U.S. DEPARTMENT OF ENERGY

Integrated Distribution System Planning Overview

Training for States on Distribution System and Distributed Energy Resources Planning

Presented by Lisa Schwartz and Natalie Mims Frick, Berkeley Lab

January 24, 2024

Western Regional Training

Agenda

- Define distribution planning and types of plans filed
- Distribution planning framework
- Planning objectives and priorities
- Stakeholder engagement, equity and justice
- Plan requirements
- Example state practices

For more information, see Berkeley Lab's Integrated Distribution System Planning website.

Distribution Planning and Types of Plans Filed

What is distribution system planning?

- Assesses needed physical and operational changes to the local grid
  - Annual planning for distribution system spending
  - Longer-term utility capital plan over 5–10 year planning horizon
    - With updated solutions and cost estimates every 1–3 years

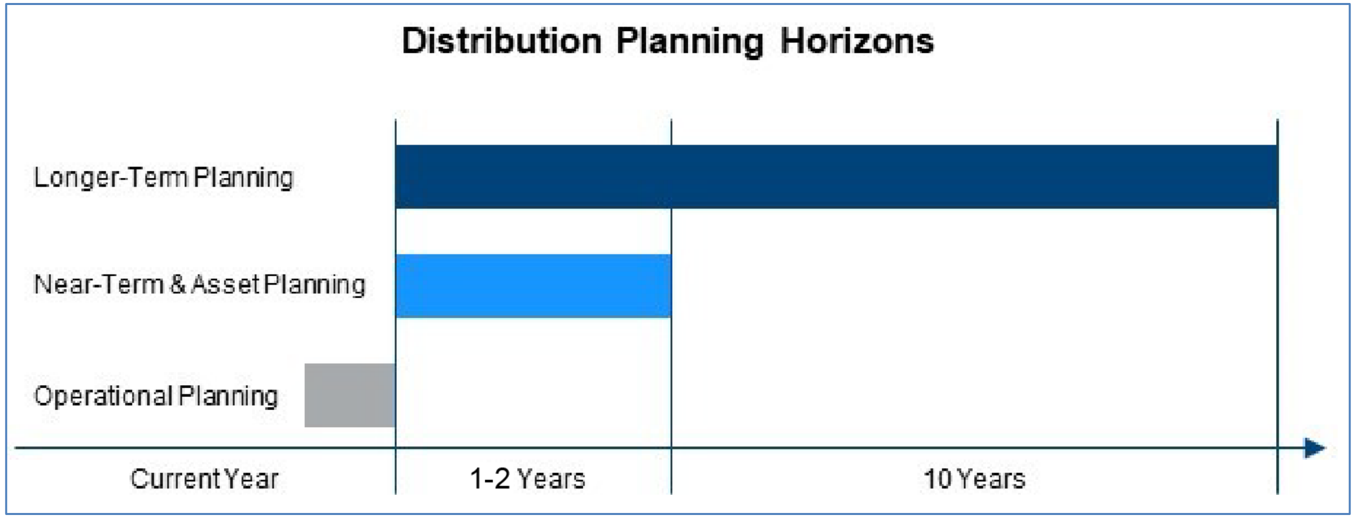


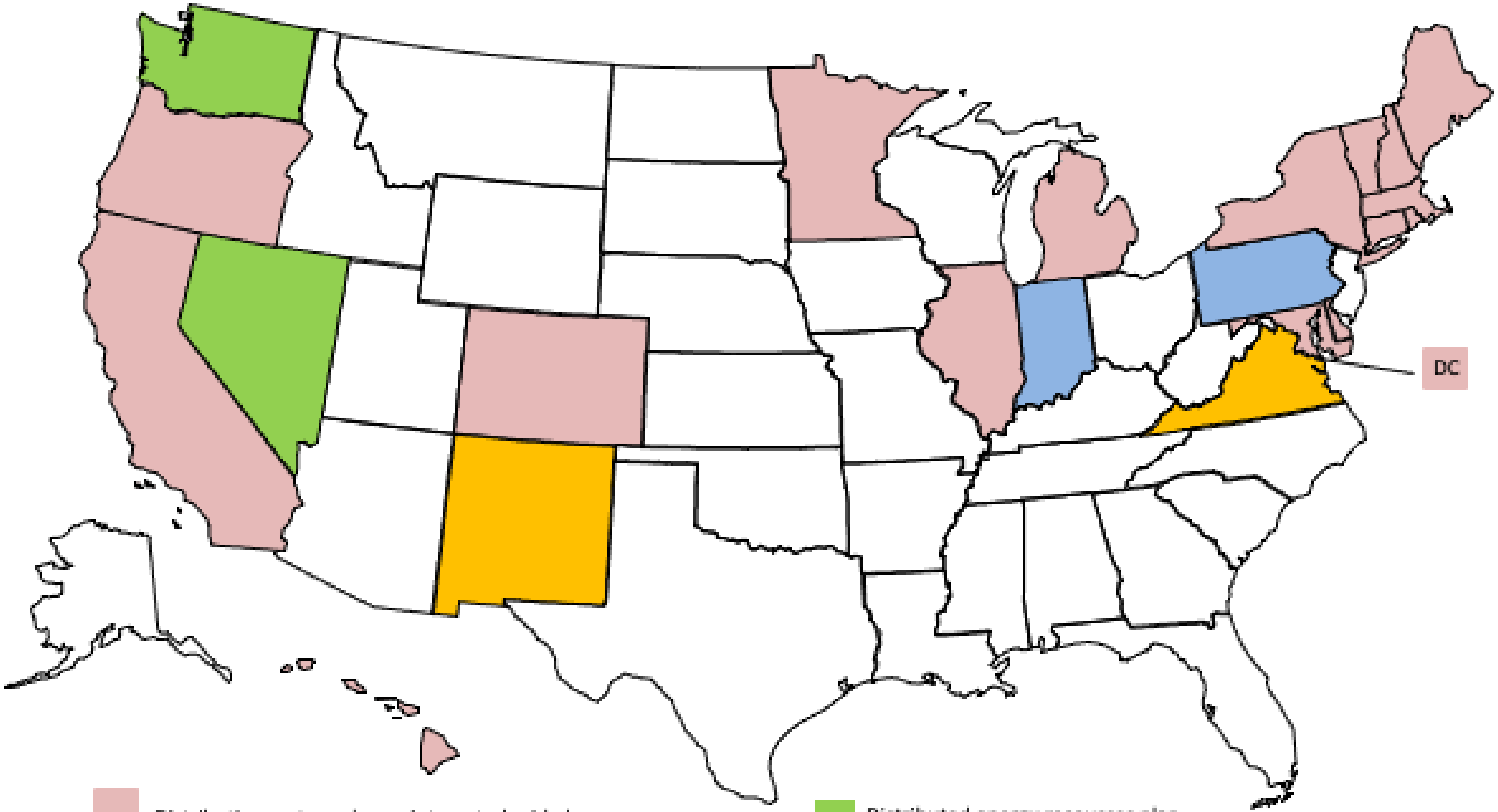
Figure: DOE 2020

Interactive poll #1

How many states require regulated utilities to file distribution system plans?

Kahoot!

States requiring regulated utilities to file distribution plans



Distribution system plan or integrated grid plan

Distributed energy resources plan

Grid modernization plan*

Transmission and distribution improvement plan**

*Some states that require distribution system plans also require grid modernization plans (e.g., Minnesota and California).
**Indiana also includes storage.

Source: *State Energy Offices' Engagement in Electric Distribution Planning to Meet State Policy Goals*

Types of distribution plans filed (1)

Distribution system improvement plans

Enables expedited cost recovery for certain system improvements

- Indiana's Transmission, Distribution, and Storage System Improvement Charge can include new or replacement transmission, distribution, or utility storage projects for safety, reliability, system modernization, or economic development.
- Pennsylvania's Distribution System Improvement Charge can be used to recover costs to repair, improve, or replace eligible distribution property.

Distributed energy resources (DERs) plan

Evaluates benefits and costs of DERs, considers ways to increase deployment of cost-effective DERs, and facilitates better integration of DERs in distribution planning

- Regulated utilities in Nevada must submit a Distributed Resource Plan to the Public Utilities Commission every three years as part of their integrated resource plan.
  - Evaluate locational benefits and costs of DERs, including distributed generation systems, energy efficiency, energy storage, electric vehicles (EVs), and demand response technologies
  - DER forecasting and hosting capacity analysis that inform grid needs assessment
  - Propose infrastructure upgrades and non-wires alternatives for identified grid constraints

Types of distribution plans filed (2)

Grid modernization plan

Reasoned strategy linking technology deployment roadmap to stated objectives

- Examples: CA, MA, MN, NM, RI, VA
- A primary focus today is replacing aging infrastructure with advanced grid technologies.
- Plans may include a request for approval of grid modernization investments and programs, with expedited cost recovery.

Integrated distribution system plan (IDSP)

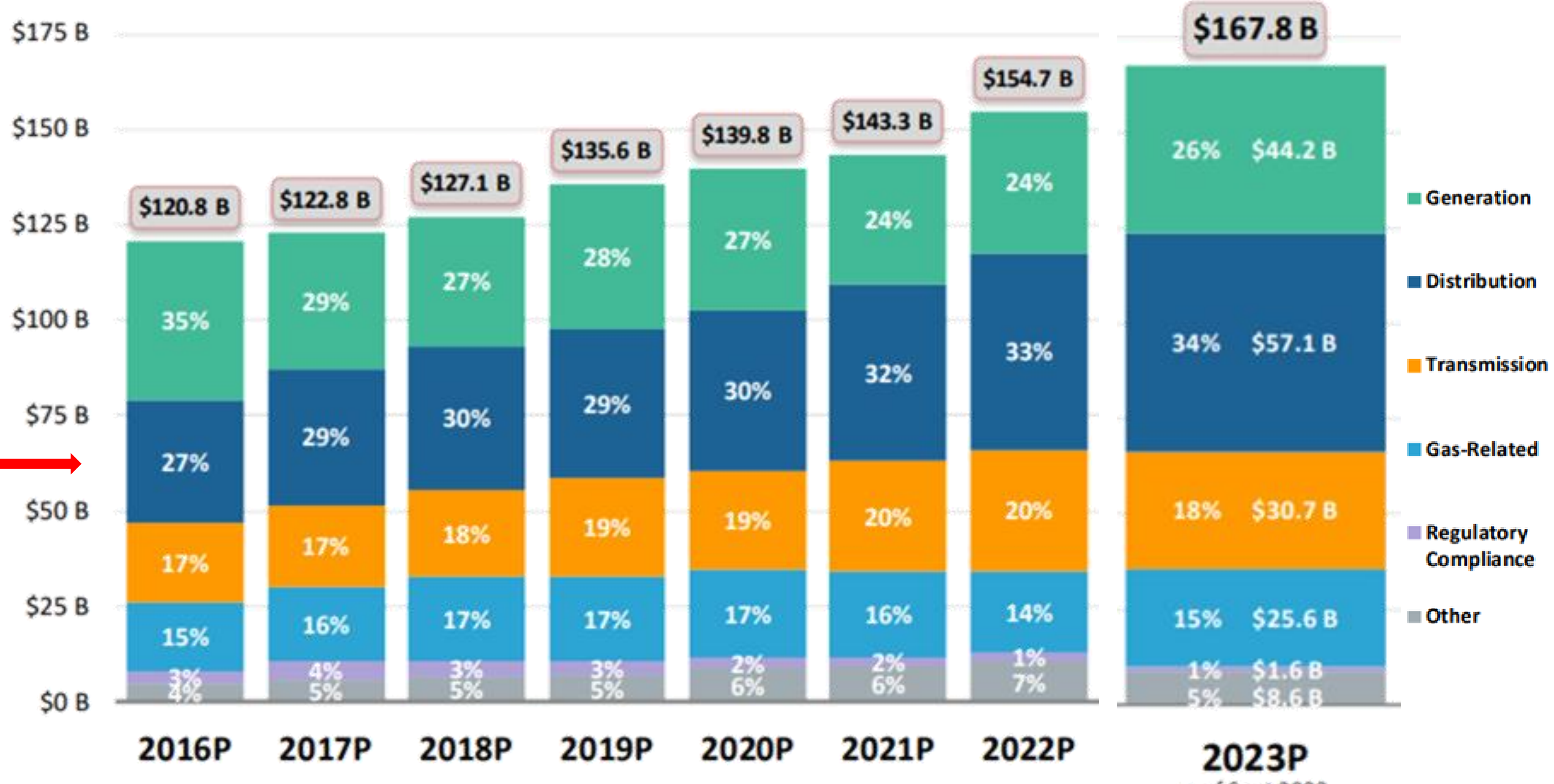
Systematic approach to satisfy customer service expectations and state objectives

- Includes grid mod strategy and DER planning
- May coordinate across planning domains (e.g., HECO's 2023 Integrated Grid Plan, Maine Integrated Grid Plan statute)

Source: EPRI

Why are states increasingly interested in distribution system planning?

Distribution system investments account for the largest portion of capex — 34% in 2023 (projected $57.1B) — for U.S. investor-owned utilities.



Source: EEI, 2023, Electric Company Industry Financial Data and Analysis

What are the potential benefits from an improved planning process?

- Better oversee utility expenditures
- Make transparent utility plans for distribution system investments in a holistic manner, before showing up individually in rate cases
- Provide opportunities for meaningful engagement with stakeholders and (for regulated utilities) regulators to improve outcomes
- Consider uncertainties under a range of possible futures (scenarios)
- Consider all solutions for least cost/risk (including DERs)
- Enable consumers and third-party providers to propose grid solutions and participate in providing grid services (e.g., grid-interactive efficient buildings)

Source: Con Edison

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Interactive poll #2

What do YOU think are the biggest potential benefits from improving distribution planning practices?

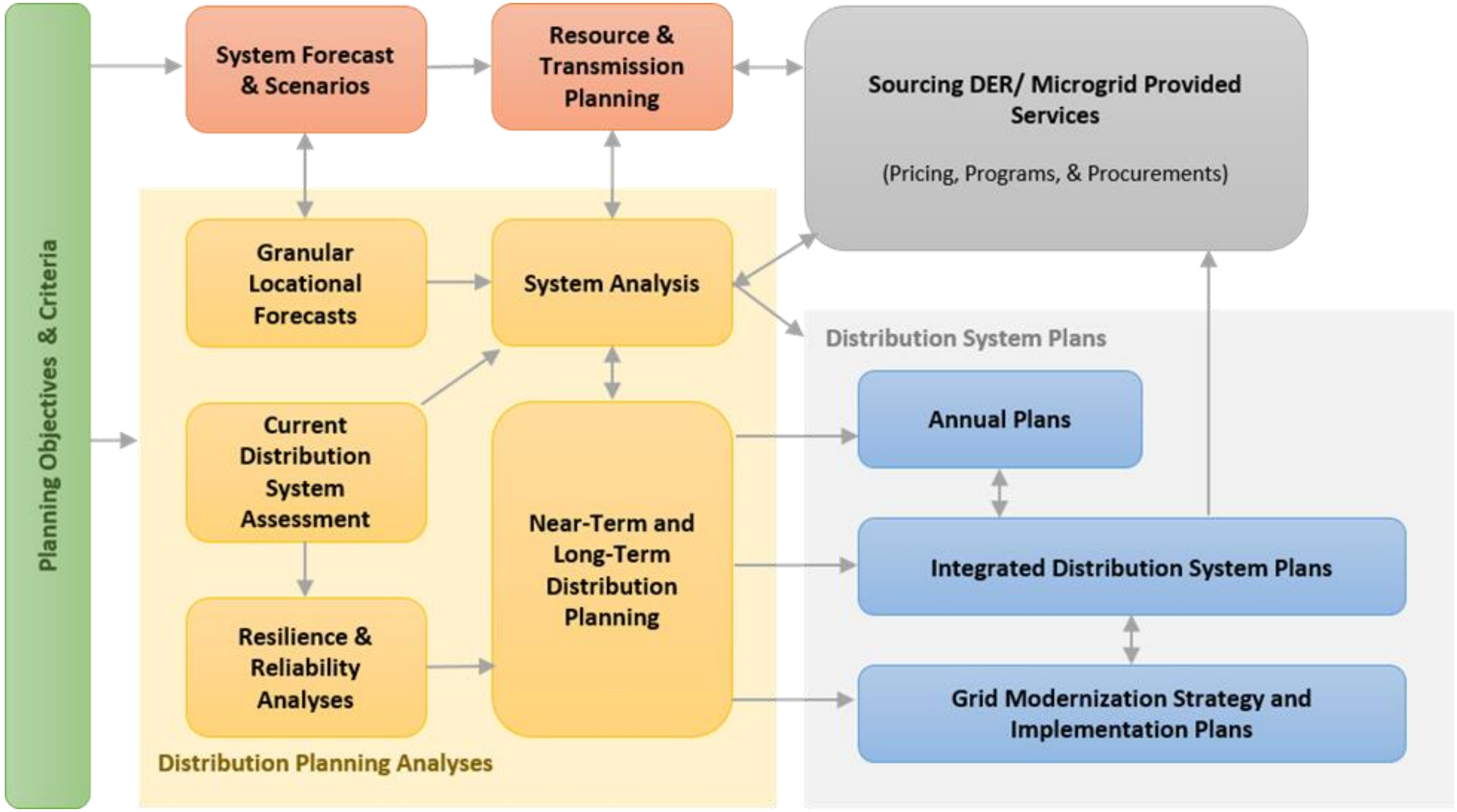
Kahoot!

Distribution Planning Framework

Objectives-based planning

Creating a shared understanding among stakeholders of strategies for incorporating objectives and priorities in planning is essential.

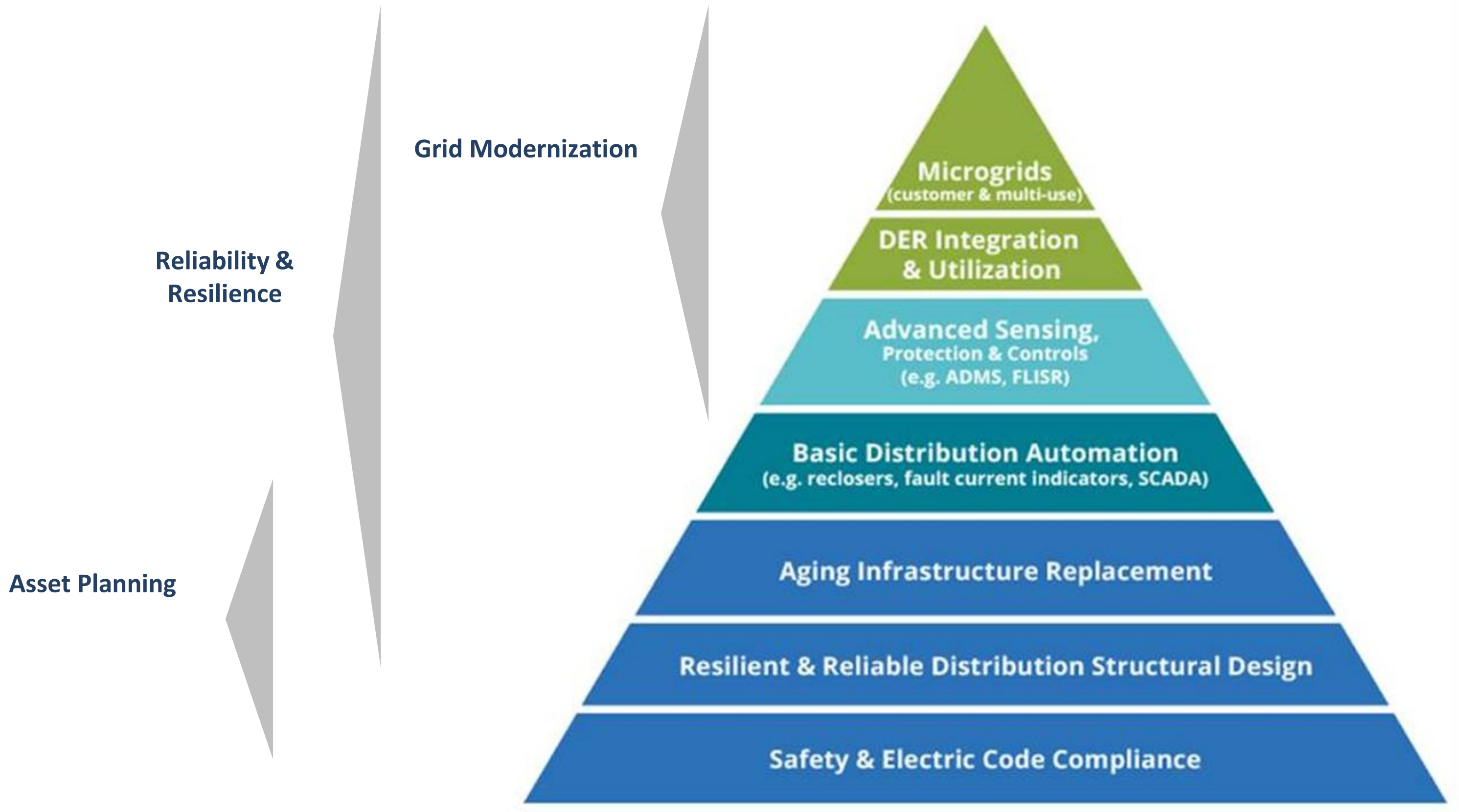
State policies and community and customer needs drive planning objectives and criteria.



Source: Modern Distribution Grid Guidebook, Volume 4, June 2020

Investment categories

Grid modernization layers on top of and integrates with foundational grid infrastructure.



Source: De Martini

Start with principles and objectives instead of picking technologies

- Planning starts with principles and objectives and the capabilities needed to achieve them. That determines functionality and system requirements.
- Holistic, long-term planning:
  - Supports state goals
  - Addresses interdependent and foundational technologies and systems
    - *Core components* — e.g., Advanced Distribution Management System, Geographic Information System, Outage Management System
    - *Applications* to support other grid modernization projects — e.g., smart meters, DER management
  - Considers proactive grid upgrades to facilitate customer choice

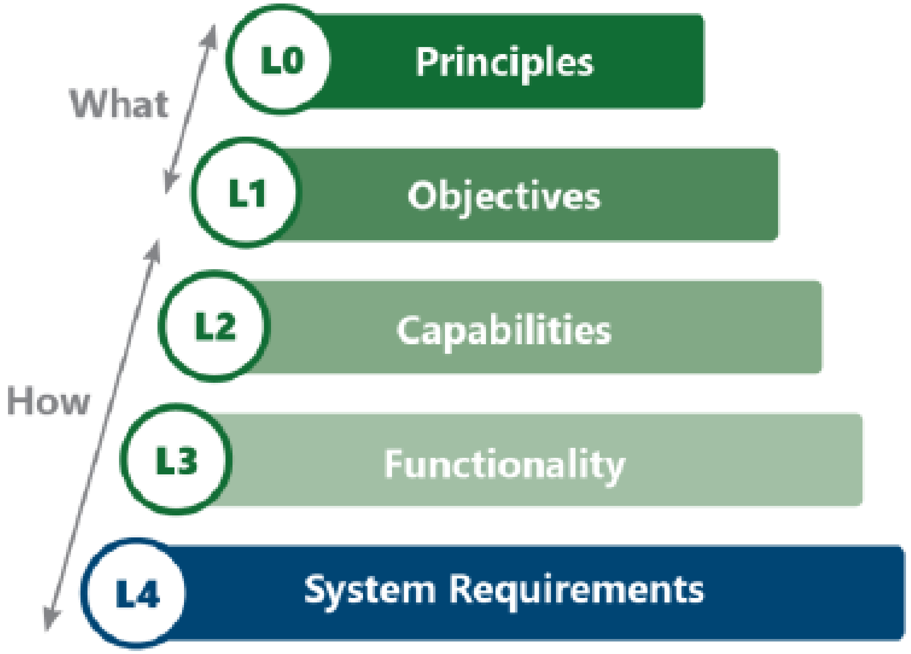


Figure: DOE 2020

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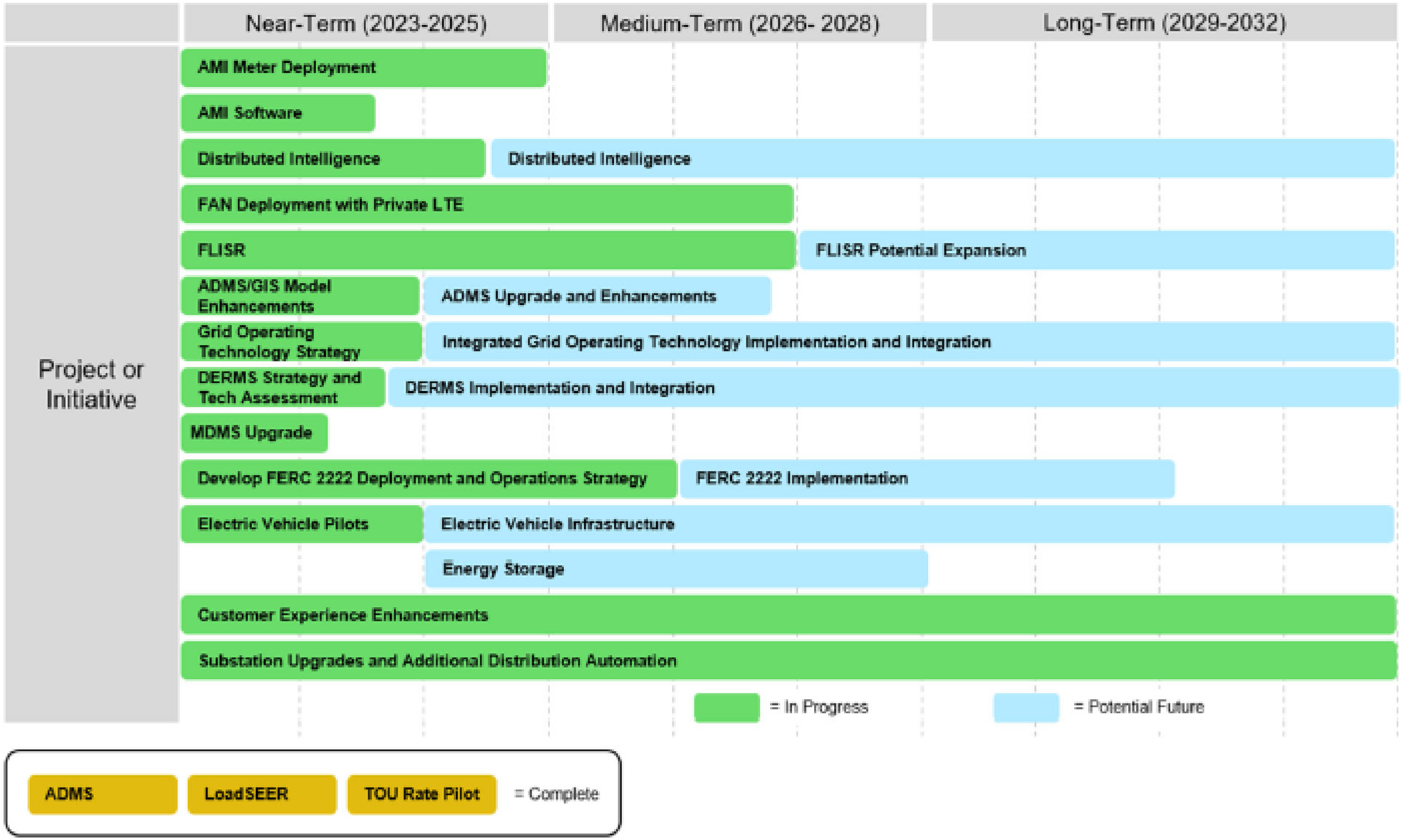
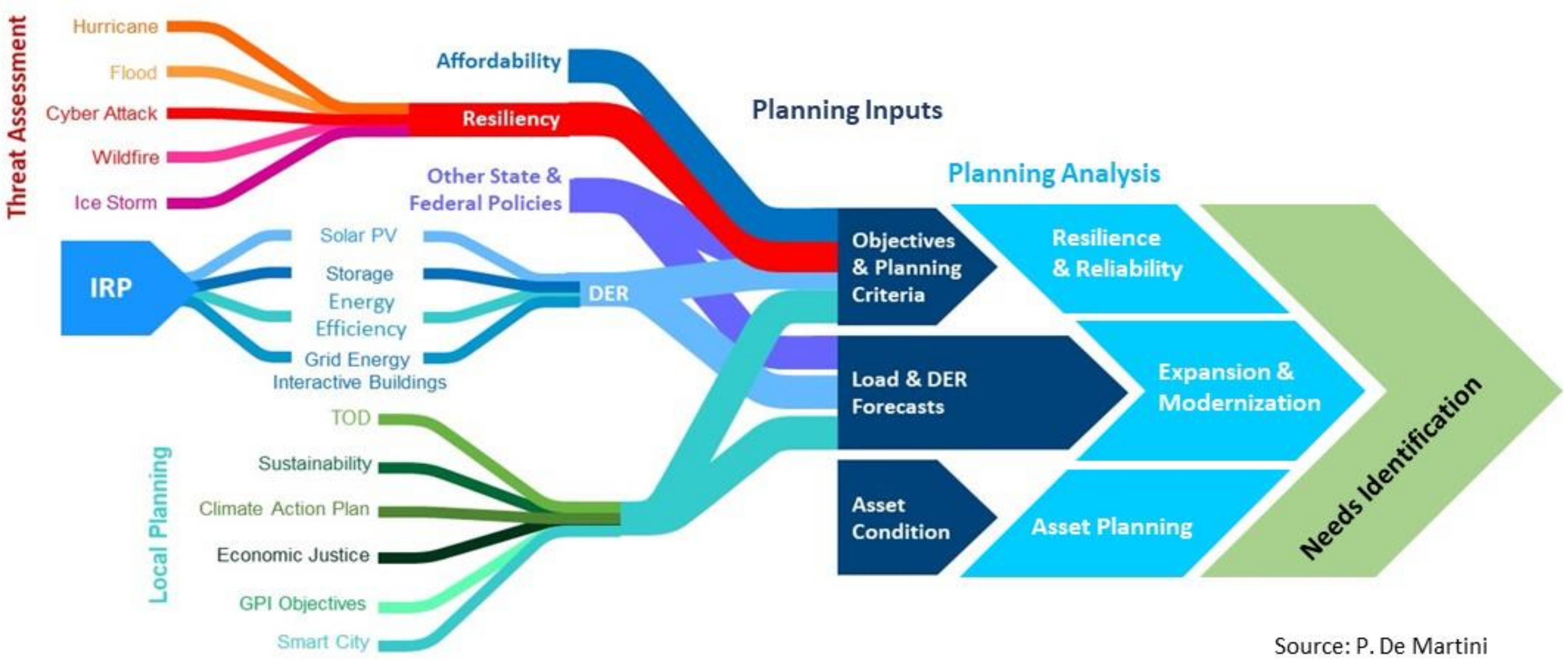
Example technology roadmap



Source: Xcel Energy (2023)

Emerging distribution system planning inputs

Distribution planning is increasingly dependent on resilience planning, bulk power system planning, local planning, and using DERs.



