC, 2024a.
[58] Additional information on SCE's forecasting process is included in the detailed case studies, available at https://eta.lbl.gov/publications/effectively-considering-distribution.
[59] CPUC, 2024a.

Methods for Disaggregating System-Level Forecasts – Southern California Edison

- **Energy Efficiency:** Savings estimates are assigned at the circuit-level in proportion to each circuit's existing consumption by customer sector. Hourly profiles from the system-level forecast shape how efficiency reduces demand at different times of day.
- **Electric Vehicles (EVs):** For light-duty vehicles, the utility applies ZIP code-level adoption models that factor in demographics, income, and historical registrations, then maps them to circuits. SCE uses proprietary tools for medium- and heavy-duty vehicle modeling, which forecasts truck electrification by location and charging pattern. Hourly charging shapes are applied to reflect usage profiles for charging.
- **Solar Photovoltaics (PV):** Growth estimates are divided between new construction—allocated using housing starts and building permit data—and existing home or business adoption, modeled using an S-curve diffusion approach at the ZIP code level. Non-residential PV is statistically allocated using historical adoption trends, customer characteristics (e.g., load profile/size), and hosting capacity to determine the distribution system's locational potential.* Hourly generation is modeled with "dependability" shapes adjusted for cloud cover and other degradation factors.
- **Battery Electric Energy Storage:** Residential battery storage is assumed to co-locate with PV, and estimates are allocated based on PV shares at the circuit level.** Nonresidential storage is assigned to customers with high peak-to-energy ratios, since they benefit most from peak reduction. Hourly storage charge and discharge profiles are scaled to circuit allocations.
- **Fuel changes:** Increases in electric demand from changing end-uses (e.g., switching between gas and electricity for space or water heating) are allocated by sector and shaped using system-level hourly profiles (SCE, 2025).

* Existing hosting capacity may not be appropriate to use for this method if, as is being pursued in several states, alternative interconnection cost allocation methods are employed to reduce economic barriers. For example, several state regulations, including Massachusetts (D.P.U. 20-75-B) and Maryland (COMAR 20.50.09.06(R)), allocate upgrade costs among the interconnecting entities that will benefit from the upgrades immediately and in the future.

** This assumption may under-estimate battery adoption because customers purchase standalone batteries for reliability and resilience. A recent study found that outages caused a 45 percent increase in battery adoption that would not have otherwise occurred. Brown and Muehlenbachs, 2023.

3.2.2 Scenario Planning and Sensitivity Analysis

A *scenario* is "a model run with a specific set of input assumptions and constraints—internal and external—to provide insights on distinct questions. Often, scenarios represent different goals or views of the future."[60] By developing multiple, contrasting scenarios, the utility can better understand uncertainties associated with forecasts and assumptions, test strategies, and prepare for a wide range of outcomes. The process begins by identifying the most important uncertainties about future conditions. Planners then develop a set of scenarios that reflect

[60] Biewald et al., 2024, at 51.

different ways these uncertainties might unfold. Leading practice is to use a common set of scenarios across both IRP and DSP and reconcile any conflicting outcomes.

A *sensitivity* is a model run that changes a single key input (e.g., gas prices or technology costs) to understand how that input affects or drives results, often across multiple scenarios.[61] Leading practices emphasize aligning key assumptions (e.g., load growth, GER adoption, fuel price changes) to ensure that resource and distribution plans are built on consistent futures. The examples below highlight emerging state trends.

Examples of Scenario Alignment Across IRP and DSP

Nevada - Nevada Senate Bill 146 (2017) required integrated resource plans, which incorporate distributed resource plans, to include "*A comparison of a diverse set of scenarios of the best combination of sources of supply to meet the demands or the best methods to reduce the demands...*" (SB 146). This requirement was reflected in the Nevada PUC 2019 IRP order (NV PUC, 2019).

Washington - Utility IRPs, which may include GER plans, must include "*a range of possible future scenarios and input sensitivities for the purpose of testing the robustness of the utility's resource portfolio under various parameters*" (WAC, Title 480, Chapter 480-100, Section 480-100-620). Utilities use these scenarios and sensitivities to "*assess the effect of distributed energy resources on the utility's load and operations,*" including identifying any "*need to develop new, or expand or upgrade existing, bulk transmission and distribution facilities*." The requirements include describing scenarios and sensitivities, including those informed by an advisory group process.

California – Utilities following California's Distribution Planning Proce each may select a system-level scenario developed by the CEC in its IEPR for use in distribution planning, as discussed above (CPUC, 2024b).

Other states - Maryland, the District of Columbia, and Minnesota are updating planning guidelines to require a common set of scenarios between bulk power planning processes and DSP.

3.3 Distribution Grid Optimization

Distribution capacity planning has become a critical foundation for more integrated electricity system planning as utilities balance growing loads with the rapid adoption of GERs. Beyond ensuring reliability during peak demand, today's planning also accounts for evolving load patterns and energy exports from distribution generation co-located with loads. Utilities are

[61] Ibid.

making advancements in distribution planning to better assess grid needs, optimize existing assets, and interconnect new loads and distribution-level generation for system reliability and customer affordability.

3.3.1 Distribution Grid Load Factor Optimization

Electric distribution feeders in the U.S. on average operate well below their peak capacity. Most U.S. distribution systems have an asset utilization of about 30–35%.[62] This means that most feeders are carrying only about one-third of their maximum demand capacity most of the time. This has a direct impact on the availability of hosting capacity and the need for capacity upgrades to address load growth. This low utilization also affects the number of distribution capacity upgrades that may be needed, as increasing utilization can reduce available capacity.

Low utilization is primarily due to two compounding factors:

- Residential and small commercial customers represent over 90% of all distribution customers on average and have low average load factors.[63,64]
- Distribution contingency planning criteria typically involves reserving a portion of distribution capacity for emergency switching.

Residential loads typically have a 25-40% load factor due to demand spikes during morning and evening hours, with load dropping off overnight.[65] The result is pronounced daily peaks with much lower consumption during off-peak hours, leaving the feeder's capacity underutilized for a large portion of the day. Likewise, mixed-use feeders serving small commercial customers (such as offices, retail, or mixed residential-commercial areas) typically have load factors in the 40–60% range. Commercial loads tend to be more constant during standard workday/operating hours due to lighting and space conditioning.[66] Figure 7 shows typical feeder loading in Duke Energy's system, which is predominantly residential load at the peak hour.

[62] Steyer, 2025.
[63] Load factor is the ratio of average load (actual energy used) to peak load (maximum demand) over a period, typically expressed as a percentage. A 33% load factor, for instance, means the feeder's average demand is one-third of its peak demand for that period. Higher load factors denote more even, efficient use of grid capacity, whereas low load factors signify sharp peaks with long periods of low utilization.
[64] There are approximately 166 million electricity customers in the U.S. — about 145 million residential, 20 million commercial, and 1 million industrial customers, according to FindEnergy.
[65] The Electricity Forum, 2025.
[66] In contrast, industrial customers, typically served by transmission or sub-transmission systems, may have very high load factors. These load factors are often greater than 70% because many industrial operations run almost continuously.

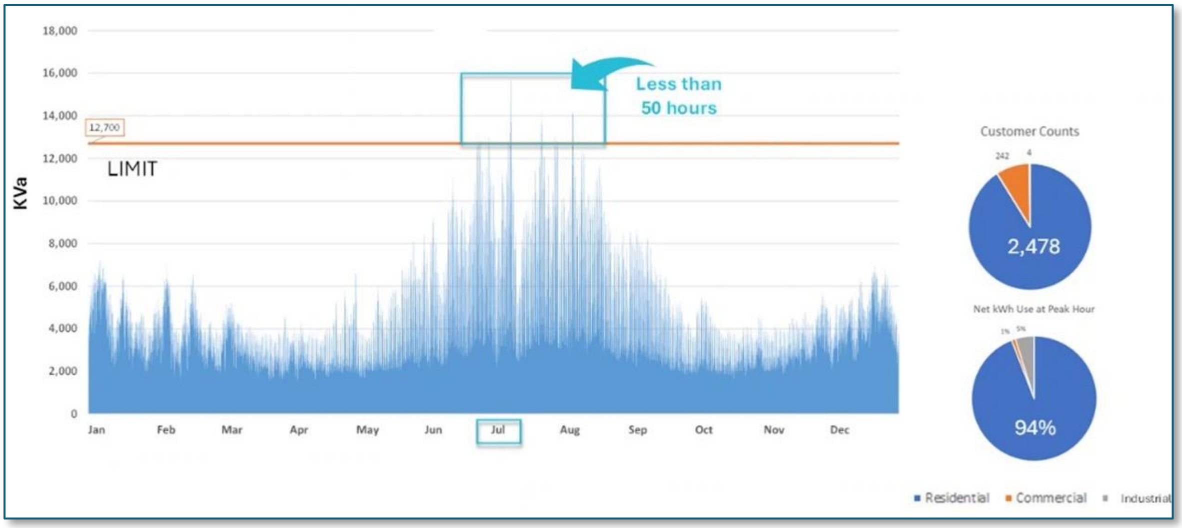

Figure 7. Duke Energy Typical Distribution Feeder Loading (Oliver, 2025)

Contingency planning is another factor affecting low distribution utilization. Utility planners perform load flow analysis to ensure that, under a contingency condition (N-1), rerouting power does not cause overloads or voltage issues on the adjacent feeder or transformer bank. This load transfer capability involves ensuring that an adjacent feeder or an alternative transformer bank has sufficient spare capacity to accept the additional load during an outage. As design and operating criteria, normal peak loading on a feeder is often limited to 60–70% of its thermal rating, and substation transformers may be operated at 75–80% of their normal rating to support load transfers. For example, Portland General Electric's (PGE's) target loading is less than 67% for feeders and less than 80% for transformers.[67]

An average mixed-customer load factor of 45% with a contingent limit of 70% yields utilization of about 31% of the normal capacity rating of a feeder or substation transformer. While this traditional planning approach provides high reliability with N-1 capability, it comes at the cost of underutilized capacity during day-to-day operations. Opportunities to improve customer load factors and better utilize flexible load and GER for reliability contingencies may lead to improved distribution utilization.

Conservation voltage reduction and Volt/VAR optimization are the most prominent approaches for improving distribution system utilization. Lowering distribution voltages within the acceptable band of the ANSI standard reduces energy losses on the network and can somewhat increase distribution capacity. For example, Dominion Energy's Voltage Optimization program leverages smart meter data to adjust system-wide voltage levels, improving efficiency and reducing overall energy use. A core element of the utility's Grid Transformation Plan, the initiative supports growing energy demand while maintaining reliable service.[68] Utilities can include conservation voltage reduction in IRP as a selectable resource or as a decrement to overall load.

[67] PGE, 2024.
[68] Dominion Energy Virginia, ND.

However, more substantive methods are needed to materially reduce distribution capacity upgrades that may be required with load growth and increasing GER adoption. Xcel Energy is addressing this challenge in a recently approved program for a battery storage network to optimize its Minnesota system and help meet growing electricity demand. The utility's Capacity Connect program will install up to 200 MW of utility-owned battery storage resources in 1–3 MW units at strategic grid locations by 2028. The approach leverages both IRP and distribution planning to identify the best customer locations for installing new battery storage resources where bulk power and local grid systems have similar load shapes. The company will integrate these large battery storage units into its system operations, charging the batteries when energy is inexpensive and dispatching batteries to address distribution and bulk power system needs and defer capital investments, maximizing benefits for ratepayers through multiple value streams (Figure 8).[69]

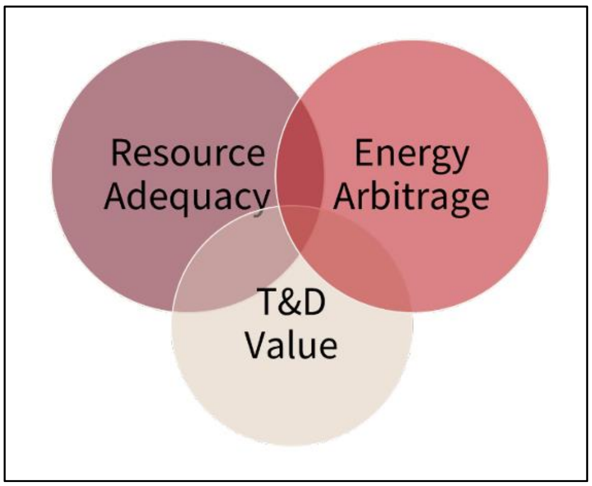

*Figure 8. Capacity*Connect Value Streams (Xcel Energy, 2025)*

The program will provide important operational experience for optimizing distribution system-connected resources for bulk system benefits. The utility expects the majority of near-term value from battery participation as a capacity resource in MISO's resource adequacy construct and additional value from participation in the energy market or avoided energy market purchases.[70] Operational experience is particularly important as utilities develop dispatching, visibility, and control capabilities.

3.3.2 GER Integration

Transparent and accurate representation of all technologies in IRP and associated procurements leads to better planning outcomes. Leading or emerging practices for modeling GERs in IRP include assessing GER adoption separately from GER operation, allowing these resources to be dispatched according to their capabilities, probabilistic modeling of GER operation on an hourly basis by customer-segment in relation to load profiles, and using up-to-date capacity accreditation practices that are technology-agnostic to enable comparison of resource adequacy contributions across different types of resources (although this practice is

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[69] Xcel Energy, 2025.
[70] Ibid; Stenclik and Hostetter, 2025.

still growing in sophistication).[71] Appropriate consideration of avoided transmission and distribution (T&D) costs also is important — for example, by internalizing avoided costs in overall cost assumptions that feed into IRP models.[72] GER services for avoiding T&D upgrades require an operational potential analysis to identify predictable performance to ensure reliable operation.[73,74] Utilities can transparently document all planning assumptions, including those that may influence GER operation, such as rate and program structures and types of GER aggregations.

In areas where GERs are essential contributors to utility resource adequacy and flexibility services, GER utilization that falls short of expected contributions to grid services can erode reserve margins, requiring utilities to rely on bulk system resources and transmission capacity that can be under strain from new loads. Incorrect assumptions about GER contributions may cause underbuilding or overbuilding of bulk power resources, creating reliability issues or financial burdens for ratepayers. Realistic and verifiable GER utilization is necessary to avoid ratepayers overpaying for resources to ensure system reliability.

As utility customers continue to adopt GERs, the following planning-related analyses become increasingly important:

- *Hosting capacity analysis*, to establish the quantity of distributed generation and storage (for example, as selected in an IRP portfolio) that can safely connect to the grid in specific locations or, conversely, where distribution system investments might be needed to cost-effectively interconnect these IRP-identified resources
- *Improved interconnection procedures and new flexible connection options*, which are needed to deliver GER projects the utility selects in the IRP process on time and at scale
- *GER deliverability reviews*, which confirm that GER aggregations can safely and reliably provide wholesale services

Together, these enablers contribute to a foundation for PUCs to treat GERs as dependable, dispatchable resources. Probabilistic analysis for dependable capacity also is needed.

Hosting capacity analysis

HCA is the amount of GERs (or loads) that can be integrated at a specific location on the distribution system before requiring distribution infrastructure upgrades (or energy export limits) to maintain safety and reliability.[75] It is an engineering study based on three key operating parameters: thermal capacity, voltage quality, and protection coordination.[76,77]
The analysis provides a snapshot of a distribution system's ability to integrate GERs.
The analysis identifies grid locations where GERs can be added at minimal cost. Publicly

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[71] ESIG, 2023; Telos Energy, report to the Illinois Commerce Commission on resource accreditation in PJM and MISO, April 2026.
[72] Biewald et al., 2024.
[73] Murdock, Goldstrom, and De Martini, 2026.
[74] Keen et al., 2026.
[75] National Laboratory of the Rockies (NLR), ND.
[76] Maryland Department of Natural Resources, ND.
[77] Electric Power Research Institute (EPRI), 2015.

available hosting capacity data provides early visibility into the likely costs and technical hurdles associated with interconnecting GER projects at specific sites.[78] This upfront transparency streamlines the interconnection process, facilitating project siting and reducing uncertainty and delays.[79] For example, to support Commission-approved procurement of 293 MW of distributed generation as part of the utility's 2022 IRP, [80] Georgia Power launched a statewide hosting capacity tool to enable prospective bidders to identify optimal interconnection locations across the distribution system. The tool streamlined procurement by directing bidders to more favorable project sites. This integration significantly enhanced efficiency, improved siting outcomes, and supported the cost-effective deployment of distributed resources to achieve the level of distributed generation capacity identified in the utility's IRP action plans.

Utilities and PUCs in some states are expanding the scope of HCA to consider longer-term implications of integrating forecasted levels of distributed generation and batteries, in addition to load growth. For example, NV Energy’s DRP forecasts hosting capacity to identify circuits that may become constrained in the future due to GER growth (Figure 9).[81] If significant rooftop solar is forecast for a particular feeder over the next five years, the DRP identifies the feeder’s current hosting capacity and any shortfall. That, in turn, informs the utility's grid upgrade plans and GER management strategies.

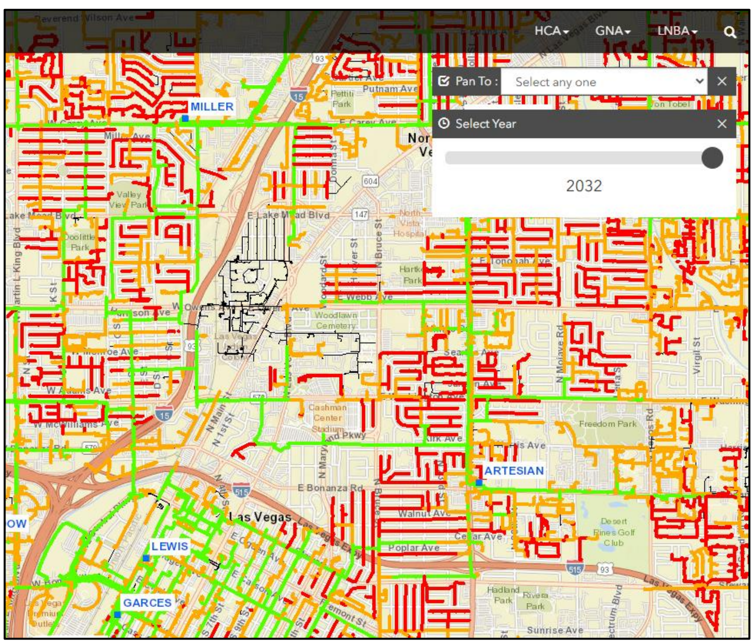

Figure 9. NV Energy 2032 Forecast Generation Hosting Capacity (NV Energy, 2025b)

By identifying the technical limits of the grid, the analysis enhances transparency across planning processes, supports the strategic and efficient integration of GERs, and helps shape investment decisions that reinforce grid reliability and system efficiency. HCA also supports the

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[78] For more information on HCA, see: https://www.energy.gov/cmei/vehicles/us-atlas-electric-distribution-system-hosting-capacity-maps.
[79] Stanfield, Safdi, and Baldwin Auck, 2017.
[80] Georgia Power, 2025.
[81] NV Energy, 2025a.

development of integration cost estimates for GERs that impact their overall net costs to serve local and bulk system needs.