Source: P. De Martini

Integrating planning & other processes

- NY Distributed System Implementation Plans support 2019 Climate Act and 2022 Scoping Plan
- CA rulemaking on Distribution Resources Planning (DRP) in part required grid mod plans filed with GRCs (2018 decision). New rulemaking to support high levels of DERs (including managed EV charging):
  - Utility roles and responsibilities
  - Utility and aggregator business models
  - More holistic planning process
  - Grid mod investments, smart inverters to provide grid services, and aligning GRC filings with infrastructure needs in DRP
- MN requires grid modernization plan and transportation electrification plan filed with Integrated Distribution Plan
- HI requires planning across domains (G, T, D), aligned with sourcing — procurement, pricing and programs (HECO's 2023 Integrated Grid Plan)

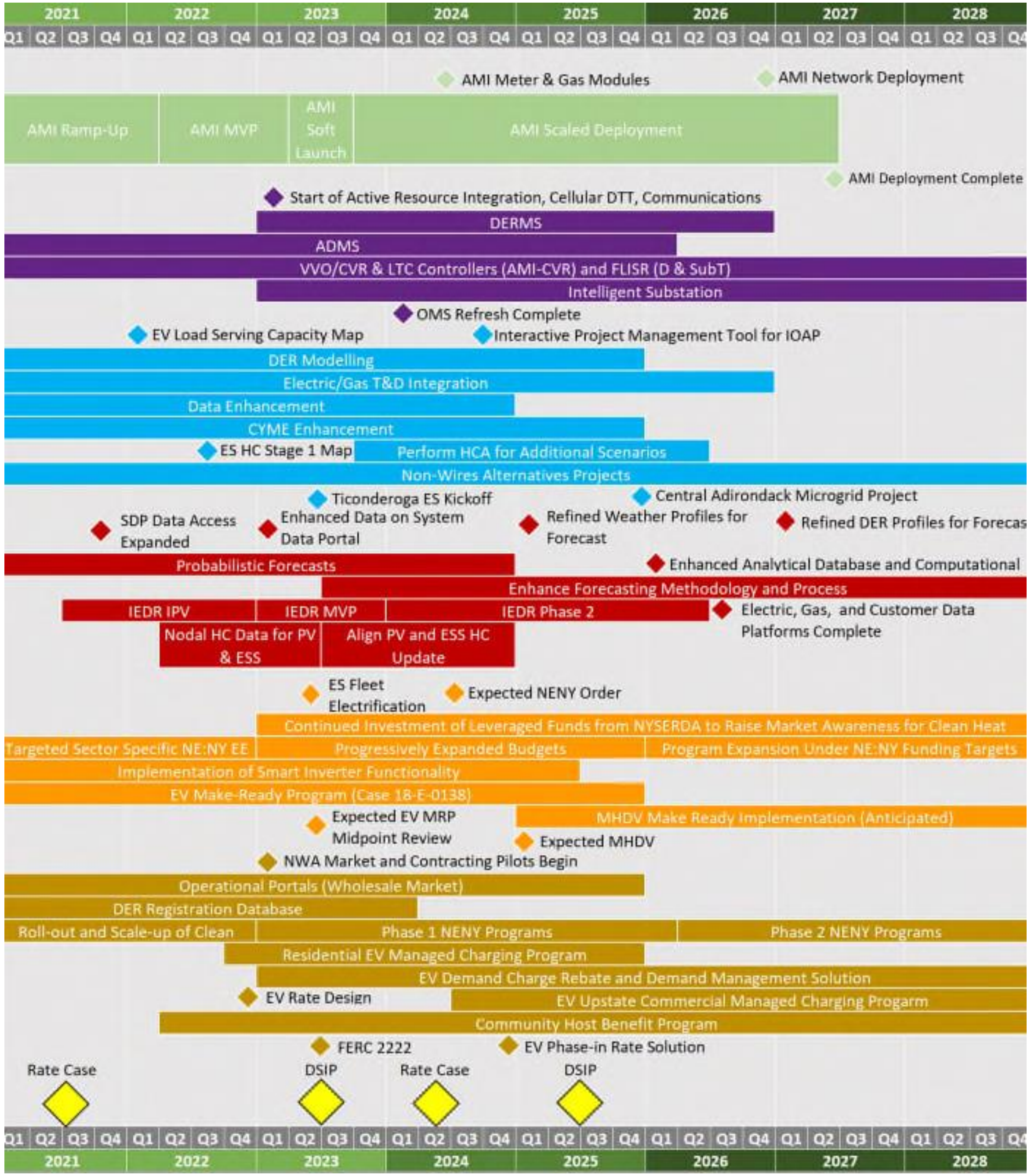


Figure source: National Grid Distributed System Implementation Plan (June 2023)

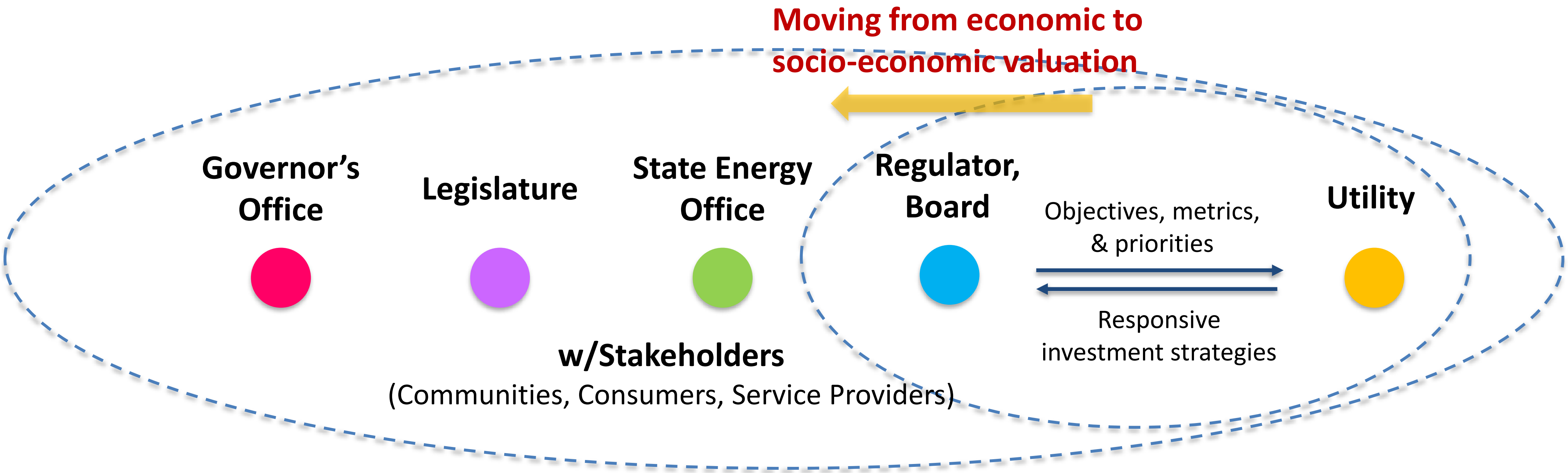
Interactive poll #3

In YOUR state, what other types of plans could be better integrated into utility distribution planning? (Select as many responses as you want)

Planning Objectives and Priorities

Formulation of objectives and priorities

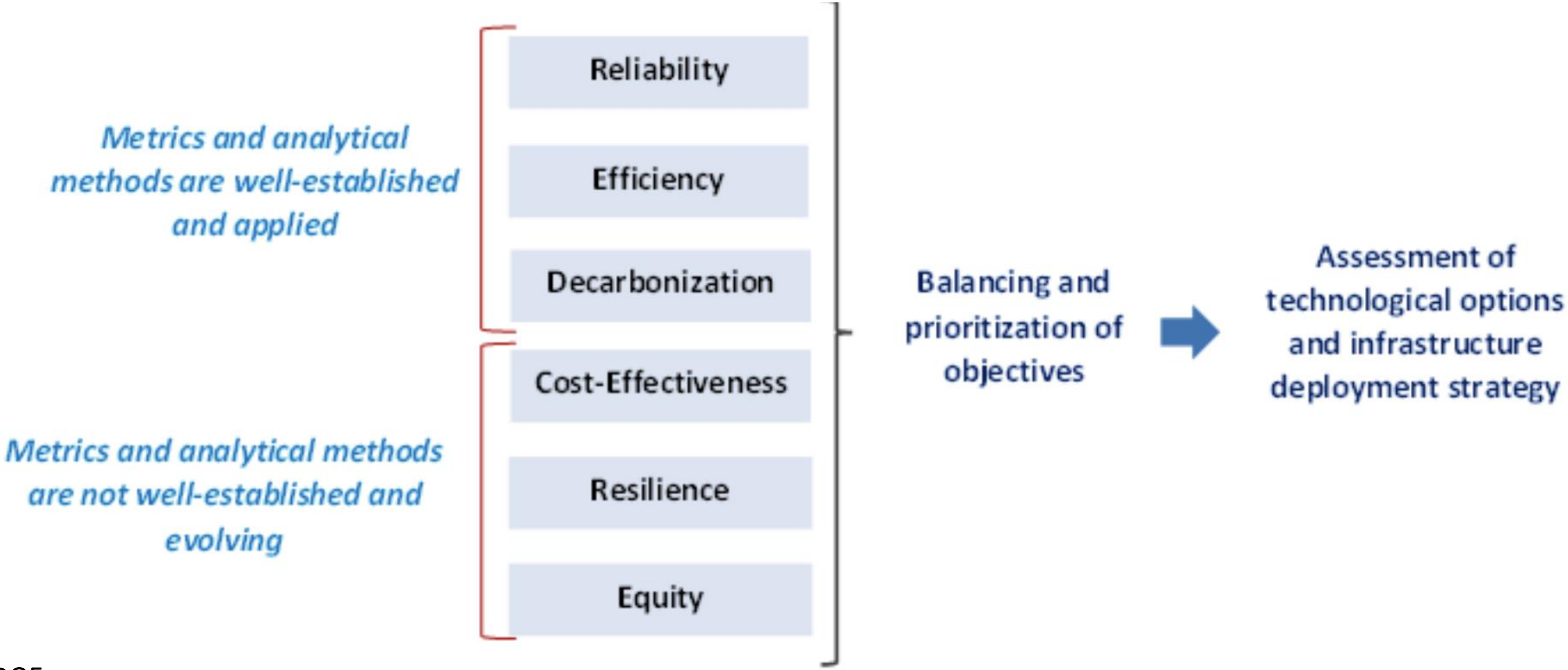
Collaborative efforts are required to enable formulation of equitable strategies for transitioning to a decarbonized and resilient electricity delivery system.



Source: DOE

Planning objectives

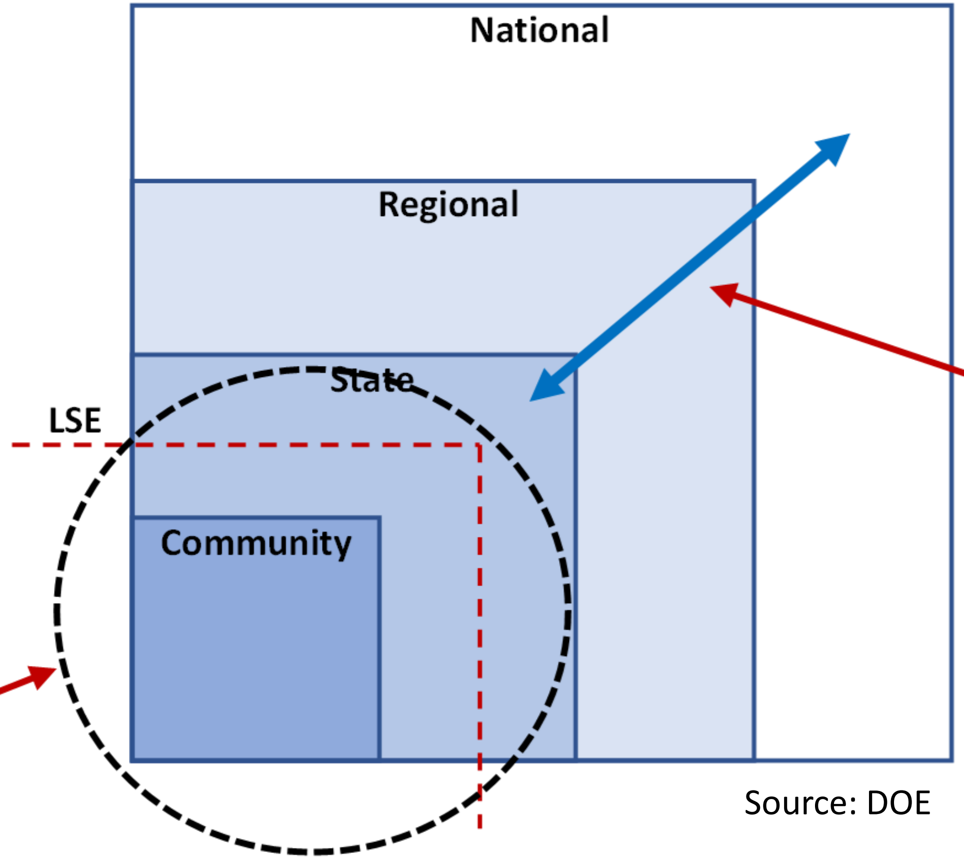
A well-designed integrated distribution system planning process provides a framework for translating policy objectives into holistic infrastructure investment strategies.



Source: DOE

Scale of integrated planning

Address community and state objectives and align with regional planning efforts



Source: DOE

Alignment of community and state strategies with regional, multi-state strategies

IDPs align community and state policy goals into multi-year investment strategies

Development of goals and priorities

- Many states have established requirements for grid planning, by legislation or regulation.
- States set goals, objectives, and priorities that define long-term, high-level outcomes for grid planning and steps to achieve them.
- Goals for grid planning include traditional regulatory aims (e.g., safety, reliability, and affordability) as well as newer policy goals (e.g., transportation electrification, more renewable resources, and emissions reductions) and related outcomes such as greater asset utilization and improved integration and utilization of DERs.
- Grid planning objectives reflect the importance of transparency and stakeholder engagement.

Source: Sunrun

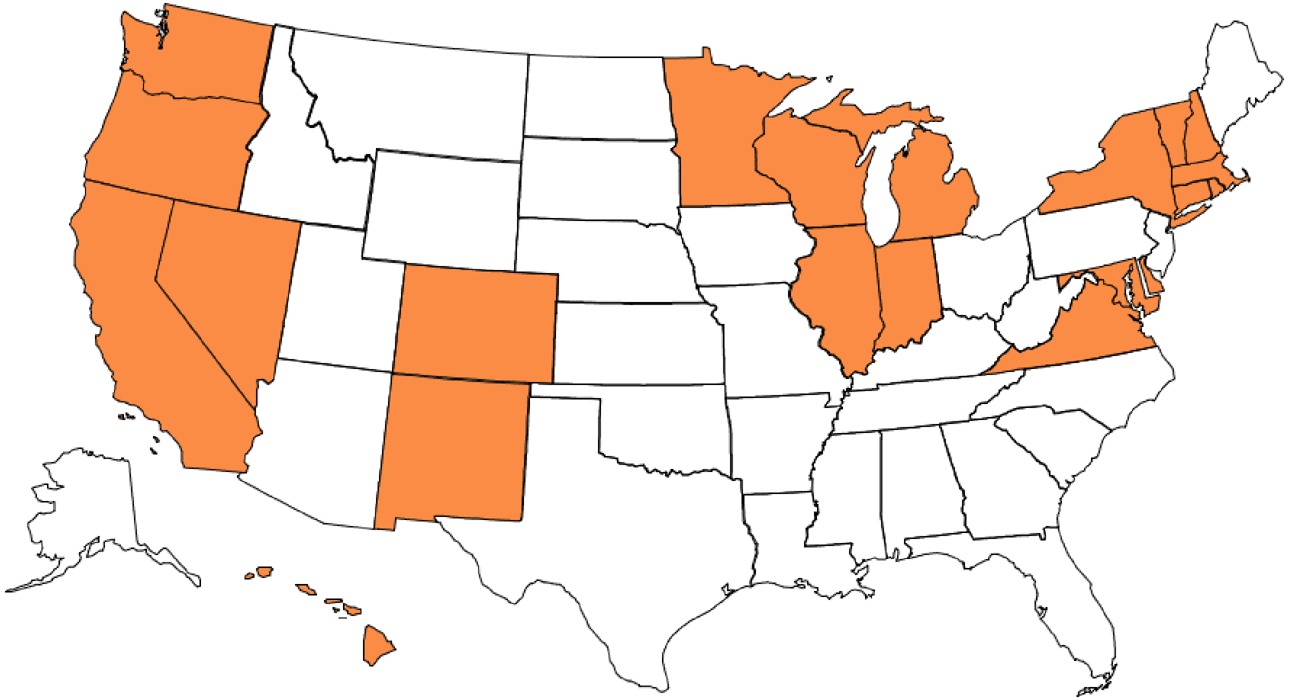
Common themes in grid planning goals and objectives

Berkeley Lab reviewed goals and objectives for grid planning for 21 states and DC.

Common themes emerge:

- Improve grid reliability and resilience
- Increase customer choice and engagement in energy services
- Support DER integration and utilization for grid services
- Reduce greenhouse gas (GHG) emissions and support the clean energy transition
- Accelerate deployment of new technologies and services to optimize grid performance and minimize electricity system costs

Several of the themes overlap.



Improve grid reliability and resilience

- 14 states and DC have goals or objectives related to reliability or resilience (CA, CT, DC, DE, HI, IN, MA, MI, MN, NM, NV, RI, VA, VT).

- Resilience and reliability are typically discussed together.

- Many states have goals to improve, enhance, or promote reliability or resilience (CA, CT, HI, IN, MA, MI, MN, NH, NM, VA). A few states and DC have a general goal of maintaining a reliable or resilient electricity system as the grid modernizes and/or more DERs are added to the grid (DC, DE, MN, RI).

Customer choice and accelerating technology deployment

Increase customer choice and engagement in energy services

- 10 states identify customer choice and engagement in energy services as an objective or goal (CA, CT, HI, IL, MA, MN, NH, NY, RI, VT).
- Two states identify objectives related to compensating customers for the value of DERs (WA, RI). DC and NH require access access to data.
- Objectives or goals related to compensation focus on fairly and appropriately compensating customers for the value DERs provide to the electricity system.

Accelerate deployment of new technologies

- Five states have a goal or objective to accelerate the deployment of new technologies and services to optimize grid performance and minimize electricity system costs (CA, CT, IL, MI, MN).

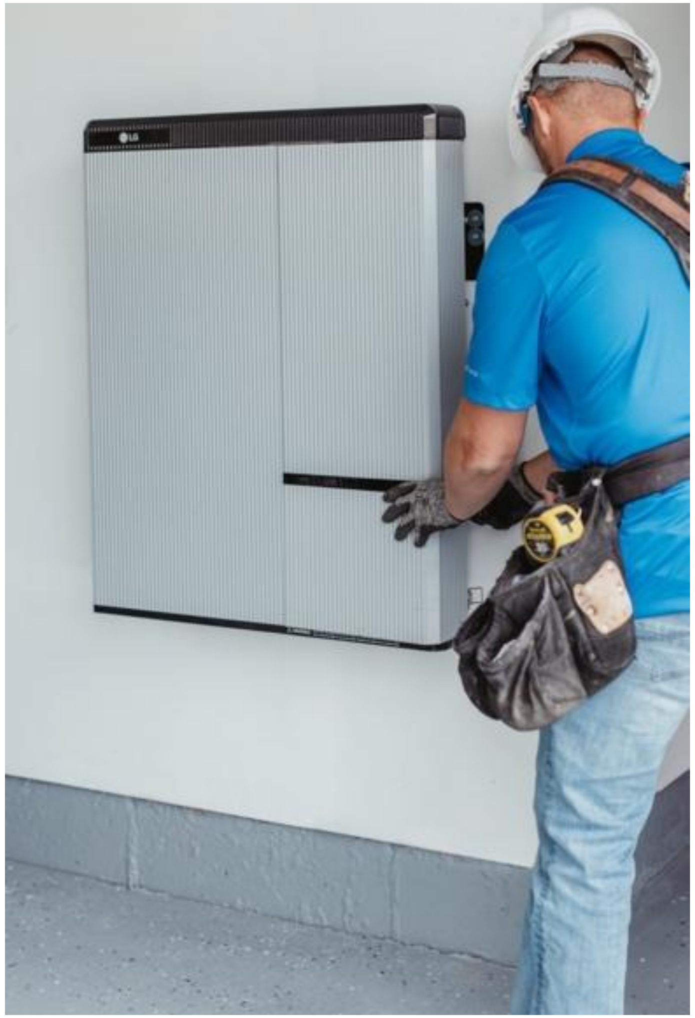
DER integration and GHG emissions reductions

Support DER integration and utilization of grid services

- Nine jurisdictions have goals or objectives that support DER integration and utilization of grid services (CA, CO, DC, HI, IL, MA, MN, OR, VA).
- Some states discuss DER integration more broadly — e.g., achieving renewable energy goals, sustainability.

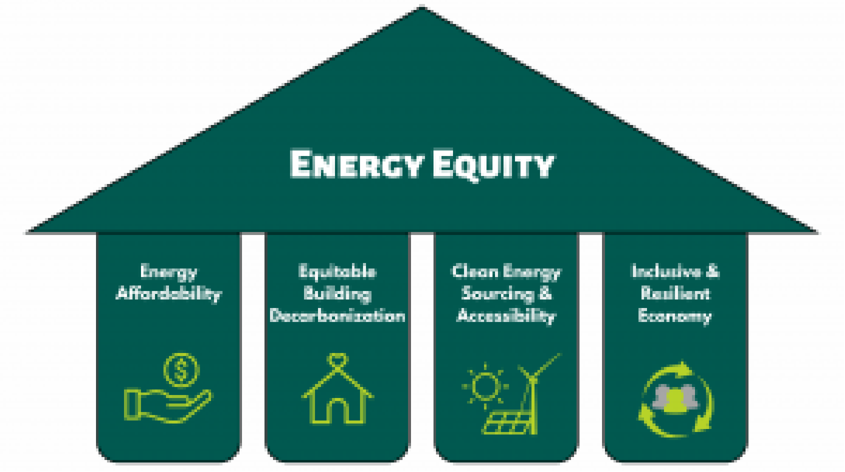
Reduce greenhouse gas emissions and support the clean energy transition

- Three states include supporting a clean energy transition as an objective or goal (CT, IL, MA).
- Several jurisdictions link their goals or objectives to emissions reduction goals (CO, HI, IL, OR) or climate action goals (DC).



Other themes

- **Stakeholder engagement and transparency** are explicitly mentioned as objectives or goals in a few states (e.g., MI). Several states include these aims in distribution system planning requirements (*see slides later in this presentation*).
- **Affordability** is mentioned in objectives or goals for several states (CO, CT, DC, IL, MI, NH, RI), typically to maintain an affordable system for *all* customers.
- **Equity** is included as a grid planning goal or objective in some states (CO, IL, OR), as well as in Commission orders (e.g., MN).



Source: Greenlining Institute

Emerging objectives: Transportation and building electrification (1)

- **Many states are taking action to equitably accelerate transportation and building electrification.**
- **Approaches to address electrification in distribution system planning:**
  - States can **require electrification analysis** in distribution system plan filings.
    - For example, the Massachusetts Climate Act requires the Department of Public Utilities to direct utilities to develop an Electric Sector Modernization Plan to proactively upgrade distribution and transmission systems to accommodate increased building and transportation electrification. The plan must describe improvements to the distribution system that will facilitate electrification.
  - **Utilities can conduct scenario analysis** of electrification in distribution plans (e.g., DTE Electric).
  - States can **require utilities to file transportation electrification plans** with distribution system-related plans (e.g., Nevada and Colorado).

Source: EVgo

Emerging objectives: Transportation and building electrification (2)

- **Coordinating electrification and distribution system planning can:**
  - Enhance knowledge-sharing across internal utility teams
  - Facilitate consistent guidance across related processes
  - Provide greater confidence in validity of resulting plans
  - Lower barriers to participation, improve understanding, and provide greater transparency for communities and stakeholders
  - Streamline discussion and improve strategic outcomes

Source: U.S. Department of Energy

Emerging objectives: Maximize use of federal funds (1)

- **Several Bipartisan Infrastructure Law (BIL) funding mechanisms impact distribution system planning — for example:**
  - State Energy Program funding now requires states to demonstrate they are engaged in transmission and distribution planning.
  - State Energy Security Plans must assess a variety of risks. Information from the assessment can inform distribution planning.
  - Grid Resilience and Innovation Partnership (GRIP) grants provide funding to strengthen grid resilience and reliability. Several grants awarded to states and municipal, cooperative, and investor-owned utilities will improve distribution planning and operations.
  - The National EV Infrastructure Formula Program provides funding to states for deployment of EV charging infrastructure. Applications must consider distribution system upgrades.

- **The Inflation Reduction Act (IRA) may drive a variety of changes in utility distribution system planning assumptions.**
  - Production and investment tax credits will lower clean energy and storage costs and may accelerate adoption of renewable energy and storage technologies on the distribution system.
  - Customer incentives may accelerate the adoption of building and transportation electrification and efficiency technologies.

Emerging objectives: Maximize use of federal funds (2)

- **Example PUC and utility actions on BIL, IRA and DSP related issues**
  - Minnesota PUC ordered utilities to discuss in integrated distribution plans (among other plans) how the utility will maximize the benefits of IRA and how IRA has impacted the utility's EV, DER and electrification assumptions (Docket 22-624).
    - Xcel Energy's 4th IDP discusses changes to EV and solar assumptions due to IRA (Docket 23-452).
  - In its order on Xcel Energy's Demand Side Management and Beneficial Electrification plan, the Colorado PUC directed the utility to establish a timeline to create or update a potential study to consider the effects of the IRA.
  - DTE (Michigan) discussed its GRIP grant applications in its 2023 Distribution Grid Plan.

Source: Sunrun

Interactive poll #4

Which ONE of these distribution planning objectives do you think is the most important for YOUR state?

Kahoot!

Stakeholder Engagement and Equity and Justice

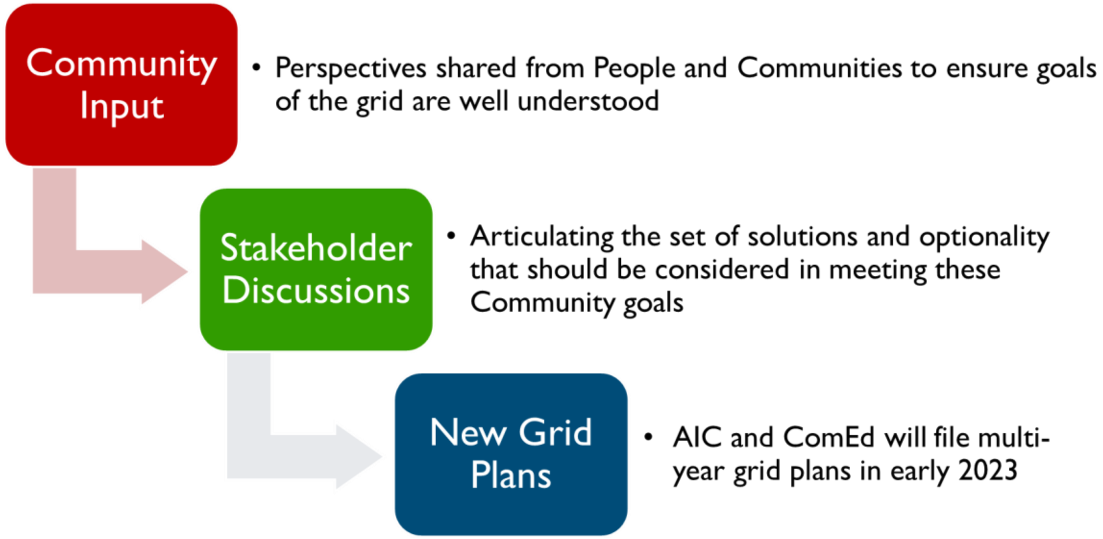
Stakeholder engagement in distribution planning

Benefits

- Improve quality of proceedings and outcomes
- Develop solutions with broad support
- Build trust among parties

Requirements

- *Before plan is filed:* Can include significant input through working groups (e.g., CA, DC, HI, MI, NH, NY) and stakeholder meetings
- *After plan is filed:* Stakeholders file comments, utility provides periodic updates



Source: Multi-Year Integrated Grid Plan Workshop Facilitator's Report: *Synthesizing the Input Collected through 15 Workshops*

Examples of stakeholder engagement in distribution system planning

- New York - Surveys, newsletters, webinars, meetings, and designated website
- Oregon - Utilities must host ≥4 stakeholder workshops before filing a distribution system plan and file a community engagement plan. A technical working group holds regular meetings for stakeholders before and after plan filings.
- Illinois - Utilities must hold ≥6 workshops run by an independent facilitator as part of the integrated grid planning process. At the conclusion of workshops, the facilitator prepares a draft and final report describing the process and areas of consensus and disagreement. The facilitator also provides recommendations to the Commission regarding the utility's plan. Stakeholders can comment on the report.
- Hawaii - Stakeholder council, technical advisory panel, working groups

Example process improvements for stakeholder engagement (1)

Among the opportunities for improvement

- Include non-traditional stakeholders
- Provide intervenor compensation
- Consider equity in identifying and assessing grid solutions
- Engage communities in resilience strategies

Based on feedback from stakeholder engagement in the distribution planning process, DTE created reliability improvement maps (figures on the right).