Forecasting hosting capacity data and identified grid upgrades can be incorporated directly into an IRP's broader least-cost optimization framework. By quantifying potential grid upgrade requirements, utilities gain the ability to balance near-term GER adoption with long-term system investment needs, improving cost-effectiveness.

Streamlining Interconnection

Utility interconnection processes in many jurisdictions throughout the country are inefficient, leading to significant backlogs that can cause material delays for GER projects. When IRPs forecast expected GER adoption at a certain pace and scale, and interconnection delays occur, utilities may face resource shortfalls. This happens when the GER capacity assumed in resource plans does not materialize in time to meet system needs. States and utilities can consider improvements related to interconnection studies, coordinating interconnection and grid planning, and cost allocation of required distribution system upgrades.[82]

Flexible Connections[83]

Flexible connection strategies involve shaping distributed resource imports and exports to remain within distribution system operating parameters (e.g., capacity and voltage limits) during periods when distribution systems are constrained (Figure 10). These strategies improve distribution system utilization, allowing more load and GER interconnections while lowering interconnection costs and/or deferring infrastructure upgrades.[84] The operating limits establish the upper and lower bounds for a given time interval for allowable import or export of power at a point of interconnection. These bounds can change across time intervals based on system conditions and anticipated constraints.

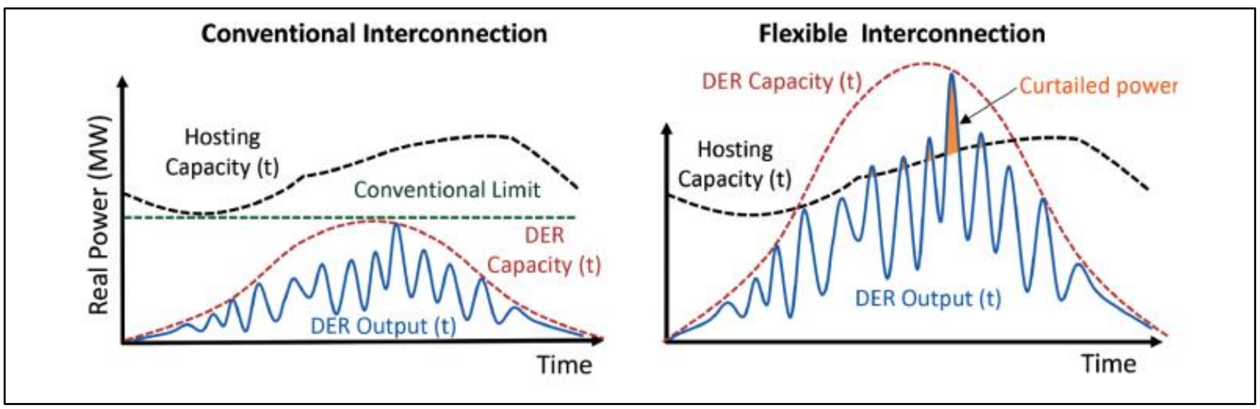

Figure 10. Conventional Interconnection Versus Flexible Interconnection (Source: EPRI, 2015)

Flexible interconnection allows for more intelligent use of the available capacity identified in enhanced distribution planning and hosting capacity analysis in exchange for modest export

[82] For more information on interconnection solutions, see https://emp.lbl.gov/interconnection-innovation-e-xchange.
[83] Adapted from Yu and De Martini, 2024.
[84] EPRI, 2022.

curtailment. The operating limits for each energy-exporting distributed resource, or demand by a large load, are determined by 8,760 hourly forecasts and coincident hourly distribution hosting capacity. This results in seasonal, monthly, or daily operating limits for GER and large loads based on available distribution capacity at each time interval. These variable operating limits are also referred to as the dynamic operating envelope.

A 2024 CPUC decision adopted Limited Generation Profiles to enable flexible distribution interconnections. These profiles are dynamic operating limits that specify the maximum amount of energy a GER can export to the grid at specific times of year, based on available distribution capacity.[85]

Flexible connection methods can serve as a temporary or a more permanent solution. In a temporary context, flexible connections enable distributed generation, energy storage, and large loads to connect more quickly, bridging the gap until completion of scheduled distribution reinforcements. Alternatively, they can serve as a longer-term solution until other proposed distributed resources and large loads necessitate a distribution system upgrade.

Deliverability reviews

Federal Energy Regulatory Commission (FERC) Order No. 2222 (2020) revised federal regulations to remove barriers to the participation of GER aggregations in RTO/ISO capacity, energy, and ancillary services markets.[86] The order required the six affected RTOs and ISOs to revise their tariff to give electric distribution companies (utilities) up to 60 days to review proposed GER aggregations for capability, safety, and reliability. FERC has accepted the final compliance filings of the RTOs and ISOs. Utility 60-day review process and methods are under development.

The review process is designed to ensure that GER aggregations are technically sound, compliant with FERC interconnection rules, and do not introduce risks to distribution operations. The review consists of two functions: a Capability Review and a Safety and Reliability Review.

The Capability Review allows distribution utilities to confirm that each GER in an aggregation has an approved interconnection agreement and that participation in wholesale markets does not conflict with retail tariffs. The review also validates that proposed operating characteristics of GERs are consistent with their interconnection agreements and they are not receiving dual, conflicting forms of compensation. In short, the capability assessment verifies that aggregations are built from eligible, properly interconnected, and tariff-compliant resources.

The Safety and Reliability Review provides a structured opportunity for the utility to examine whether GER aggregations may pose risks to the safe and reliable operation of its distribution system. This includes evaluating dispatch profiles, hourly schedules for storage resources, and interconnection agreement limits (e.g., export caps or service restrictions). The review may

[85] IREC, 2024.
[86] FERC, 2020.

differentiate among different types of GERs, since each has distinct impacts on feeder operations. Such an assessment would consider hosting capacity limits, potential impacts from reverse power flow, minimum net load, and other relevant factors. If the utility identifies risks, it may recommend upgrades, operational limits, or additional studies.[87] Utilities are expected to establish a streamlined and consistent process to ensure that the 60-day review is fairly administered and supports participation in wholesale markets for projects that do not jeopardize distribution system reliability. Beyond compliance, these reviews are critical for building confidence in the deliverability of distributed generation and batteries supplying wholesale energy.

Even without regulatory mandates, the same principles apply to states without organized wholesale electricity markets. Deliverability confidence ensures that GERs included as resources in IRPs are not constrained by distribution system limits. If unidentified constraints arise, this could erode resource adequacy or require reliance on costlier resources.

Deliverability reviews will become foundational for credible resource planning and resource adequacy assessments for utilities with material levels of distribution-connected generation and batteries. This requires confidence that GER resource paths are unconstrained by local hosting limits or tariff conflicts. As such, incorporating findings of a distribution deliverability assessment, such as identified operating limits, of forecast energy injection from supply-oriented distributed generation and batteries into an IRP will be increasingly important. Strengthening this link, combined with a probabilistic-based operational potential analysis, improves certainty that GERs can be dispatched as planned, enabling planners to reduce contingency margins and better integrate GERs as reliable resources. As GER aggregations serving wholesale needs becomes more common, it will also become increasingly important to consider and clarify dispatch practices, priorities, and the impacts on distribution systems when dispatched for bulk needs.

3.4 Integrated System Analysis

As states move toward more comprehensive and coordinated approaches to electricity system planning, integration of distribution system elements in IRPs is increasing. The joint NARUC-NASEO comprehensive planning initiative[88] underscore the importance of treating these traditionally separate functions as interconnected layers of a single system, where investment decisions at one level inevitably shape options and costs at the other. This illustrates the shift underway to embed distribution system insights (e.g., values for avoided distribution system costs) and resource interactivity (e.g., value of grid services) into long-term planning and procurement processes.

3.4.1 Convergent and divergent value analysis

A divergence between bulk system peak demand and distribution feeder peak demand means that the overall electricity usage for the utility's service area might peak at a different time or have a different magnitude than the peak demand experienced by individual distribution

[87] RTOs/ISOs may require supporting documentation to substantiate these recommendations.
[88] NARUC-NASEO, 2021b.

feeders. *Convergence* occurs when local grid demand peaks coincide with bulk power system peaks, and resource benefits align at both levels of the electricity system. If peak demand is *divergent,* benefits at one level of the electricity system may be offset or diminished by another level of the electricity system, underscoring the importance of coordinated planning. The convergence or divergence of peak demands impacts the total value of GERs for the distribution and bulk power system, as illustrated in Figure 11.[89]

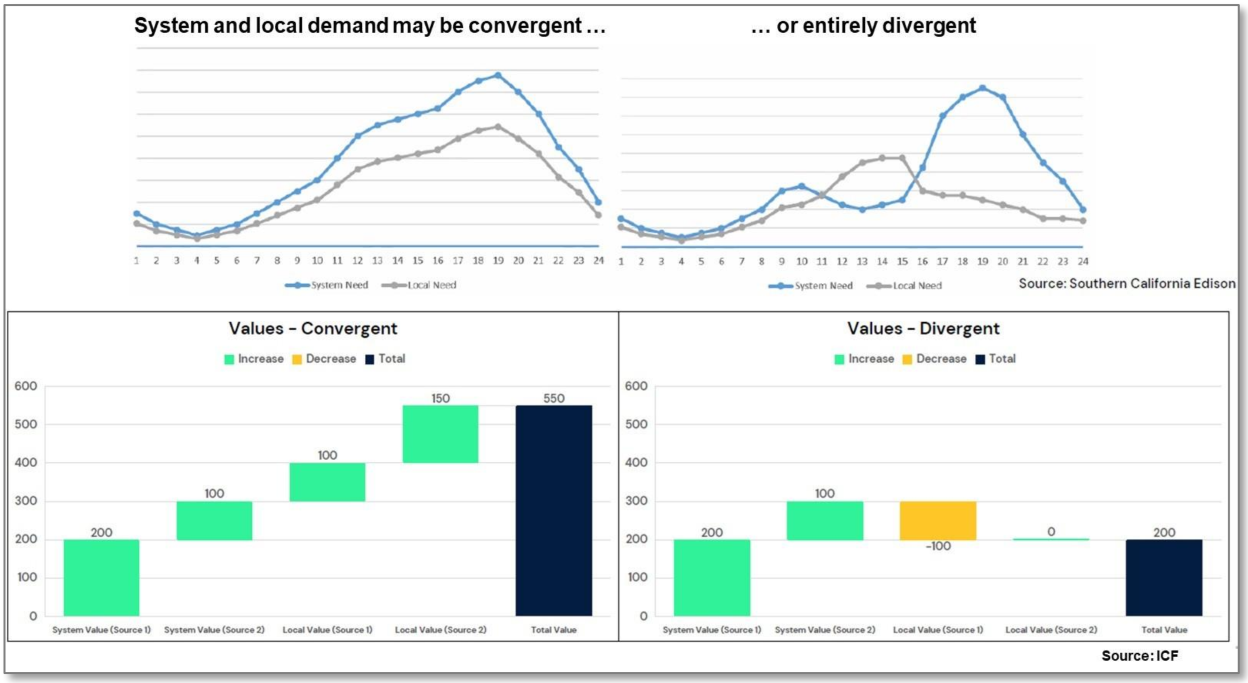

Figure 11. Alignment of System and Local Demand (Source: Southern California Edison 2024; ICF, 2026)

Alignment or divergence of peak demand can occur based on timing differences related to the net effect of bi-directional energy flows (i.e., consumption and export) for individual feeders or substations due to customer composition (e.g., residential, commercial, light industrial), interconnected distributed generation and battery storage, and weather (e.g., micro-climate zones), compared to system peaks and weather patterns across a service territory.

- Diverse load profiles across feeders - Different types of loads on various feeders may peak at different times. For example, residential feeders might peak in early morning or evening, whereas commercial and industrial feeders might experience peak demand during daytime business hours.
- Weather variations - Service area and regional differences in temperature and weather conditions, combined with differences in building heating and cooling technologies, can lead to variations in peak demand across different parts of distribution and bulk power systems. This can occur when hot weather in a local area causes a surge in air conditioning use and thus a peak on a particular feeder, while the overall bulk system might not be at its peak at that moment. This also can be true if bulk system planning

[89] EPRI, 2023; SEE Action, 2020; De Martini, Succar and Cook, 2024; SCE 2024 at 28; ICF, 2026.

includes different climate zones across a service territory, as these can exhibit more granular microclimate variations from the system average zone temperatures and humidity. For example, PGE observed that the east side of its service territory peaked heavily in winter, predominantly due to electric baseboard heating.[90] In contrast, the west side had a higher concentration of gas heat and electric heat pumps, resulting in lower winter demand. The west side had high peaks in the summer due to air conditioning load, while the east side traditionally had low saturation of cooling equipment.[91]

- GER Integration - Distributed generation, battery storage, and large loads sited on individual distribution feeders can shift the timing and magnitude of net feeder load independently of bulk system conditions because the drivers of distribution-level load (e.g., feeder-specific EV charging behavior, rooftop PV penetration, localized weather) are not necessarily correlated with the drivers of system-wide peak demand.
    - For example, a feeder with a high concentration of public EV charging and residential air conditioning may see its net load peak shift earlier in the day, driven by daytime charging activity and rising cooling load as ambient temperatures climb, while the bulk system peak may occur later, in the early evening, once solar output declines and aggregate cooling and lighting load across the broader territory reaches its system-wide maximum. The result is a feeder-level peak that is out of phase with the bulk system peak. In this divergent case, GER used for distribution may not create value for the bulk power system.
    - In a convergent case where peaks are aligned, by contrast, the same resource that serves a distribution peak also provides bulk power system peak-management benefits.
    - In certain divergent cases, however, a GER may have sufficient capability (e.g., state of charge, available capacity) to be dispatched to serve the distribution-level need during its peak window while still retaining capability to serve the bulk system during its separate peak window. A feeder-level GER and load forecast, along with the corresponding hourly feeder power flow analysis, can enable identification of the value potential for both feeder and bulk power system peak management.
- Diversity Factor - The diversity factor describes how the sum of individual peak demands on multiple feeders affects demand on the originating substation. For example, while individual feeders might have high peak demands, their peaks may not coincide, resulting in a lower overall peak for the substation interface to the bulk power system. This is why substation-level GER aggregations spanning multiple feeders may not always address feeder-level constraints. The participating GER may not be located on the constrained feeder or feeder section, or may not be dispatched at times that coincide with individual feeder constraints.[92] Analysis of distribution constraints should first focus on the specific locations and characteristics of individual constraints.

[90] Murtaugh, 2025.
[91] Keeling et al., 2021.
[92] De Martini, Succar, and Cook, 2024.

Afterward, the constraints may be collectively assessed at a higher level to consider larger GER aggregations.

Assessing the relative convergence and divergence of peaks and how resources impact those peaks informs different value streams of distribution-sited resources that may feed into rate designs, resource operation (e.g., storage dispatch or charging), and resource siting. For example, Xcel Energy's Capacity*Connect program aims to site batteries where distribution and bulk loads coincide to reduce or defer investment.[93]

3.4.2 Co-optimizing Bulk and Distribution System Resources

A central element of comprehensive system planning is co-optimization of bulk power and distribution connected resources. This multi-level planning approach explicitly accounts for interdependencies across the grid. It involves aligning investment strategies and modeling assumptions to ensure that GER impacts, including changes in electricity consumption and peak demand, are incorporated into bulk power system plans. Granular DSP outputs are systematically aggregated into higher-level analyses, rolling up from feeder- and substation-level assessments to sub-transmission nodes and regional bulk system models.[94]

Planners also evaluate system stability and power flow impacts to understand how GERs influence both distribution and bulk power system operations. Importantly, this approach helps distinguish between convergent value cases in which GERs benefit both levels of the electricity system, and divergent cases in which a resource that relieves local constraints may not serve broader system needs.

For example, Puget Sound Energy (PSE) in Washington state is developing an ISP, to be filed on April 1, 2027, that incorporates distribution planning, as required by statute. The ISP builds on previous utility efforts to include DSP elements in IRP. PSE's 2021 IRP included a 10-year "Delivery System Analysis" that included visibility, control, reliability, GER integration, cybersecurity, and major infrastructure needs. Figure 12 depicts PSE's iteration between this analysis and IRP, with the delivery analysis providing avoided T&D values and NWA forecasts, and IRP providing the value of systemwide grid services back to the delivery analysis.

[93] Xcel Energy, 2025.
[94] See ESIG, 2025, for additional information.

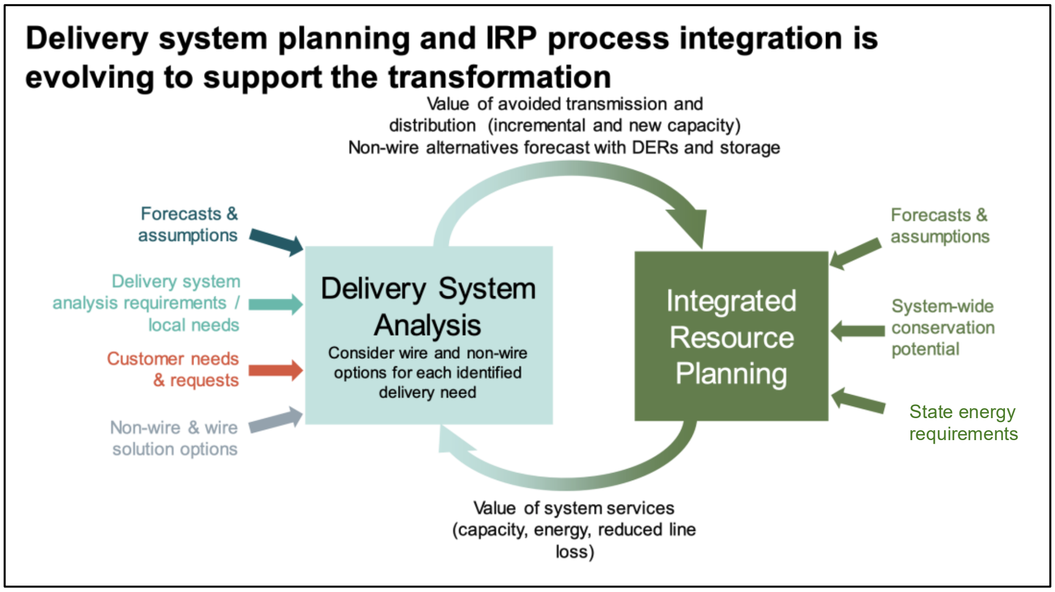

Figure 12. PSE Iteration between DSP and IRP (Adapted from PSE, 2024)

For the 2027 ISP, PSE's DSP priorities are to:

- Invest in T&D systems to timely meet load growth
- Build modeling approaches to evaluate distribution investments in ISP scenarios
- Advance NWAs and GER deployment to optimize GER utilization for system needs.[95]

Figure 13 shows PSE's planning schedule. The utility is building inputs and conducting modeling across different levels of the electric and gas systems at the same time, with built-in opportunity for updates if needed about a year after developing T&D inputs. This aligns with PSE's process for planning distribution system investments based on annually refreshed load forecasts.[96]

[95] PSE, 2025.
[96] Ibid.