The Massachusetts Grid Modernization Advisory Council suggested improvements to stakeholder engagement in its recommendations to the electric utilities.

- Develop goals and clear reporting on metrics of success to measure the efficacy of proposed stakeholder engagement
- Include the Clean Energy Stakeholder Advisory Group within the Advisory Council, possibly within the Equity Working Group
- Develop specific and consistent definitions of equity and adopt quantifiable reporting metrics

Exhibit 17.1.1 Electric Reliability Improvement Map (DTE Service Territory)

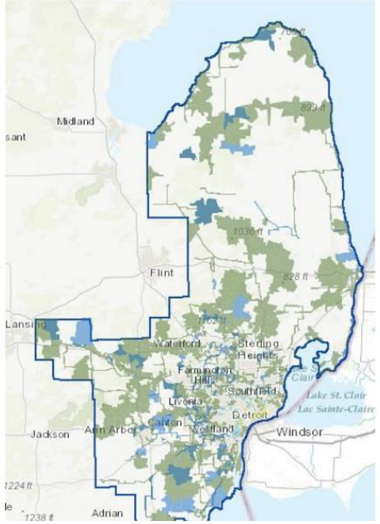
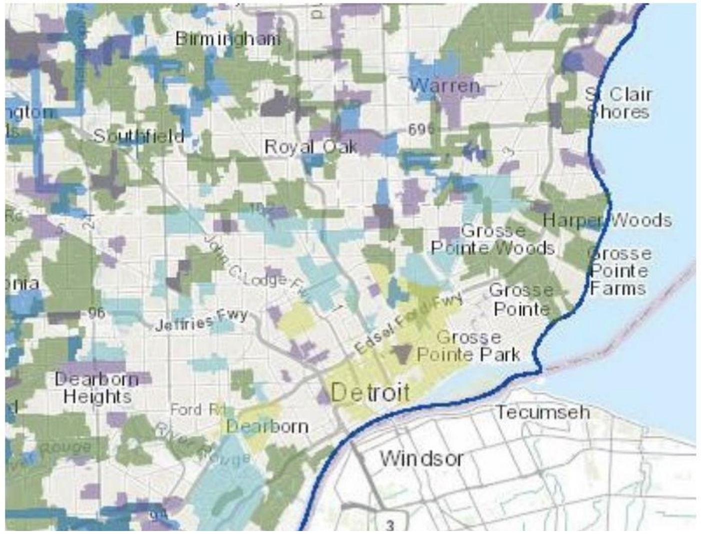


Exhibit 17.1.2 Electric Reliability Improvement Map (Metro Detroit)



	Tree Trimming	Tree limbs and branches are responsible for nearly 70% of the time our customers spend without power. That's why we're surging our efforts to trim overgrown trees in your neighborhood to keep you safe and the energy grid reliable.
	Strengthen Power Lines	We're upgrading and strengthening power lines to ensure the electric system in your neighborhood is more resilient and reliable.
	Utility Poles Maintenance	We're inspecting and repairing utility poles and replacing cross arms and other pole top equipment to ensure our system delivers the power you need when you need it.
	Rapid Response	Tree trimming and pole top equipment repairs/replacements to quickly improve reliability in communities experiencing emergent issues in between planned maintenance schedules.
	Modernizing & Rebuilding the Grid	Modernizing electrical substation equipment, as well as the underground and overhead infrastructure that delivers power to you, including replacing poles and wiring. Tree trimming will be completed, as necessary, in advance of pole replacements.

Source: DTE Electric

Example process improvements for stakeholder engagement (2)

The Minnesota PUC ordered Xcel Energy to file a summary of the stakeholder process for its next integrated distribution plan and list next steps by August 2023.

- The PUC required at least four stakeholder meetings. The utility held six meetings to cover all of the content in the plan.
- The utility observed that fewer participants attended workshops when the content was more detailed and technical.
- To encourage participation, Xcel asked stakeholders about preferred meeting format.
- Participants could submit questions during the registration process or during workshops.
- Xcel concluded that it may not be possible to develop “a shared vision for the distribution grid of the future.”

Stakeholder workshop series generated new ideas for Xcel on:

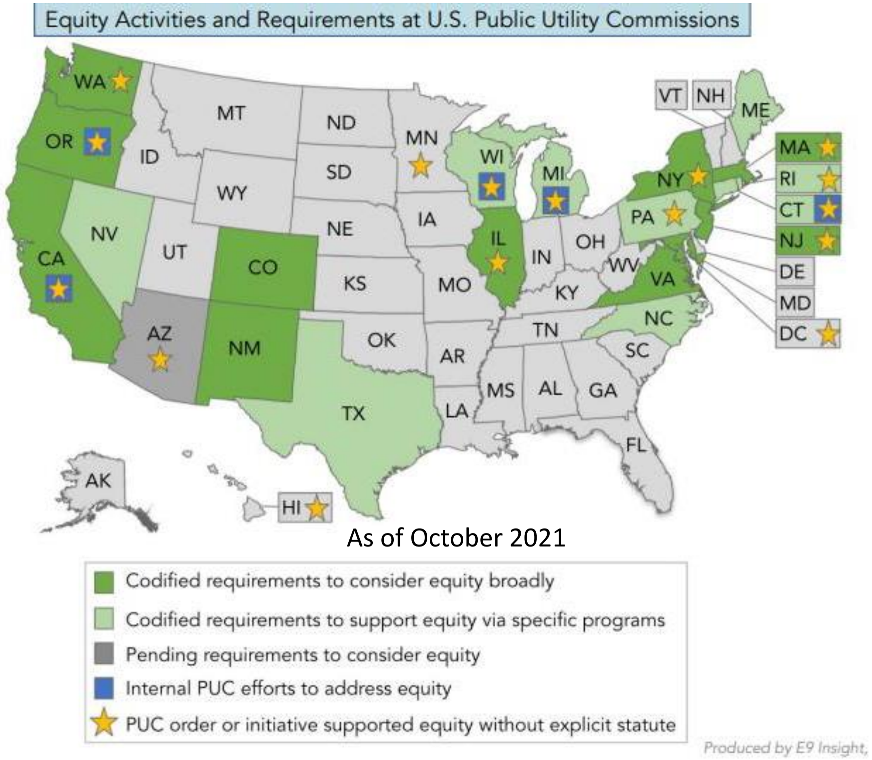
- How to prioritize projects
- Reflecting distribution system constraints in forecasting
- Reflecting benefits of distributed PV for reducing system peak
- Considering multi-value projects

Stakeholder information available in Docket 21-M-694 (eDockets)

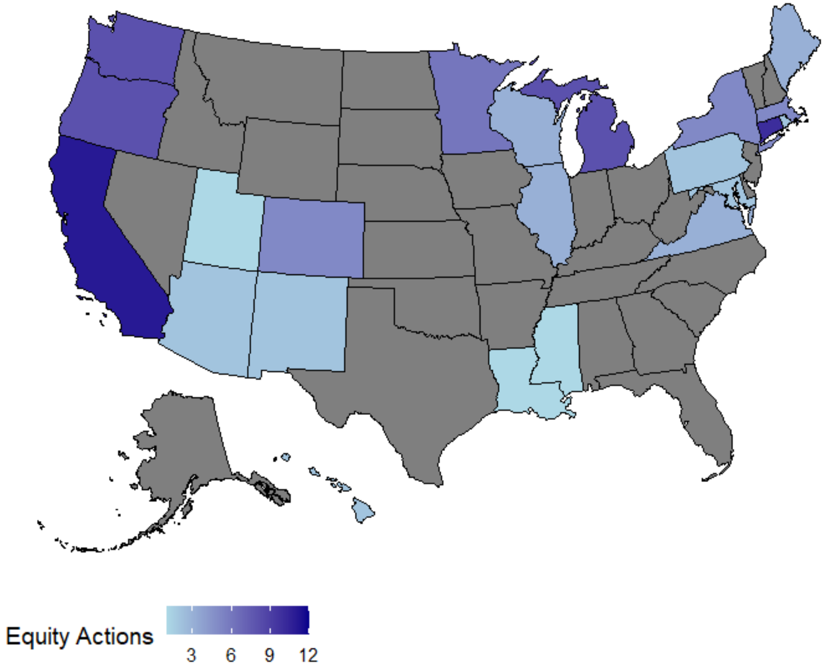
Energy equity and justice (1)

Many states are adopting equity and justice provisions that apply to regulated utilities, including for planning.

- To address social, economic and health disparities
- Through legislation, governor's executive orders, PUC orders, or actions by other agencies*



Almost half of U.S. states took action on energy equity between January 2020 and July 2022.



*See Farley et al. 2021, McAdams 2023, Hanus et al. 2023

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Energy equity and justice (2)

OR – Compensating intervenors and engaging communities

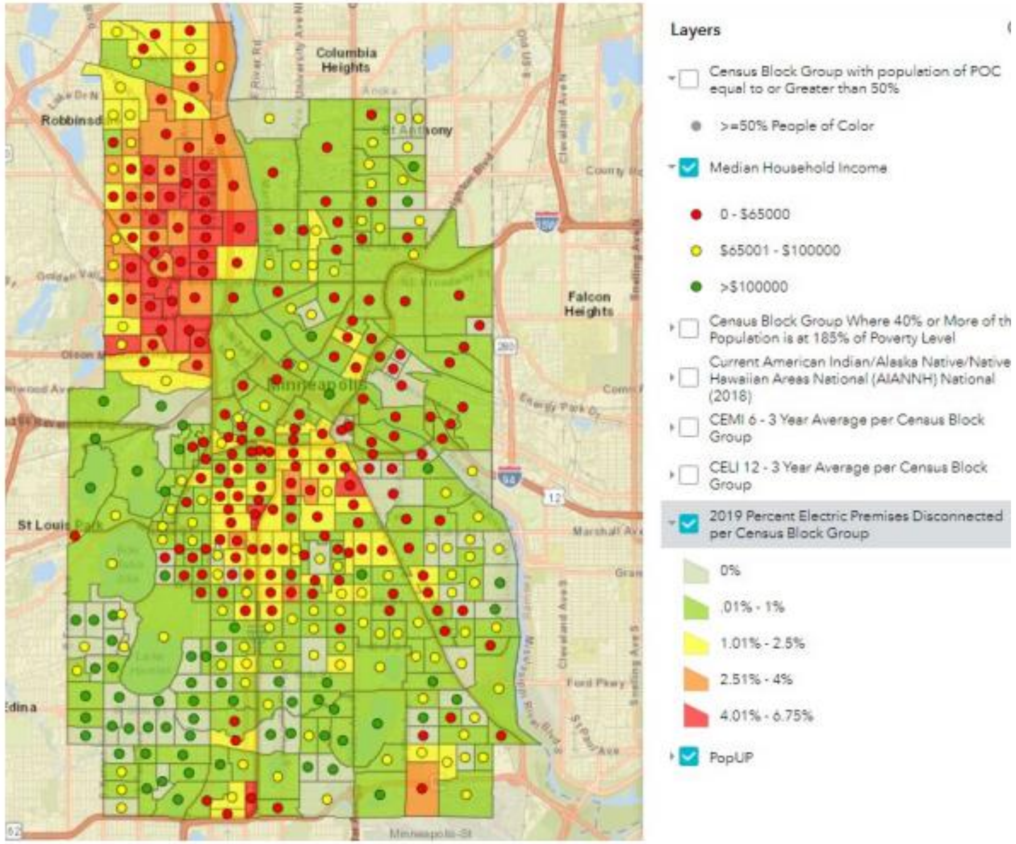
- HB 2475 (2021) provides OPUC the authority to provide financial assistance to organizations that represent broad customer interests, including environmental justice organizations, in regulatory proceedings.
- Order 20-485 initially requires consultation with community-based organizations (CBOs) before plan filing, plus a community engagement plan.* It evolves to active collaboration with CBOs and environmental justice communities so community needs (energy burden, customer choice, resilience) inform distribution projects.
  - Portland General Electric hired CBOs to recruit for and convene community workshops, develop educational materials, and conduct research for the utility's first distribution plan.

MN – Mapping metrics and demographic data

- The PUC required Xcel Energy to map reliability and service quality metrics and demographic data to reveal any equity issues (Dec. 18, 2020, order in Docket 20-406).

ME – Assessing equity impacts

- The Integrated Grid Planning law requires "An assessment of the environmental, equity and environmental justice impacts of grid plans."



Source: Xcel Energy, Oct. 1, 2021, filing, Docket 20-406

*For example, see section 3.4 in PGE's 2021 Distribution System Plan.

Example improvements for energy equity and justice

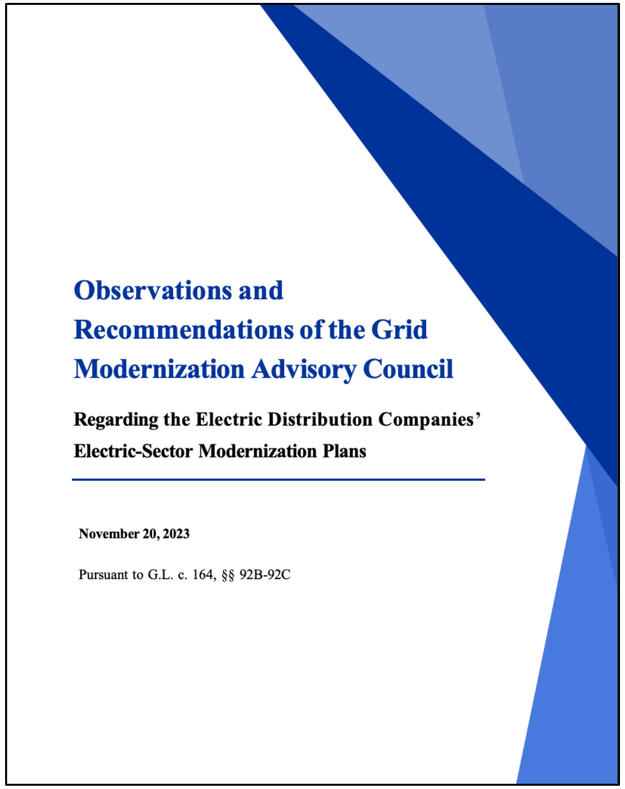
In Massachusetts, the Grid Modernization Advisory Council charged the Equity Working Group with providing input and feedback on how to consider equity in the Council's review of utility electric sector modernization plans. Among the Working Group's observations and recommendations:

- Include collaborative stakeholder development
- Incorporate early stakeholder engagement to shape engagement plans and modeling assumptions
- Standardize definitions of equity across the utilities
- Metrics should reflect the impact of work, not just effort
- The plans should include customer benefits *after* considering cost of grid updates

The Working Group made 12 procedural, recognition and distributive equity recommendations on the draft plan to improve the final plan and process.

The report includes proposed metrics for equity assessments and stakeholder engagement. Equity assessment metrics are grouped into five categories:

Accessibility and community engagement
Workforce and economic benefits
Health benefits
Financial benefits and incentives
Affordability


Observations and Recommendations of the Grid Modernization Advisory Council

Regarding the Electric Distribution Companies' Electric-Sector Modernization Plans

November 20, 2023

Pursuant to G.L. c. 164, §§ 92B-92C

Planning Requirements

Procedural elements*

Frequency of filing

- Typically annual or biennial
- *Considerations:* alignment with utility capital planning, workload, tracking progress on goals and objectives, filing cycle for other types of plans

Planning horizon

- Action plan: 2–4 years
- Long-term investment plan: 5–10 years

Confidentiality

- Level of specificity for hosting capacity
- Peak demand/capacity by feeder
- Contractual cost terms
- Bidder responses to non-wires alternatives solicitations
- Proprietary model information

Source: EPRI

*Stakeholder engagement and equity covered in last section

Substantive elements (1)

Baseline information on current state of distribution system

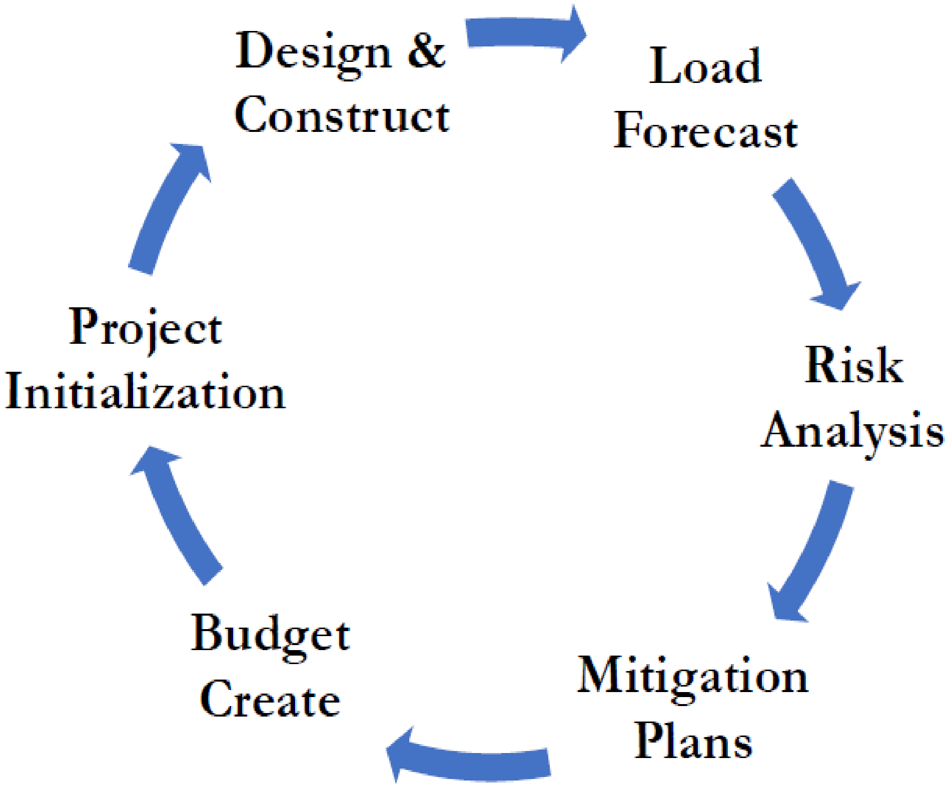
- Such as system statistics, reliability performance, equipment condition, historical spending by category

Description of planning process

- Load forecast – projected peak demand for feeders and substations
- Risk analysis for overloads and plans for mitigation
- Budget for planned capacity projects
  - Asset health analysis and system reinforcements
  - Upgrades needed for capacity, reliability, power quality
  - New systems and technologies
  - Ranking criteria (e.g., safety, reliability, compliance, financial)

Distribution operations

- Vegetation management
- Event management



Source: Xcel Energy

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Substantive elements (2)

Data access

- **Customer usage data - AMI interval data for customers and third parties**
  - Some states require utilities to use or evaluate feasibility of the Green Button framework* (e.g., CA, CO, CT, DC, HI, IL, MI, NH, NY and TX).
    - Download My Data – standard enables customer to download their data
    - Connect My Data – data exchange protocol allows automatic transfer of data from utility to third party on customer authorization
- **System level data – To support customer and third-party solutions**
  - NY, NH, MN, OH, CA and DC are examples of jurisdictions with detailed system data sharing requirements.
  - Some states require data platforms, or centralized online resources where energy data are aggregated, stored in a common format, and accessible to customers and third parties.
    - For example, see Joint Utilities of New York Utility System Data Portal and Integrated Energy Data Resource (IEDR) Platform
- **Some states define specific aggregation levels for data sharing to protect privacy.**
  - Colorado example: *At a minimum, a particular aggregation must contain at least fifteen customers; and, within any customer class no single customer's customer data or premise associated with a single customer's customer data may comprise 15 percent or more of the total customer data aggregated per customer class to generate the aggregated data report (the "15/15 Rule").*
- **New NARUC resources on sharing grid data**

*The Green Button initiative is an industry-led effort to provide utility customers with easy and secure access to their energy usage information in a consumer-friendly and computer-friendly format.

Substantive elements (3)

DER forecast

- Types, sizes, amounts and locations

Hosting capacity analysis*

– Maps showing where interconnection costs will be low or high; supporting data provide details
– Use cases: guidance for DER developers, interconnection screens, distribution planning

Geotargeting DER programs

- Efficiency, demand flexibility, distributed PV and storage, and managed EV charging to meet location- and time-dependent distribution needs

Grid needs assessment and analysis of non-wires alternatives**

- Existing and anticipated capacity deficiencies and constraints
- Traditional utility mitigation projects
- A subset of these planned projects may be suitable for non-wires alternatives to defer or avoid infrastructure upgrades for load relief, voltage issues, reduction of power interruptions, or resilience.

**Amount of DERs that can be interconnected without adversely impacting power quality or reliability under existing control and protection systems and without infrastructure upgrades*

***DERs that provide specific grid services at specific locations to defer some traditional infrastructure investments*

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Substantive elements (4)

Grid modernization strategy and technology roadmap

Near-term action plan

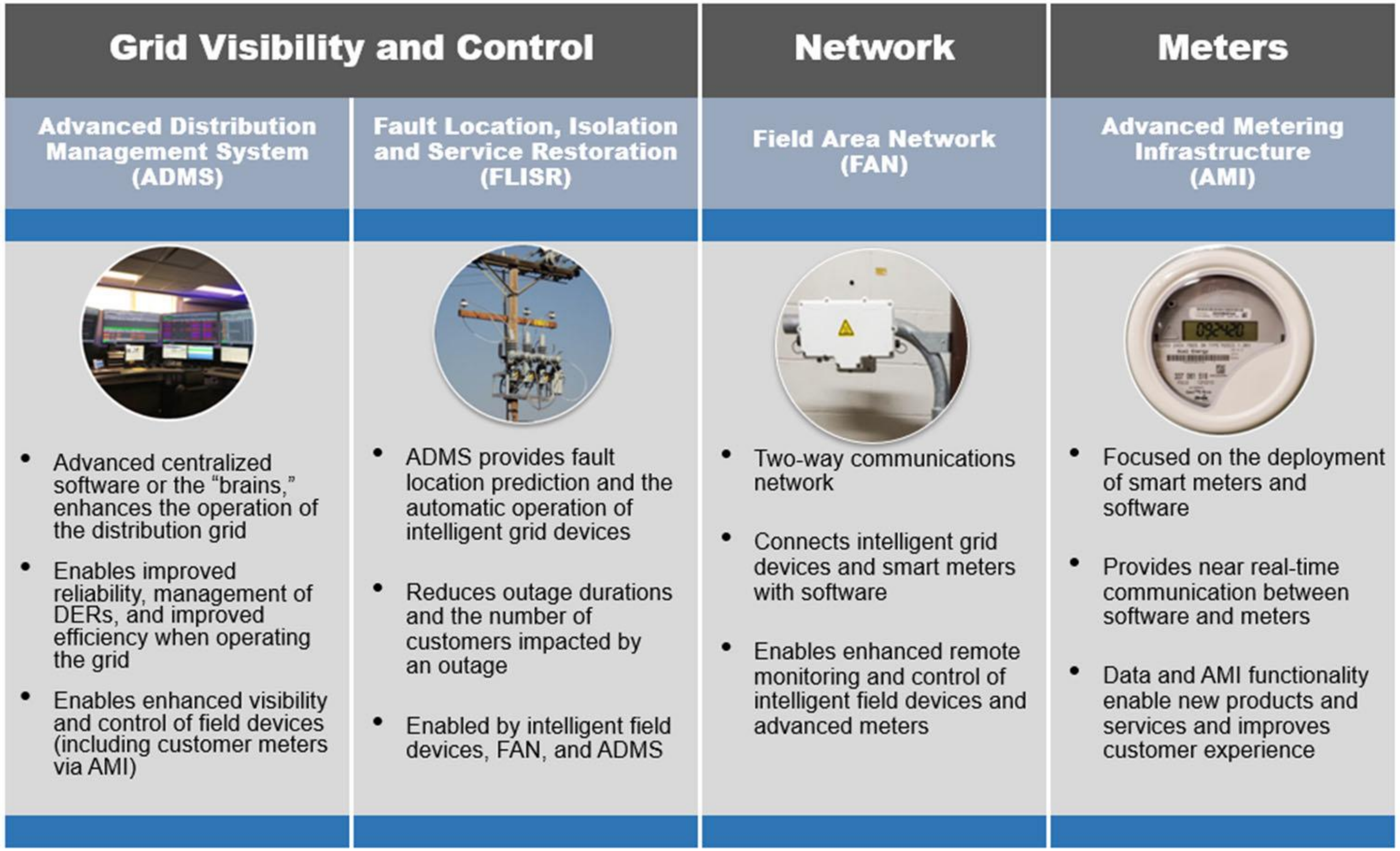
Long-term utility vision and objectives

Discussion of how distribution planning is coordinated with other types of planning

Summary of stakeholder and community engagement

Proposals for pilots

- Resilience projects (e.g., solar+storage, community microgrids)
- Time-varying pricing (e.g., for EV charging)



Source: Xcel Energy (2023)

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Example State Practices

Example state practices (1)

Source: Portland General Electric

- Establish planning goals, objectives, and priorities with stakeholder engagement
- Build on work by other states, tailored to your state's interests
  - Forthcoming Berkeley Lab/PNNL report and catalog of state distribution planning requirements
- Host presentations to increase stakeholders' understanding
  - Colorado, Illinois, Maine, Massachusetts, Michigan, New Mexico, Oregon
- Engage stakeholders and communities in the planning process
  - Joint Utilities of NY stakeholder plan and timeline
  - Oregon's community engagement plans – see Portland General Electric distribution plan
- Ask utilities to respond to a questionnaire to gather baseline information on their distribution system and planning practices
  - Minnesota utilities, New Jersey utilities, Oregon utilities and third-party energy efficiency administrator and stakeholders

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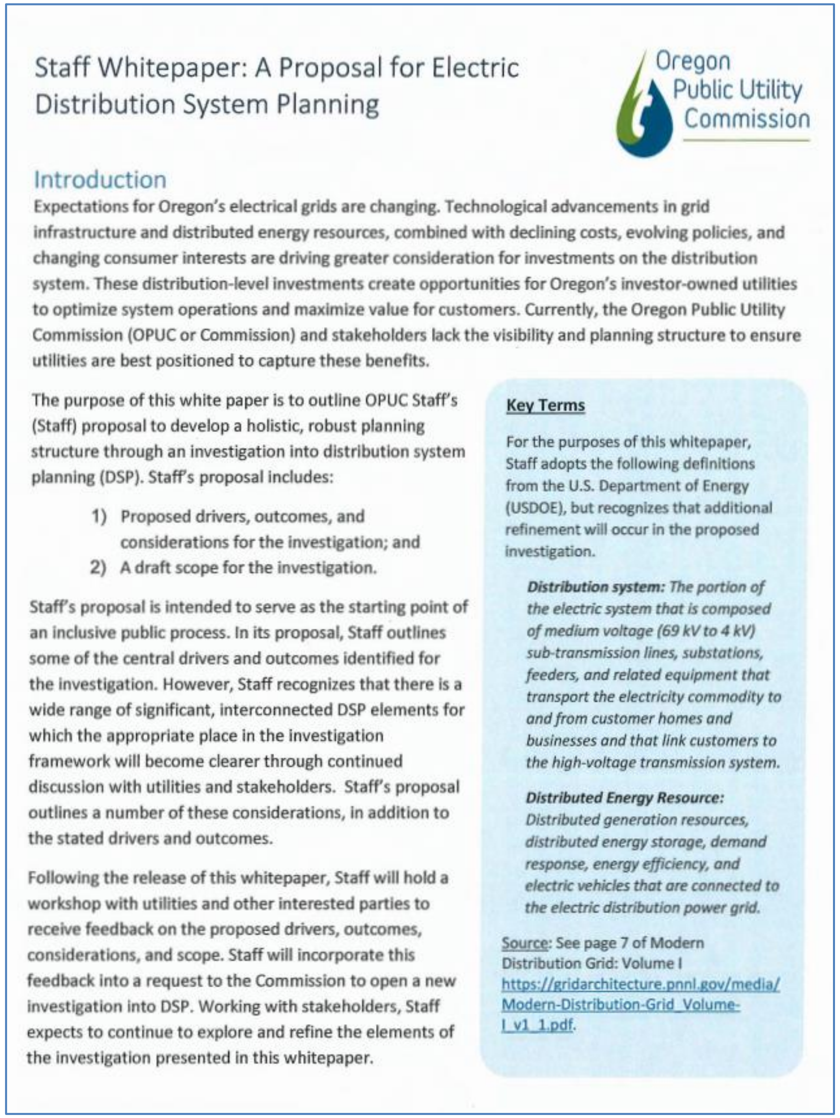
Example state practices (2)

- Determine whether any current filings can be integrated/consolidated in DSP filings
  - Oregon PUC suspended smart grid filings (e.g., order on PGE's DSP)
  - Minnesota PUC integrated grid modernization plans and transportation electrification plans into DSP
- Prepare a white paper to lay out a vision for DSP processes and provide guidance for utility filings
  - Minnesota – Defined grid modernization for Minnesota, proposed a phased approach, and identified principles to guide it
  - New York – Proposed changes in filing requirements for effective interaction with the PSC's Coordinated Grid Planning proceeding to achieve the state's climate goals
  - Oregon – Outlined rationale and key drivers for opening a DSP investigation, desired outcomes and future planning process, near-term scope and schedule for investigation, and planning considerations



Staff Whitepaper: A Proposal for Electric Distribution System Planning

Oregon Public Utility Commission

Introduction

Expectations for Oregon's electrical grids are changing. Technological advancements in grid infrastructure and distributed energy resources, combined with declining costs, evolving policies, and changing consumer interests are driving greater consideration for investments on the distribution system. These distribution-level investments create opportunities for Oregon's investor-owned utilities to optimize system operations and maximize value for customers. Currently, the Oregon Public Utility Commission (OPUC or Commission) and stakeholders lack the visibility and planning structure to ensure utilities are best positioned to capture these benefits.

The purpose of this white paper is to outline OPUC Staff's (Staff) proposal to develop a holistic, robust planning structure through an investigation into distribution system planning (DSP). Staff's proposal includes:

1) Proposed drivers, outcomes, and considerations for the investigation; and
2) A draft scope for the investigation.

Staff's proposal is intended to serve as the starting point of an inclusive public process. In its proposal, Staff outlines some of the central drivers and outcomes identified for the investigation. However, Staff recognizes that there is a wide range of significant, interconnected DSP elements for which the appropriate place in the investigation framework will become clearer through continued discussion with utilities and stakeholders. Staff's proposal outlines a number of these considerations, in addition to the stated drivers and outcomes.

Following the release of this whitepaper, Staff will hold a workshop with utilities and other interested parties to receive feedback on the proposed drivers, outcomes, considerations, and scope. Staff will incorporate this feedback into a request to the Commission to open a new investigation into DSP. Working with stakeholders, Staff expects to continue to explore and refine the elements of the investigation presented in this whitepaper.

Key Terms

For the purposes of this whitepaper, Staff adopts the following definitions from the U.S. Department of Energy (USDOE), but recognizes that additional refinement will occur in the proposed investigation.

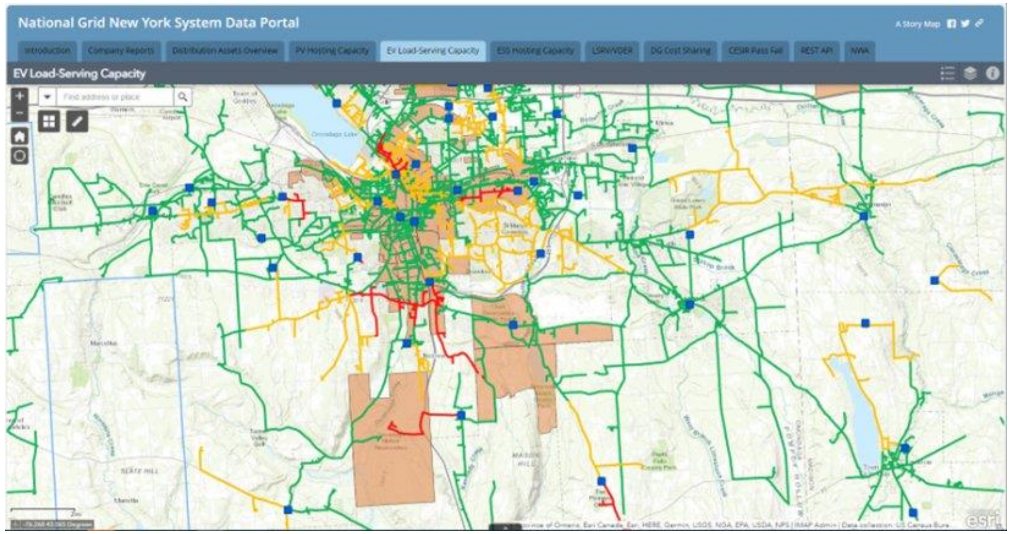
Distribution system: *The portion of the electric system that is composed of medium voltage (69 kV to 4 kV) sub-transmission lines, substations, feeders, and related equipment that transport the electricity commodity to and from customer homes and businesses and that link customers to the high-voltage transmission system.*

Distributed Energy Resource: *Distributed generation resources, distributed energy storage, demand response, energy efficiency, and electric vehicles that are connected to the electric distribution power grid.*

Source: See page 7 of Modern Distribution Grid: Volume I https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf.

Example state practices (3)

- Host work groups to help develop and refine requirements — and address emerging planning issues
  - Hawaii – Stakeholder council, technical advisory panel, and working groups
  - Maine – Working groups on forecasting, solutions evaluation criteria, and data availability/collection
  - Oregon – DSP Work Group serves as a forum to identify, articulate, discuss and, when possible, resolve technical and other questions that arise. The primary objective is finding solutions to barriers that would otherwise inhibit completion of the utilities' plans.
  - New Jersey – Third-party facilitated Integrated DER Working Group with electric distribution companies and stakeholders will make recommendations for integrated DER planning — *forthcoming*
- Consider pilots for new processes and technologies
  - Non-wires alternatives (Oregon)
  - Resilience — Resilient Minneapolis project (Minnesota)
  - Hosting capacity analysis — start with solar PV, expand to other DERs, and specify use cases*
  - Time-based rates — for general service rates and EV charging (e.g., Oregon, Minnesota, Hawaii, New York)



National Grid's New York System Data Portal

*See Minnesota PUC orders in Docket Nos. 15-962, 18-684, 19-666, and 21-694

Questions to ask

- Have clear state objectives been established for distribution system planning?
- Are other types of planning (e.g., resource planning, transmission, energy efficiency, grid modernization, electrification, climate action, resilience) coordinated with distribution planning?
- Are there opportunities to improve diversity of participating stakeholders, data access, and consideration of stakeholder and community feedback?
- How are DERs considered — e.g., in the utility's grid modernization strategy, technology roadmap, as non-wires alternatives?
- How is electrification of transportation and buildings considered in distribution planning?
- How are utilities incorporating BIL and IRA impacts into distribution planning assumptions?
- Are State Energy Offices, PUCs and utilities working together to maximize federal dollars for distribution system improvements?

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For more information

Download publications from Energy Markets & Policy: https://emp.lbl.gov/publications

Sign up for our email list: https://emp.lbl.gov/mailing-list

Follow Energy Markets & Policy on Twitter: @BerkeleyLabEMP

Resources for more information

Berkeley Lab's Integrated Distribution System Planning website, including slides and recordings for previous trainings

U.S. Department of Energy, *Modern Distribution Grid* guidebooks

S. Murphy, L. Schwartz, C. Reed, M. Gold, and K. Verclas, *State Energy Offices' Engagement in Electric Distribution Planning to Meet State Policy Goals*, National Association of State Energy Officials, 2023

J. Carvallo and L. Schwartz, *The use of price-based demand response as a resource in electricity system planning*, Berkeley Lab, 2023

J. Keen, E. Pohl, N. Mims Frick, J.P. Carvallo and L. Schwartz, *Duke Energy's Integrated System and Operations Planning: A comparative analysis of integrated planning practices*, Grid Modernization Laboratory Consortium, 2023

Berkeley Lab, Pacific Northwest National Lab and NARUC, Peer-Sharing Webinars for Public Utility Commissions on Integrated Distribution System Planning, 2023

N. Frick, S. Price, L. Schwartz, N. Hanus and B. Shapiro, *Locational Value of Distributed Energy Resources*, Berkeley Lab, 2021

Load Forecasting

Training for States on Distribution System and Distributed Energy Resources Planning

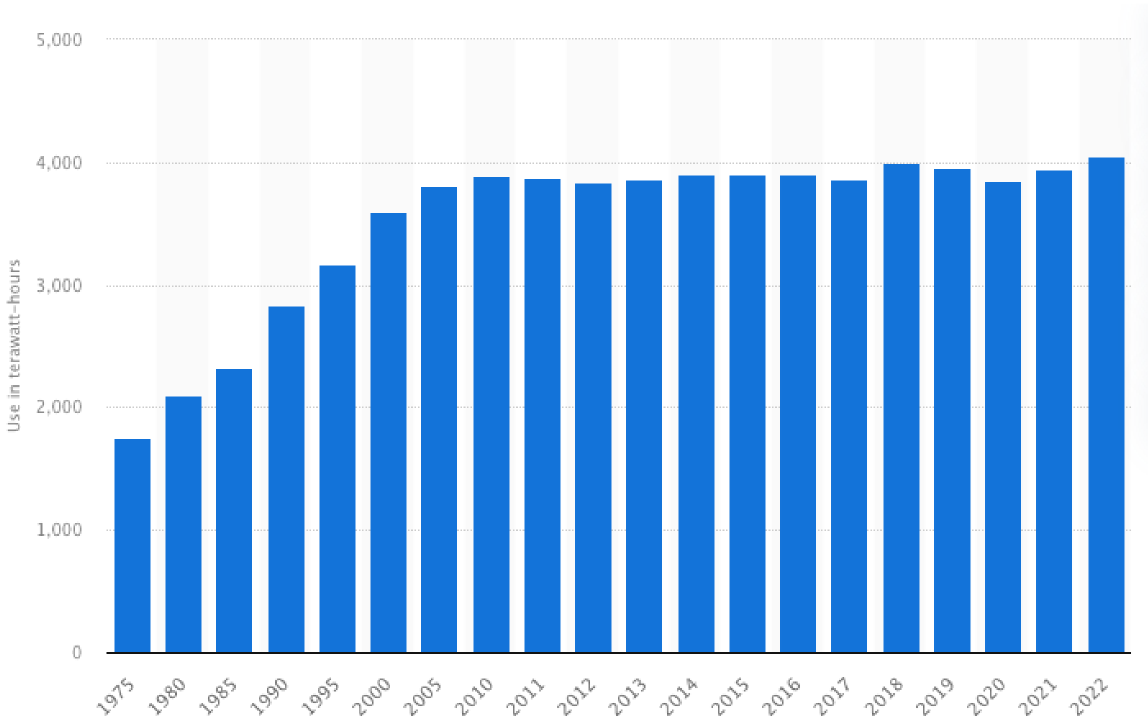
Presented by Julieta Giraldez, Kevala
Western Regional Training

January 24, 2024

Load Forecasting – What Is the Status Quo?

- **Demand** has been **flat** for the past 20 years
- Utilities had time to **"react"** to local load growth from new customers and businesses
- **Past** consumption was a **good representation** of **future** consumption

Electricity end use in the United States from 1975 to 2022

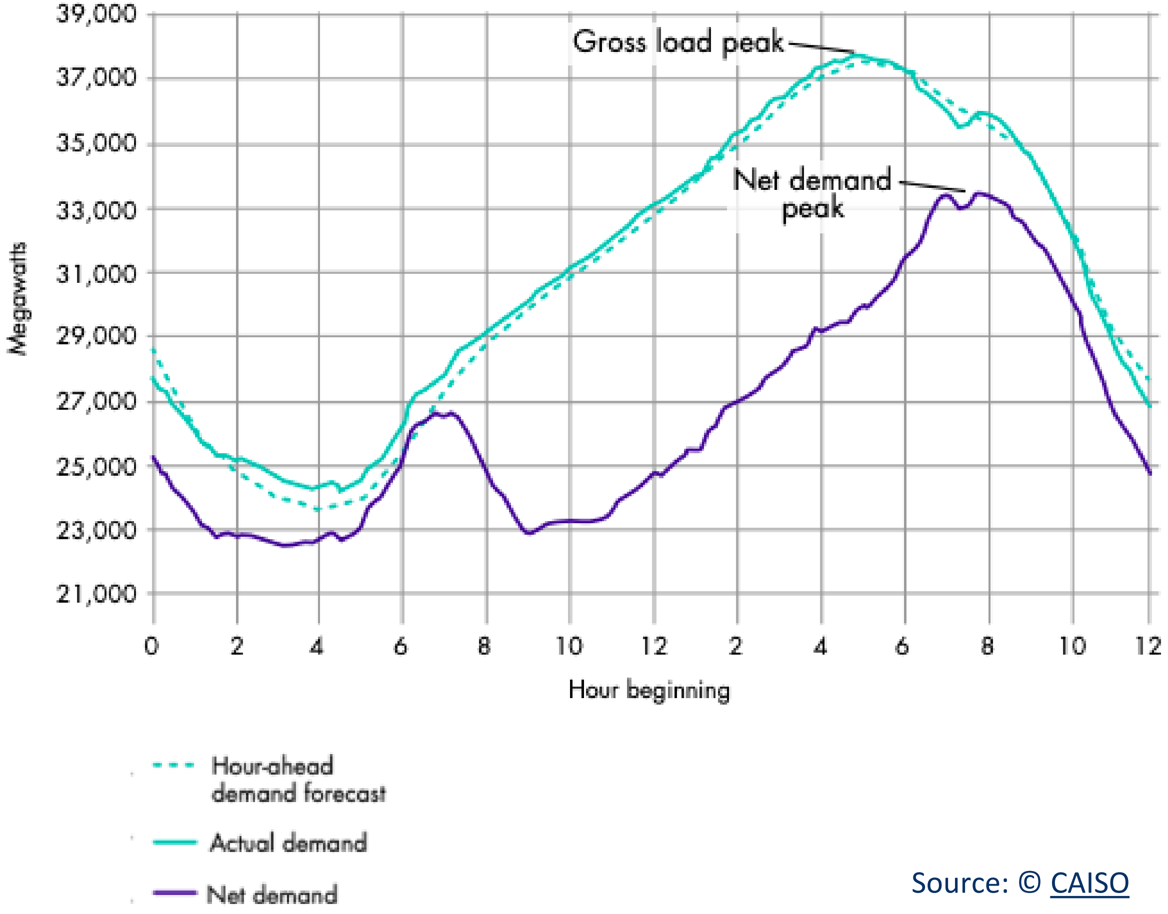


Source: © Statista 2023

Load Forecasting – What Has Changed?

- **Econometric modeling** using historical data (typically load, weather) **is not sufficient** to forecast future load
- **Customers are adopting** new **technologies** behind-the-meter
  - Need to understand *gross load* versus *net load*
  - Need to understand *where* and *when* technologies are being adopted today and in the future
  - *Rapid DER adoption trends* are very different than a new development or business customer
- **Past weather** is **not representative** of future weather

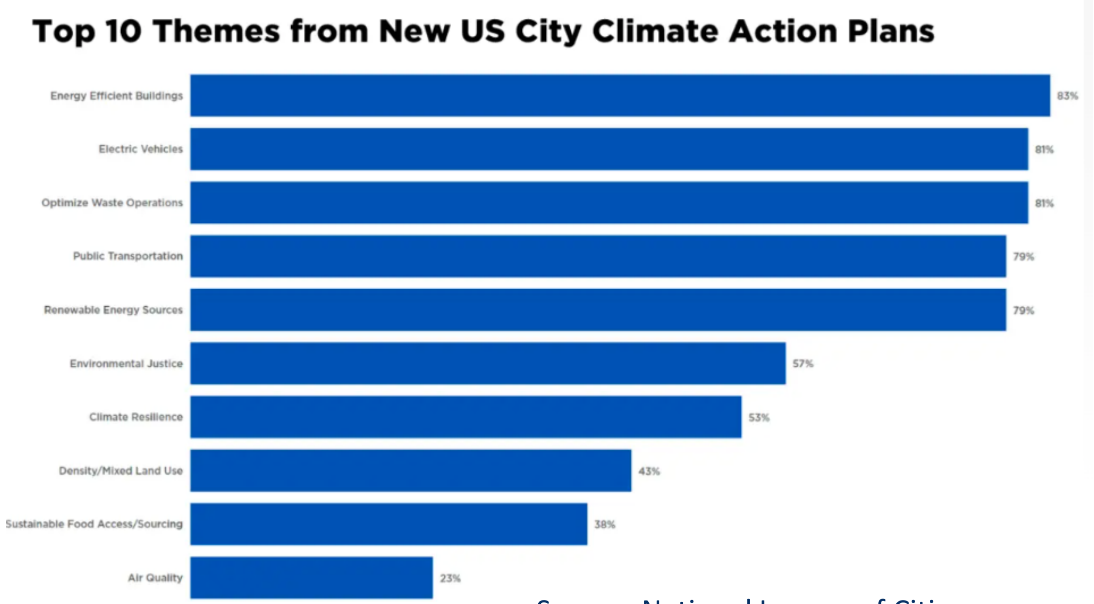
Gross load versus net load example



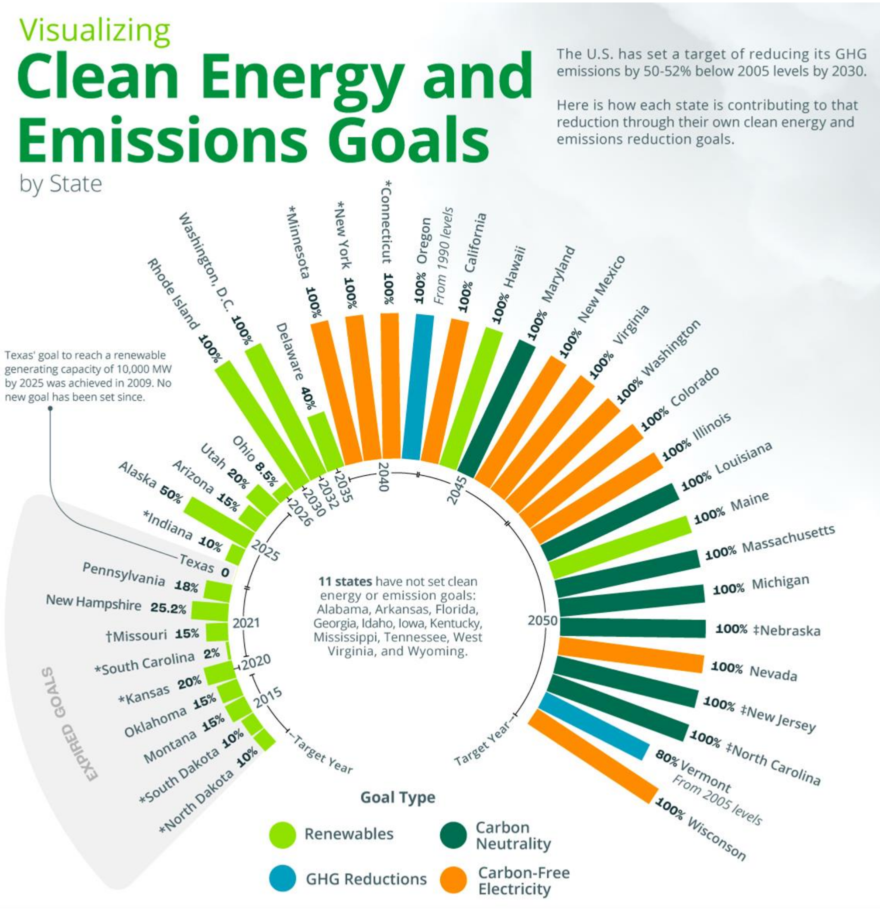
Source: © CAISO

Policy Is Greatly Influencing Load Forecasting

- **DER adoption is heavily influenced by federal/state/local/utility policies and goals**
  - Harder to quantify implications and what is possible
  - Initiatives and programs have to be converted into quantifiable input assumptions on technology adoption, utilization, operation



Source: National League of Cities

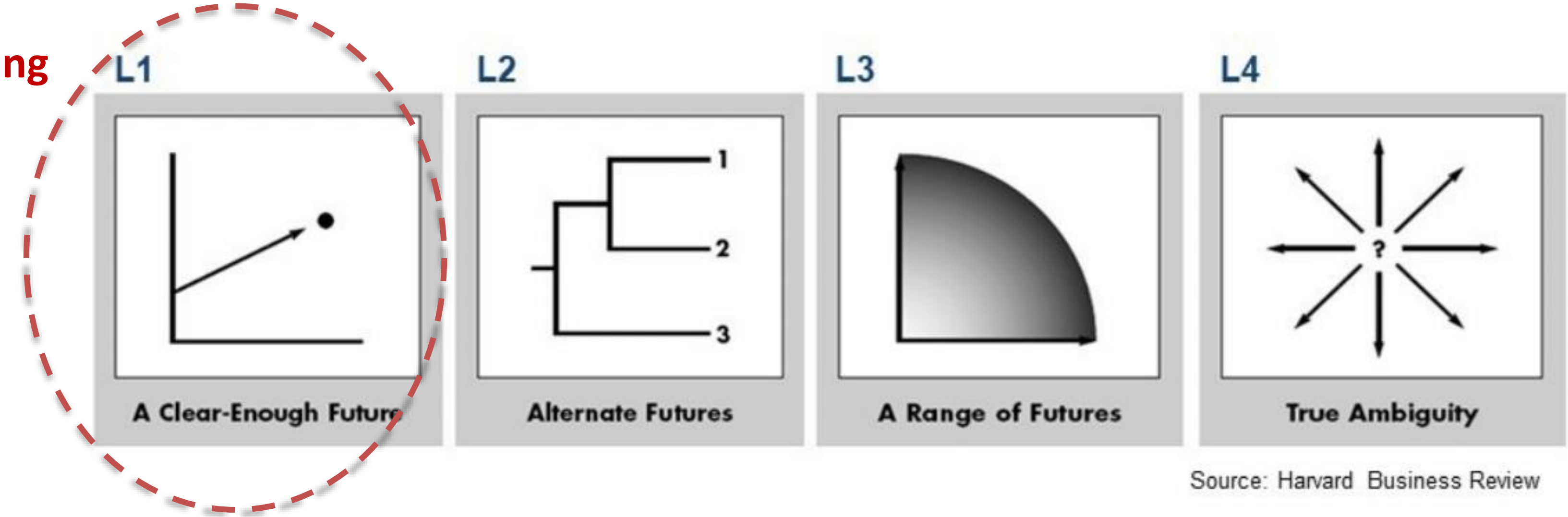


Source: National Public Utilities Council

Policy Is Greatly Influencing Load Forecasting

- **Need to plan for longer time horizons**
  - Distribution planning has typically looked 3-5 years ahead
  - Long lead time on grid assets and transmission constraints are increasing the pressure on distribution planning
- **Need to consider multiple scenarios**

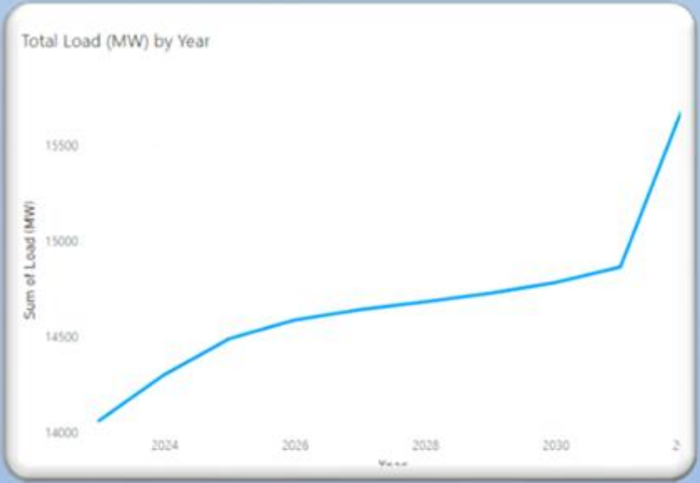
Distribution Planning



Source: Harvard Business Review

Past - Current - Future in Load Forecasting for Distribution Planning

Past

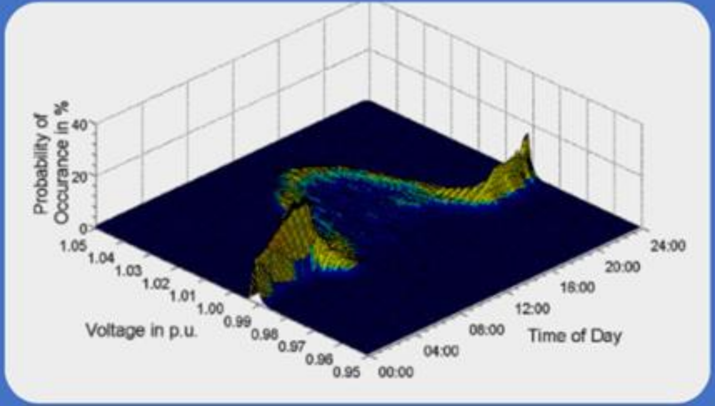


- 5 year time horizon
- Econometrics trends
- DER adjustments
- System level
- Deterministic

Present

- 5, 10, 30 year time horizon
- 8760 trends
- DER adoption and spatial allocation
- Substation / feeder level
- Deterministic scenarios

Future



- Customer level
- 8760 + disaggregated load components
- Parametric distributions for variable to consider uncertainty
- Probabilistic

Source: Eversource

Who Performs Load Forecasting?

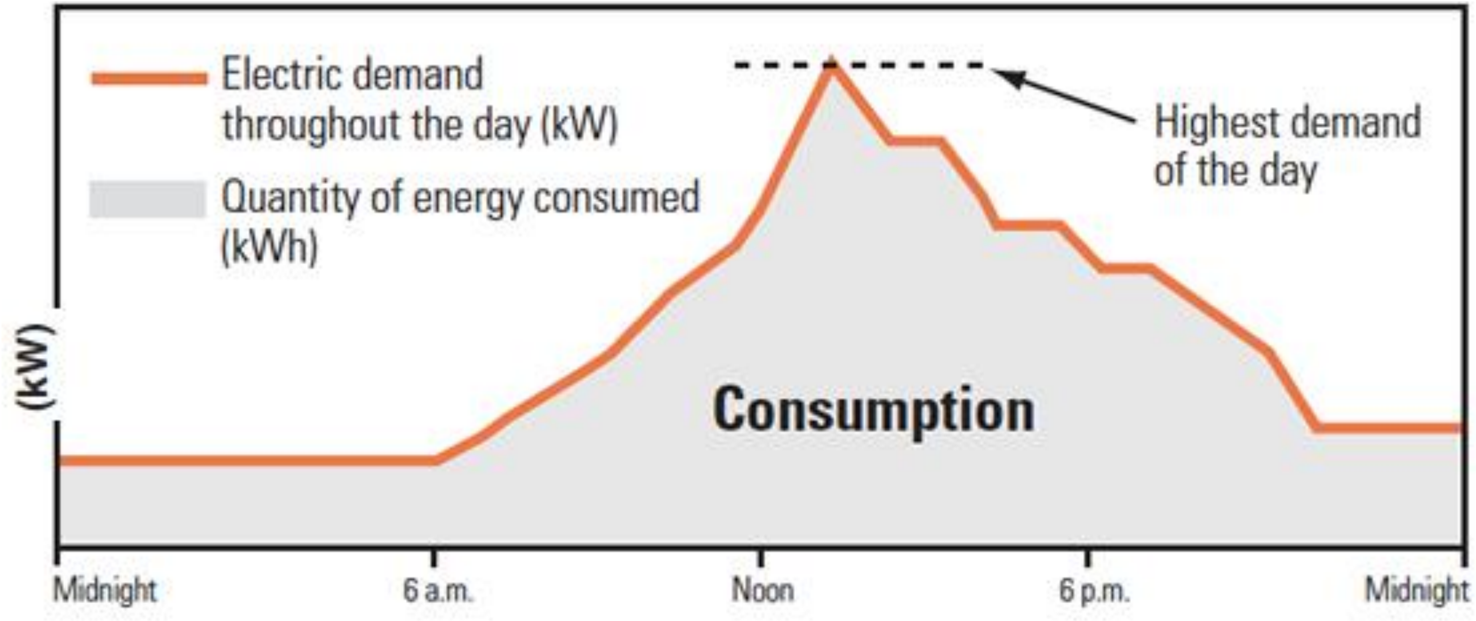
Forecasters
Research organizations
State energy offices
Independent system operators
Utilities – load forecasting departments (typically, the rates department)
Utilities – distribution planning department

Use Cases
National and state studies
Integrated resource planning, renewable portfolio standard plan
Resource adequacy
Transmission planning
Rate design
Corporate forecast & revenue projections
Procurement
Distribution planning

Distribution planning has traditionally not used the forecast from the load forecasting department.