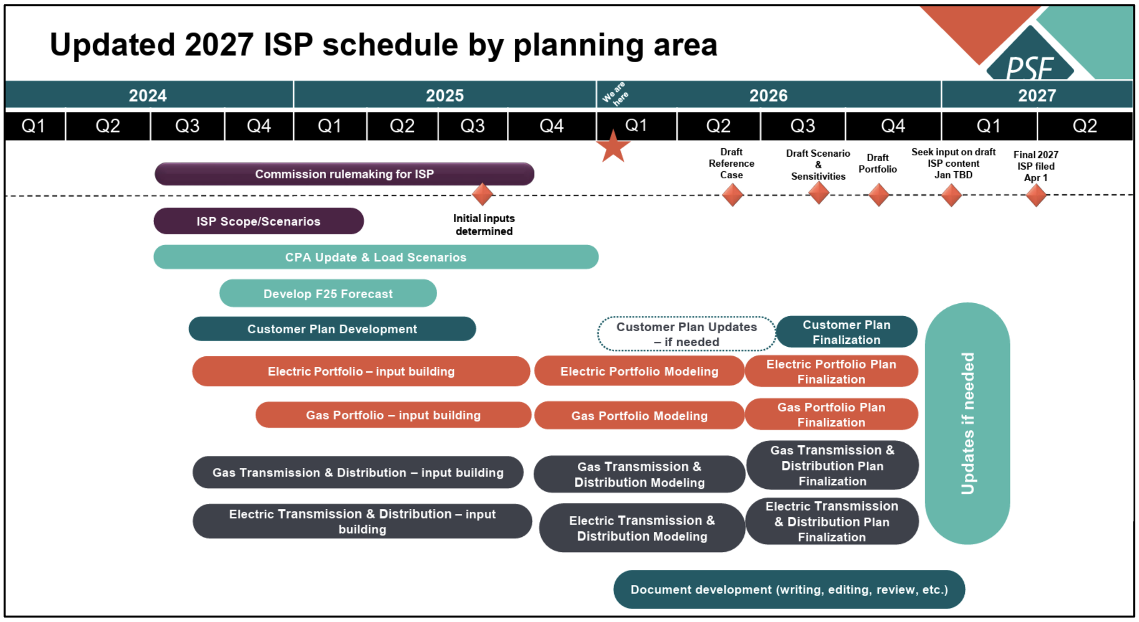

Figure 13. PSE ISP Workstream Sequencing (Adapted from PSE, 2026). Diamonds indicate milestones.

Integration Processes

Integrated planning across bulk power and distribution systems depends on aligned timelines, data, assumptions, and analyses. Successful integration processes also require strong engagement and governance. Transparent processes that incorporate stakeholder input, supported by regulatory frameworks for integrated planning that foster alignment among the utility, PUC, and stakeholders, facilitate reliable and cost-effective outcomes.

Toward aligning timelines, distribution system forecasts and analyses can be extended across the entire IRP horizon. For example, Hawaiian Electric uses LoadSEER to “statistically represent the geographic, economic, and weather diversity across a utility’s service territory and use that information to forecast how circuit- and transformer-level hourly load profiles will change over the next 30 years.”[97]

Because DSP may be updated more frequently than IRP, thoughtful workstream sequencing can allow such distribution-level findings to be incorporated sufficiently early to inform IRPs, ensuring that bulk power system plans reflect the operational realities of rapidly evolving local grids. In this way, electricity system planning moves beyond siloed exercises toward a unified, interactive process that better supports reliability and affordability goals.

Synchronized planning cycles enable distribution feeder- and substation-level insights to inform IRPs. For example, net load forecasts based on granular GER forecasts may impact the location of resource and transmission needs for the bulk power system. Suppose an IRP identifies a particular quantity of distributed generation and batteries as part of the least-cost resource mix, but distribution-level analysis shows that local grid upgrades to interconnect those resources are cost-prohibitive. In that case, the utility would procure more transmission-

[97] Hawaiian Electric, 2020 at 8.

level resources instead. Conversely, distributed generation and batteries may be needed if utility-scale resources or transmission cannot be developed in time to meet projected loads. For example, significant transmission constraints are driving a greater role for customer-sited resources in PGE's resource planning process.[98]

For example, Duke Energy's Integrated System and Operations Planning (ISOP)[99] process synchronizes distribution, transmission, and resource planning by aligning timelines, data inputs, and scenarios. The IRP provides a 15-year outlook, while distribution and GER forecasts are updated more frequently. ISOP bridges these cycles by establishing a continuous feedback loop, where each plan informs the others. This ensures that distribution, transmission, and resource strategies are developed in parallel, using shared assumptions rather than isolated, sequential processes.

A central feature of ISOP is its unified data and forecasting platform, which integrates disparate data into a common system. This enables scenario-driven long-term resource forecasts to be combined with bottom-up distribution analysis and supports coordinated identification of electricity system needs based on information flow across planning levels and horizons. That includes considering distribution hosting capacity analysis for load growth and GER adoption in IRP decisions.[100]

ISOP also institutionalizes evaluation of non-traditional solutions such as batteries that could defer or avoid utility grid investments. When assessing the relative costs of such solutions compared to traditional grid investments, Duke applies IRP-derived values such as avoided supply-side costs and bulk capacity contributions to evaluate distribution-level alternatives on an equal footing with supply-side infrastructure. The process allows Duke to optimize system investments.

Another example is New York's Coordinated Grid Planning Process to improve the integration of resource procurement plans with distribution, transmission, and NYISO planning. [101,102] While tactics have evolved somewhat over time, the initial process envisioned six stages over a 24-month cycle:

- **Stage 1 – Data collection, scenario definition, and capacity expansion modeling:** Selection of inputs and development of assumptions to support least-cost modeling and scenario analysis, focused on identifying bulk generation buildout scenarios using capacity expansion modeling
- **Stage 2 – Network model development:** Development of short circuit and power flow models, over a 20-year period, to identify areas where resources selected by the

[98] PGE, ND.
[99] Keen et al., 2023.
[100] Duke Energy Progress and Duke Energy Carolinas, 2023.
[101] Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; Long Island Power Authority; National Grid (upstate); New York State Electric & Gas Corporation; Orange & Rockland Utilities, Inc.; and Rochester Gas and Electric Corporation.
[102] New York DPS, 2021, at 19.

capacity expansion model can use local T&D assets

- **Stage 3 – Local T&D assessment:** Evaluation of T&D investment needs to enable GERs and utility-scale generation; consideration of distribution upgrades and NWAs to meet grid needs
- **Stage 4 – Review of preferred solutions:** Assessment of systemwide impacts of T&D upgrades identified in the local T&D assessment
- **Stage 5 – Least-cost planning assessment:** Determination of the least-cost resource portfolio considering system limitations identified in stage 3 and the portfolio of T&D solutions developed in stage 4
- **Stage 6 – Cycle I final report:** Production of a final report taking into consideration stakeholder input[103]

Stakeholder input occurs through the Energy Policy Planning Advisory Council, which provides feedback on planning assumptions and analytical approaches.[104] Figure 14 illustrates the Coordinated Grid Planning Process.

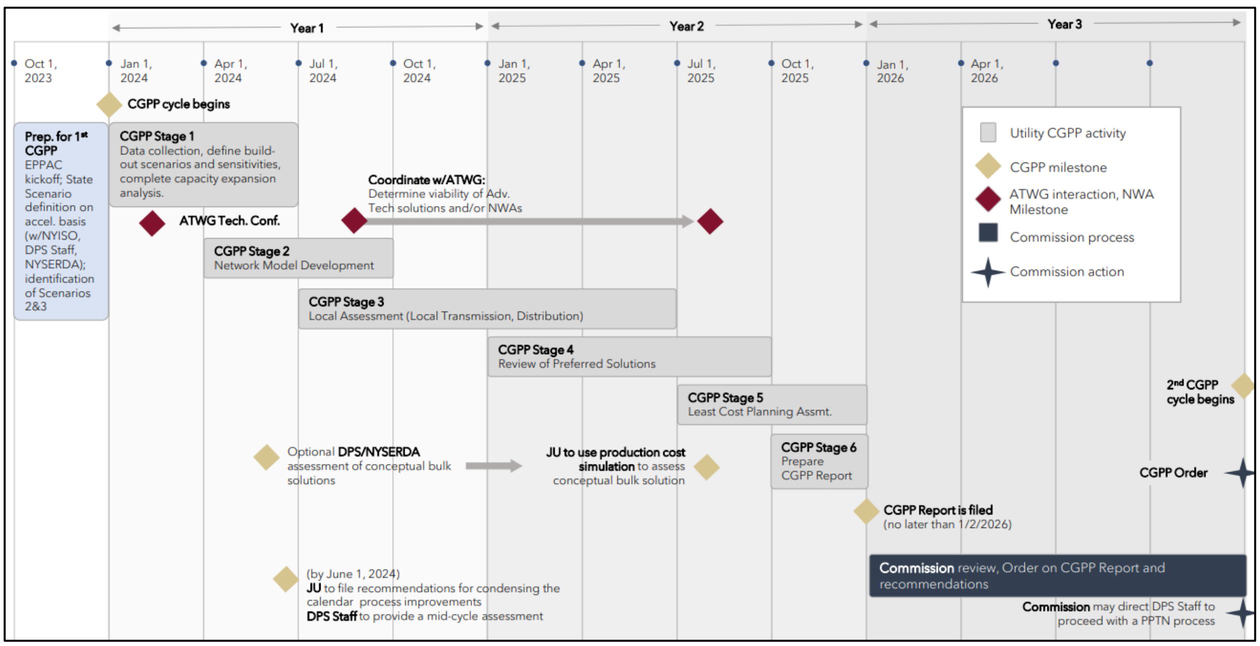

Figure 14. Coordinated Grid Planning Process Timeline (Burrell, 2024) – Acronyms include Advanced Technologies Working Group (ATWG), Coordinated Grid Planning Process (CGPP), Energy Policy Planning Advisory Council (EPPAC), Department of Public Service (DPS), Joint Utilities (JU), New York Independent System Operator (NYISO), New York State Energy Research and Development Authority (NYSERDA), Non-wires alternative (NWA), and Public Power Transmission Need (PPTN)

3.4.3 Coordinated Procurement Practices

As distribution-level needs grow more complex and GER adoption increases, many states are moving toward utility procurements that solicit both distribution and bulk system-connected resources to meet grid needs. Such coordinated procurement ensures that solicitations reflect both bulk-system needs identified in the IRP and locational needs identified through DSP. A

[103] New York DPS, 2023 at 8.
[104] See https://dps.ny.gov/energy-policy-planning-advisory-council.

roadmap developed through the NARUC-NASEO Task Force on Comprehensive Electricity Planning envisions procurement as part of a framework that identifies electricity system needs through integrated distribution and resource planning. Alternatively, solutions identified through distribution NWA procurement also may address a need identified in the IRP. In this approach, procurement serves as both an output of integrated planning and a mechanism for validating planning assumptions (e.g., cost and performance data) through market response (e.g., bids submitted in response to a request for proposals).[105]

Distribution planning also informs deliverability-based screening that affects which resources identified in the IRP move forward into procurement. Utilities increasingly use DSP to validate that proposed GER portfolios can be reliably interconnected and deliver the modeled services. For example, Hawaiian Electric uses iterative modeling across transmission, distribution, and generation systems to verify that GER portfolios identified through planning are physically deliverable before they are procured. When distribution constraints emerge, the utility adjusts the analysis to consider the cost of required distribution system upgrades to make sure the aggregated GER resource is still selected as cost-effective in the plan before procurement.[106]

In lieu of competitive procurements, utilities may develop programs or rate designs based on IRP findings. Hawaiian Electric modeled the value of grid services from GERs to inform program design and rate-based price signals.[107]

[105] NARUC-NASEO, 2021a.
[106] Hawaiian Electric, 2023.
[107] Ibid.

4. Summary of Methods in Practice

Each of the procedural and analytical coordination methods described in Chapter 3 are in use or are being tested today. Table 5 summarizes tactics and key takeaways from case study examples of utilities across the country using these practices. The Lab's detailed case studies provide additional information on how utilities are implementing these practices that utilities and states can adapt for their jurisdiction.

Common themes include:

- Sharing forecasts across IRP and DSP, including disaggregating systemwide forecasts
- Deploying distribution system optimizations, such as conservation voltage reduction, and incorporating the impacts into IRP modeling
- Using a roadmap to improve utility planning processes over time and establish a shared vision among stakeholders

Table 5. Key Findings from Utility Case Studies

Utilities and Jurisdiction	Distribution System Elements in IRP	Takeaways
Integrated System Planning Practices		
Duke Energy (NC, SC, IN)	• Coordinates generation, transmission, and distribution planning through advanced analytics, scenario alignment, and iterative modeling • Identifies distribution-level technologies, such as conservation voltage reduction, to include as resources in IRP	• Iterative data and information exchange across planning teams is critical • DSP can inform locational avoided costs for IRP
Salt River Project (AZ)	• Conducts ISP using a single set of forecasts and assumptions • Plans distribution capacity to optimize substation upgrades across ISP scenarios • Identifies in distribution enablement roadmap how local grid planning will become more sophisticated in future ISP iterations	• Tying distribution capacity planning and optimization to bulk system resource siting can help cost-effectively meet system needs
IRPs that Include Distribution System Elements		
Dominion Energy (VA)	• Includes a distribution planning roadmap • Focuses IRP analysis of distribution elements on GER forecasting, hosting capacity analysis, and locational value assessment	• IRP recognizes that strategic GER siting, streamlined distribution-level interconnection, and advanced technologies benefit both the local grid and bulk power systems • The distribution planning roadmap describes grid modernization and identifies strategies for improving modeling capabilities and streamlining workflows over time • Distribution system modeling remains procedurally and analytically separate from resource modeling
DTE and Xcel Energy (MI)	• Uses forecasts consistent with DSP • Uses improved distribution analytics	• Setting aspirational goals for integration helps engage all parties toward a common end-state • Stakeholder engagement can be an effective tool for advancing planning capabilities because parties can encourage a focus on coordinated planning and bring emerging practices into the record of the proceeding

Utilities and Jurisdiction	Distribution System Elements in IRP	Takeaways
Idaho Power (ID, OR)	• Uses disaggregation and reconciliation tactics to align IRP and DSP forecasts • Models distribution-sited batteries for T&D deferral in IRP	• System-wide forecasts serve as the basis for granular DSP forecasts • Near-term actions identified in the DSP are included as assumptions in the IRP
Indiana Michigan Power (IN, MI)	• Reconciles IRP forecasts with granular, short-term forecasts • Includes grid modernization efforts in IRP to inform NWAs and improve load forecasting	• Planning requirements in one state may have spillover effects for a multi-jurisdictional utility that applies improved practices across its service area
Minnesota Power (MN)	• Uses GER forecasts and assumptions consistent with DSP and considers whether aggregated GERs can provide peak-hour capacity services • Applies a Grid Essential Services framework that uses multiple analyses to evaluate whether T&D systems can reliably support future resource portfolios	• New planning tools enhance grid visibility and strengthen analytical coordination
Public Service Company of Oklahoma (OK)	• Models distribution-level capacity savings from conservation voltage reduction • Is developing an integrated planning roadmap through its parent company	• Despite a lack of formal requirements, the utility includes distribution elements in its IRP to provide greater visibility into capital spending
Southern California Edison (CA)	• Disaggregates statewide common forecasts for use in IRP and DSP • Uses hosting capacity and constraint analysis to inform resource siting	• Planning coordination benefits from a single data set for inputs and assumptions
Vermont Electric Cooperative and Green Mountain Power (VT)	• Aligns inputs and assumptions across utilities, a statewide transmission company, commercial customer representatives, energy supply companies, and other and other stakeholders through transmission planning process • Deploys distribution assets and NWAs at the transmission level to defer or avoid T&D upgrades	• Established discussion forums are important for aligning processes with multiple entities involved

5. Conclusion and Leading Practices Checklist

Electricity system planning is increasing in sophistication to more effectively plan for utility investments to meet local grid and systemwide needs at least cost. With a growing focus on distribution system spending and affordability, utilities, PUCs, and stakeholders are advancing IRP practices to provide greater visibility into electricity system needs and improve decision-making under uncertainty. In particular, identifying key linkages between distribution and bulk power systems — and, where appropriate, conducting analyses and implementing solutions across both domains — improve cost-effectiveness of electricity system spending.

Integrating distribution system elements in IRP offers significant value, including:

- Optimized electricity system investments
- Reduced utility costs to meet growing loads
- Greater insight into utility expenditures that are driving increases in electricity rates
- Reduced functional silos at utilities
- Improved plan credibility

At the same time, integrated or coordinated planning activities require significant time and resources for the utility, PUC, and stakeholders and are still in early stages in most parts of the country. Additional experience will identify which practices provide the greatest value for different planning contexts.

The following checklist summarizes leading practices identified in this study to help guide integration of distribution system elements in IRP using processes that are transparent, data-driven, and capable of optimizing investments across all levels of the electricity system. While the checklist includes the primary actor(s) for each item — PUCs, utilities, or both — stakeholder engagement is a hallmark of effective planning processes. For example, State Energy Offices and utility consumer advocates play important roles in identifying state and utility customer interests and actions that support those interests.