Peak versus Energy Load Forecasting

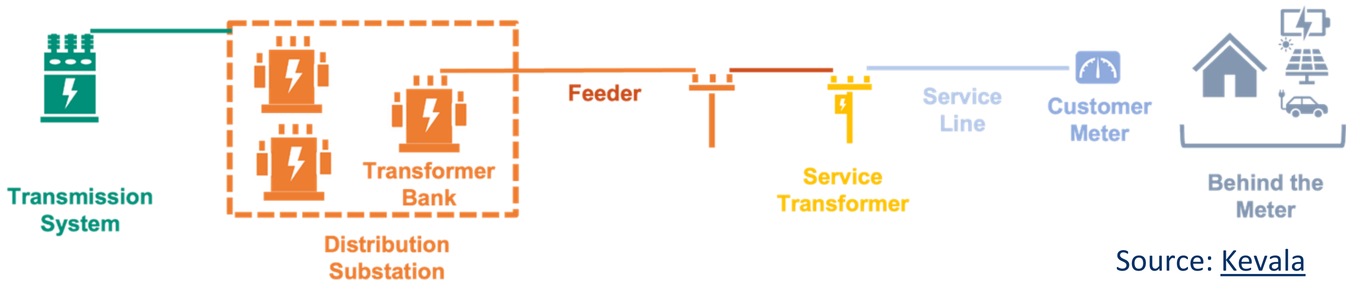
- Load forecasting departments at utilities typically forecast energy and demand separately
- **Distribution Planning** has traditionally only been concerned about **substation/ feeder peak load** to determine how big the infrastructure needs to be



Source: We Energies

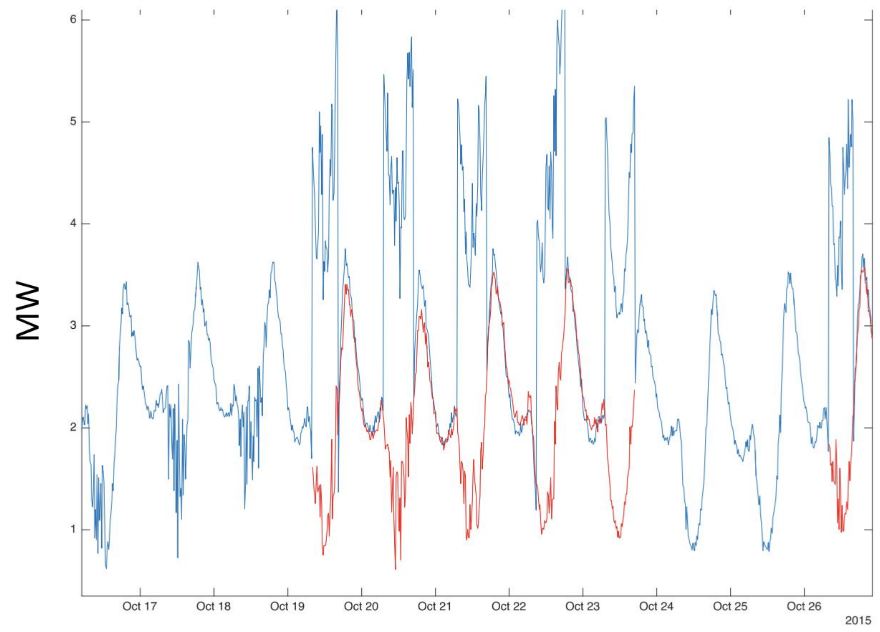
Peak Load Forecast Modeling in Distribution Planning

- **Historical peaks from SCADA measurements at substation and/or feeder-head**
  - SCADA needs to be processed to confirm the ”normal” peak (vs. an abnormality)
    - Typically, a manual and burdensome task
  - Generate a 1-in-10 (90th percentile) load forecast based on historical weather



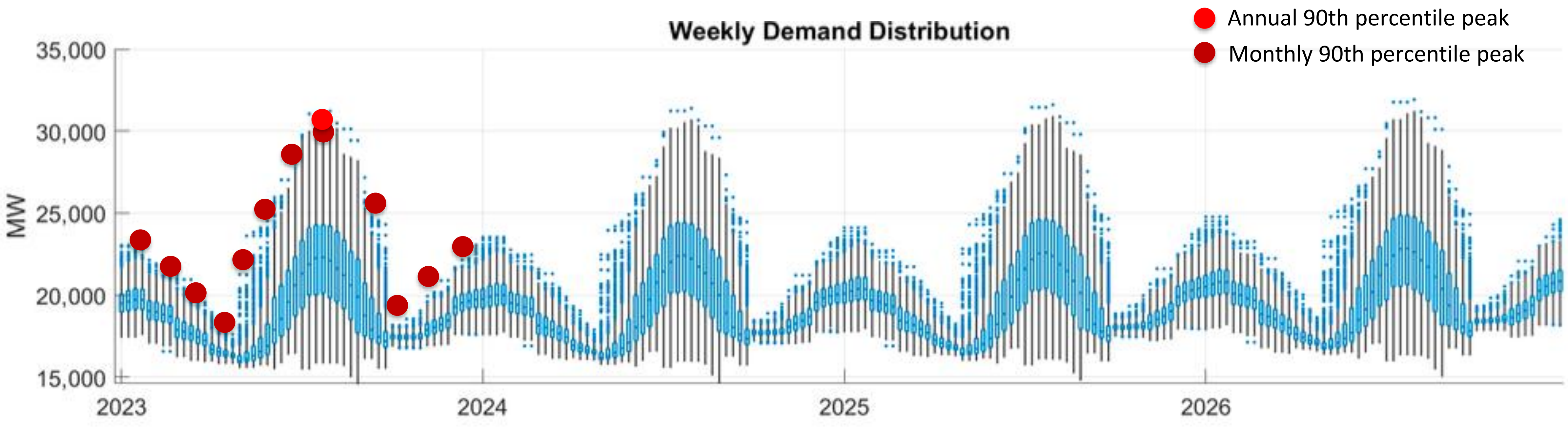
Source: Kevala

Example of Outliers for Abnormal Reconfiguration Event



Source: NREL

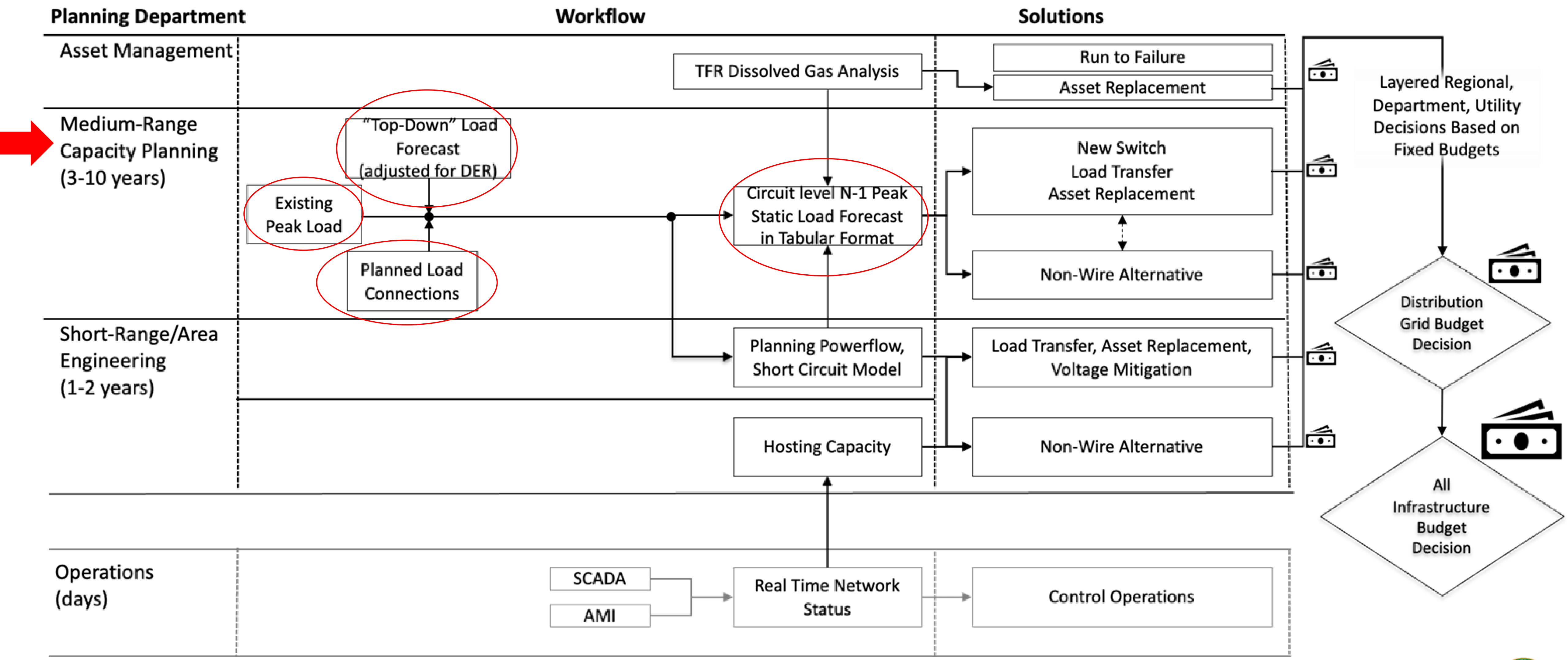
Load Forecast Modeling in Distribution Planning



Source: Modified from ISO-NE

- Distribution Planning typically uses **annual peak 1-in-10-year** load forecasting at the substation and/or feeder levels and might or not disaggregate top-down forecasts for load or DERs
- New local **large customer interconnection requests** are added to the historical peak

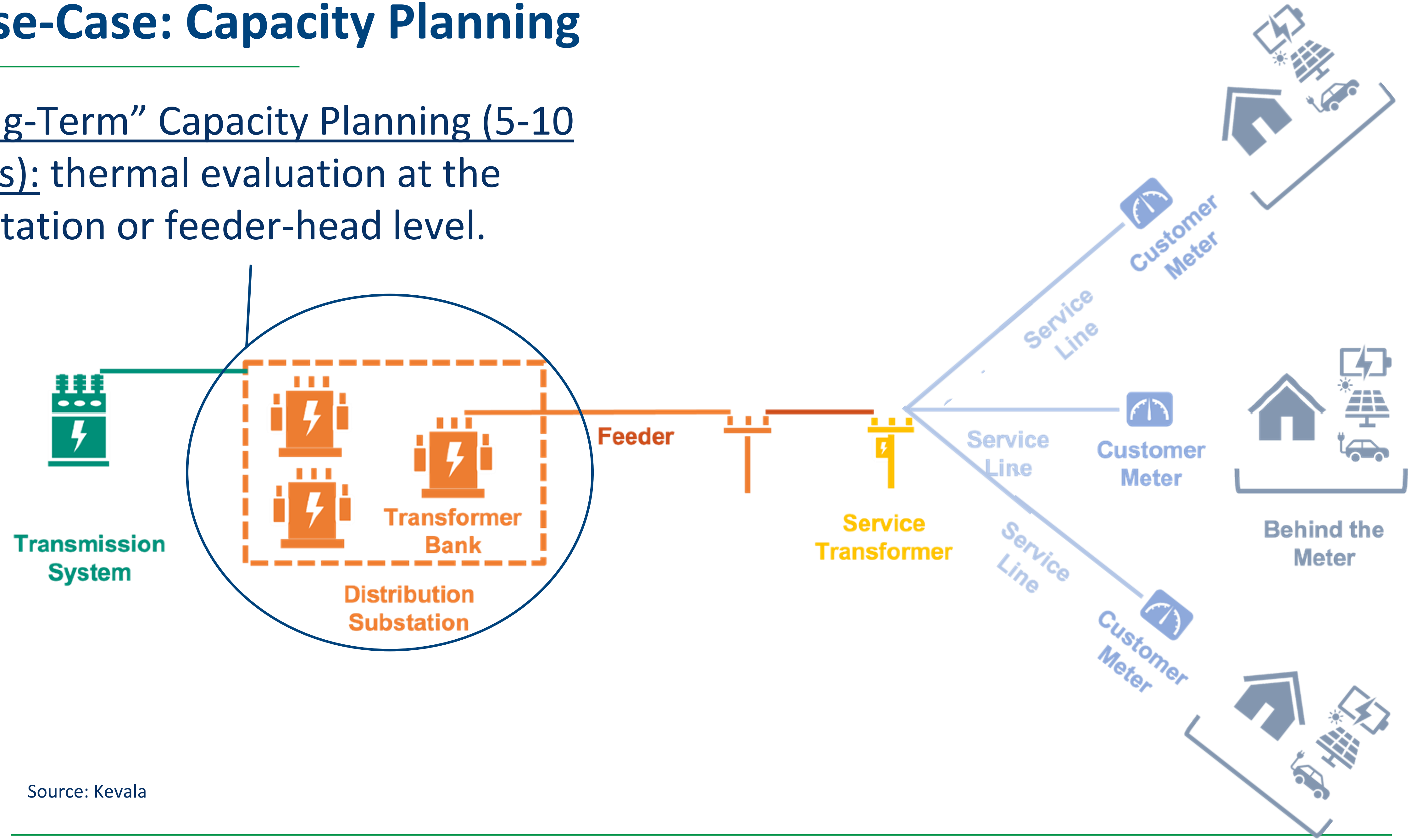
Distribution Planning Load Forecasting



Source: NREL/Kevala

Use-Case: Capacity Planning

<u>"Long-Term" Capacity Planning (5-10 years):</u> thermal evaluation at the substation or feeder-head level.



Source: Kevala

Load Forecast - Key Input to Capacity Planning

- Spreadsheet exercise to predict peak load at every substation and/or feeder
- Single deterministic forecast
- Overload criteria typically 100%
  - When equipment is overloaded, it may fail

Peak Deficiency and Loading			2021				
Peak Facility Loading (%) 2021-2025	Peak Facility Deficiency (MW) 2021-2025	Peak Facility Deficiency (%) 2021-2025	Facility Rating (MW)	Facility Loading (MW)	Facility Loading (%)	Deficiency (MW)	Deficiency (%)
80%	0.00	0%	15.05	11.64	77%	0	0%
76%	0.00	0%	8.40	6.17	73%	0	0%
66%	0.00	0%	11.82	7.75	66%	0	0%
91%	0.00	0%	6.49	5.71	88%	0	0%
31%	0.00	0%	10.16	2.93	29%	0	0%
31%	0.00	0%	10.16	3.14	31%	0	0%
36%	0.00	0%	9.28	3.11	34%	0	0%
20%	0.00	0%	6.50	1.04	16%	0	0%
84%	0.00	0%	3.04	2.55	84%	0	0%
CC	CC	CC	10.39	CC	CC	CC	CC
CC	CC	CC	10.28	CC	CC	CC	CC

PG&E 2021 Grid Needs Assessment (GNA)
Appendix E: GNA Results - Bank & Feeder Capacity Needs
Version Date: 08/16/21
Public

	Facility Information					Distribution Service			Peak Deficiency and Loading		
GNA Need ID	Distribution Planning Region	Division	Facility Name	Facility ID	Facility Type	Primary Driver	Distribution Service Required	Anticipated Need Date	Peak Facility Loading (%) 2021-2025	Peak Facility Deficiency (MW) 2021-2025	Peak Facility Deficiency (%) 2021-2025
GNA_1822901_Capacity	Central Coast	Central Coast	HATTON BANK 1	1822901	Bank	None	None	None	80%	0.00	0%
GNA_182291101_Capacity	Central Coast	Central Coast	HATTON 1101	182291101	Feeder	None	None	None	76%	0.00	0%
GNA_182291102_Capacity	Central Coast	Central Coast	HATTON 1102	182291102	Feeder	None	None	None	66%	0.00	0%
GNA_1823701_Capacity	Central Coast	Central Coast	LAURELES BANK 1	1823701	Bank	None	None	None	91%	0.00	0%
GNA_182371111_Capacity	Central Coast	Central Coast	LAURELES 1111	182371111	Feeder	None	None	None	31%	0.00	0%
GNA_182371112_Capacity	Central Coast	Central Coast	LAURELES 1112	182371112	Feeder	None	None	None	31%	0.00	0%
GNA_1829401_Capacity	Central Coast	Central Coast	OTTER BANK 1	1829401	Bank	None	None	None	36%	0.00	0%
GNA_182941101_Capacity	Central Coast	Central Coast	OTTER 1101	182941101	Feeder	None	None	None	20%	0.00	0%
GNA_182941102_Capacity	Central Coast	Central Coast	OTTER 1102	182941102	Feeder	None	None	None	84%	0.00	0%
GNA_1820702_Capacity	Central Coast	Central Coast	CAMPHORA BANK 2	1820702	Bank	None	None	None	CC	CC	CC
GNA_182071101_Capacity	Central Coast	Central Coast	CAMPHORA 1101	182071101	Feeder	None	None	None	CC	CC	CC

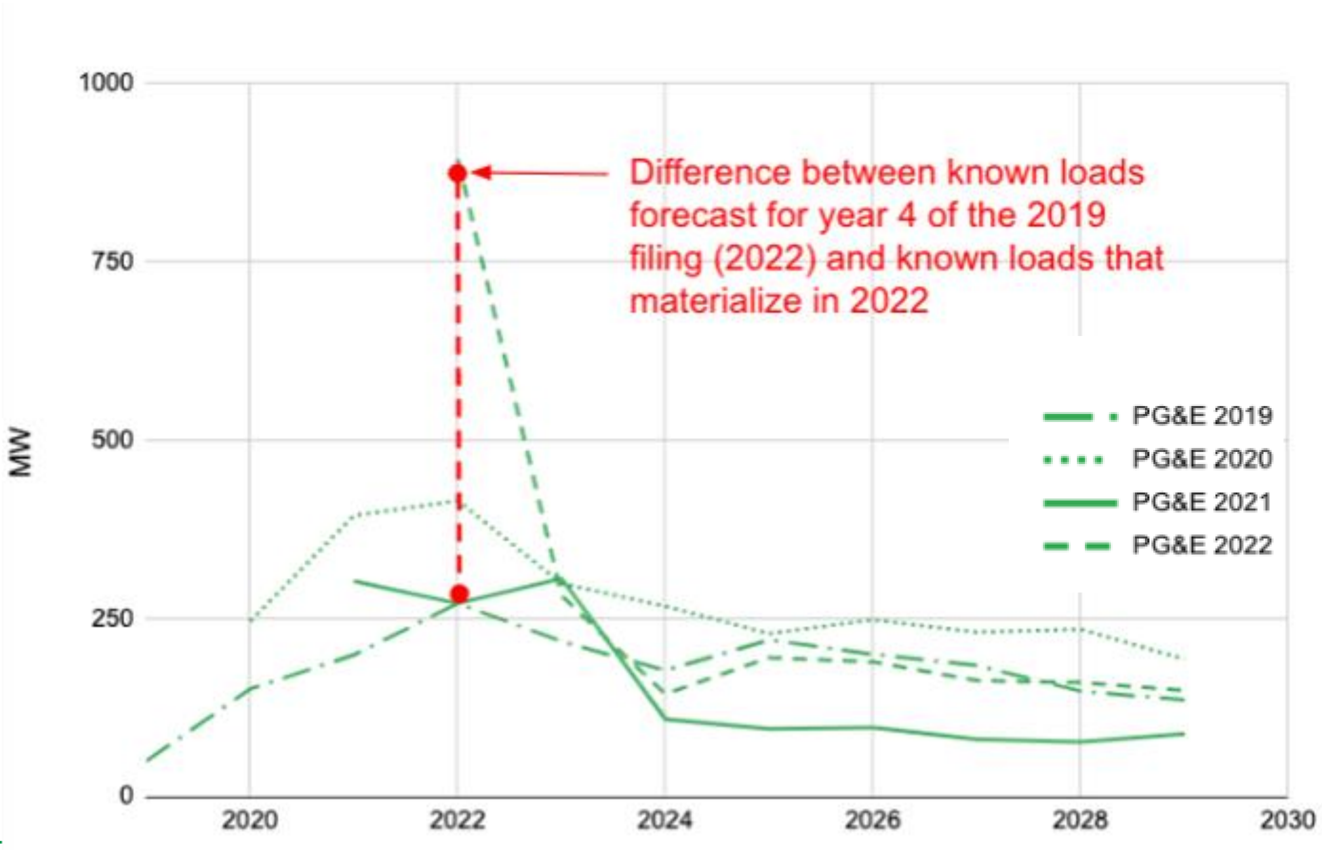
	2021					2022				
GNA Need ID	Facility Rating (MW)	Facility Loading (MW)	Facility Loading (%)	Deficiency (MW)	Deficiency (%)	Facility Rating (MW)	Facility Loading (MW)	Facility Loading (%)	Deficiency (MW)	Deficiency (%)
GNA_1822901_Capacity	15.05	11.64	77%	0	0%	15.05	11.72	78%	0	0%
GNA_182291101_Capacity	8.40	6.17	73%	0	0%	8.40	6.22	74%	0	0%
GNA_182291102_Capacity	11.82	7.75	66%	0	0%	11.82	7.75	66%	0	0%
GNA_1823701_Capacity	6.49	5.71	88%	0	0%	6.49	5.76	89%	0	0%
GNA_182371111_Capacity	10.16	2.93	29%	0	0%	10.16	2.98	29%	0	0%
GNA_182371112_Capacity	10.16	3.14	31%	0	0%	10.16	3.14	31%	0	0%
GNA_1829401_Capacity	9.28	3.11	34%	0	0%	9.28	3.16	34%	0	0%
GNA_182941101_Capacity	6.50	1.04	16%	0	0%	6.50	1.1	17%	0	0%
GNA_182941102_Capacity	3.04	2.55	84%	0	0%	3.04	2.53	83%	0	0%
GNA_1820702_Capacity	10.39	CC	CC	CC	CC	10.39	CC	CC	CC	CC
GNA_182071101_Capacity	10.28	CC	CC	CC	CC	10.28	CC	CC	CC	CC

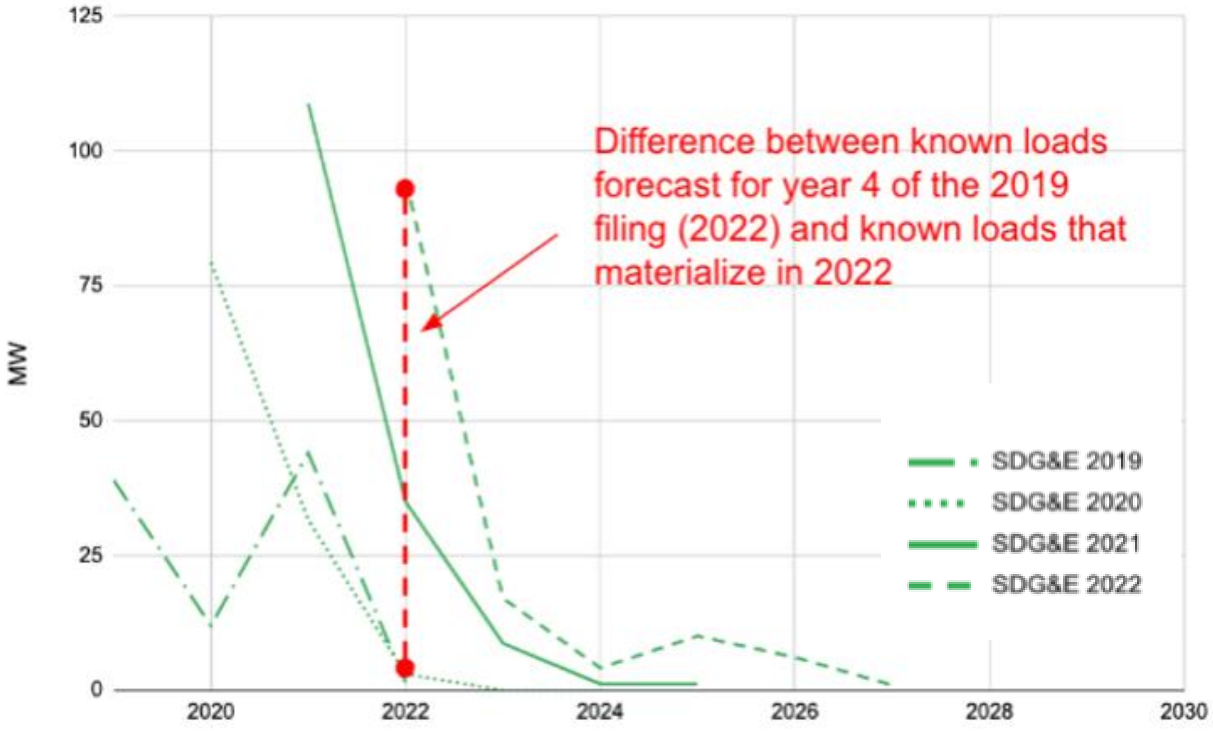
	2023					2024					2025				
GNA Need ID	Facility Rating (MW)	Facility Loading (MW)	Facility Loading (%)	Deficiency (MW)	Deficiency (%)	Facility Rating (MW)	Facility Loading (MW)	Facility Loading (%)	Deficiency (MW)	Deficiency (%)	Facility Rating (MW)	Facility Loading (MW)	Facility Loading (%)	Deficiency (MW)	Deficiency (%)
GNA_1822901_Capacity	15.05	11.81	78%	0	0%	15.05	11.9	79%	0	0%	15.05	12	80%	0	0%
GNA_182291101_Capacity	8.40	6.27	75%	0	0%	8.40	6.33	75%	0	0%	8.40	6.38	76%	0	0%
GNA_182291102_Capacity	11.82	7.74	65%	0	0%	11.82	7.72	65%	0	0%	11.82	7.7	65%	0	0%
GNA_1823701_Capacity	6.49	5.82	90%	0	0%	6.49	5.88	91%	0	0%	6.49	5.93	91%	0	0%
GNA_182371111_Capacity	10.16	3.03	30%	0	0%	10.16	3.09	30%	0	0%	10.16	3.14	31%	0	0%
GNA_182371112_Capacity	10.16	3.14	31%	0	0%	10.16	3.14	31%	0	0%	10.16	3.14	31%	0	0%
GNA_1829401_Capacity	9.28	3.21	35%	0	0%	9.28	3.26	35%	0	0%	9.28	3.31	36%	0	0%
GNA_182941101_Capacity	6.50	1.16	18%	0	0%	6.50	1.22	19%	0	0%	6.50	1.28	20%	0	0%
GNA_182941102_Capacity	3.04	2.52	83%	0	0%	3.04	2.51	83%	0	0%	3.04	2.49	82%	0	0%
GNA_1820702_Capacity	10.39	CC	CC	CC	CC	10.39	CC	CC	CC	CC	10.39	CC	CC	CC	CC
GNA_182071101_Capacity	10.28	CC	CC	CC	CC	10.28	CC	CC	CC	CC	10.28	CC	CC	CC	CC

Source: PG&E

New Business Customers Driving Investments Is Reactive

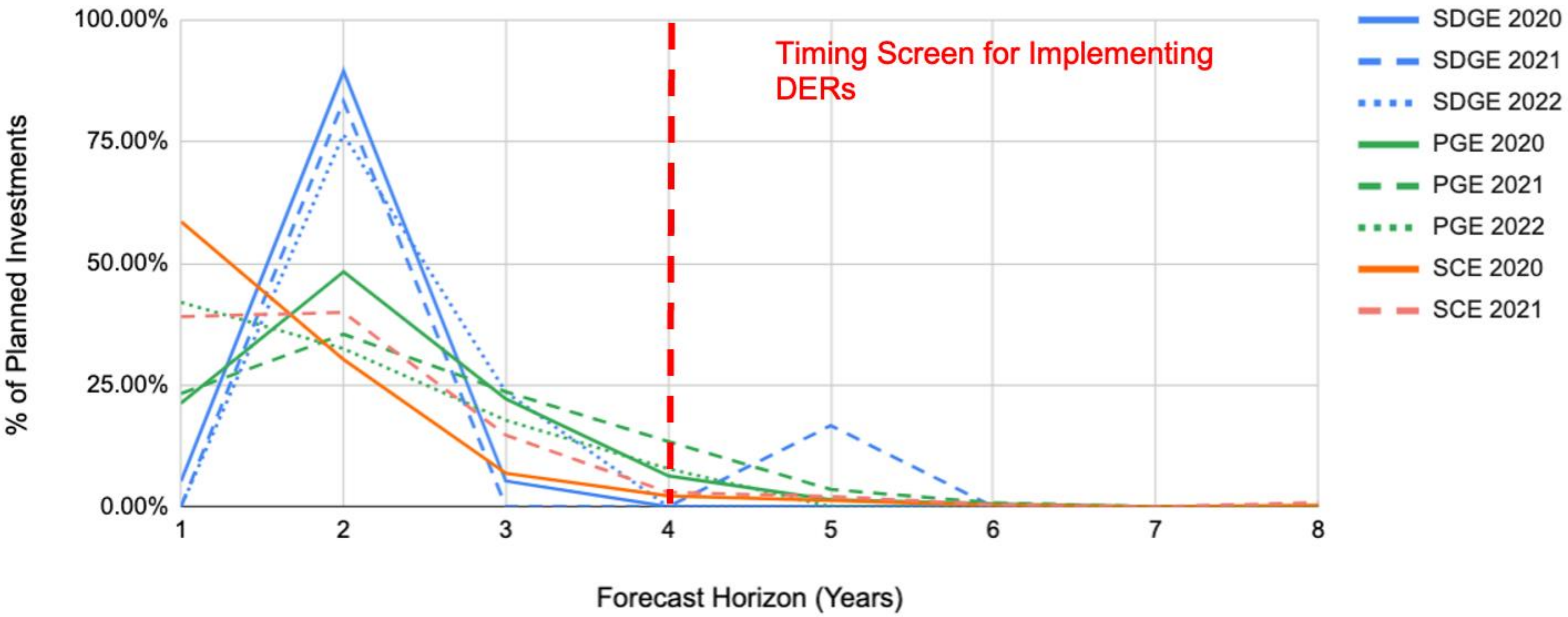
- Load growth is consistently missed





Source: [Distribution Investment Deferral Framework: Evaluation and Recommendations]()

Investments Consistently Needed

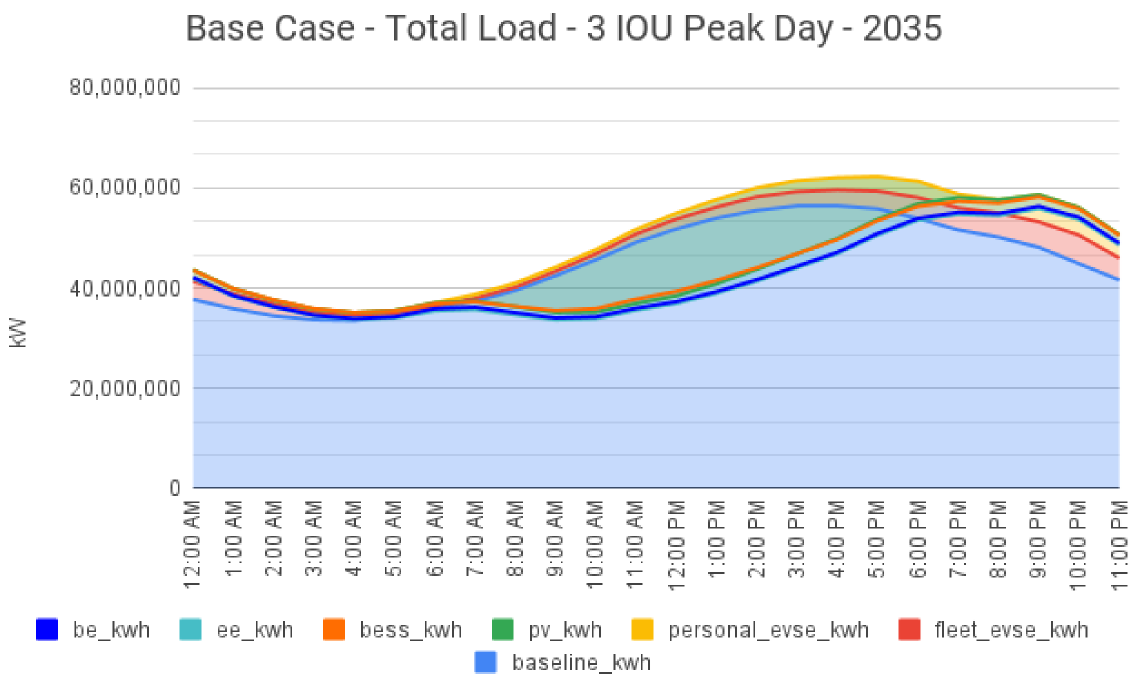


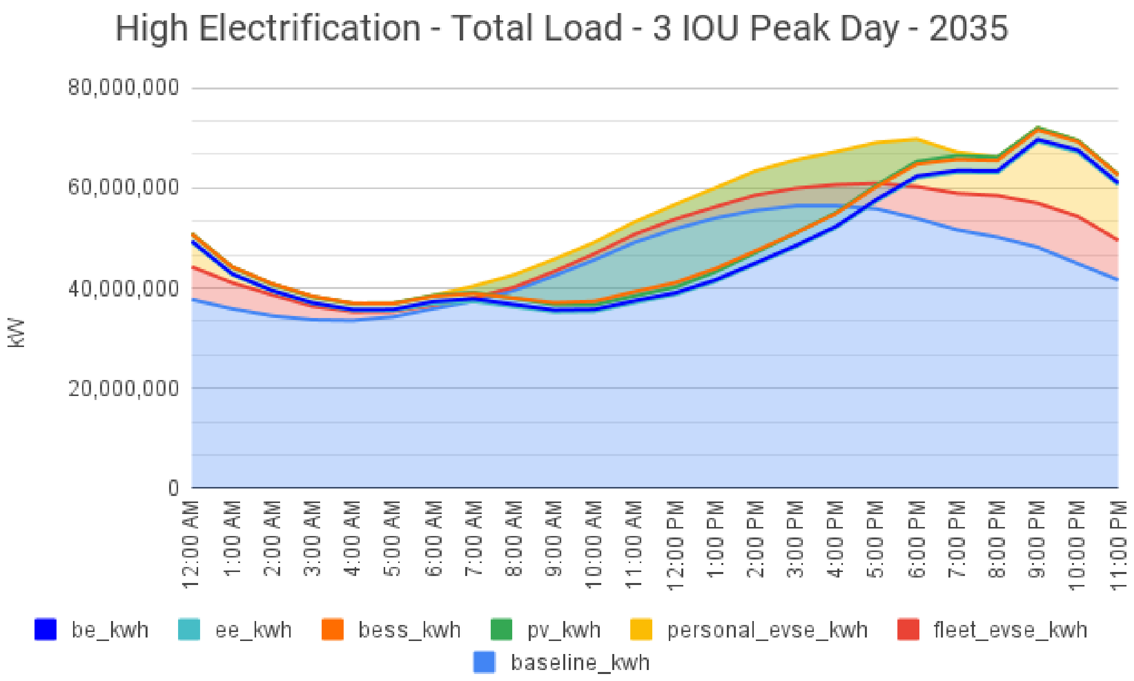
Source: [Distribution Investment Deferral Framework: Evaluation and Recommendations]

Q&A Break

DERs Are Challenging the Peak Load Forecast Model

- **Increasing need to understand full load-shape profile to model future peak load quantity and time of year and day**
  - Overall load can be taken apart (disaggregated) to identify individual end use trends
  - Customer segment at the substation/feeder level by customer class is used for DER adoption and forecasts
- **Full bottom-up models leveraging AMI and SCADA are starting to be used**
  - Kevala - CPUC Electrification Impacts Study - Part 1





Source: Kevala

CPUC Electrification Impacts Study - Part 1 - Impact of EV Charging

Adding between 3.2M and 10.0M light-duty (LD) ZEVs by 2035 across the three IOUs has roughly the same energy impacts as adding 2.9M to 8.7M residential customers’ worth of new energy demands.

Base Case

ZEV adoption sources:
- **LD:** CEC 2021 IEPR Base Case
- **Medium duty/heavy duty (MD/HD)**: CEC 2021 IEPR Base Case

2035 ZEV-equivalent energy:
- **3.2M LDs:** 2.9M residential customers
- **227k MD/HDs:** 173k commercial customers

High Electrification

ZEV adoption sources:
- **LD**: CARB ACC II
- **MD/HD**: CARB 2020 SSS (ACT & ACF)

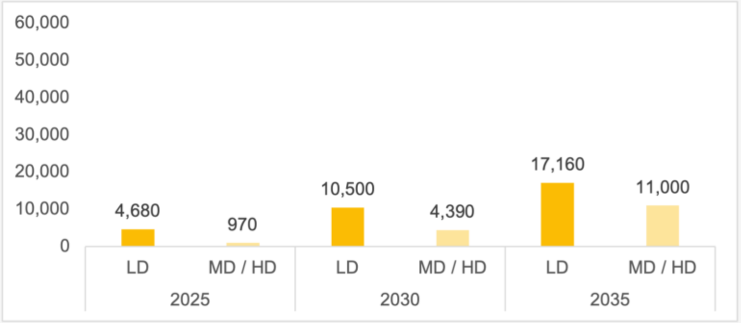
2035 ZEV-equivalent energy:
- **10.0M LDs:** 8.7M residential customers
- **219k MD/HDs:** 198k commercial customers

Accelerated High Electrification

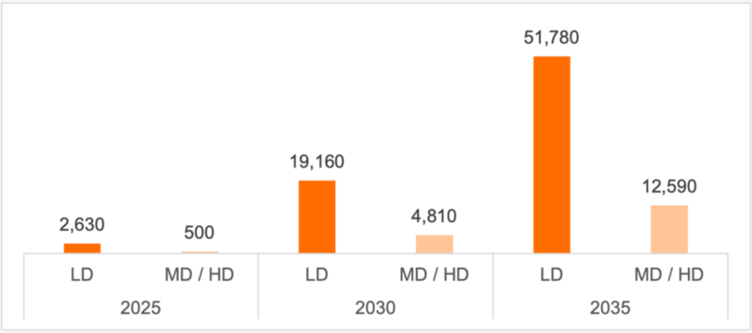
ZEV adoption sources:
- **LD**: CEC 2021 IEPR Bookend Case
- **MD/HD**: CEC 2021 IEPR High Case

2035 ZEV-equivalent energy:
- **9.5M LDs:** 8.2M residential customers
- **231k MD/HDs:** 164k commercial customers

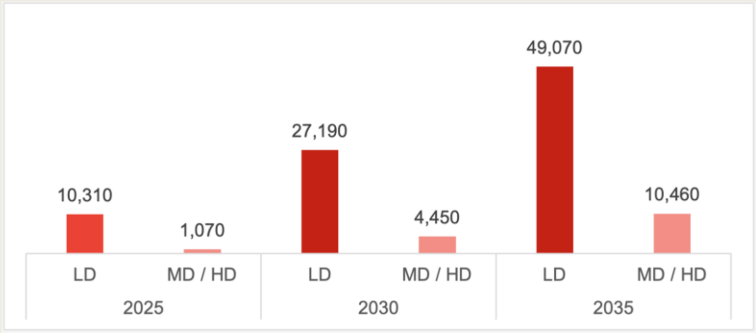
Three IOUs’ Total EV Energy (GWh)
Base Case



Three IOUs’ Total EV Energy (GWh)
High Electrification

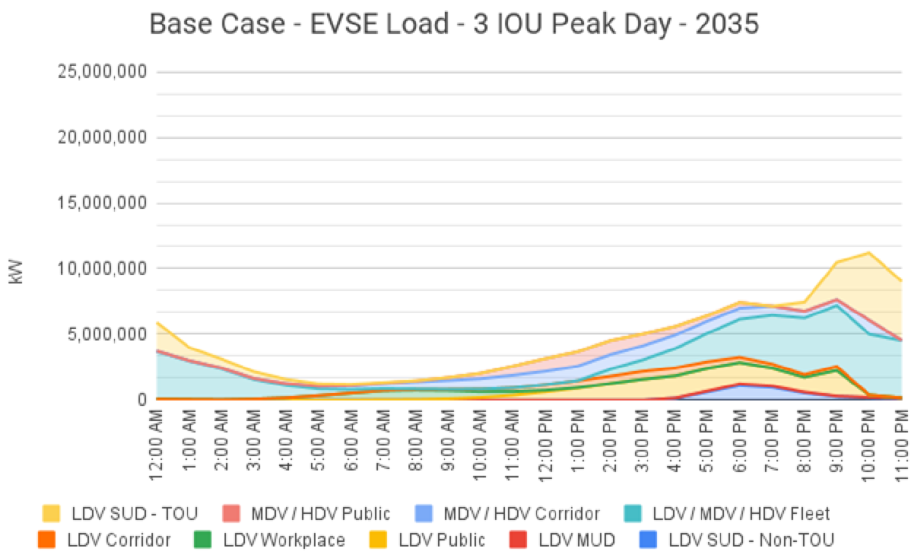


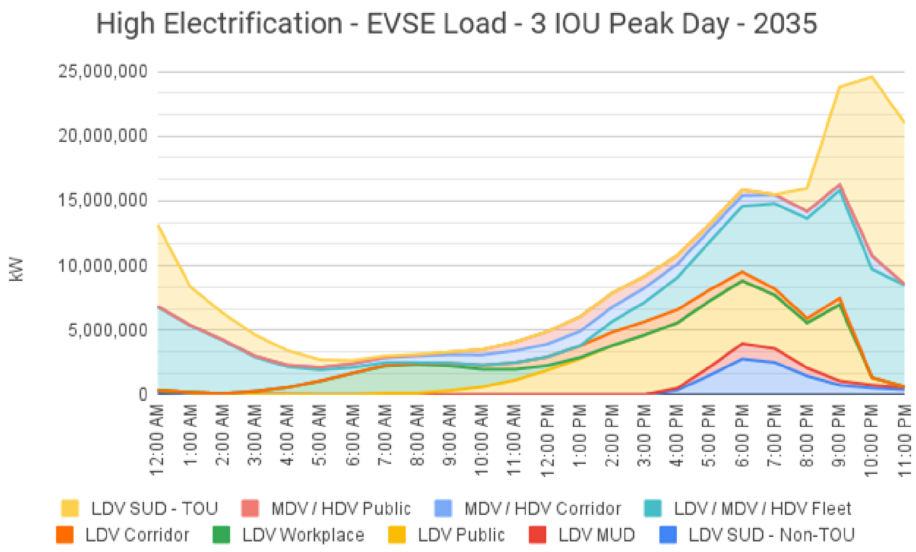
Three IOUs’ Total EV Energy (GWh)
Accelerated High Electrification

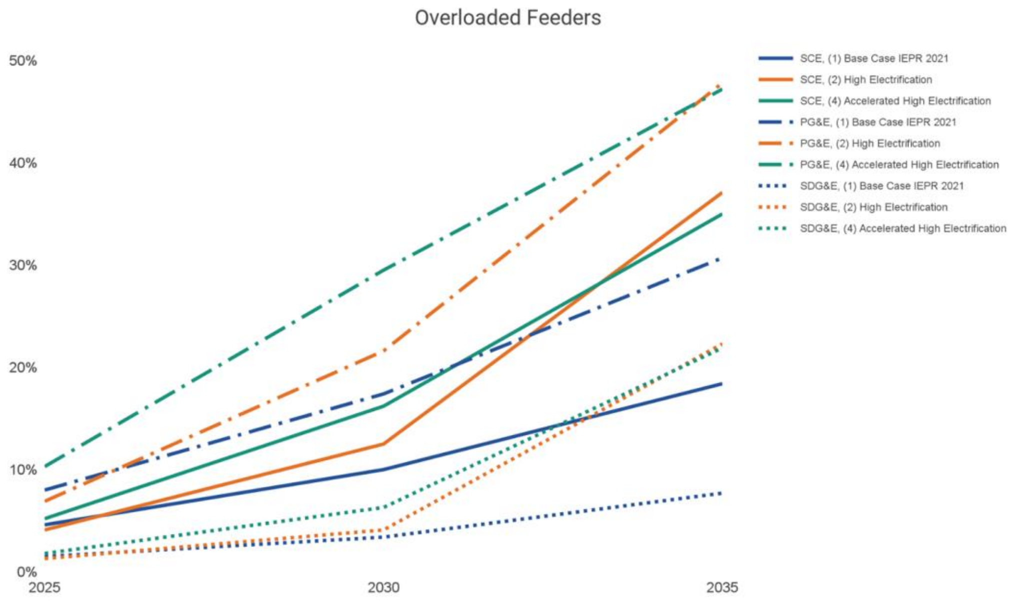


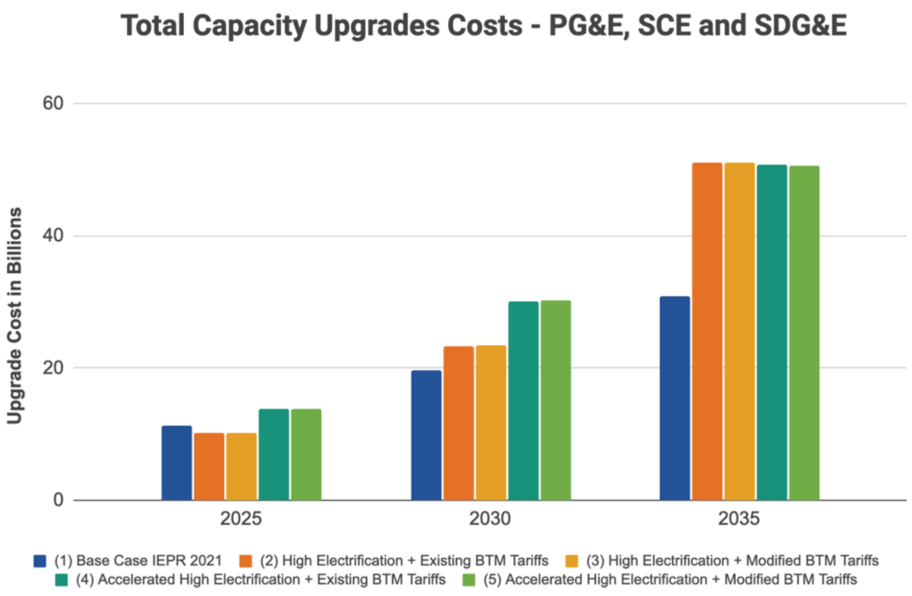
Source: Kevala

Example Electrification Scenarios – Base Case versus High









Source: Kevala

DERs – Demand-Side Modifiers

- **How to predict where (which substation and feeder) and when will each technology be adopted?**

Behind-the- Meter Photovoltaics (PV)

Behind-the-Meter Battery Energy Storage System (BESS)

Building Electrification (BE)

Electric Vehicles (EV) and Electric Vehicle Service Equipment (EVSE)

Energy Efficiency (EE)

Demand Response (DR)

Pricing & Programs (P&P)

Smart Controls

Source: Kevala

Challenges with EE & BE Adoption and Behavior in Distribution Planning

- **EE methods in distribution planning often rely on ratio of savings rather than specific measure adoption**
  - In contrast, for other DERs, the specific technology adopted is estimated along with load implications (size and behavior) of that technology
  - The type of load conversion could dramatically impact the behavior and level of BE adoption.
- **Assumes uniform savings across baseline loads, potentially attributing savings in hours when savings may not occur**
  - For example, savings of 2% could be due primarily to lighting, yet lighting savings are limited during the day or early mornings
  - Could miss compounding benefits from temperature-sensitive measures
  - Converting heating loads from natural gas to electricity (for both commercial and residential sectors) could transition a customer with low energy use to a much higher electric bill in exchange for a much lower (or nonexistent) gas bill
- **Methods typically model savings proportional to size of customer's load**
  - While intuitive (customers with high energy usage potentially have more opportunities for greater savings), this results in very large customers capturing the 'target' savings first, potentially missing smaller premises that also could adopt

Challenges with EE & BE in Adoption and New Load Growth

Need to consider recent state and federal level legislation:

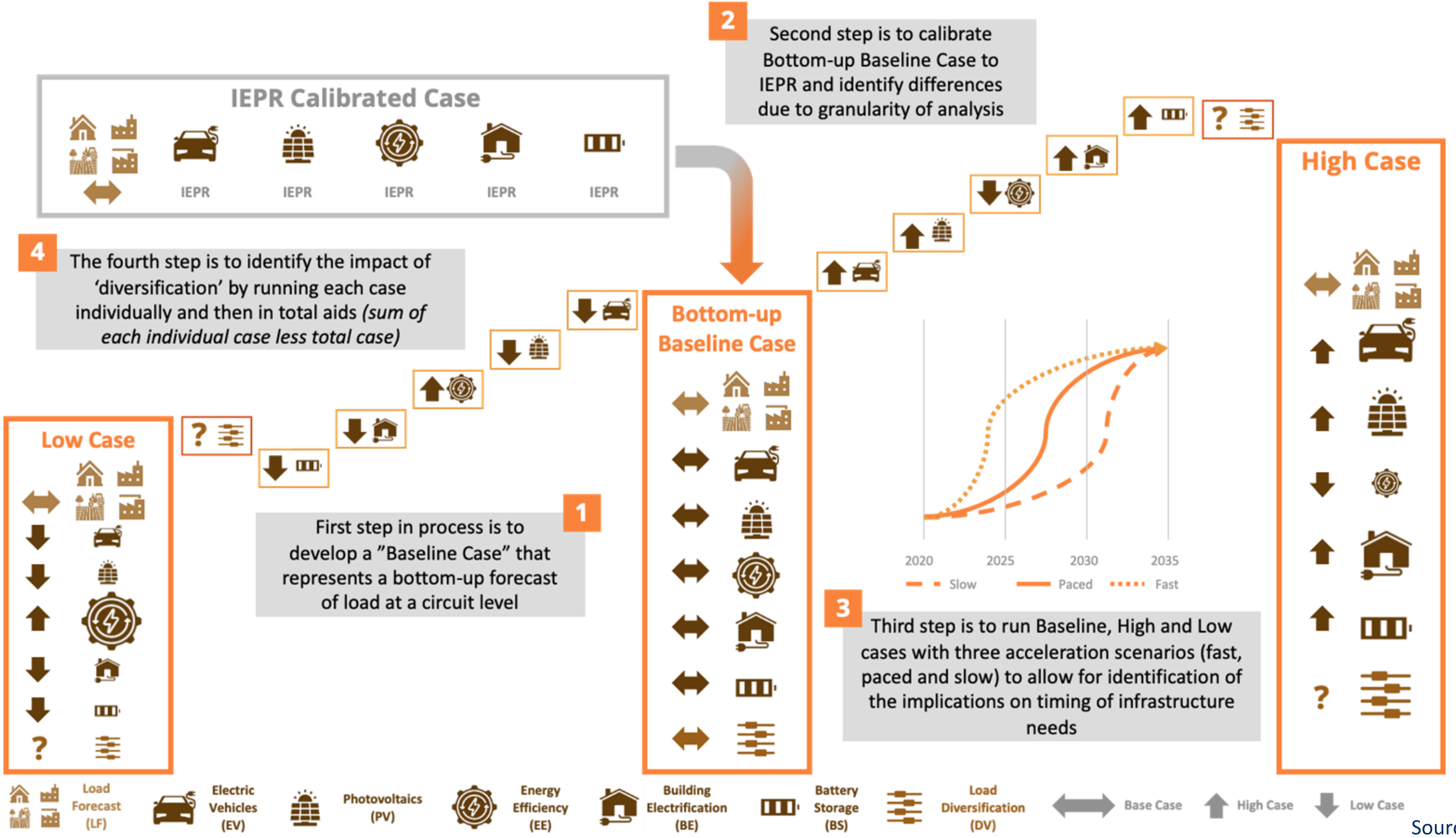
- IRA appliance rebates
- CA example
  - SB 1477 (2018) calls on the CPUC to develop two programs (BUILD and TECH) aimed at reducing greenhouse gas emissions associated with buildings.
  - AB 3232 (2018) directs the California Energy Commission (CEC) to “assess the potential … to reduce the emissions of greenhouse gases in … residential and commercial building stock by at least 40 percent below 1990 levels by January 1, 2030.”
  - SB 68 (2021) directed the CEC to develop guidance and best practices to overcome barriers to building electrification and electric vehicle charging equipment.
  - CEC 2022 building code - Encourages electric heat pump technology and electric-ready requirements for other technologies for new construction

Deterministic Scenarios vs. Probabilistic Load Forecast

- **Deterministic Scenarios**
  - Change assumptions for final target and speed of DER adoption
  - Results in a range but does not quantify uncertainty
- **Probabilistic Load Forecasting**
  - Determines a range and probability distribution for each of the driving variables of the forecast
  - Individual components of the load and DER forecast are turned into probabilistic forecasts with calculated uncertainty

Challenge: How to combine uncertainty from every load and DER model into one capacity planning model that can be used to make investment decisions

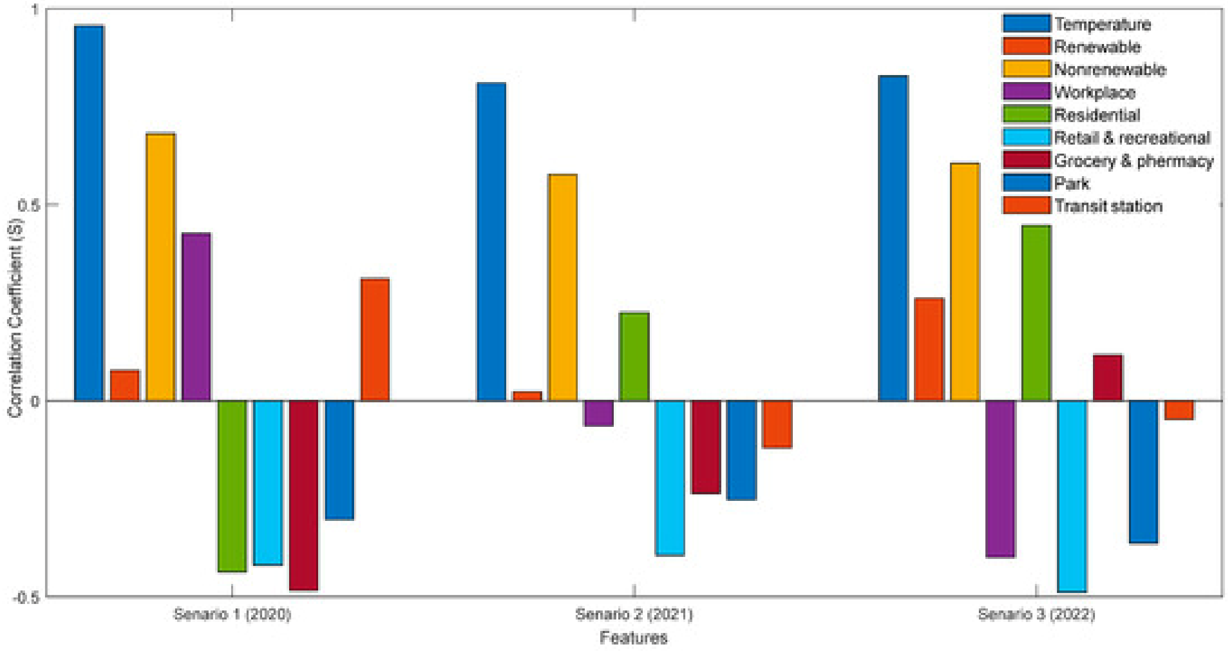
Deterministic Scenario Matrix Design

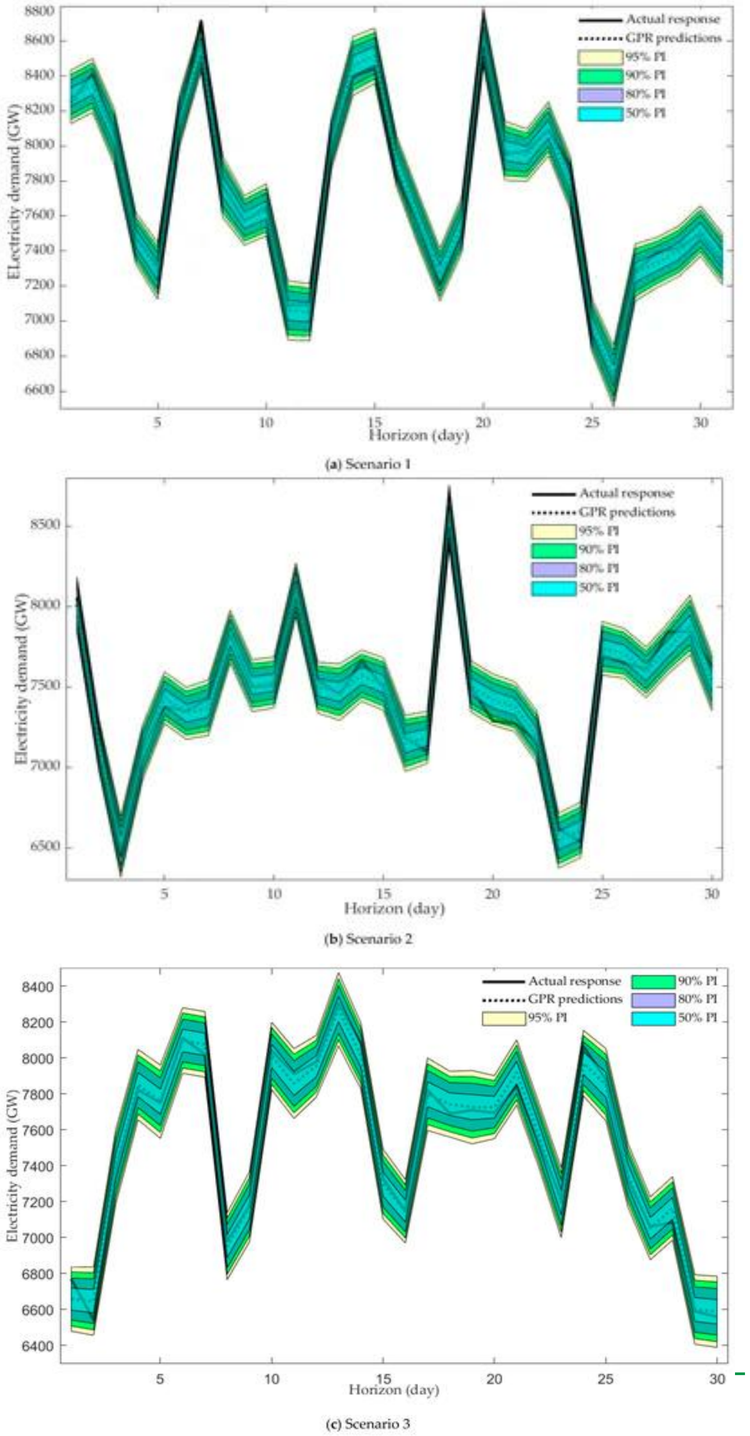


Source: Kevala

Probabilistic Load Forecasting

- **Quantifies uncertainty for each scenario**
  - Probabilistic component forecasts





Source: *Appl. Sci.* **2023**, *13*(11), 6520; **https://doi.org/10.3390/app13116520**

Key Gaps and Needs in Distribution Planning Load Forecasting

- Statistical load forecasting based on historical load and weather events will miss extreme weather events

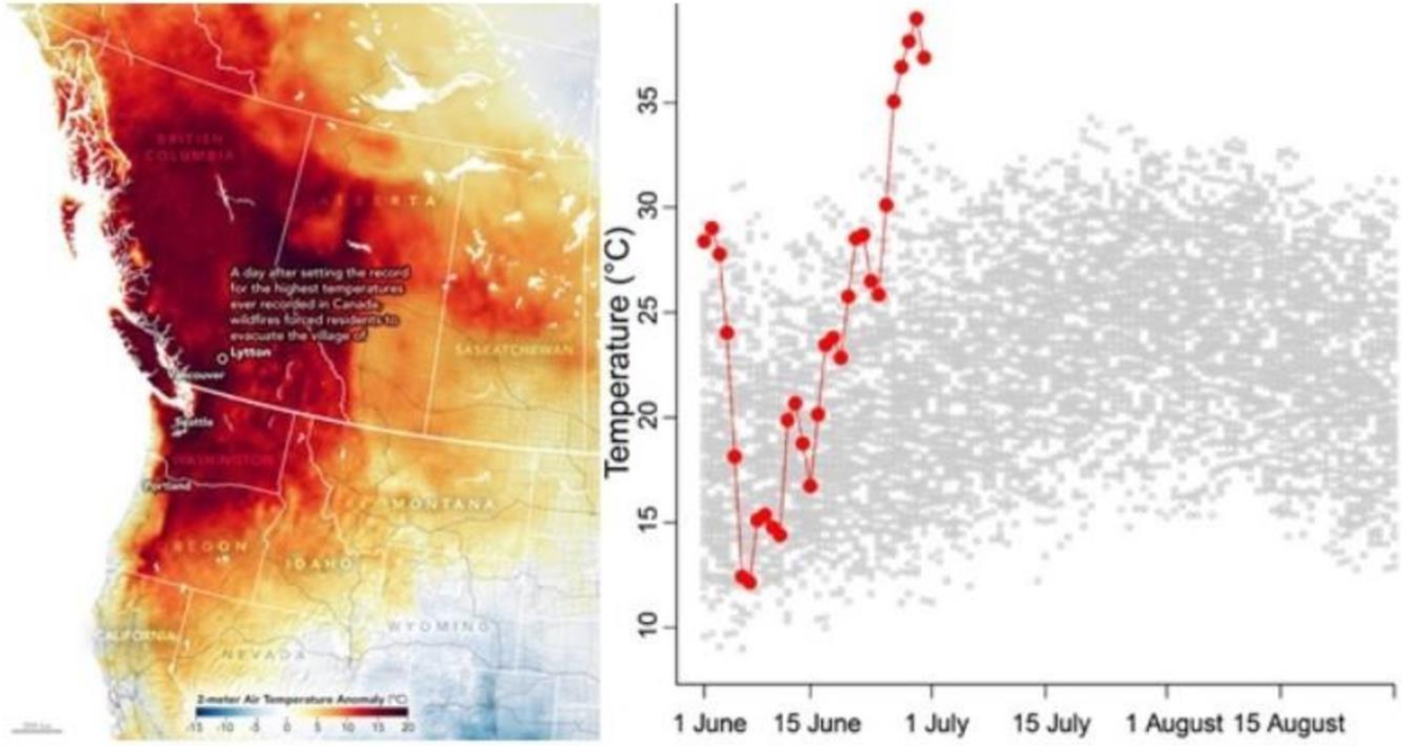
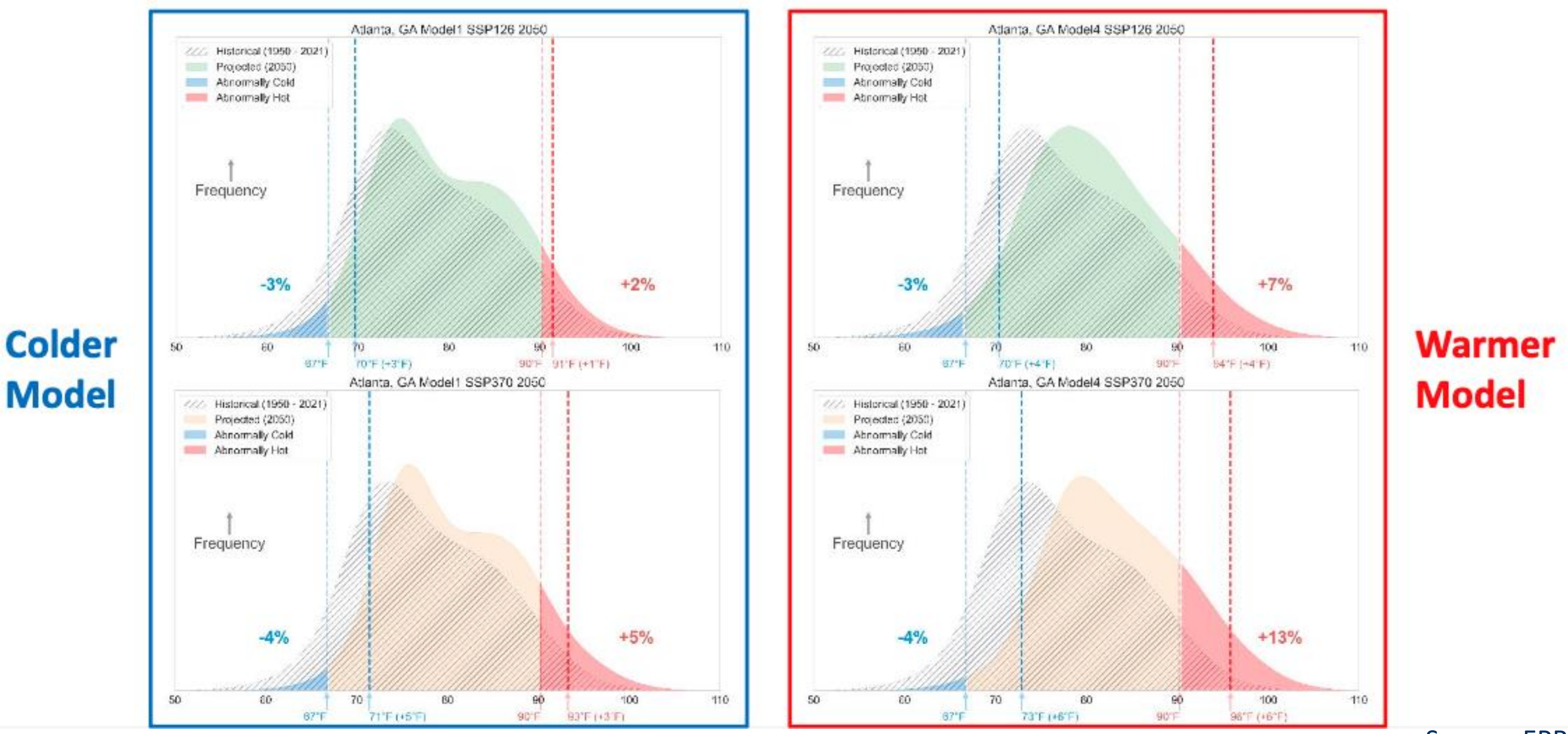


Figure1: (left) Temperature anomalies during the 2021 Pacific Northwest heatwave (NASA 2021) and (right) area-average temperatures in 2021 (red) compared to the period 1950-2020 (grey dots) in ERA5 reanalysis (plot by Erich Fischer).