Action	Primary Actor(s)	Primary Benefit(s)
Regulatory & Institutional Alignment		
☑ Develop regulatory frameworks for integrated or coordinated system planning	PUCs	Establishes guidance and expectations for planning improvements
☑ Align utility regulatory guidance for IRP and distribution system planning (e.g., specify expectations for consistent forecasts and scenarios)	PUCs	Specifies how planning coordination or integration will occur
☑ Develop a roadmap to improve practices over time and establish a common vision	Utilities	Outlines a long-term vision toward integrating distribution and bulk power system planning and tangible steps to achieve benefits
Aligned Timelines & Horizons		
☑ Sequence planning cycles so distribution insights (e.g., available hosting capacity) feed into IRP decisions on time, and vice versa (e.g., quantity of GERs selected in IRP)	PUCs	Facilitates timely availability of data inputs to coordinate or integrate planning processes
Stakeholder Engagement & Transparency		
☑ Share scenarios, assumptions, and results openly with public utility commissions and stakeholders to solicit input on consistency	Utilities	Enables feedback on assumptions, inputs, and processes to make use of external expertise and stakeholder engagement in regulatory review
☑ Incorporate stakeholder input from various forums into unified forecast assumptions, scenario design, and review processes	Utilities	Facilitates consideration of stakeholder interests and up-to-date knowledge from external experts
Common Data & Assumptions		
☑ Establish unified methodologies, associated load and grid-edge resource (GER) forecasts, and adoption scenarios across IRP and distribution planning	Utilities, PUCs	Aligns forecasts and scenarios to reduce potential conflicts between planning outcomes
☑ Maintain a unified integrated data set in an accessible repository for sharing inputs and results	Utilities	Allows all utility planners to use the same information to achieve least-cost outcomes
Disaggregated Distribution Forecasting		
☑ Align IRP and feeder and substation-level distribution forecasts through a reconciliation method to capture both local and bulk system needs	Utilities	Enables utilities to plan consistently across distribution and bulk power systems

Hosting Capacity & Deliverability		
☑ Assess results of hosting capacity and GER deliverability studies in the IRP process	Utilities	Determines whether GERs can deliver services identified in IRP
☑ Publish hosting capacity maps/tools to guide developer siting decisions for procurements coming out of IRPs	Utilities, PUCs	Enables more efficient siting of distributed generation and storage on local grids
Convergent vs. Divergent Value Analysis		
☑ Screen all eligible identified electricity system needs for cost-effective non-wires alternatives	Utilities	Evaluates all potential solutions to grid needs on equal footing to identify least-cost solutions to grid needs
☑ Identify when, where, and how GERs provide simultaneous (convergent) benefits to bulk power and distribution needs and evaluate these potential solutions in more detail	Utilities	Maximizes benefits across local and systemwide needs
☑ Flag cases where GERs help one level of the electricity system but not the other (divergent) and determine possible mitigations	Utilities	Enables more effective siting of distribution assets to minimize grid constraints or violations
Bulk Power & Distribution System Resource Co-Optimization		
☑ Use technology-neutral procurements	Utilities	Identifies the most cost-effective solutions to electricity system needs
☑ Include GERs as a selectable resource in IRPs and use technology-neutral methodologies for performance accreditation to allow GERs to contribute to resource adequacy assessments	Utilities	Avoids overbuilding and associated costs
☑ Incorporate findings from coordinated planning into procurement processes and validate planning assumptions for cost and performance based on procurements	Utilities	Activates planning to acquire the most cost-effective solutions to electricity system needs and improves information used in the next planning cycle

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Appendix A. Details on the Distribution System Planning Process

The DSP process is increasing in sophistication, enabling better integration with IRP. Modern DSP employs a suite of analytical methods, including the following.

- **Load forecasting:** Like IRP, forecasting is the foundation of the DSP process. Historically, utilities forecasted systemwide peak demand, or seasonal peak demand. Increasingly, utilities are incorporating more spatially and temporally granular forecasts, down to the substation or feeder levels on an hourly (8760) basis, to better understand localized risks and upgrade needs.
- **GER forecasting:** GER forecasting assesses when and where GER adoption may occur, producing estimates of installed capacity and generation and load and dispatch profiles. GER forecasts are important inputs to other components of the DSP. The GER and load forecasts combined create a net load forecast.
- **Power flow studies:** These studies assess voltage profiles, thermal loading, reactive power flows, and unbalanced loading under different grid conditions and futures. Outputs include forecasted voltage and power quality data. Power flow studies are fundamental for hosting capacity analyses and inform grid investment needs.[108]
- **Hosting capacity analyses (HCA):** Derived from power flow analysis, HCA evaluates how much additional GER capacity[109] can be integrated at specific points on the distribution system without negative impacts to power quality or reliability, assuming no changes to the distribution system. This helps to identify the potential location and causes of distribution system constraints and associated modifications such as grid upgrades or operational changes.
- **Resilience and reliability analyses:** Utilities assess the performance of the distribution system across multiple reliability indices such as the System and Customer Average Interruption Duration and Frequency Indices (SAIDI and SAIFI, CAIDI, and CAIFI).[110]
- **NWA analyses:** Utilities assess whether storage or portfolios of GERs can meet certain identified future distribution system needs, such as to provide load reduction, reduce power interruptions, or address voltage issues, in a more cost-effective manner compared to traditional infrastructure.
- **Locational value analyses:** HCA can be used to determine the locational benefits of GERs at specific locations on the distribution system. The analysis can help identify high-value locations for GERs, assist in prioritizing NWAs and other investments, and inform GER compensation and incentive strategies.[111]

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[108] Homer et al., 2020.
[109] Some utilities consider hosting capacity for electric vehicle charging and other loads. The granularity and usefulness of HCA information may vary by type of load (e.g., large loads connected at primary distribution voltage) or GERs assessed. The U.S. DOE tracks HCA information at https://www.energy.gov/cmei/vehicles/us-atlas-electric-distribution-system-hosting-capacity-maps.
[110] Schwartz et al., 2024.
[111] Homer et al., 2020.

Distribution Capacity planning

Distribution capacity planning primarily involves planning for customer load, GER growth, and spare capacity to ensure operational flexibility.[112] The process aims to identify needed upgrades or new equipment where system components no longer meet or are forecasted to exceed (fail) planning standards.

Utilities typically "plan to peak," meaning they design distribution system assets to reliably operate during forecasted peak demand[113] expected to occur during the planning period. The analysis includes the coincident net effect of any export power flows from distribution-level generation. The analysis is based on disaggregated forecasts for loads and GER, weather data, and scenarios (discussed above).

Distribution capacity planning is fundamentally an engineering exercise to ensure substations and circuits can deliver power within thermal, voltage, and protection limits across normal and contingency conditions over a 5- to 10-year planning horizon. The process includes several engineering analyses:[114]

- **Thermal Capability**[115] - Assess the ability of conductors, cables, transformers, voltage regulators, breakers, and other equipment to carry projected loading within design standards for normal and emergency ratings, contingency margins, loading durations, and weather conditions
- **Voltage/Power Quality** - Assess whether steady-state voltages and other service quality operating criteria, such as acceptable service voltage levels, flicker, power factor, and harmonic distortion, that may be affected by customer machinery and generation inverters remain within required standards[116]
- **Contingency Transfer Capability** - Assess the capacity of the distribution network to enable switching plans and back-ties without violating thermal or voltage limits during planned and unplanned events
- **Protection and Safety** - Assess fault-current duties within transformer, conductor, and other distribution equipment ratings; coordinate relay and fuse protection with GER adoption, including bidirectional flows; and determine proper protection settings for contingency grid reconfigurations
- **Deliverability Paths** - Determine unconstrained and constrained distribution areas, substation transformers, and feeders to interconnect and transport injected energy from

[112] Operational flexibility allows the utility to move load on the distribution system when needed for planned maintenance and reliability during unplanned outages.
[113] Often caused by extreme temperatures. Utilities typically use a probability-based metric in power distribution to ensure grid reliability. For example, a P90 forecast indicates a 10% chance that actual peak demand will exceed the forecast.
[114] Hawaiian Electric, 2020.
[115] Electric current flowing through a distribution network generates heat. The higher the current (and associated power), the greater the heat generated. "Ampacity" refers to the safe level of current-carrying thermal capability. It is a calculated, continuous rating of the conductors' ability to operate safely, even on the hottest day, without failing.
[116] The national standard, ANSI C84.1-2020, establishes nominal voltage ratings and operating tolerances for 60 Hz electric power systems above 100 Volts (V), up to a maximum system voltage of 1,200 kV. For example, for a nominal operating voltage of 120 V, the acceptable operating voltage range is 114 V–126 V.

distributed generation and batteries (both front of the meter and behind the meter) to desired locations in the bulk system[117]

The outputs of DSP include technical metrics, documentation of analyses and decision making, including investment plans. Documentation includes hosting capacity maps, reliability indices, system upgrade requirements, locational value estimates, and NWA assessments. Increasingly, these outputs are shared publicly through filings, data portals, and stakeholder workshops. Many states now require utilities to demonstrate how they engage stakeholders such as utility consumer advocates in shaping planning assumptions and evaluating alternatives.[118]

DSP Procurements

DSP has historically focused only on procuring utility-owned equipment to meet engineering-based needs. However, DSP increasingly evaluates alternatives to traditional distribution infrastructure investments. Utilities may use competitive solicitations to determine whether NWAs are cost-effective, as well as geotargeted utility programs and rate design (Schwartz et al., 2024).

[117] This may involve hosting capacity analysis and additional deliverability analysis to assess impacts of reverse power flow.
[118] Schwartz et al., 2024.

Appendix B. Key Resources

- Best Practices in Integrated Resource Planning
- Bridging the Gap on Data and Analysis for Distribution System Planning: Information That Utilities Can Provide Regulators, State Energy Offices and Other Stakeholders
- Changing Considerations for Integrated Resource Planning (IRPs) for Systems in Transition
- Charging Ahead: Grid Planning for Vehicle Electrification
- Distributed Energy Resources and Electric Vehicle Adoption
- Distribution Capacity Expansion Planning: Current Practice, Opportunities, and Decision Support
- Distribution Grid Orchestration
- Distribution Planning with Local Resources: Integration and Valuation
- Distribution System Evolution
- Distribution System Scenario Planning Case Study and Guidance on Considering Scenarios and Investment Approaches in Distribution Planning
- Evolving Paradigms in State-Level Integrated Resource Planning
- Flexible DER & EV Connections
- Gaps, Barriers, and Solutions to Demand Response Participation in Wholesale Markets
- Grid Planning for Building Electrification
- Integrated Distribution Planning: A Path Forward
- Integrated Resilient Distribution Planning
- Integrated System Planning Guidebooks
- Integrated System Planning: Holistic Planning for the Energy Transition
- NARUC/NASEO comprehensive electricity planning resources
- Reimagining Resource Planning
- Resource Planning and Regulatory Considerations
- Sourcing Distributed Energy Resources for Distribution Grid Services
- State regulatory opportunities to advance Distributed Energy Resource Aggregations in Wholesale Markets
- State Requirements for Distribution System Planning
- Summary of Electric Distribution System Analyses with a Focus on DERs

Appendix C. List of Organizations Interviewed

Organization	Type
California Public Utilities Commission	PUC
Camus Energy	Industry
Duke Energy	Utility
E3	Industry
Georgia Public Service Commission	PUC
Green Mountain Power	Utility
Hawaiian Electric Company	Utility
Idaho Power	Utility
Indiana Utility Regulatory Commission	PUC
Maryland Public Service Commission	PUC
Michigan Public Service Commission	PUC
Minnesota Public Utilities Commission	PUC
Missouri Public Utilities Commission	PUC
New York Department of Public Service	PUC
Salt River Project	Utility
Telos Energy	Industry
University of Vermont	Industry
Vermont Electric Coop	Utility
Virginia State Corporation Commission	PUC

June 2026

Case Studies: Effectively Considering the Distribution System in Integrated Resource Plans

Grace Relf, Paul DeMartini,[1] Jasmine McAdams, Lisa C. Schwartz, and Vinita Srinivasan, Lawrence Berkeley National Laboratory

[1]Newport Consulting Group

The following case studies accompany the report, *[Effectively Considering the Distribution System in Integrated Resource Plans]*. They discuss examples of utilities and states implementing procedural and analytical tactics to incorporate elements of distribution system planning (DSP) in integrated resource plans (IRP). Each case study provides information on the regulatory and planning context in the jurisdiction, details on the distribution system elements that are included in IRP, and key takeaways.

The case studies demonstrate how planners are employing the methods described in the report under a variety of planning requirements, market types, and in service of different planning objectives. Utilities, regulators, and other stakeholders can draw on these real-world examples to begin considering distribution system element in IRP, or improve on current methods. LBNL selected case studies based on three criteria:

1. The presence of explicit or emerging efforts to coordinate DSP and IRP processes
2. Availability of recent publicly available planning documents
3. Geographic diversity to capture utilities operating under different regulatory and market contexts and stages of integration

The case studies include utilities that are conducting integrated system planning (ISP) and those that include distribution system elements in IRP.

Case studies include:

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ISP Practices

Duke Energy (North Carolina, South Carolina, Indiana)

Regulatory and Planning Landscape

Duke Energy Corporation owns electric utilities in multiple jurisdictions, including Duke Energy Indiana serving central and southern Indiana, Duke Energy Carolinas (DEC) serving western North Carolina and western South Carolina, and Duke Energy Progress (DEP) serving eastern North Carolina and eastern South Carolina. While each jurisdiction has different regulatory frameworks, planning objectives, and requirements, Duke Energy Corporation is moving to better coordinate DSP and IRP in all three states.

<u>North Carolina and South Carolina</u>

In the Carolinas, Duke develops a single Carolinas Resource Plan that serves both states through one analysis, supplemented by state-specific chapters.[1] The North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC) each review these filings under their respective schedules. North Carolina legislation requires that the IRP process be combined with another required plan.[2] The combined plan must include (1) multiple resource portfolios examining different pathways to meet reliability and other objectives; (2) a near-term action plan identifying supply- and demand-side projects, generator retirements, and transmission upgrades necessary to support modeled portfolios; and (3) a discussion of how the IRP is integrated into transmission system planning, ensuring resource portfolios align with local and regional transmission studies.[3]

In South Carolina, the IRP follows Integrated Resource Plan statute requirements.[4] Utilities file a plan at least every three years, with annual updates each year, that provides a long-term forecast of sales and peak demand under multiple scenarios and a strategy for meeting those needs. Utilities may include distribution resource plans or integrated system operations plans in their filings.[5]

<u>Indiana</u>

Utilities file an IRP with the Indiana Utility Regulatory Commission (IURC) every three years. Indiana's IRP administrative code requires "A discussion detailing how information from advanced metering infrastructure and smart grid, where available, will be used to enhance usage data and improve load forecasts, DSM [demand-side management] programs, and other aspects of planning, and a "discussion of distributed generation within the service territory and its potential effects on: (A) generation planning; (B) transmission planning; (C) distribution planning; and (D) load forecasting."[6] Additionally, the utility is required to file a 5–7 year plan for Transmission, Distribution, and Storage System Improvement Charges (TDSIC), updated annually. Utilities use

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[1] Duke Energy, 2023a.
[2] N.C.G.S. § 62-110.1(c).
[3] NCUC, 2023.
[4] South Carolina Code § 58-37-40.
[5] South Carolina Code § 58-37-40 B(2).
[6] Indiana Administrative Code (IAC), Chapter 170, 4-7-4.

the planning process to propose transmission, distribution, and energy storage infrastructure installations or replacements intended for system reliability, safety, or system modernization, and request incremental cost recovery for such projects.[7] In some cases, Duke assesses the system-wide impacts of TDSIC projects as part of the IRP, which can help to identify how distribution-level investments support a cost-effective portfolio to meet future demand.

Distribution System Elements in the IRP

Duke Energy has taken steps toward integration between distribution and resource planning. The utility developed tools and processes to coordinate across planning domains to improve reliability, reduce costs, and manage impacts of changing loads and GERs.[8]

Integrated System and Operations Planning - North Carolina and South Carolina

To meet regulatory expectations in North Carolina and South Carolina, Duke Energy developed an Integrated System and Operations Planning (ISOP) framework (summarized in Figure 1), which coordinates planning across generation, transmission, distribution, and demand-side resources. The ISOP aligns planning outcomes with systemwide reliability and affordability objectives while also capturing localized distribution constraints.[9]

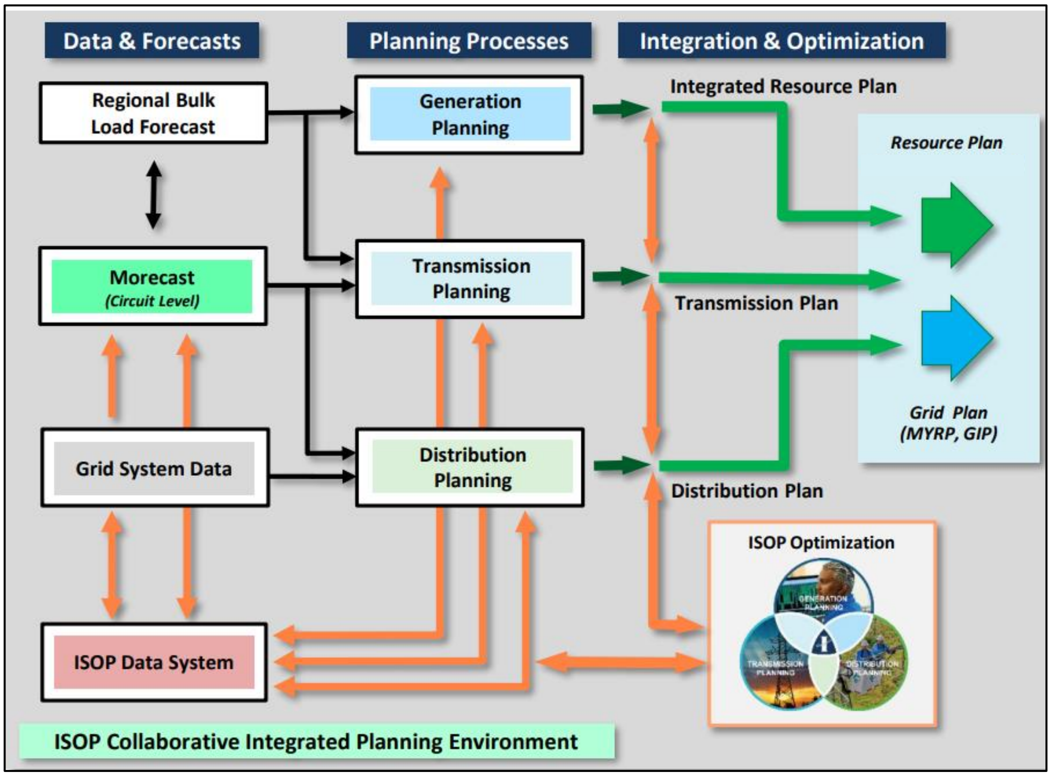

Figure 1. ISOP Process Diagram (Duke Energy, 2026)

ISOP analysis is an iterative process that includes feedback loops with the IRP and annual grid-planning updates. Key process components that coordinate IRP and DSP processes include the following.

[7] https://law.justia.com/codes/indiana/title-8/article-1/chapter-39/section-8-1-39-6/.
[8] Keen et al., 2023.
[9] Ibid.