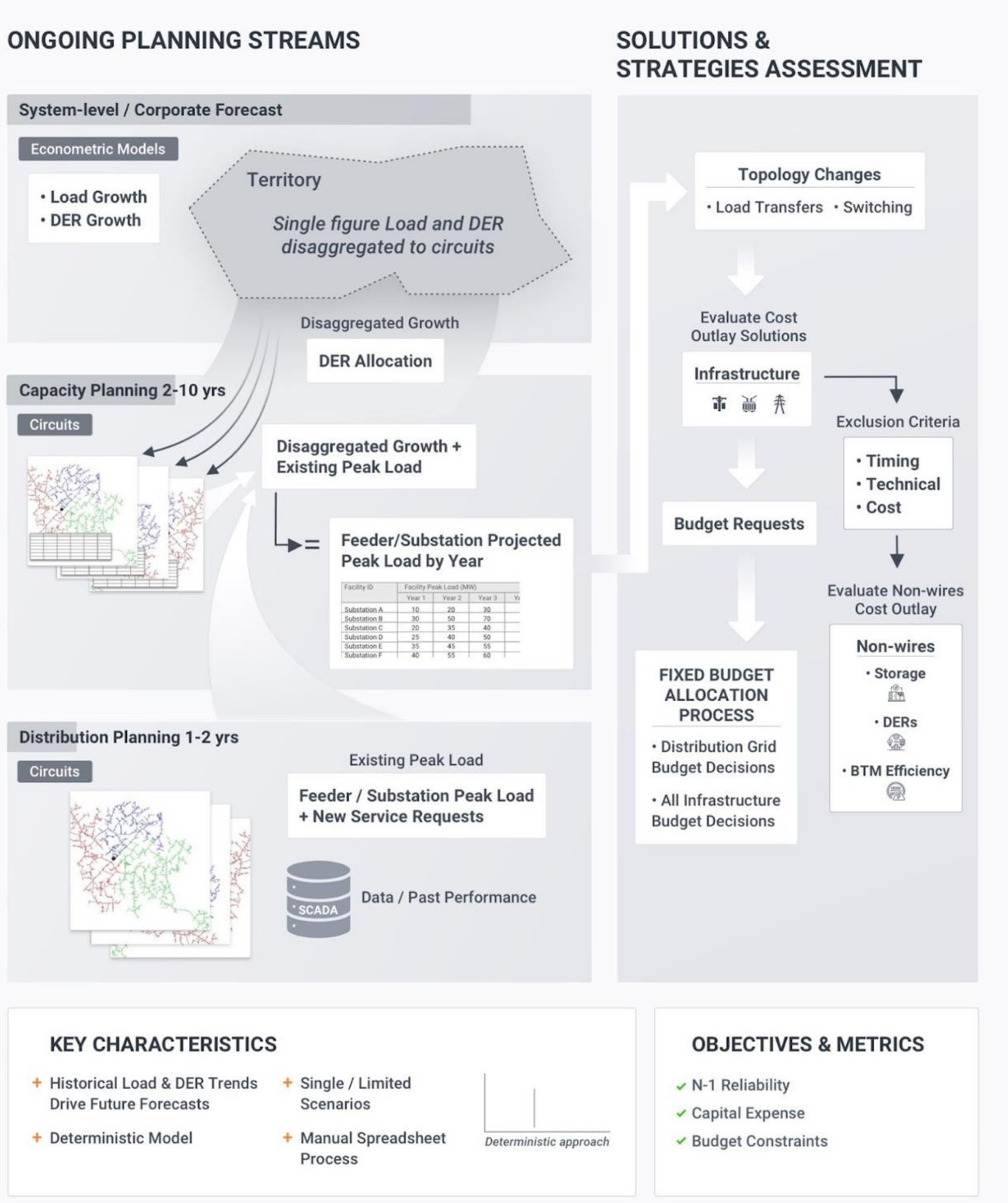
Key Gaps and Needs in Distribution Planning Load Forecasting

- **Statistical load forecasting based on historical load and weather events will miss extreme weather events**
  - Hourly climate model projections are currently being developed



Source: EPRI

Existing Load Forecasting for Capacity Planning

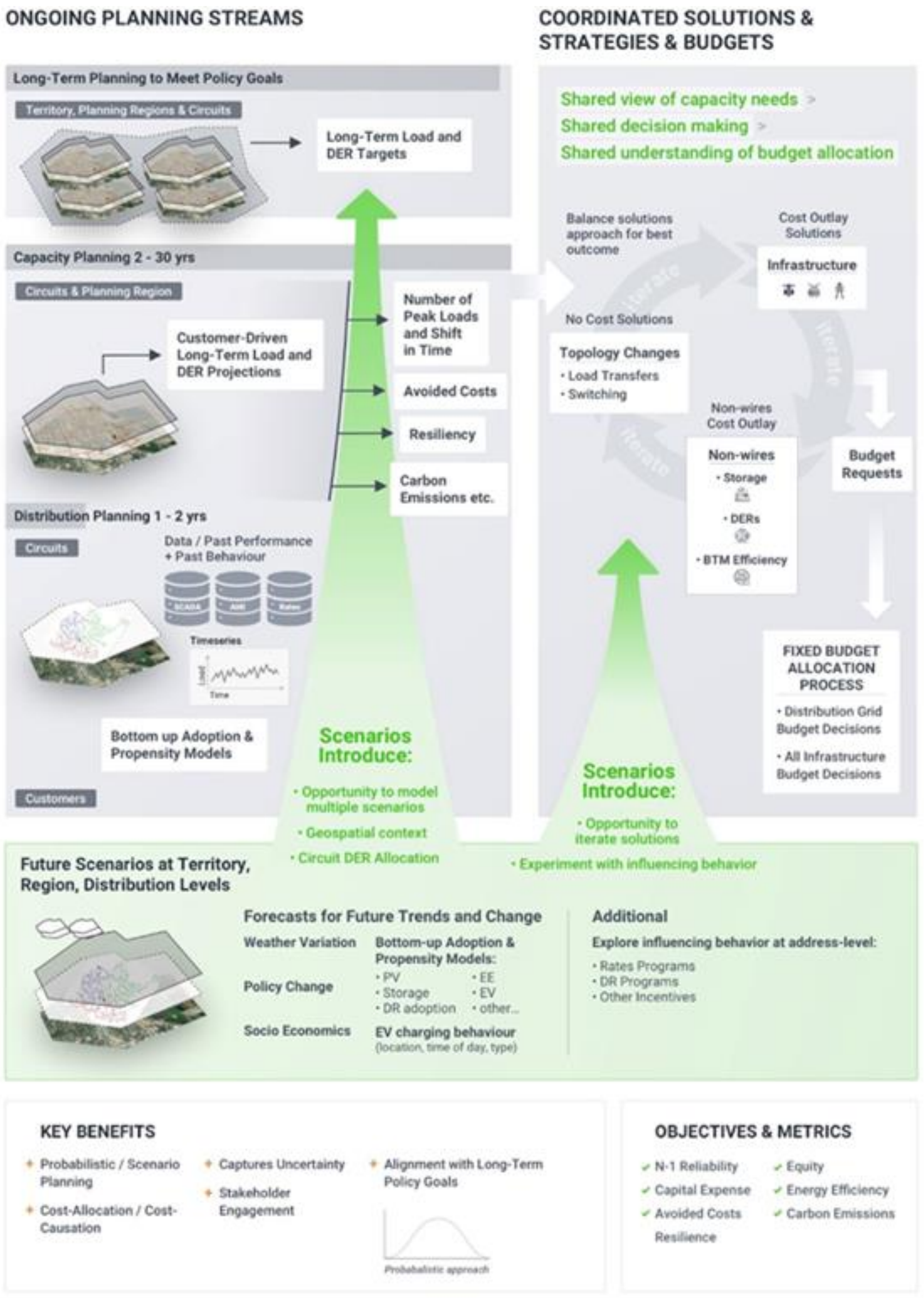


- Capacity planning mismatch with long-term changing policy goals
- Historical trends (load, weather, etc.) are used to predict the future
- Allocation/forecasts not aligned with electrical infrastructure and meters

Source: [NREL/Kevala]

Future Load Forecasting for Capacity Planning

- High spatial and temporal resolution for load and DER forecasting
- Longer term forecast
- Scenario and probabilistic methods
- Include climate change models and extreme weather events



Source: NREL/Kevala

Questions to Ask

- Does **distribution planning coordinate** with or take inputs from the **load forecasting department**?
- Do you forecast **peak load** or some form of **timeseries**?
- What **DERs** are **explicitly forecasted** and modeled in your distribution planning forecast?
- What **weather data** is used in your distribution planning load forecast? Does it include the **effects of climate change**?
- Do you perform a **single point load forecast**, or do you consider a range of **scenarios** and **probabilistic methods** to determine infrastructure needs?

Questions?

Julieta.giraldez@kevala.com

Distributed Energy Resources Planning

Training for States on Distribution System and Distributed Energy Resources Planning

Presented by Cody Davis, Sr. Manager, Electric Power Engineers

January 24, 2024

Western Regional Training

Agenda

- Introduction
- DER Forecasting
- Hosting Capacity Analysis
- Non-Wires Alternatives
- Questions

INTRODUCTION

Types of DERs

Solar Photovoltaic Systems

Wind Turbines

Energy Storage Systems

Combined Heat and Power

Electrical Vehicles
Managed or Price-Based Charging

Grid Interactive Buildings
Building equipped with smart appliances and energy management systems to contribute in EE and DR programs

Energy Efficiency

Microturbines
Localized generation using natural gas

Distribution Planning with DER

Planning Goals:

- Understand and prepare for the future
- Meet customer needs in a timely and efficient manner

Who does Distribution Planning?

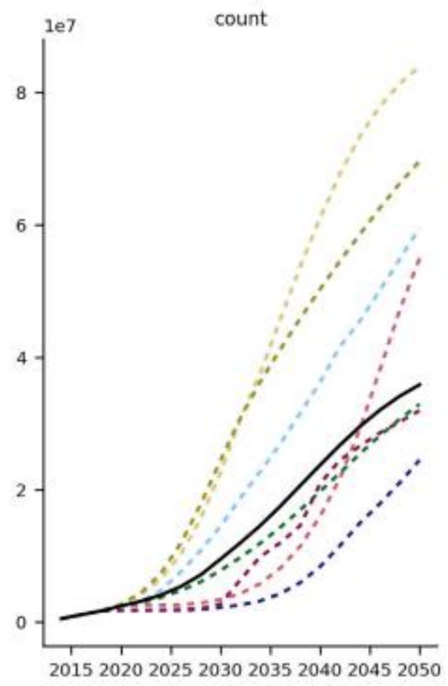
- Everyone who controls a distribution system that changes over time
- Investor-owned utilities (IOUs), Municipal Utilities, Cooperatives, Campuses, etc.

DER are driving changes in Distribution Planning

- Increasing visibility, scrutiny, and importance to customer outcomes
- Significantly more complex due to DER considerations

Planning for DER Growth – Predict, Identify, Resolve

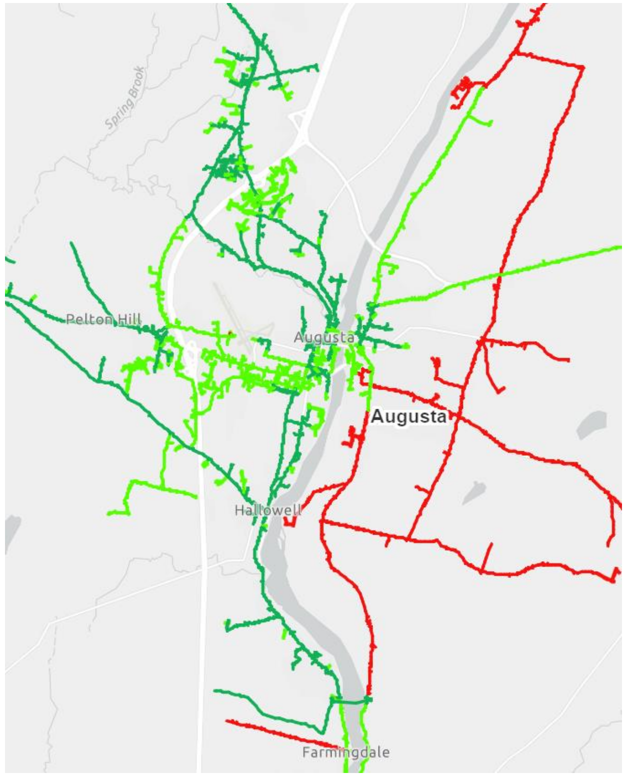
DER Forecasting



- Estimate Future Adoption
- Understand System Impacts

[Source]

Hosting Capacity Analysis



- Identify System Constraints
- Inform Applicant Siting/Sizing

[Source]

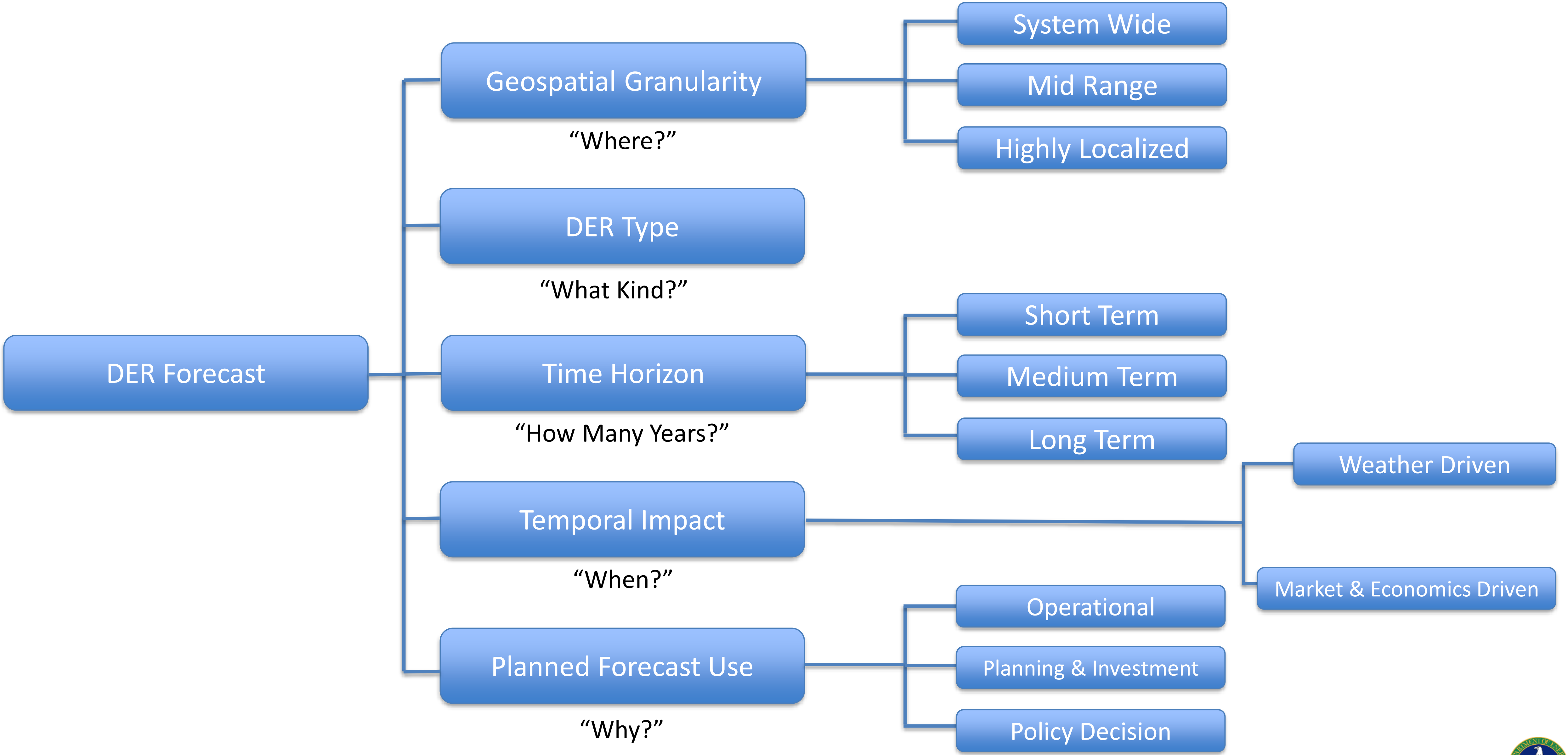
Non-Wires Alternatives

- Leverage DER As a Resource
- Mitigate System Needs Efficiently

[Source]

DER Forecasting

DER Forecasts – Methodology Design Elements



Geospatial Forecast – System Wide

Highly Aggregated Data

This level of data aggregation is crucial for grasping **overarching trends** and for planning at a broader system level.

RTO/ISO Level Forecast:
Regional grid operator-level data provides a **regional outlook**, encompassing **multiple states** or a significant part of a state. This level is key for understanding **regional energy trends, transmission planning, and managing the electricity market**.

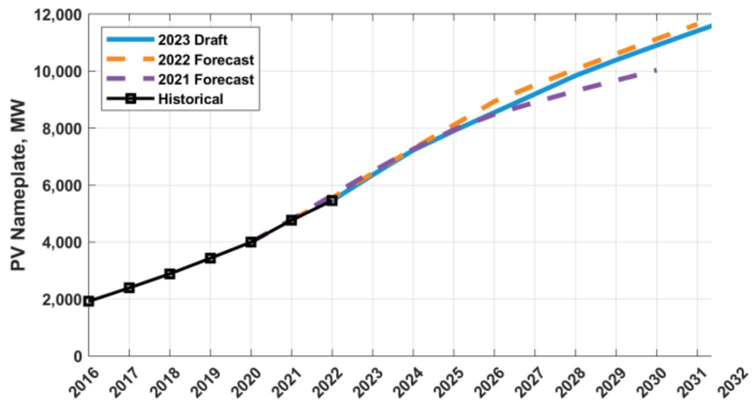
State Level Forecast
These forecasts offer insights into the future energy needs and resource availability for an **entire state**, aiding in **policy-making and statewide energy planning**.

Utility Wide Forecast
Forecasting at this level focuses on the specific needs and trends within a **utility's service area**. It is essential for the utility's own **planning, infrastructure development, and meeting regulatory requirements**.

Policy Drivers	Other Drivers
Feed-in-tariffs (FITs)/Long-term procurement	Role of private investment in PV development
State Renewable Portfolio Standards (RPS) programs	Future equipment and installation costs
Net energy metering (NEM) and retail rate structure	Future wholesale and retail electricity costs
Federal investment tax credit (ITC) and federal depreciation	Costs and issues associated with grid infrastructure constraints and needed upgrades
Federal trade policy	Siting issues

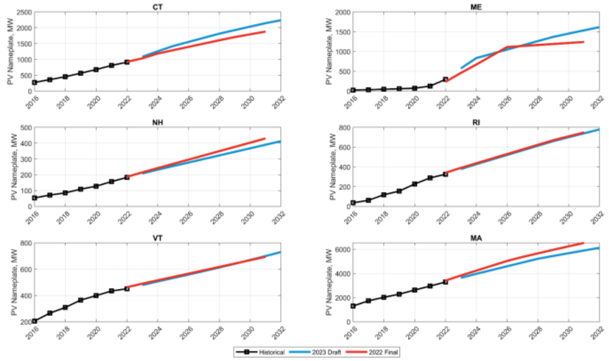
Factors influencing Uptake of Distributed PV– ISO NE [Source]

Historical vs. Forecast



Regional PV Nameplate Capacity Growth

Historical vs. Forecast



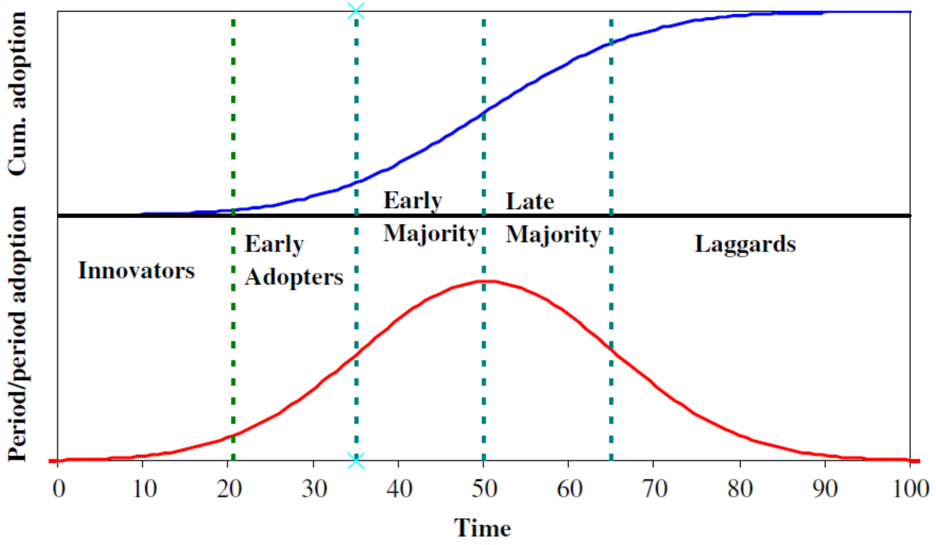
State PV Nameplate Capacity Growth

Source: ISO NE 2023 PV Forecast

Geospatial Forecast – Highly Localized – Propensity Modeling

Highly Localized Forecast

Highly localized spatial DER forecast refers to detailed analysis at the **customer level**, diving into the granular aspect of individual customer behaviors and preferences. This analysis is referred to as **customer propensity analysis**, and it uses a wealth of **customer/community specific data** to estimate the **probability that an individual customer adopts** a technology.



Adoption Diffusion Curves [source]

Source – Forecasting Load on Distribution Systems with DERs

Bass Diffusion and Fisher-Pry are two common models to build to build logistical S-Curve adoption models.

Geospatial Forecast – Mid Range

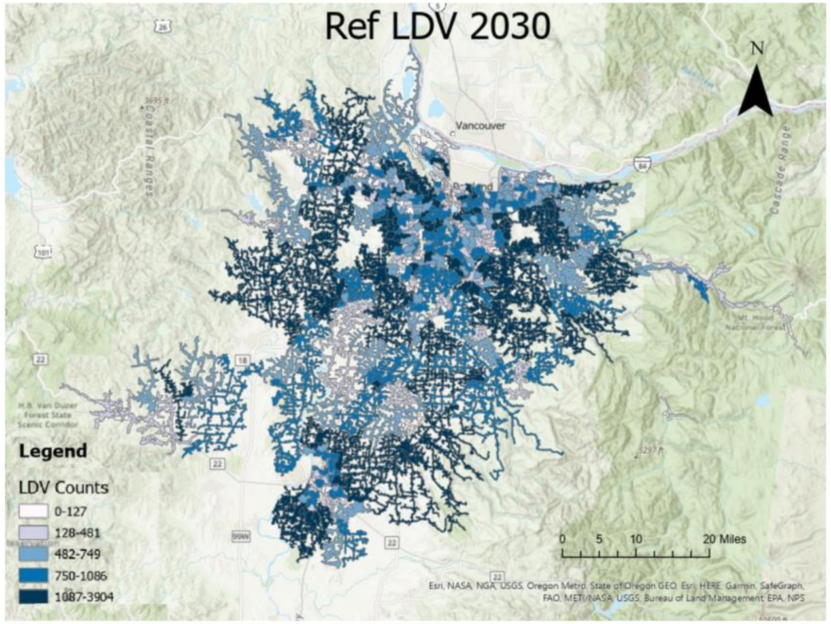
Mid Range Forecast

Mid range spatial forecast provides a balance between system level and highly localized forecast. It is derived from the **disaggregation of system-wide** data or the **aggregation of highly localized** forecasts.

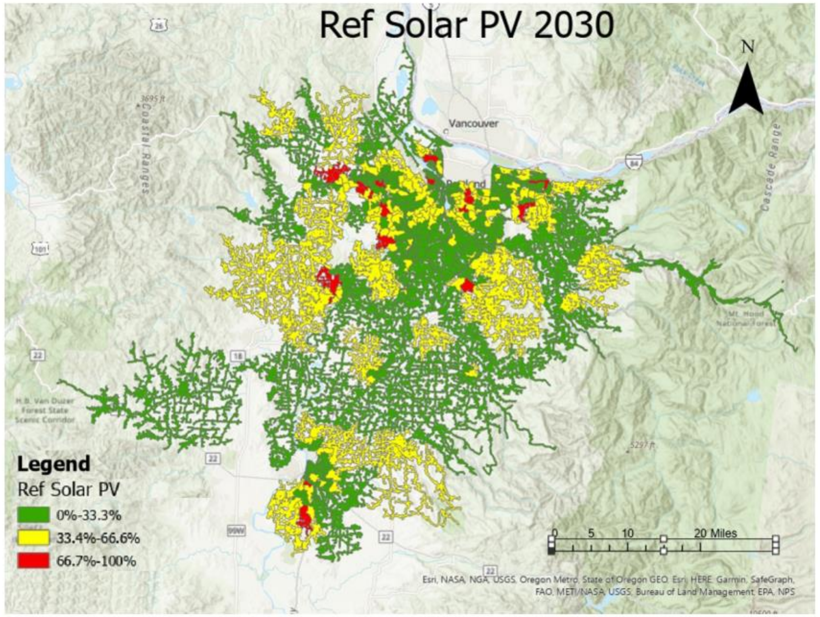
Distribution Feeder/Substation Level:
Forecasts at this level usually are focused on DER uptake for **specific feeder or substations** within a utility network. These forecasts are impactful in assessing the **impact of growth** of DERs **on segments of the distribution grid and targeting mitigation strategies**.