- **Granular Load Forecasting (Morecast):** Duke's Morecast tool produces 10–11 year hourly forecasts at the distribution circuit level. These granular forecasts disaggregate jurisdiction-wide IRP load projections into feeder-level using GIS-linked data. They incorporate assumptions about GER adoption, EV growth, and energy efficiency. Feeder-level forecasts are aggregated to align with IRP systemwide load projections. Duke uses collaborative review sessions between DSP and IRP teams to reconcile differences between Morecast and IRP load projections. The teams then work to identify underlying drivers of the discrepancies and determine whether to adjust forecasts or note distribution-specific constraints.[10,11]

- **Advanced Distribution Planning:** This includes granular, circuit-level power flow analyses to identify capacity and voltage constraints under projected load and GER adoption scenarios. Historically, this type of analysis informed only traditional solutions, such as reconductoring, transformer upgrades, and phase balancing. Under ISOP, planning is evolving to evaluate NWAs on longer time horizons and with greater spatial granularity.[12]

  One innovative feature is the ability to generate localized avoided cost values that link distribution investments to bulk system planning. By quantifying the deferral and reliability benefits of site-specific DERs, Duke can translate distribution-level insights into inputs for the IRP. These avoided costs inform IRP modeling of non-traditional solutions.[13]

  To make these comparisons between distribution-sited and bulk system investments, Duke uses IRP modeling software to estimate the marginal system value of grid services (e.g., capacity, energy, and ancillary services) and then adjusts these proxy values using distribution-level data. This approach allows planners to test whether targeted investments on the distribution grid, such as strategically placed batteries, can provide comparable or greater system value than traditional transmission upgrades or new generation capacity. These site-specific adjustments help quantify how localized resources contribute to broader system reliability, cost, and other objectives. Because these assessments depend on detailed circuit-level modeling, the Advanced Distribution Planning tool is essential for evaluating project-level tradeoffs that the IRP cannot capture on its own.[14]

- **Scenario-Based Alignment:** IRP future scenarios are shared with ISOP, providing a common foundation for modeling across planning functions. This ensures consistency in assumptions, enabling alignment between bulk system portfolios and local distribution system needs. In the Carolinas Resource Plan, Duke developed three Energy Transition Planning Pathways. Within these pathways Duke also modeled three core portfolios with variants for each pathway as well as ten sensitivity analysis portfolios.[15]

- **DER Contributions and Resource Adequacy:** Duke evaluates the effective load carrying capacity (ELCC) of DERs to quantify their contribution to system reliability. These ELCC values

[10] Keen et al. 2023.
[11] Duke Energy, 2023b.
[12] Keen et al. 2023.
[13] Duke Energy, 2023b.
[14] Ibid.
[15] Ibid.

are aggregated to the system level and incorporated into IRP resource adequacy assessments.[16]

- **Data Integration & Guidance Maps:** ISOP brings together disparate datasets across generation, transmission, and customer programs into common reference points. For example, distribution generation guidance maps illustrate areas on the distribution system with cumulative and individual site constraints that could impact interconnection of additional distributed generation. Maps based on hosting capacity analysis conducted through the utility's distribution planning process identify where additional DERs can be accommodated. Distributed generation studies and hosting capacity analysis inform Duke's IRP assumptions about distributed generation potential in a particular area of the distribution grid.

ISOP also is a valuable framework for meeting operational needs. Rapid GER adoption, load growth, and evolving load profiles are placing increasing pressure on Duke's bulk power and distribution systems, resulting in upward pressure on electricity rates.[17] This has pushed the utility to optimize resources across planning domains to support least-cost planning. Additionally, the ISOP framework has added organizational value by coordinating DSP and IRP teams. Leveraging distribution-level operational perspective also helps bulk power system planners check whether their portfolios are realistic, called the "check-and-adjust" approach, and provides information for siting resources to maximize system benefits.

<u>Smart Grid and Voltage Optimization - Indiana</u>

Duke Energy Indiana implements smart grid technologies through the TDSIC process, including an objective of serving 65% of customers through automated circuits.[18] One such initiative is automated voltage optimization, or Integrated Volt/VAR Control (IVVC). Duke completed phase I of its implementation in 2022 and operates IVVC in Conservation Voltage Reduction (CVR) mode. IVVC uses voltage regulators, capacitors, and a software-based control system Distribution Management System that together manage voltage and reactive power. CVR creates a sustained reduction in voltage year-round, which translates into consistent energy savings. For example, a 2% voltage reduction equates to a 1.4% load reduction for circuits with CVR.[19]

Duke Energy Indiana incorporates IVVC into IRP as a supply-side resource to allow the model to optimize resource selection across all options. The utility estimates demand reduction from IVVC on the distribution system at 0.69% in 2024, reaching 0.8% by 2028. The utility uses these estimates as inputs for the IVVC resource in IRP capacity expansion and production cost modeling. Modeling results project winter peak load reductions from the IVVC resource in 2025, 2030, and 2035 (Table 1).[20]

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[16] Keen et al. 2023.
[17] Duke Energy, 2023a.
[18] Duke Energy Indiana (DEI), 2021.
[19] DEI, 2024.
[20] Ibid.

Table 1. IVVC Winter Peak Load Reduction Shaving Capacity (DEI, 2024)

Year	Winter (MW)
2025	41
2030	46
2035	46

Key Takeaways

Duke's explicit inclusion of distribution-level technologies developed and implemented through its distribution planning process results in meaningful reductions in peak load in the IRP. The utility also discusses the importance of its distribution-level investments for improving customer reliability through reduced outages.[21]

Salt River Project (Arizona)

Regulatory and Planning Landscape

Salt River Project (SRP) is a not-for-profit, community-based water and electric utility company serving over 2 million people in central Arizona. An elected board oversees the utility; the Arizona Corporation Commission does not regulate it.[22]

The utility proactively conducts a holistic planning process across all levels of the electricity system — ISP — to prepare for fast-changing conditions, including customer adoption of GERs and unprecedented load growth driven by data centers and other large load customers moving into the region. SRP recognized that this complex power system and the challenges associated with it, such as two-way power flow from distributed generation and storage, requires optimizing across the utility's whole system by accounting for T&D needs, in addition to generation requirements.[23]

Previously, SRP conducted planning sequentially, starting with an IRP that subsequently informed T&D and customer program planning, with limited integration between the processes given their asynchronous nature.[24] The shift to ISP allows the utility to consider all key planning components — forecasting, generation planning, transmission planning, distribution planning, and customer programs — within a common modeling framework. This helps SRP to efficiently identify, locate, and prepare for investment needs for an increasingly dynamic electricity system. Further, SRP's ISP provides a consolidated platform to integrate stakeholder feedback throughout the process.[25]

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[21] Ibid.
[22] See https://www.srpnet.com/about/about-srp.
[23] SRP, 2023.
[24] Ibid.
[25] Ibid.

Distribution System Elements in the ISP

The 2023 ISP is SRP's inaugural plan. SRP filed annual updates in 2024 and 2025 and continues to meet with an ISP advisory group to support ongoing planning activities.[26]

SRP starts the ISP process with load forecasting. The utility forecasts significant load growth from advanced manufacturing, new customers, and tech firms. To model expected loads, SRP allocates the system-level forecast to each substation using LoadSEER, a distribution forecasting and planning tool that relies on geographic, economic and historical customer usage data. The process provides SRP with visibility into how customer demand is changing at the substation level[27] and determine where capacity constraints may materialize across the distribution system.

To evaluate possible solutions, SRP first explores operational changes such as shifting loads to neighboring substations with available capacity, to make optimal use of existing infrastructure and avoid additional investments. Where operational changes will not adequately address system needs, the utility aims to strategically site capacity additions where they will maximize value and relieve the most constraints, while adhering to reliability planning criteria.[28] SRP repeats this process for each scenario studied in the ISP, resulting in a plan that specifies capacity additions including details on location and load-carrying capacity requirements for both new and existing distribution substations (Figure 2 and Figure 3). This ranges from 26 substation bay additions in the Desert Contraction scenario (with the lowest load growth) to 84 substation bay additions in the Desert Boom scenario (with the highest load growth) through 2035.[29] These scenarios enable SRP to identify and proactively prepare for distribution and bulk resource needs.

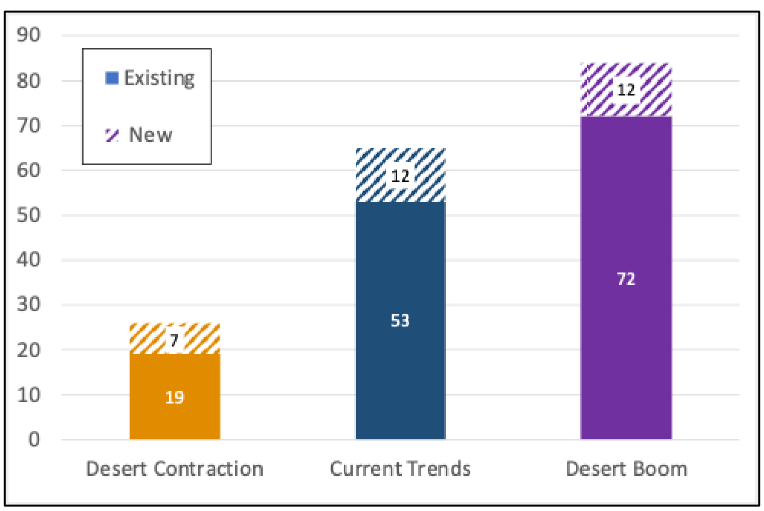

Figure 2. Substation Bay Additions at New and Existing Distribution Substations by 2035 (Adapted from SRP, 2023)

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[26] SRP provides ISP updates on its website: https://www.srpnet.com/grid-water-management/future-planning/integrated-system-plan.
[27] SRP does not disaggregate forecasts beyond the substation level in the ISP due to the number of scenarios it analyzed and time constraints for that level of granularity.
[28] SRP's reliability planning criteria states: (1) A distribution substation bay may not exceed 85% of its emergency rating, and (2) The total distribution system load should not exceed 70% of the total distribution system capacity.
[29] SRP, 2023.

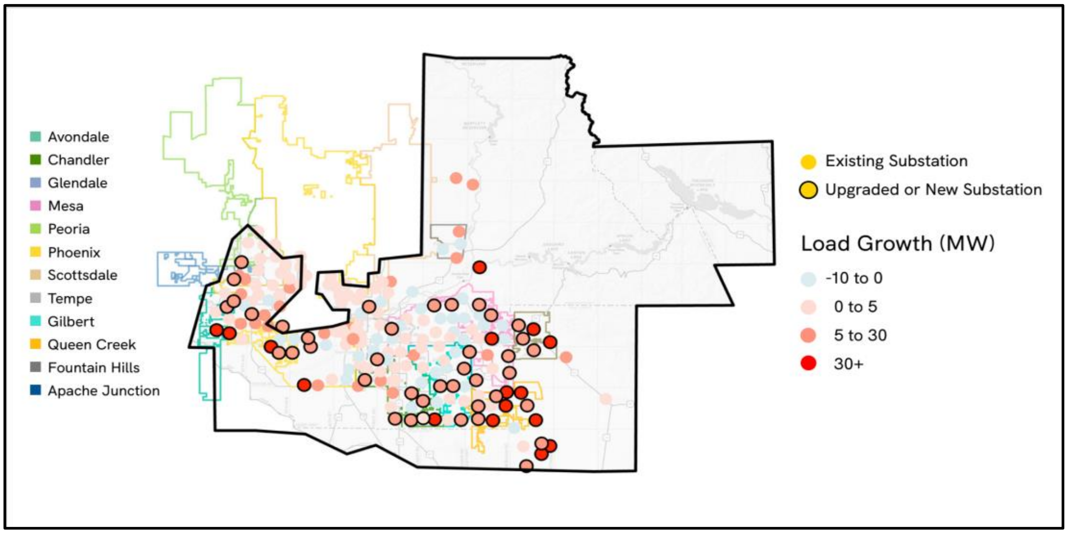

Figure 3. Load Growth by Distribution Substation through 2035 in SRP's Current Trends Scenario (SRP, 2023)

SRP has also developed a Distribution Enablement Roadmap that builds on grid modernization efforts launched in 2014. In the 2025 update to the roadmap, SRP identified that a modern distribution grid enables visibility for proactive grid management, helps to optimize decision making for resource investments and operations that lead to a more affordable energy system, and enhances the physical and cybersecurity of the grid.[30] The plan is centered on four broad focus areas (Figure 4).

1 DEVELOP AGILE GRID ASSET PLANNING

- Create more precise grid expansion and optimization plans that adjust to real-time needs.
- Introduce more granular data and conduct detailed studies and analyses.

2 BUILD ADVANCED GRID MANAGEMENT

- Strategically deploy sensing and control devices to enhance visibility and situational awareness across the grid.
- Upgrade operational systems to effectively orchestrate the integration of distributed energy assets while enhancing power quality, reliability and safety.

3 STRENGTHEN ROLE AS ENERGY OFFERINGS PARTNER

- Optimize the customer experience when connecting behind-the-meter resources to the grid.
- Standardize and automate the interconnection process.
- Enable more tailored, value-added offerings to our customers, including microgrids and virtual power plants.

4 EMPOWER OUR WORKFORCE

- Train and equip employees with future-oriented skills to support the development, maintenance and everyday operations of the modernized grid.
- Invest in the resiliency and flexibility of the local workforce as part of our commitment to the Valley's continued prosperity.

Figure 4. SRP's Distribution Enablement Focus Areas (SRP, 2025)

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30 SRP, 2025.

Aligned with the focus areas, the strategy consists of six integral initiatives, including advanced planning.[31] "[T]he Advanced Planning initiative evolves SRP's approach to develop and deploy efficient, cost-effective solutions for optimizing system growth, with the ability to incorporate new resources and demands by analyzing localized load and demographic information."[32] Through advanced planning, the utility uses locational load and demographic information to improve modeling and forecasting capabilities, including through power flow analysis enhanced with automated modeling capabilities. This could support more accurate load forecasting and spatial allocation in the ISP — moving from the substation to customer-level — and impact investment decisions.

Other projects in the advanced planning initiative include developing feeder-level hosting capacity maps and vehicle scenario planning tools. SRP allocated $3.3 million towards its advanced planning endeavors.[33]

Key Takeaways

SRP is one of the first utilities to undertake a fully integrated planning initiative through the ISP. The utility is conducting distribution capacity planning and optimization and tying it to strategic bulk resource siting to meet system needs at least cost. In the ISP, SRP is disaggregating its system level forecasts to the substation level, rather than to the customer level, due to modeling computational time and the number of scenarios analyzed. SRP has developed a forward-looking Distribution Enablement Roadmap which outlines several advanced planning initiatives that could be integrated into future ISP processes.

[31] The other initiatives are advanced operations, research & development, sensing and control, interconnection improvements, and workforce. Each initiative includes multiple projects.

[32] SRP, 2025, at 16.

[33] SRP, 2025.

IRPs that Include Distribution System Elements

Dominion Energy (Virginia)

Regulatory and Planning Landscape

Dominion Energy Virginia files an IRP with the State Corporation Commission (SCC) every two years, following requirements established under the Virginia Code and SCC guidelines,[34] including elements requiring integration with distribution system elements.[35] The IRP identifies recommended plans to assure adequate and reliable service to meet the utility's long-term demand forecasts, considering electricity generated from existing and future facilities, purchased power agreements with affiliates and third parties, load reduction and demand-side programs, and the deployment of energy storage facilities on the distribution system to support grid transformation. IRPs also must provide systematic evaluations of all resource options, weighing costs, benefits, risks, uncertainties, reliability, and customer acceptance, where appropriate.

IRPs also must evaluate long-term distribution grid planning and distribution grid transformation projects.[36] Distribution grid transformation projects promote grid reliability and security through grid-enhancing technologies, defined as "a set of technologies that maximize the transmission of electricity across the electric distribution grid in a manner that ensures grid reliability and safeguards the cybersecurity and physical security of the electric distribution grid, including storage as a transmission asset, dynamic line rating, power flow control, and topology optimization."[37] If a utility does not include such projects in its IRP, it must provide a detailed discussion of why it did not do so.

Virginia also separately requires distribution planning through the Grid Transformation and Security Act.[38] Under the Act, utilities file annual Grid Transformation Plans for electric distribution grid transformation projects that utilities use to inform IRP or incorporate directly into IRP filings.

IRP and DSP occur simultaneously but remain procedurally separate with touchpoints. Each proceeding stems from a different statutory authority and is subject to separate approval standards. While the IRP must reference and account for distribution-related developments, the SCC reviews and approves distribution investments through separate filings. To illustrate, Dominion includes the Grid Transformation Plan as an appendix in the IRP, but the SCC considers proposed investments associated with the Grid Transformation Plan in a different proceeding.

Distribution System Elements in the IRP

Dominion's 2024 IRP filing includes distribution system elements that provide important context for understanding system constraints, capabilities of distribution-connected resources, distribution

[34] VA SCC, 2008.
[35] Virginia Code §§ 56-598–599.
[36] Ibid.
[37] Ibid.
[38] Grid Transformation and Security Act, 2018 Va. Acts chs. 296–297.

investment needs, and grid modernization approaches. The utility expects load within its RTO delivery zone to double before 2040. In addition, more than 3,500 MW of larger-scale GERs are in the development pipeline, and penetration of such smaller-scale technologies has grown 1400% in the six years prior to IRP filing. Dominion recognizes the need to expand and improve the distribution grid to meet load growth and accommodate customer-hosted technologies, and thoughtfully integrate new distribution-connected resources to avoid possible negative impacts on power quality and reliability.[39]

The *Distribution Grid Transformation* section of the 2024 IRP summarizes the utility's ongoing Grid Transformation Plan activities and highlights distribution system conditions relevant to long-term resource planning. This section provides a high-level overview of the utility's distribution modernization trajectory.

The Grid Transformation Plan is iterative and comprehensive. The intent is to modernize Dominion's distribution grid and prepare for large-scale integration of distribution-connected resources. The plan focuses on six main components:

1. Advanced metering infrastructure
2. Customer information platform
3. Grid infrastructure and technology upgrades
4. Transportation fuel substitution investments
5. Cybersecurity and physical security measures
6. Telecommunications infrastructure.[40]

Dominion's Grid Transformation Plan discusses GER forecasting, hosting capacity analysis, and locational value assessments. These tools allow Dominion to model where GERs are likely to interconnect, how much GER capacity feeders can accommodate, and the potential of GERs in deferring or offsetting grid investments.

Dominion is beginning to implement a more advanced integrated distribution planning framework, included as an appendix in it 2024 IRP. The 2024 Integrated Distribution Planning Roadmap (Figure 5) lays out a multi-year plan that defines the analytical, data, and modeling capabilities the utility intends to develop as it transitions toward more mature integrated planning. The roadmap outlines plans for expanded methodologies for hosting capacity analysis, GER interconnection tools capable of conducting automated time series-based interconnection studies, advanced feeder-level forecasting, distribution engineering model enhancements, resiliency metrics, and a framework for evaluating the locational value of GERs.[41]

[39] Dominion Energy Virginia, 2024a.
[40] Dominion Energy Virginia, ND.
[41] Dominion Energy Virginia, 2024a.

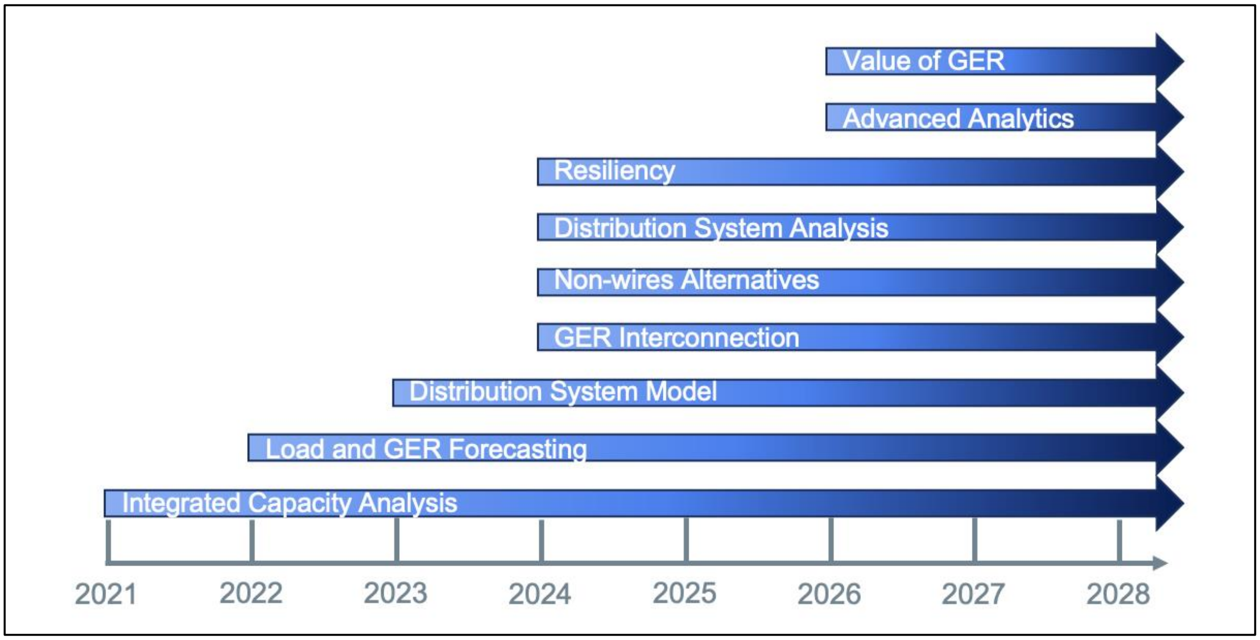

Figure 5. Dominion Virginia Integrated Distribution Planning Roadmap (Adapted from Dominion Energy Virginia, 2024a)

The Grid Transformation Plan also discusses distribution system elements that impact bulk system needs, particularly impacts of the distribution system on electricity service reliability:

- Optimally locating GERs to reduce interconnection costs and defer distribution system investments through hosting capacity maps and NWAs
- Encouraging off-peak EV charging to reduce overall system costs
- More effectively restoring power after outages through situational awareness, outage management investments, and strategic undergrounding to reduce outages overall, freeing up staff resources for restoration activities
- Deploying GERs to optimize grid usage and capacity factor, allowing more flexibility for reliable electricity for critical services

The current phase of the Grid Transformation Plan is focused on distribution system visibility and control functions, including near-complete AMI deployment (approximately 99% of meters), substation technology upgrades, intelligent grid device installations, and early-stage implementation of a GER management system. These investments provide the data visibility and operational flexibility necessary to manage growing GER adoption, electric transportation loads, and increasingly bidirectional power flows (Table 2).[42]

Table 2. Dominion Virginia's Substation Modernization Program (Adapted from Dominion Energy Virginia, ND)

Need	Integrate GERs; improve reliability, power quality, and safety; study advanced substation technology
Deployment Timeline	Modernize 44 substations through completion of the Grid Transformation Plan; deploy advanced substation technology as appropriate based on outcome of pilots

[42] Ibid.

Alternatives Considered	Considered addressing substation equipment issues reactively rather than proactively, but rejected this alternative because it could preclude effective integration of GERs or feeder automation (e.g., Fault Location, Isolation, and Service Restoration) on associated feeders
Benefits	Support for integration of GERs while maintaining voltage stability; improved reliability, power quality, and resilience of the distribution grid; improved visibility and control; enhanced understanding of advanced substation technology
Phase III Request	Modernize 20 substations
Progress to Date	Began design, procurement, permitting, and construction at targeted substations; installed 75 power quality monitors as of December 31, 2022

Dominion explicitly incorporates distribution-level customer intelligence, particularly from data center interconnection processes, into the load forecast. Dominion expects its investment in AMI to further enhance abilities to create feeder-level distribution forecasts for various customer segments that it can roll up for comparison with the system-level forecast. The utility cites its extensive experience with data center customers to inform its data center load forecast using a combination of historical metered data and forward-looking customer intelligence. The forecast is validated by existing contracts with customers, which inform the necessary T&D infrastructure needed for data center interconnection.[43]

Additionally, state code requires IRPs to consider integrating energy storage facilities to improve grid transformation. In response, Dominion is studying distribution substation-sited battery systems to prevent backfeed onto the transmission system and to serve as NWAs, with promising initial results from the first two batteries deployed. Dominion is continuing to build on the pilot storage deployments to understand operational impacts and benefits (Table 3).

Table 3. Dominion Virginia's NWA Program (Adapted from Dominion Energy Virginia, ND)

Need	Gain experience with integrated distribution planning concept in a manner that will provide useful information as the Company moves forward with NWAs; address statutory requirement related to the deployment of energy storage
Deployment Timeline	Issued first RFP for NWA solutions in 2024
Alternatives Considered	Considered alternative timelines for implementing NWA program and energy storage
Benefits	Address statutory requirement related to deployment of energy storage through NWA program; gain experience with NWAs; gain experience with energy storage; potentially defer traditional capital investments

[43] Ibid.

Phase III Request	Approval of process used to solicit and, if selected, implement NWA solutions

Dominion also is starting to evaluate how distribution-level resources can contribute to bulk system reliability as more variable resources come online and more synchronous generators retire. For example, as part of its IRP transmission system reliability analysis, the utility conducted a study to determine how inverter-based resources affect system inertia and frequency and identified that distribution-level resources may be able to provide important inertia services if installed with grid-forming inverters. Dominion is testing this technology as part of a microgrid project.

Key Takeaways

Dominion's 2024 IRP makes distribution system considerations visible, but integration is still mostly limited to conceptual impacts of the distribution system on the bulk power system. Several themes emerge:

- Distribution-level customer intelligence shapes the IRP load forecast.
- Distribution modernization efforts such as strategic GER siting, streamlined interconnection, and advanced grid technologies can have positive impacts on both the local and bulk power systems, particularly for reliability.
- It is important to gain experience with these approaches and build a foundation for future improvements, including improved hosting capacity maps, deployment of advanced distribution technologies, and strategic battery siting.
- Tools for improving DSP capabilities over time are emerging, but they are not fully coordinated with the IRP.
- State code requiring coordination drives inclusion of distribution planning elements in IRP.
- Distribution modernization, while described in the IRP, remains procedurally and analytically separate from bulk power resource modeling.

While the utility files Grid Transformation Plans in a separate docket, its inclusion in the IRP helps to highlight distribution-system needs and capabilities and improve distribution-level visibility to stakeholders in the resource planning context.

DTE and Xcel Energy – MI Power Grid Initiative (Michigan)

Regulatory and Planning Landscape

Michigan's IRP process is codified under Public Act 341,[44] which requires utilities to submit comprehensive IRPs every five years that "represent the most reasonable and prudent means of meeting the electric utility's energy and capacity needs."[45] In 2022, the Michigan Public Service Commission (MI PSC) issued revised filing requirements, expanding expectations for utilities to integrate distribution-level information, NWAs, and GER adoption forecasts into IRP modeling. These revisions require utilities to describe how load forecasts used in IRP modeling align with

[44] Michigan Public Act 341 of 2016, § 6t, MCL 460.6t.
[45] Ibid.

distribution planning forecasts and to assess resource co-benefits that contribute to distribution reliability, resilience, or cost savings.[46]

These changes occurred in parallel with the PSC's 2019 launch of MI Power Grid – a customer-focused, multi-year stakeholder initiative designed to ensure safe, reliable, affordable, and accessible energy resources for the state's energy future. As part of this initiative, the PSC directed staff to investigate opportunities for alignment of Michigan's IRP, DSP, and transmission planning processes through a stakeholder-engaged effort.[47]

Through the Integration of Resource, Distribution, and Transmission Planning Workgroup, Commission staff convened more than 20 subject matter experts representing national laboratories, federal research institutions, utilities, transmission companies, consultants, and other stakeholders. The resulting staff report summarized the stakeholder effort and offered recommendations for improving coordination and information flow between planning domains. These recommendations emphasized the need for:

- Bidirectional information exchange between DSPs and IRPs, ensuring that forecasting assumptions, GER projections, and locational data flow between distribution and resource planning models
- Coordinated planning timelines to enhance transparency and enable consistent scenario assumptions across processes
- Organizational alignment within utilities to support iterative planning, where DSP informs IRP resource needs and IRP-identified resources are explicitly tied to locational distribution constraints or opportunities.[48]

<u>DTE Energy</u>
Michigan utilities have operationalized these expectations in their filings. For example, DTE Electric's 2021 IRP included a suite of integrated planning practices designed to better align resource, distribution, and transmission planning. The utility established common planning objectives across IRP and distribution functions: safe, reliable and resilient, affordable, and customer-focused. DTE also developed shared GER-inclusive forecasting methodologies that generate 8,760 hourly load forecasts at both the system and substation/circuit level, ensuring that both IRP and DSP rely on consistent data and assumptions. These forecasting methods draw on AMI-enabled load shape analytics, localized weather normalization, and feeder-level modeling tools such as CYME, which allow planners to capture the effects of GER adoption, fuel substitution, load growth, conservation voltage reduction, and other distribution-level interventions on both peak and hourly load. The forecasts are developed in coordination with DTE's transmission planning partners using common engineering models (e.g., PSSE/PSLF for transmission studies and unified load flow cases), ensuring that distribution-informed insights translate into regional and bulk power system assumptions.

DTE models distribution-level resources as options in the IRP. Distribution-level pilots, such as conservation voltage reduction/volt-VAR optimization, inform the resource characteristic

[46] MI PSC, 2022.
[47] MI PSC, 2021.
[48] Ibid.

assumptions used in IRP modeling. DTE further coordinates with transmission providers and the MISO Transmission Expansion Plan process through common engineering models that provide an additional layer of alignment across transmission, distribution, and resource planning.[49]

<u>Xcel Energy</u>

Xcel Energy, a multistate utility serving part of Michigan's Upper Peninsula, is operationalizing coordinated planning through an Integrated System Planning (ISP) team, established to integrate generation, transmission, distribution, and gas planning. Xcel Energy's ISP features a five-part system planning cycle – origination, integrated planning, modeling and analytics, conceptual design, and standards & compliance – that ensures a cyclical, cross-functional planning process (Figure 6).[50] This aligns with Michigan's framework, which calls for organizational alignment that links planning objectives and information flows across functional silos.

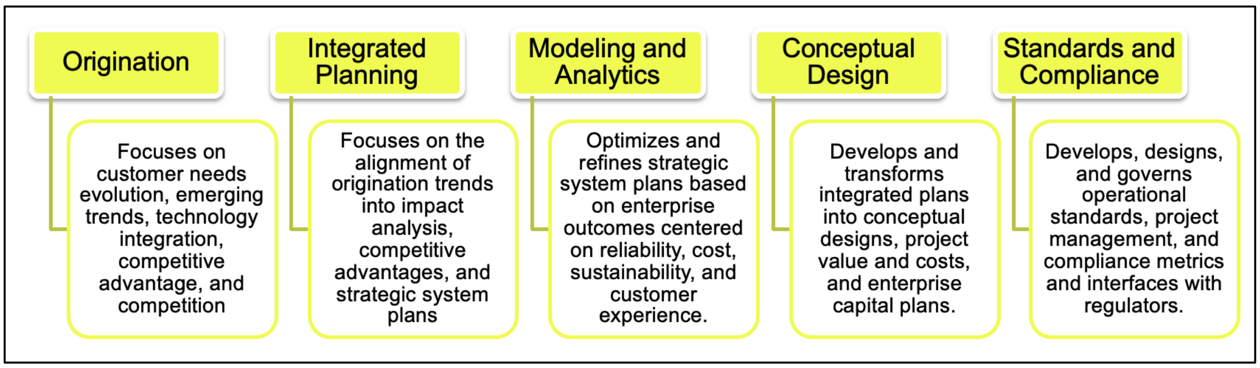

Figure 6. Xcel Energy Michigan's ISP Planning Cycle (Source: Based on Xcel Energy, 2024)

Foundational to this effort, Xcel Energy has advanced its forecasting and technical planning coordination. The utility is working to align IRP and integrated distribution planning (IDP) forecasts, but differences in forecast cadence and modeling timelines can create disconnects, even when the underlying data sets are aligned. This underscores that utilities must balance the analytical value of greater coordination with the practical demands of coordinating distinct processes. Even with timing synchronization challenges, the utility aligns the underlying assumptions and methodologies to make sure plan results are not in conflict with one another.

The utility also now systemically feeds distribution-level insights into IRP modeling through tools such as LoadSEER, which allocates GER growth to specific feeders and produces location-specific upgrade cost estimates that are directly incorporated into resource portfolio modeling, capacity expansion analysis, and transmission and distribution deferral assessments.[51] In addition, the utility enhanced its hosting capacity methodology through the addition of Technical Planning Study Capacity Utilization information —a metric derived from the utility's deeper-resolution engineering studies that evaluate feeder thermal loading, voltage performance, and contingency conditions — and new feeder-update criteria, further improving the accuracy and locational value of distribution planning inputs.[52] These improved distribution-system analytics

[49] DTE, 2021.
[50] Xcel Energy, 2024.
[51] Ibid.
[52] Ibid.

support more targeted siting of storage and other GERs by identifying constrained feeders, transformer loading, and areas experiencing reliability violations.

Process Considerations

MI Power Grid was not only a multi-objective coordination effort, but also an exercise in building institutional capacity. It required new staff knowledge, analytical tools, aligned planning timelines, and governance structures capable of translating coordination goals into actionable modeling and investment decisions.

From a process perspective, MI Power Grid has reshaped stakeholder engagement. The initiative's Phase II recommendations created structured avenues for intervenors and PSC staff to surface analytical gaps and propose methodological improvements, such as linking IRP resource selections to locational distribution needs and evaluating GER contributions to T&D system performance.[53] For example, in Consumers Energy's 2021 IRP proceeding, stakeholders actively used these new channels to improve analytical rigor, including more accurate storage value-stack assessments and more granular analysis of GER benefits for T&D, both of which staff stated as necessary to meet MI Power Grid's expectations for integrated planning.[54]

Even with this expanded engagement, translating MI Power Grid's high-level coordination goals into actionable modeling linkages has been challenging in the early stages of implementation. Commission staff highlighted gaps in the utility's ability to operationalize coordinated planning expectations. At the same time, overlapping state policy frameworks and ISO-level requirements shape IRP decisions in ways that both underscore the need for cross-jurisdictional coordination and introduce additional complexity. For example, staff cautioned that Consumers Energy's proposed resource portfolio could negatively affect adequacy in one MISO region.[55] As a result, utilities conducting coordinated planning may have to consider multiple levels of regulatory or legal requirements, which can at times be misaligned or place competing constraints on planning decisions.

Key Takeaways

MI Power Grid highlights that defining aspirational and longer-term objectives is important to set utilities on a path to improve practical dimensions of integrated planning over time. Alignment across planning domains is widely supported in Michigan. However, the state's early efforts demonstrate that institutional capacity to conduct iterative planning, integrate modeling across different levels of the electricity system, and balance objectives from multiple decision-makers is a key enabler for realizing the full value of coordination between IRP, DSP, and transmission planning.

Michigan's efforts have advanced the state's analytical capacity and reshaped how utilities approach coordination and transparency. Through updated Michigan Integrated Resource Planning Parameters, IRP filing requirements, shared forecasting tools, and stakeholder workgroups, the PSC has begun to institutionalize integrated planning. For example, Xcel Energy is using granular distribution data to inform IRP analysis and resource siting. Still, as Xcel

[53] Michigan Public Service Commission Staff, 2023.
[54] Ibid.
[55] Ibid.

Energy's 2024 IRP illustrates, aligning forecasts across processes remains a challenge due to proceeding timelines. Using the same forecasting methodology helps address that challenge. The state's electric resource planning continues to evolve through Michigan Public Acts 231 and 235, which codify some of the findings of MI Power Grid.

Idaho Power (Idaho and Oregon)

Regulatory and Planning Landscape

Idaho Power is an investor-owned utility that serves customers in Idaho as well as about 20,000 customers in Oregon.[56] The utility files a single IRP to the Idaho Public Utilities Commission (IPUC)[57] and Oregon Public Utility Commission (OPUC)[58] and a DSP with the Oregon PUC covering its Oregon territory. The OPUC initially adopted DSP guidelines in 2020[59] and updated the guidelines in 2024, requiring descriptions of "how the (DSP) investment fits with the utility's other planning processes (such as the most recent IRP)," for both near- and long-term action plans.[60]

Distribution System Elements in the IRP

Idaho Power's IRP includes a discussion of distribution system planning and notes differences between the IRP and DSP processes. IRP analyzes several long-term peak forecast scenarios focused on long-term needs, generally without specifying resource locations, and DSP focuses on "near-term loading scenarios that can stress local capacity or operating constraints."[61] Idaho Power also describes at a high-level how IRP and DSP inform and impact one another.

Forecasting connects both plans. The high-level IRP forecast serves as the basis for elements of DSP forecasting. Idaho Power allocates forecasted EV and GER adoption rates used in the IRP proportionally to each state and then to individual distribution substations and feeders for the Oregon DSP using granular distribution-level data. Specifically, for the systemwide (Idaho and Oregon) GER adoption forecast, the utility forecasts resources that it can monitor and control because those resources are good candidates for distribution-targeted deferral projects.[62]

Idaho Power uses historical adoption trends and customer billing data for its IRP forecast. For the DSP, the utility geolocates GER installations and applies the IRP growth rate assumptions to develop feeder-level GER forecasts.

For the DSP vehicle adoption forecast, Idaho Power uses systemwide IRP EV estimates developed using historical adoption trends and city-level registration data and the Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite.[63] Idaho Power developed an Oregon EV forecast

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[56] In February 2026, the utility announced an agreement to sell its Oregon service area to Oregon Trail Electric Cooperative. The agreement is subject to state and federal approvals.
[57] Pursuant to Order 22299 - Electric Utility Conservation Standards and Practices, issued in January 1989.
[58] Pursuant to Order No. 07-002, Investigation into Integrated Resource Planning, and Order 24-421, Investigation into Distribution System Planning.
[59] OPUC, 2020.
[60] OPUC, 2024.
[61] Idaho Power, 2025a.
[62] Idaho Power, 2022.
[63] EVI-Pro Lite allows users to estimate EV charging load profiles using locationally-specific data and other adjustable assumptions.

based on proportional registrations, then allocated that forecast to each feeder in Oregon with the exception of feeders with fewer than 266 customers, in which case the maximum allowable vehicle loading was set not to exceed 50% customer adoption in the near-term forecast. The utility combines the GER and vehicle forecasts to develop substation and transformer/feeder level loading impacts under different weather scenarios.[64]

DSP informs Idaho Power's IRP by providing T&D deferral values used in the resource stack, which can lead the model to select distribution-connected resources that can defer T&D investments. In turn, any distributed generation and other GERs identified for development in Idaho Power's IRP near-term action plan feed back into the DSP as adjustments to local peak load forecasts.[65]

Idaho Power includes distribution-connected battery electric storage systems (BESS) as selectable resources in IRP modeling. Specifically, the company set its capacity expansion model to select 5 MW increments of distribution-connected BESS annually to provide resource capacity and defer location-specific, growth-driven T&D investments. Idaho Power identified the type and size of the BESS resource to use as a proxy in the IRP model through its DSP process. The modelled storage is based on 4-hour lithium-ion batteries, capable of providing dispatchable capacity and balancing/flexibility services, with an economic life of 20 years. For the 2025 IRP, the utility assumed a levelized fixed capacity cost of $16/kW-month ($2026) for distribution-connected BESS, which is about the midpoint cost of supply-side resource candidates, excluding fuel costs.[66] The smaller resource size and relative cost make distribution-connected BESS an attractive resource for the capacity expansion model.

Idaho Power installed four distribution-connected energy storage projects in 2024 to provide system capacity and alleviate transformer peak loads and defer growth-driven transformer system upgrades. These projects are located at different substations, are all under 5 MW, total 11 MW together, and are expected to defer investment needs for between 4 and 10 years (Table 4).[67] As part of Oregon's IRP process, Idaho Power is expected to share lessons learned about the construction and operation of these resources to identify best practices and lessons learned.[68]

[64] Ibid.
[65] Idaho Power, 2021.
[66] Idaho Power, 2025b.
[67] Idaho Power, 2025a.
[68] Idaho Power, 2025b.

Table 4. Idaho Power Distribution-Connected Storage Systems (Idaho Power, 2025a)

Location	Year	Capacity (MW)	Energy (MWh)	Estimated Deferral Years
Filer	2024	2	8	5
Weiser	2024	3	12	10
Melba	2024	2	8	4
Elmore	2024	4	16	9

Key Takeaways

Idaho Power created feedback loops between planning assumptions and outputs from the DSP and IRP processes. The IRP system-wide EV and GER forecasts serve as the basis for such forecasts for DSP, which the utility then allocates for greater temporal and locational granularity. Conversely, the utility uses analysis performed for distribution planning to inform T&D deferral values used in the IRP.

Idaho Power also models distribution-connected BESS in its IRP to enable cost savings through deferral of both T&D system upgrades and has installed these resources at multiple locations. In areas of rapid load growth, where load-driven capacity expansion needs outpace what distribution-connected deferrals can achieve, BESS can still enable additional GER and EV hosting capacity.[69]

Indiana Michigan Power company (Indiana and Michigan)

Regulatory and Planning Landscape

Indiana Michigan Power Company (I&M) is an AEP subsidiary that is subject to regulation by both Indiana and Michigan.[70] IRP requirements in each state shape how I&M models future system needs and the extent to which the utility incorporates distribution system elements.

In Indiana, the IRP process is governed by the Indiana Code and requires filings every 3 years with a 20-year planning horizon.[71] The IURC does not formally approve IRPs, but instead conducts a technical review process in which staff evaluate the adequacy and transparency of each utility's modeling. The director of the Commission's Research, Policy, and Planning Division is required by statute to comment on whether the preferred resource portfolio accounts for reliability, affordability, resiliency, and other factors.[72] This approach to the IRP filing process means that the impetus for integrating distribution system elements has historically come primarily from commission staff and stakeholders, rather than commission or legislative requirements. In 2025, Indiana amended the code to include a requirement that IRPs filed after 2029 include a description of the electric utility T&D system.[73]

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[69] Idaho Power, 2022.
[70] Michigan's IRP requirements are described in the MI Power Grid case study, above.
[71] IN Code § 8-1-8.5-3 to § 8-1-8.5-5 (2024).
[72] IN Code § 8-1-8.5-3.3 (2024).
[73] IN Code § 8-1-8.5-3.4(d) (2025).

Indiana's flexible IRP framework means that much of the innovation in planning occurs through informal mechanisms such as commission workshops or negotiated settlements. One regular venue for stakeholder engagement is the IURC's annual Contemporary Issues Technical Conference. It provides an opportunity for utilities, stakeholders, and the Commission to better understand and improve IRP processes and analyses. In the 2025 conference, for example, the agenda included discussion on ways to enhance coordination with distribution system planning.[74]

Settlement agreements between stakeholders and the utility also have advanced DSP-IRP integration. In 2023, a settlement agreement as part of I&M's rate case explicitly linked distribution system initiatives to the utility's 2024 IRP. Under the agreement, I&M committed to:

- Provide executable IRP modeling licenses and structured data access to Commission staff, the Office of Utility Consumer Counselor, and Citizens Action Coalition during the IRP process
- Update the utility's Market Potential Study and coordinate with stakeholders to jointly develop DSM and GER modeling inputs
- Include long-duration and multi-day storage technologies in IRP portfolio analysis
- Work with stakeholders to explore and evaluate implementing topics such as distributed generation planning and integrated distribution planning methods[75]

Distribution System Elements in the IRP

Although Indiana's regulations do not formally require DSP-IRP integration, I&M's IRP embeds many DSP-aligned elements, partly reflecting influence from requirements under Michigan Public Act 341 and additional MI PSC requirements. Distribution system elements incorporated into I&M's IRP contribute to resource planning decisions in both states.

Load Forecasting

For residential and commercial customers where electricity usage is sensitive to weather, I&M reconciles short-term, more granular modeling with long-term models that account for macro-economic factors like structural economic changes to yield a product that is "a reasonable and reliable forecast used for various planning purposes."[76]

In general, the forecasting methodology uses a statistically adjusted end-use model considering customer class data, econometric drivers, and emerging distribution-level trends. The utility includes DSM as a variable in its residential and commercial forecasting methodology and impacts of EVs and GERs.

The forecast explicitly incorporates the effects of EV adoption, distributed generation, battery storage, and demand response. GERs are modeled both as load modifiers that reduce net system demand and, in sensitivity cases, as supply-side resource candidates that contribute capacity and energy to the system. I&M conducted a market potential study assessing the increased potential for residential and commercial customer-owned GERs and reflected the

[74] IURC, 2025.
[75] IURC, 2023.
[76] I&M, 2024a at 34.

results in IRP resource optimization.[77] This dual approach enables I&M to assess how GER adoption patterns affect peak demand and bulk power system investment needs.

I&M discussed its modeling approach with stakeholders. For distribution-sited storage, the utility discussed dispatching resources against market prices in an hourly production cost model run, to extract generation and charging costs as inputs to expansion planning optimization (Table 5). Storage assets can be deployed for two use cases. The first addresses deferring upgrades to avoid thermal overload conditions at substations nearing violations. In this case, the capital cost of storage is reduced by the upgrade deferral value. The second use case reserves 50% of the storage capacity for reliability events, with the remaining 50% available for energy market sales. In this case, the capital cost of storage is reduced by avoided outage cost estimates.[78]

Table 5. I&M Distributed Storage Resource Assumptions (I&M, 2024a)

Distribution Storage Resource Option Specs

Target Station(s)	Technology	Power (MW)	Capacity (MWh)	RTE%	Direct Capital Est ($M	Need By (Date)	Expected Life (years)	Primary Use Case
County Road 4	Lithium - Ion	3	12	87%	$18	4/1/2028	20	Thermal
Robison Park	Lithium - Ion	3	12	87%	$18	12/1/2028	20	Thermal
Colfax	Lithium - Ion	3	12	87%	$18	6/1/2029	20	Thermal
Summit	Lithium - Ion	4	16	87%	$24	6/1/2028	20	Thermal
Beech Rd	Lithium - Ion	3	12	87%	$18	6/1/2033	20	Thermal
Pleasant-Yoder	Lithium - Ion	1	4	87%	$6	12/31/2028	20	Reliability
Whitaker-Elk	Lithium - Ion	3	12	87%	$18	12/31/2028	20	Reliability

Note*: The Direct Capital Est is deducted by Deferred Capital Cost for Thermal use cases and CMI Savings for Reliability use cases

Grid Modernization

I&M's IRP directly references how the utility's distribution planning efforts help inform bulk power system decisions. The utility describes ongoing efforts to modernize its distribution system to support GER integration, microgrid development, distribution automation, and emerging grid technologies. The company also is developing an Advanced Distribution Management System with a GER management system module, and expects to use AMI data for granular load forecasting in the next IRP. These grid modernization efforts enable consideration of cost-effective NWAs and improve load forecasting. I&M is developing a NWA screening and evaluation process and considered several NWAs in the IRP resource portfolio analysis.[79]

Key Takeaways

State requirements and stakeholder engagement drive inclusion of distribution system elements in I&M's IRP. For example, in relation to DSP, Michigan's IRP rules require explicit screening of GERs and NWAs,[80] while Indiana's statute encourages consideration of DSM.[81] I&M's multistate footprint led to adoption of a more integrated approach. In response to a negotiated settlement in Michigan, I&M's IRP in Indiana includes GER adoption scenarios and evaluation of GERs as supply-side candidates, including distribution-sited storage, to defer more costly investments and reduce customer outages.

I&M's IRP also reconciles long-term forecasts with granular, short-term forecasts that capture customer responsiveness to changing weather. This approach allows I&M to maximize the value of each type of modeling to produce more reliable forecasts.

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[77] I&M, 2024a.
[78] I&M, 2024b.
[79] I&M, 2025.
[80] MI PSC, 2017.
[81] IN Code § 8-1-8.5-3 (2024).

Minnesota Power (Minnesota)

Regulatory and Planning Landscape

Minnesota Power is an IOU serving the northeastern region of the state. IOUs file IRPs and IDPs in coordinated cycles. Under Minnesota statutes, electric utilities must file IRPs every two years, demonstrating how they will meet forecasted energy and capacity needs, evaluate demand-side and supply-side resources, and comply with state decision-making objectives.[82] The Minnesota Public Utilities Commission (MN PUC) requires IOUs to file IDPs every 2 years.

The Commission began exploring distribution planning through a grid modernization docket in 2015. In 2018, the Commission adopted comprehensive IDP filing requirements for all IOUs in the state, including Minnesota Power[83] and Xcel Energy.[84] The requirements set out the core components of distribution planning in the state, ranging from stakeholder engagement processes and baseline data reporting to more advanced analyses such as hosting capacity, GER modeling, and NWA evaluation.

The Commission updated IDP requirements in 2025,[85,86] including the following:

- Use consistent GER and load growth forecasts across IRP and IDP
- Analyze base, medium, and high GER and load growth scenarios using aligned assumptions
- Improve feeder-level forecasting and visibility into GER impacts
- Proactively plan hosting capacity and identify distribution system upgrade needs to support GER growth
- Strengthen NWA evaluation and solicitations
- Consider whether aggregated GERs can provide capacity for peak-hour support

Utilities must also explain how distribution planning informs the IRP, and how IRP decisions (e.g., resource retirements) feed back into distribution system needs.[87] These IDP practices support integration of distribution system elements into IRPs.

Distribution System Elements in the IRP

Minnesota Power's IRP reflects increasingly coordinated planning between bulk resources, transmission, and distribution systems. The IRP demonstrates how IDP processes inform resource planning assumptions.

<u>Load Forecasting</u>

Minnesota Power adopted a unified forecasting framework across its IRP and IDP, consistent with Commission direction that GER and load growth assumptions align across planning processes.[88] The IRP uses an "Expected Scenario" from an Annual Electric Utility Forecast

[82] Minnesota Statutes § 216B.2422.
[83] Minnesota Public Utilities Commission (MN PUC), 2018a.
[84] MN PUC 2018b.
[85] MN PUC, 2025a.
[86] MN PUC, 2025b.
[87] *Ibid.*
[88] MN PUC, 2025a.

Report[89] for the foundational load forecast and applies the same GER and load growth adoption trajectories used in the IDP.[90] The utility's planning teams meet at "regular intervals throughout the year to share information on potential supply side and demand side opportunities located at the distribution level."[91]

The distribution planning team provides historical, feeder-level loading data from SCADA and AMI systems each year, and the load forecasting group develops feeder-specific annual growth rates based on the Annual Forecast Report. These growth rates are provided to the distribution planning team to construct peak scenarios for out years. This two-way exchange ensures IRP load forecasts are grounded in actual customer behavior on the distribution system and emerging GER trends.[92]

Minnesota Power's forecasting process also is informed by close engagement with large industrial customers. These customers provide development plans and inform long-term load expectations that shape both IRP and IDP forecasts.[93]

Integrated Planning Through the Grid Essential Services Framework

Grid Essential Services is part of Minnesota Power's reliability criteria framework (Figure 7) that integrates elements of planning between bulk power resources, transmission, and distribution to ensure holistic system reliability during a time of rapidly changing loads and resource needs and grid transformation. The process evaluates whether T&D systems can reliably support future resource portfolios.

Multiple analyses identify local and regional impacts of major resource decisions, such as generator retirements, or the addition of new industrial load that requires additional capacity. Studies include steady-state thermal and voltage performance, voltage stability, transient stability, inertia, frequency response, and short-circuit strength. Studies are conducted in coordination across the utility's resource planning, transmission planning, and distribution planning groups. Results are directly incorporated into IRP scenario analysis, shaping the timing, feasibility, and cost of resource portfolios.[94] The process is tightly coupled with distribution planning activities, especially in areas where GER interconnection or load growth may create localized reliability constraints.

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[89] The Annual Electric Utility Forecast Report is a filing required under Minnesota Rules §§ 7610.0100 to 7610.0700, which provides standardized long-term forecasts of energy sales, peak demand, and customer growth submitted annually to the Department of Commerce.
[90] Minnesota Power, 2025.
[91] Ibid, Appendix G at 2.
[92] Ibid.
[93] Ibid.
[94] While these additional studies improve the ability to see systemwide impacts of different planning scenarios, regulators PUCs may need to adjust planning procedures to respond to increased technical and procedural complexity.

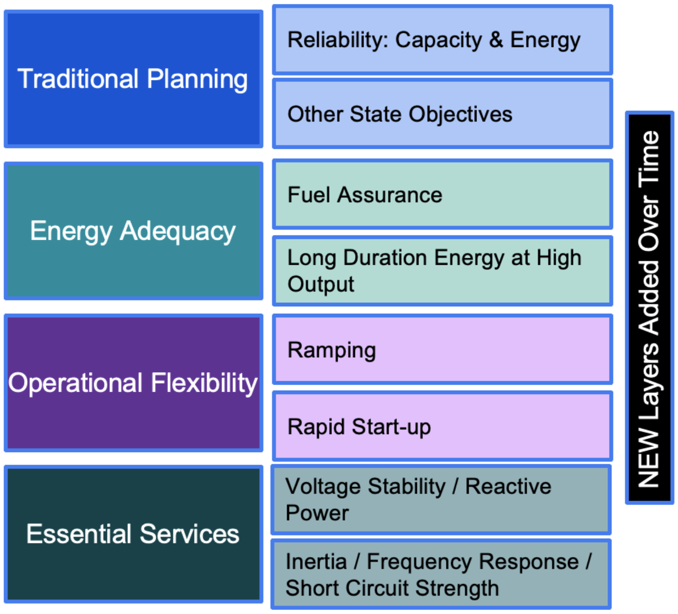

Figure 7. Minnesota Power's Reliability Criteria Framework (Adapted from Minnesota Power, 2025)

Minnesota Power's real-time Utility Network Model, which unifies transmission, distribution, and customer-level assets into a single geospatial model, supports the technical analysis that underpins the process by providing granular visibility into the distribution system. The model will increasingly enable distribution-level validation of bulk resource decisions.[95] It enhances planning across domains by providing more precise information about asset connectivity, feeder topology, and interaction between distribution conditions and bulk system performance. It is part of Minnesota Power's work to modernize its distribution planning tools and system visibility capabilities in ways that directly support more coordinated DSP-IRP planning.[96]

Recent upgrades to foundational systems, such as AMI, GIS, and grid monitoring, have expanded the utility's ability to analyze feeder conditions, validate DER impacts, and assess how load growth and customer behavior evolve over time.[97] These data feed into the Utility Network Model.

Non-Wires Alternatives

Minnesota Power incorporates NWAs into its planning framework through a structured process that links emerging distribution needs with bulk planning considerations. As part of its routine distribution assessments, the utility identifies feeders, substations, or geographic areas with developing reliability or load growth challenges. When these issues surface, Minnesota Power conducts a more detailed review to determine whether the traditional wires solution is the most prudent investment. For high-cost projects, the utility initiates a formal alternatives analysis to assess whether NWAs could address the underlying need in a more cost-effective or flexible manner.[98]

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[95] Minnesota Power, 2025.
[96] Ibid.
[97] Ibid.
[98] Minnesota Power, 2023.

This process develops the operational and technical requirements that NWAs would need to meet, such as duration and responsiveness of a storage system to provide redundancy, or magnitude and timing of load reduction required by a demand response program to alleviate a constraint. These scoping parameters are shared with resource planning teams, who evaluate whether the proposed NWA could reasonably function as a resource option in future IRPs. This workflow creates a structured channel through which distribution-identified solutions inform the set of candidate resources in resource planning.[99]

Key Takeaways

The state's sophisticated IDP and IRP frameworks shape the degree and form of coordination between the two processes. Integrated planning expectations in Minnesota primarily originate from the IDP process, resulting in Minnesota Power's integration of processes through:

- Coordinated and iterative load forecasting and scenario analysis
- Modernized planning tools that provide enhance grid visibility and strengthen analytical coordination
- Consideration of NWAs through a structured bridge between IDP and IRP

Public Service Company of Oklahoma (Oklahoma)

Regulatory and Planning Landscape

Public Service Company of Oklahoma (PSO) is a vertically-integrated utility that owns and operates electricity generation, transmission, and distribution for customers in eastern and southwestern Oklahoma. The Oklahoma Corporation Commission (OCC) requires the utility to file an IRP every three years. The rules require an analysis of how the transmission system will serve load during the IRP forecast period. This includes a description of the utility's transmission capabilities, which impacts distribution system needs.[100]

Distribution System Elements in the Utility's IRP

While the IRP rules do not specifically include requirements related to distribution systems, PSO discusses its distribution system in the context of its transmission system overview. In its 2024 IRP, PSO provides an overview of its distribution system investment portfolio. Projects include distribution automation and hardening the distribution system, with the goal of improving grid reliability.

One such project that PSO undertakes is conservation voltage reduction (CVR), which the utility began evaluating in its 2015 IRP. CVR monitors and regulates voltage within a lower acceptable bandwidth on distribution circuits. That saves energy and reduces peak demand on the distribution system. In addition, voltage-dependent end-use devices draw less power, providing direct savings for some customers as well.

PSO evaluated energy savings from CVR across substations, circuits, and seasons.[101] For the 2021 IRP, the utility grouped CVR-enabled circuits based on peak demand reductions and costs

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[99] Minnesota Power, 2025.
[100] Pursuant to 165:35-37-4.
[101] Pursuant to 165:35-41-7 (not part of IRP guidelines).

and used these “tranches” as resource inputs in the capacity expansion model to identify the most cost-effective locations. As of 2023, PSO had deployed CVR on 159 distribution circuits. PSO aims to implement CVR on 250 circuits by 2029.[102]

PSO’s parent company, American Electric Power, embarked on an integrated planning roadmap process across generation, transmission, and distribution in 2021. The roadmap envisions an integrated planning model, called CIP-MAP. The model would support integrated planning processes across seven dimensions (e.g., goals and objectives, utility load, external drivers) (Figure 8). Implementation of the roadmap is expected to span multiple years, increasing maturity over time, through development of new tools, modeling and business processes, and staff reorganizations.[103] A significant outcome of this effort to date is bringing together the generation, transmission, and distribution planning groups under the same utility leadership area.

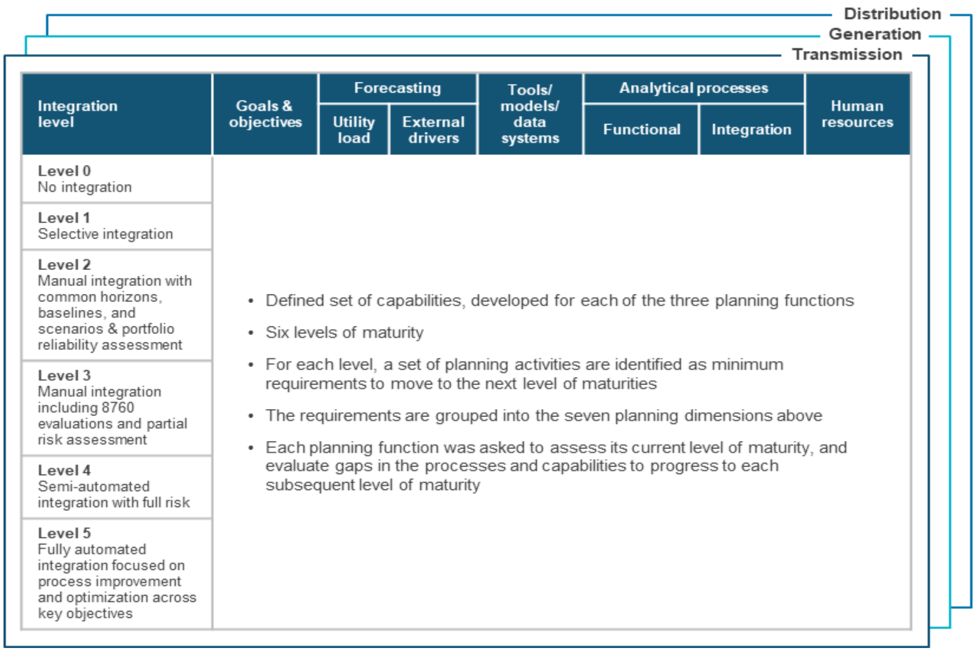

Figure 8. Illustration of the CIP-MAP maturity model (McMahon et al., 2023)

Key Takeaways

While the OCC does not require PSO to file a DSP, the IRP discusses distribution system investments and performance. This early seed, coupled with American Electric Power’s integrated planning efforts, could pave the way for a more holistic planning approach for PSO.

Southern California Edison (California)

Regulatory and Planning Landscape

Utilities in California operate in a complex planning environment, where long-term resource planning, distribution system planning, and transmission planning occur through distinct but increasingly interconnected regulatory channels. Multiple state agencies, including the CPUC,

[102] PSO, 2024.
[103] McMahon et al., 2023.

California Energy Commission (CEC), and California ISO (CAISO) oversee distinct aspects of system planning, and utilities must navigate these processes simultaneously.[104]

An IRP framework established in 2018 consolidated a number of proceedings at the commission, resulting in coordination of many planning activities.[105] For example, Southern California Edison's (SCE) recent IRP lists more than a dozen active CPUC proceedings – related to such topics as resource adequacy, GERs, innovation programs, and transportation load growth – that must be coordinated alongside the IRP.

DSP occurs in a parallel but related track, called the "High DER Future Grid" proceeding.[106] The process includes a Distribution Planning and Execution Process that intersects with IRPs at key touchpoints.

Elements of DSP in the IRP

<u>Alignment of Load and GER Forecasts</u>

SCE integrates distribution system planning and resource planning primarily through statewide Integrated Energy Policy Report (IEPR) forecasts. SCE begins with the CEC's IEPR forecasts, which serve as the planning baseline for IRP modeling and distribution assessments. However, its application differs by planning process. For IRP, SCE applies stochastic analysis around the IEPR forecast to capture uncertainty and inform resource adequacy and reliability outcomes at a system level. For DSP, SCE typically begins with a selected IEPR scenario and incorporates known load loads and disaggregates these system-level forecasts to the substation and circuit levels based on historical loading, customer characteristics, and local development (Figure 9).[107]

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[104] CPUC, 2025b.
[105] CPUC, 2016a.
[106] CPUC, R.21-06-017: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/distribution-planning.
[107] SCE, 2025.

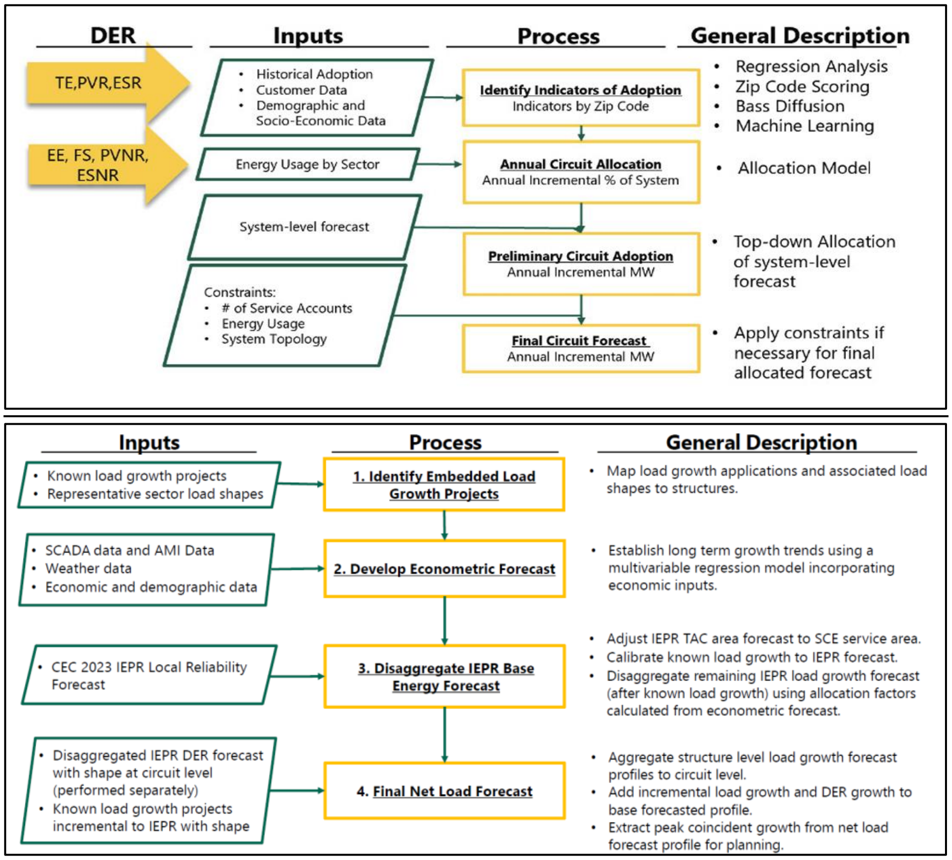

Figure 9. Overview of SCE's GER and load disaggregation process (SCE, 2025)

For DSP, to capture localized load dynamics not reflected in the IEPR, SCE supplements the forecast with additional inputs, including:

- Known Load Growth Projections identified through coordination with developers to assess electric needs, location, and timing of forthcoming projects
- Pending loads such as port electrification and truck stop charging
- Econometric allocation data, used to distribute IEPR forecast growth across circuits[108]

Hosting Capacity and Constraint Analysis

SCE's integrated forecasting process feeds directly into Integration Capacity Analysis. The CPUC requires utilities to incorporate GER-driven load modifications and potential backflow conditions into Integration Capacity Analysis, producing granular insights into where GER expansion may require distribution upgrades or relieve local constraints.[109]

These results, along with capacity-related needs identified in the utility's Grid Needs Assessment, highlight areas where GER portfolios may face infrastructure limitations and where resource siting must account for distribution system feasibility.[110] In its 2022 IRP, SCE emphasized that energy

[108] SCE, 2025.
[109] CPUC, 2016b.
[110] SCE, 2025.

storage provides greater flexibility for T&D systems, directly supporting local reliability and DER hosting needs.[111]

Key Takeaways

SCE disaggregates statewide forecasts using methods tailored to each type of load and GER. These forecasts are used in DSP and other processes, supporting planning alignment. Additionally, analysis of constraints on the distribution system helps to identify less optimal locations for distributed generation.

Vermont Electric Cooperative and Green Mountain Power (Vermont)

Regulatory and Planning Landscape

Vermont is part of ISO New England. A statewide transmission utility, Vermont Electric Power Company (VELCO), serves Green Mountain Power (GMP) — the state's sole IOU and largest distribution utility, and several municipal utilities and rural electric cooperatives. The Vermont Department of Public Service (PSD) prepares a Comprehensive Energy Plan, updated every six years.[112] The plan informs utility planning goals.

Vermont requires utilities to develop a "least-cost integrated plan" that describes the portfolio of resources required to meet need for energy services at the lowest present value lifecycle cost through a strategy combining investments and expenditures on energy supply, transmission, and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs.[113] Utilities file IRPs with the Vermont Public Utility Commission (PUC) every three years.

The PSD develops IRP guidance, including how utilities will evaluate T&D systems as part of the IRP. The guidance states that utilities will provide an overview of their system, conduct engineering and economic analyses, devise programs to address any system improvement needs as part of the IRP, and document this process in their IRPs on an ongoing basis. The guidance states that doing so is crucial to "meet the public's need for energy services by providing transmission and distribution services that are adequate, reliable, safe, secure, efficient, and environmentally sound at the lowest present-value life-cycle cost."[114]

In addition, VELCO is required to file, at least every three years, a 20-year long-range transmission plan with the PUC.[115] An objective of the plan is to identify the potential need for transmission system improvements as early as possible to allow sufficient time to plan and implement more cost-effective non-transmission alternatives to meet reliability needs, wherever feasible.[116]

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[111] SCE, 2022.
[112] 30 V.S.A. § 202b.
[113] 30 V.S.A. § 218c.
[114] Vermont PSD, 2022.
[115] 30 V.S.A. § 218c(d)(1).
[116] Ibid.

A process has been established for consideration of cost-effective non-transmission alternatives. The process is binding on all Vermont utilities.[117] The retail electricity providers in affected areas must incorporate the long-range transmission plan into their individual least-cost integrated planning processes and must cooperate as necessary to develop and implement joint least-cost solutions to address any reliability deficiencies identified in the plan.[118] Utilities work with VELCO to evaluate non-transmission alternatives to upgrades in a process coordinated by the Vermont System Planning Committee (VSPC). The process also includes energy supply and demand resource providers, PSD, and the public. The VSPC is composed of various subcommittees covering topics such as load forecasting and geographic targeting of alternatives.

The VSPC acts as a bridge for aligning inputs and modeling assumptions across various planning processes, including utility IRPs, long-range transmission plans, and ISO-NE planning. The forecasting subcommittee reviews the development of baseline forecasts across utilities, provides a platform for reconciling any differences, and coordinates with other planning groups. A key outcome of this process is the Load Forecast Report for VELCO,[119] which incorporates inputs from several entities. For example, residential EV data from GMP informs the charging profiles, which shape temporal system loads. Utility inputs from managed charging programs inform the ISO's forecast process.[120] Figure 10 illustrates the overall transmission planning process.

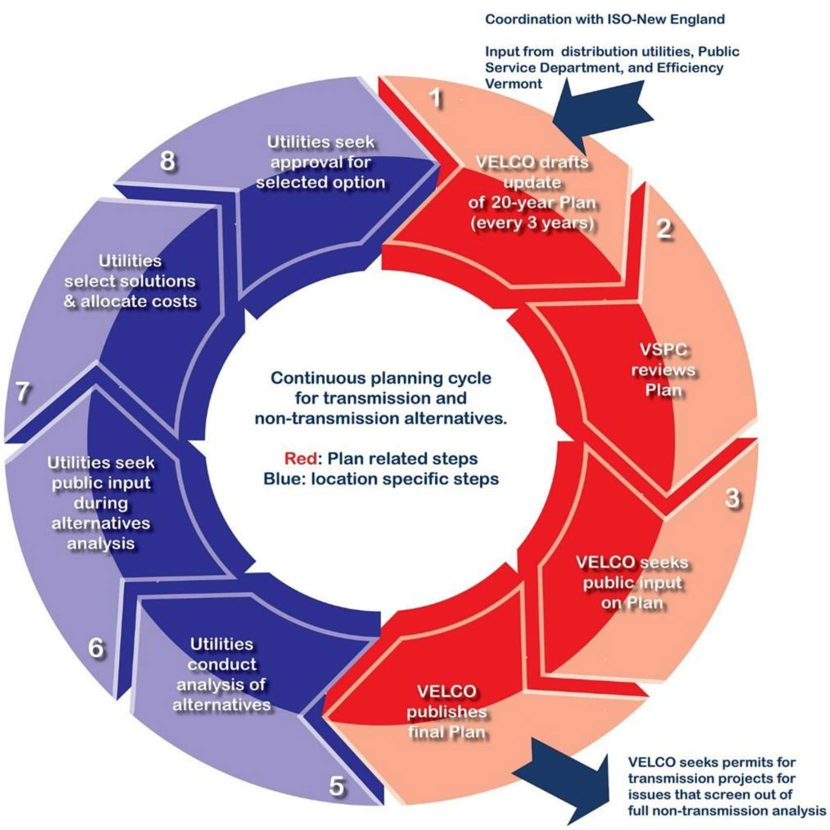

Figure 10. Vermont's Transmission Planning Coordination Process (VT PSC, ND)

117 30 V.S.A. § 218c.
118 30 V.S.A. § 218c(d)(6).
119 Itron, 2023.
120 ISO New England, 2025.

Distribution System Elements in the IRP

GMP's commitment to least-cost planning drives its inclusion of distribution system elements into the IRP process. For example, IRP modeling includes evaluation of the potential of storage and EV charging management for deferring transmission investments. GMP is using controlled EV charging as a solution to mitigate local peak loads that are coincident with systemwide peak loads. GMP estimates that it can achieve a 50% reduction in coincident peak load, assuming control of 65% of home EV charging in addition to public and other charging.[121]

In GMP's "Accelerated Adoption" scenario with high levels of EV adoption, unmanaged charging results in about 100 MW of coincident peak demand in the year 2030, while managed charging results in a coincident peak demand of about 40 MW. This substantial reduction in peak demand also can help accommodate new loads without requiring significant T&D upgrades.[122] GMP also works with VELCO to align forecasts across the IRP and the Long-Range Transmission Plan. For example, GMP demonstrated how 50% controlled charging can shift EV loads to off-peak hours, compared to VELCO's charging profile that assumed no utility control of EV charging (Figure 11).[123]

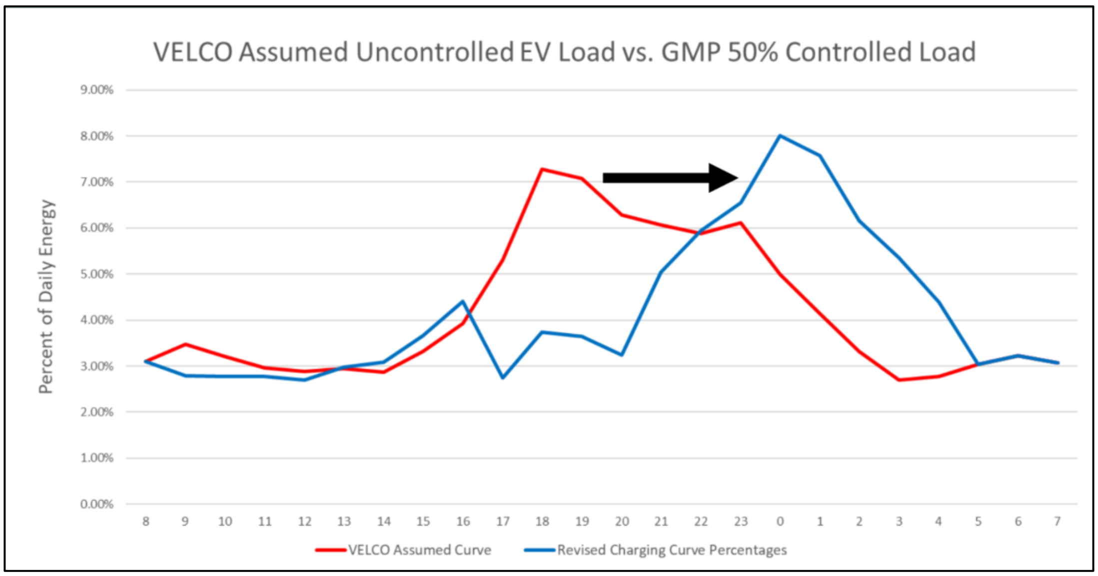

Figure 11. Comparison of charging curves Source (GMP, 2025)

Utilities also have collaborated to address the transmission constraint at the Sheffield Highgate Export Interface in northern Vermont. Vermont Electric Cooperative's 2025 IRP describes its partnership with GMP to help mitigate the need for new transmission to address a constraint from average load (about 35 MW) exceeding total generation capacity (about 450 MW).[124] In 2024, the two utilities launched the 3 MW/12 MWh BESS project at the North Troy distribution substation. This strategic location will help avoid significant distribution system investments to accommodate the project. The ability to absorb excess generation will provide peak shaving benefits and reduce the need for transmission upgrades.

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[121] GMP, 2024.
[122] Ibid.
[123] GMP, 2025.
[124] Vermont Electric Cooperative, 2025.

Key Takeaways

The state's statute for least-cost planning is a key driver for utilities to optimize electricity system planning. Utilities in Vermont assess all possible resource options and work with the statewide transmission utility to optimize electricity systems in the state. Utility IRPs identify how distribution-level resources can defer or avoid the need for some T&D upgrades, translating into customer savings. Further, the collaborative transmission planning process brings together various entities to devise solutions that help utilities meet objectives for their electricity system.

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