ZIP Code/County Level:
This level involves DER forecasting for **smaller, administratively defined** areas like zip codes or counties. It provides a **more localized view** than state or utility forecasts, allowing for **finer planning** and analysis that considers the **specific characteristics and needs** of these areas.

Census Tract Level
These forecasts are the most localized within the mid range category and cover **small, relatively homogenous regions** defined for statistical purposes. This helps in aligning the **DER planning** strategies to a **specific community or neighborhood**.



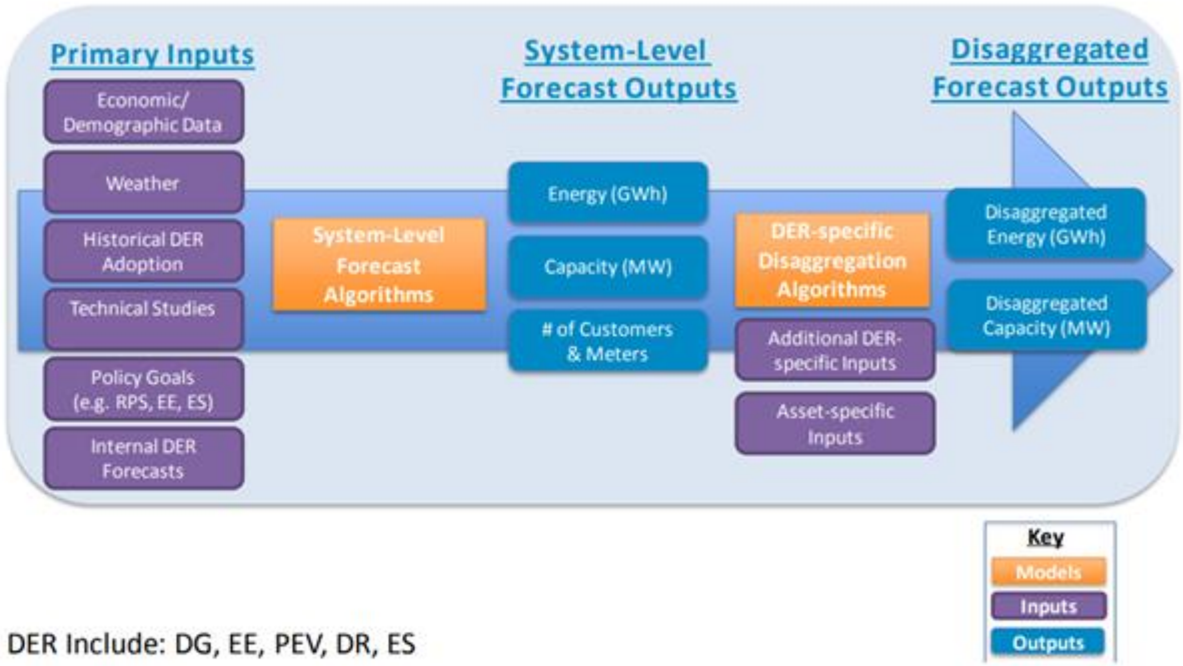
PGE Reference case LDV and Solar PV adoption at the feeder level in 2030



Source PGE Load and DER forecast

DER Forecast Disaggregation - Purpose

- Disaggregation refers to the method of distributing a system-wide forecast of DERs for a **specific utility service area** down to **individual circuit levels**.
- The primary aim of disaggregation methodologies is to pinpoint, as accurately as possible, the likely locations for the adoption of new DERs.
- It involves considering multiple factors, ultimately to pinpoint customer behavior, which is inherently uncertain.
- The disaggregated forecast is then used as an **input to distribution planning studies**.



Source – Overview of System Level Forecasting

Source: Distribution Forecast Working Group Presentation

DER Disaggregation Techniques

Source – [Forecasting Load on Distribution Systems with DERs]

Proportional Allocation

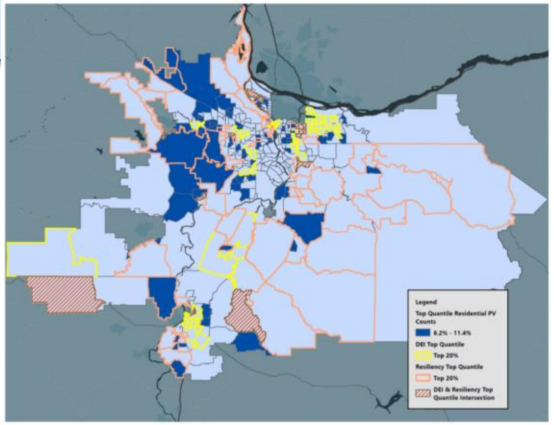
- Allocates system-level DER forecast to individual circuits using specific local distribution data
  - Proportional to Load
  - Proportional to # of Customers
  - Proportional to Existing DER
- Another approach is to use adoption patterns of one technology (e.g., PV) to drive adoption for another (e.g., energy storage)

Propensity Models

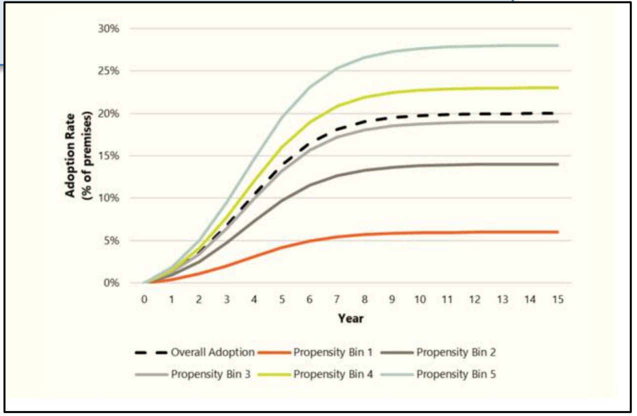
- Propensity models use customer characteristics to compute a propensity score. Based on the score, a fraction is computed as the ratio of the score for that area divided by the sum of scores across all areas.
- For example, the propensity model can be estimated using ZIP code data where the models relate historical adoption to customer characteristics in each ZIP code.
- Statistics- based (Regression and ML)

Adoption Model

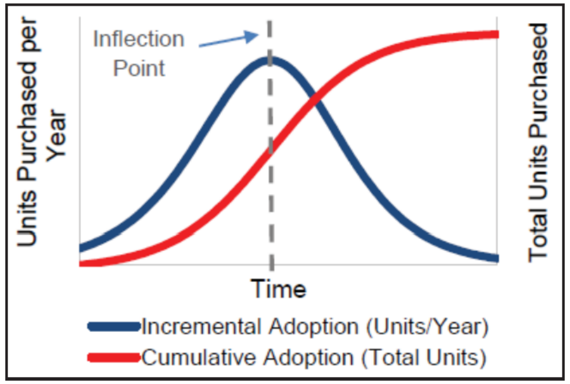
- This uses a bottom-up adoption approach based on adoption patterns and estimated adoption model parameters.
- These models are S Curve-based. They forecast technology adoption based on characteristics of early adaptors, market factors, and adoption rates, applied to the remaining potential.



Solar PV Locational Adoption PGE



PGE Propensity Scoring Results



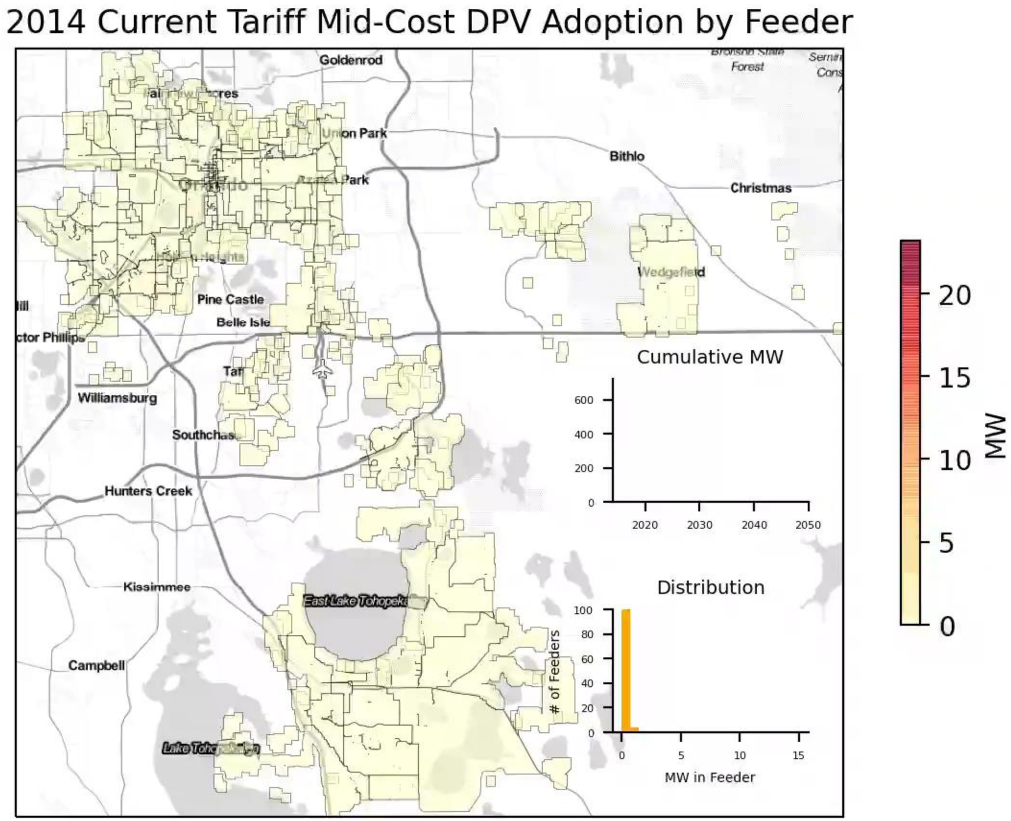
Generalized S-Curve Model
Source [SCE DFWG Progress Report]

Source PGE [Load and DER forecast]

Adoption Modeling - NREL's dGen Tool

dGen is a forecasting tool which simulates customer decisions to adopt DERs based on future DER adoption factors like economics, market conditions, and policy incentives.

- dGen models the decisions of individual 'agents' (which can be households, businesses, or other entities) based on their unique circumstances and the broader market environment.
- It offers detailed geographic modeling, allowing for analysis at national, state, and more localized levels.
- The tool incorporates a wide range of variables, including energy prices, policy incentives, and technological advancements.



Source – NREL dGen Model Applications

Planning Forecast Duration – Short, Medium and Long Term

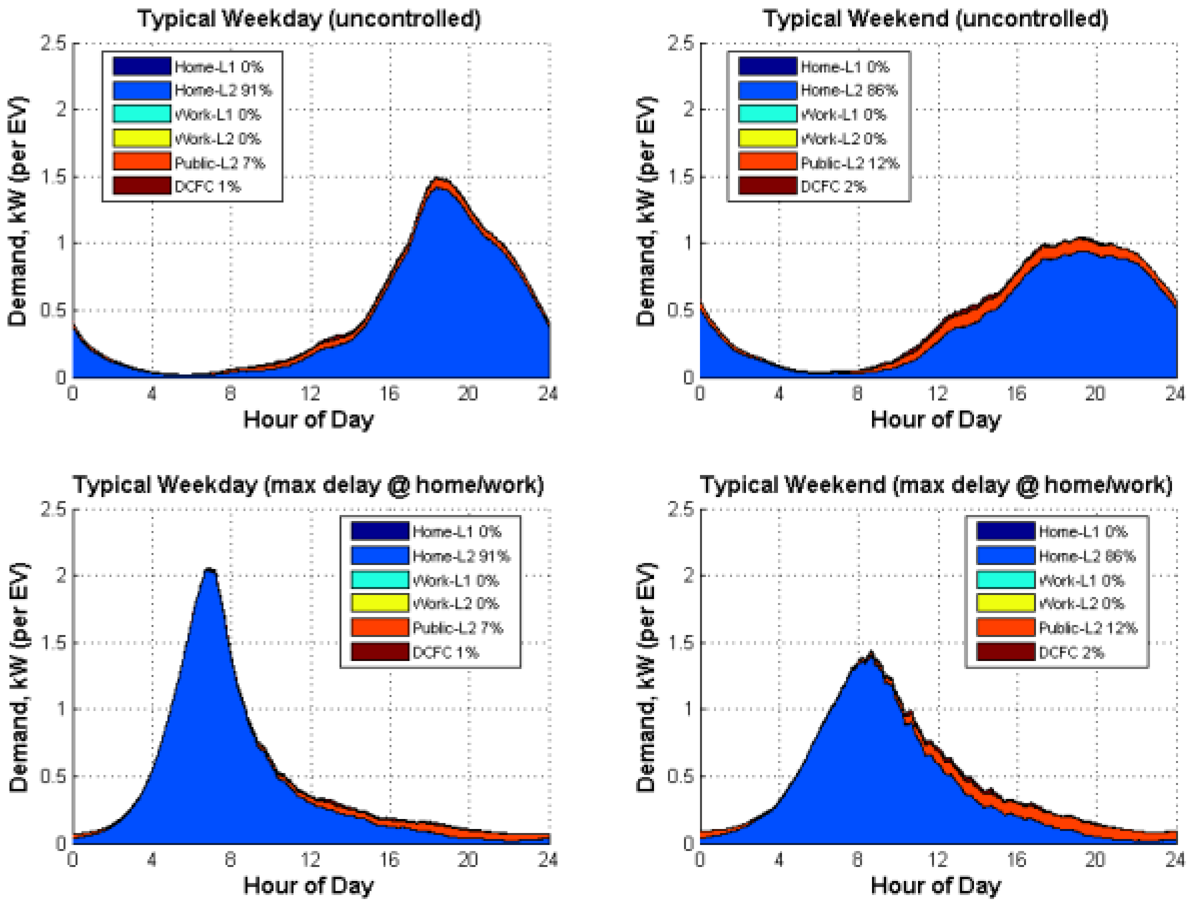
Short Term	Medium Term	Long Term
0-3 Years	3 – 10 Years	10+ Years
Focus: Centered around upcoming **operational requirements** with DER penetration for stable grid operations, preparing for **immediate growth and operational contingencies.**	**Focus**: Infrastructure **planning** with upcoming DER growth, integration of new technologies, and regulatory policy updates. **Common Historical Practice: 5-Year Planning Forecast** **Increasing Focus on 10-Year Forecast for Capital Plans**	**Focus**: Align with strategic objectives like **achieving clean energy targets** and adapting to **major technology shifts**. Useful to guide long term investments, policy decisions, and direction for sustainable future.

DER Temporal Impact – When?

Actual DER Load or Generation Profiles can vary significantly based on many factors

- Solar PV: Lat/Long, DC:AC ratio, Tracking, Shading, Direction & Azimuth
- Electric Vehicles: EV-specific or Time of Use Rates, Managed Charging, Availability, Location
- Battery Storage: Individual Use Case, Value Stack Incentives, Import/Export Restrictions

Determining expected resource profiles is critical to <u>converting adoption forecasts into system impacts.</u>



EV Charging Demand Profiles Under Varying Control and Incentive Regimes

Source: [DOE 2019 Summary Report on EVs at Scale]

Scenario Modeling

Scenario modeling

- Examines how different variables could shape future DER adoption and subsequent **system needs as a whole**
- Attempts to forecast for **multiple potential pathways** in order to **inform investment plans**
- Varying factors like technology adoption rates, economic conditions, and policy changes provide a range of possible outcomes.
  - Example: Solar adoption under varying compensation structures

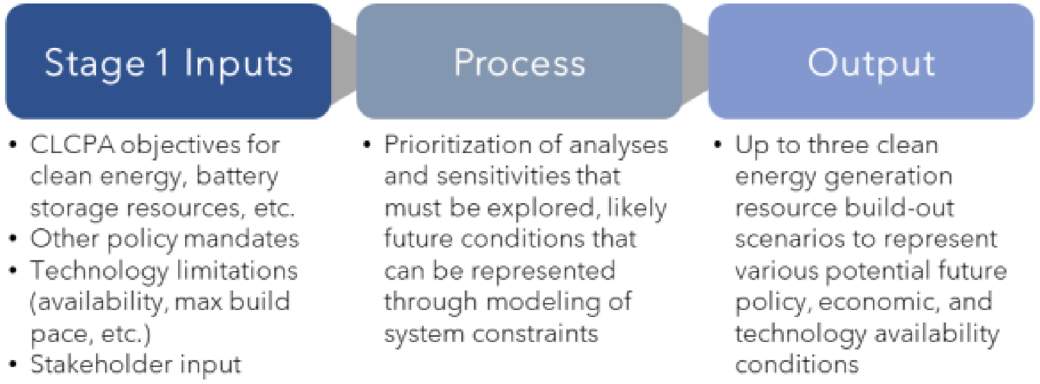
Key Components of Scenario Modeling

- **Adoption Rates -** Analyzing how quickly consumers might adopt various DER technologies under different circumstances.
- **Technological Developments -** Considering advancements in DER technologies and their potential effects on adoption and efficiency. For instance, developments in EV technologies have greatly impacted EV uptake and consumer behavior changes.
- **Policy and Regulatory Changes** - Assessing the impact of potential future policy shifts, building code requirements, and other regulatory changes.
- **Market Dynamics** - Understanding how changes in energy prices, consumer preferences, and economic conditions could influence DER growth.
- **Incentive Structure** – Assessing how different incentive and pricing changes can impact DER growth, including time of use rates and PV and EV incentive programs.

General Goals

- **Identify "no regret" investments -** Focus on actions and investments that will be beneficial across most/all potential future scenarios
- **Prepare for the future** - Prepare for longer-term needs that may arise, "future-proof" when making investment decisions.
- **Facilitate goal achievement -** Make investments necessary to facilitate reaching goals where appropriate

NY Coordinated Grid Planning Process
Stage 1 – Build-Out Scenarios



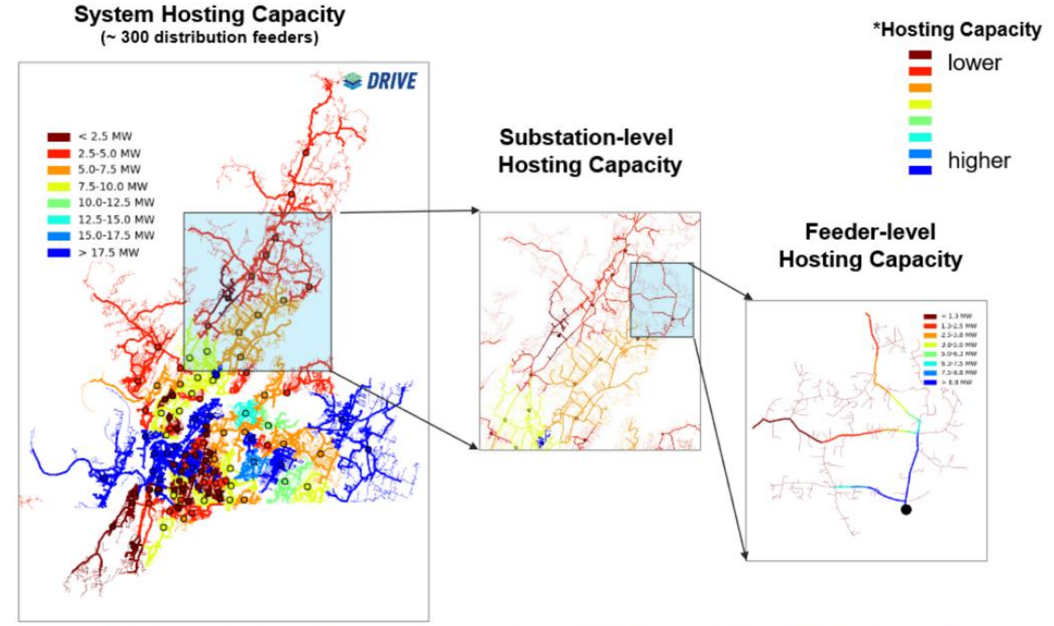
Source: [Link]

Hosting Capacity Analysis

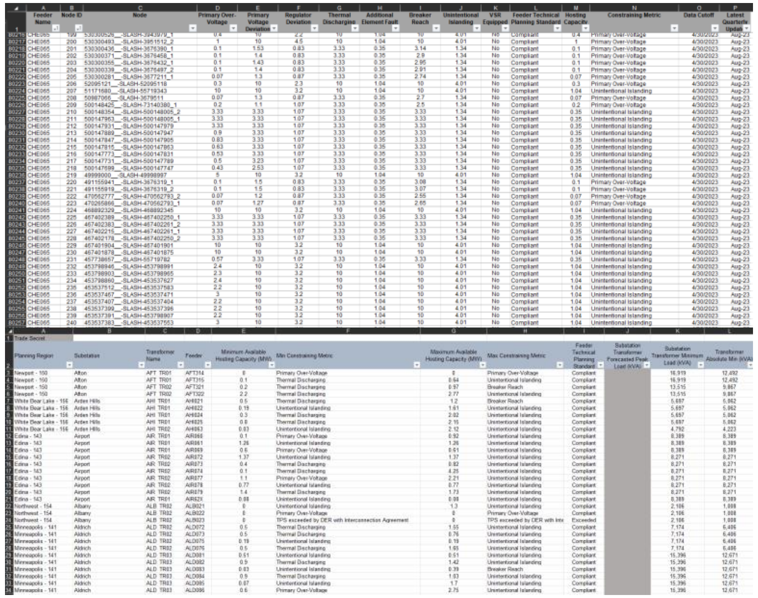
Hosting Capacity - Overview

Hosting capacity is the amount of DERs that can be **interconnected** to the distribution grid without compromising power quality or reliability, and **without necessitating upgrades** to the current control, protection systems, or infrastructure.

- Hosting capacity analysis evaluates a subset of interconnection criteria at various system locations, commonly including:
  - Thermal Limits
  - Overvoltage
  - Reverse flow limitations
  - Protection Considerations
- It is usually represented as a map, with varying level of information.
  - In some cases, utilities provide tabular information about constraints (e.g., minimum daytime load) in conjunction with maps.
- Due to scale, analysis results may not be as accurate as detailed interconnection studies, creating potential discrepancies.



Source: Jeff Smith, Methods, Applications, Opportunities and Challenges, EPRI. MPSC Distribution Planning Stakeholder Meeting, June 27, 2019, p.4.



Xcel Energy Minnesota Hosting capacity study and sub feeder spreadsheets

Hosting Capacity Use Cases

	Objective	Capability	Challenges
Development Guide	Support market-driven DER deployment	Identify areas with potentially lower interconnection costs	Security concerns; analysis/model refresh; data accuracy and availability
Technical Screens	Improve the interconnection screening process	Augment or replace rules of thumb; determine need for detailed study	Data granularity; benchmarking and validation to detailed studies
Distribution Planning Tool	Enable greater DER integration	Identify potential future constraints and proactive upgrades	Higher input data requirements; granular load and DER forecasts

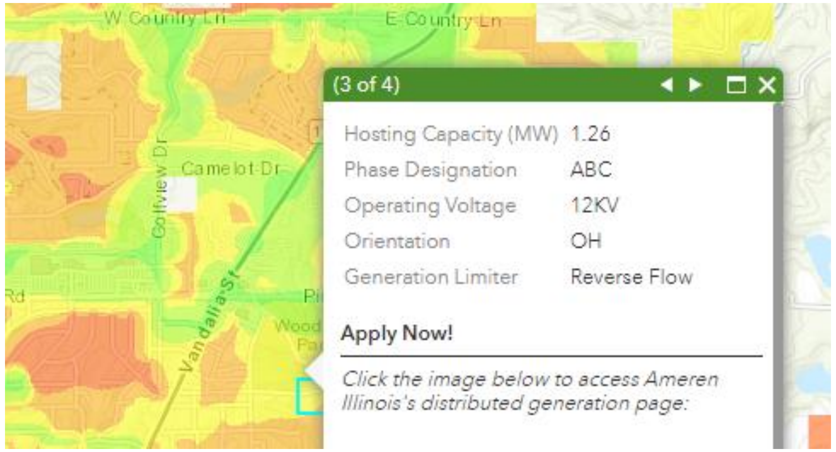
Source: U.S. DOE, Office of Electricity, Integrated Distribution Planning - Utility Practices in Hosting Capacity Analysis and Locational Value Assessment, 2018, p.3.

Use Case #1 - Facilitating Efficient Project Siting

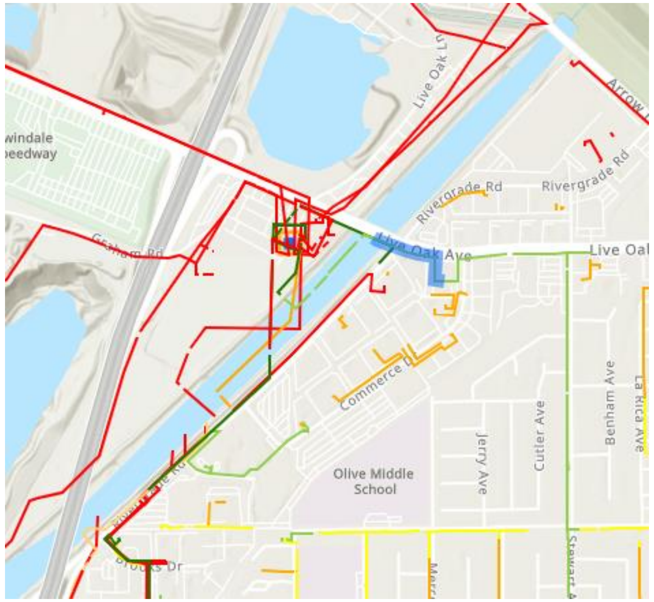
Goal: Direct project developers to sites with available capacity to **reduce the submission of non-viable applications**.

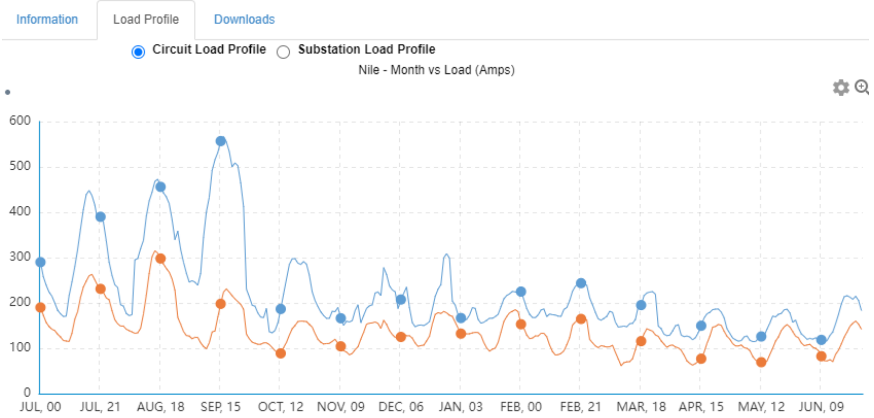
- **Basic Information:** Utilities may offer calculated DER megawatt (MW) capacity values across geographic blocks, typically visualized through a **"heat map"** indicating areas with good versus limited hosting capacity.

- **Most Effective Information**: **All data** necessary to **effectively site and size projects**, for example, calculated hosting capacity values, information on existing and queued DER projects, load profiles, grid constraints and more



Basic Hosting Capacity Map Example [Link]





Segment Level

Segment ID	236667746
Node ID	236667932
Rule 21 Screen L	Likely to Pass

	Integration Capacity (MW)	
	Static Grid	Operational Flexibility
Uniform generation	13.15	0.66
Photovoltaic	14	0.72

Circuit Level

Circuit Name	Nile
Circuit Voltage (KV)	12
Substation Name	Rio Hondo
System Name	Rio Hondo 220/66 System
Existing Generation (MW)	1.89
Queued Generation (MW)	0.26
Total Generation (MW)	2.14

Hosting Capacity Advanced Information Example

Hosting Capacity Map Information Breakdown

Hosting Capacity (HCA) Map Elements	Benefits to DER Developer
Substation location and HCA data	• Determine substation level constraints (e.g., size and voltage of transformer) • Identify equipment that may impact hosting capacity (e.g., load tap changer or regulator) • Determine approximate distance from circuit to substation
Feeder location and HCA data	• Determine feeder HCA constraints for DER load and generation • Assess if costly system upgrades are likely at a location given constraints • Identify equipment that may impact HCA (e.g., voltage supervisory reclosing)
HCA criteria violations	• Determine which violation criteria (e.g., thermal, voltage) is causing the limit, identify appropriate technical solutions to overcome constraint(s), and estimate associated costs (e.g., for system upgrade)
Substation/feeder load profiles	• Screening tool for locating DER load interconnections (e.g., storage, EV chargers) • Assess if costly system upgrades are likely at a location given constraints
DER connected and in queue	• Determine if hosting capacity is likely available to new projects

Benefits of Hosting Capacity Information to Developers – Source: Synapse Report

Common Hosting Capacity Map Design: Tensions and Trade-Offs

Topic Area	Common Utility Perspective	Common Developer Perspective
Update Frequency: (e.g., Annual, Monthly, Bi-monthly)	More frequent updates increases ongoing maintenance costs	More frequent updates improve usefulness due to increased accuracy
Level of Geographic Granularity (Blocks vs. Circuit Maps)	Aggregated maps reduce risk to utility assets (security)	Detailed circuit maps improve developer site selection capabilities
Amount of Information Provided (e.g., calculated HC, information on constraints, load profiles)	Providing additional information increases HC tool development and ongoing costs	Providing additional information increases project siting/sizing screening capability
Security Concerns (Critical Energy Infrastructure Information – CEII)	Highly detailed information may contain CEII or expose the distribution system to additional risk	HC maps are outside distribution substations and not part of the bulk power system, thus not CEII
Cost Burden	Map development and maintenance costs impact utility customer bills and are not paid by developers	HC maps reduce utility study burden and aid in compliance with state goals and programs
Data Export and Tabular Format Availability	Allowing export in tabular format may increase system security risk	Tabular results are much easier to use for prospecting good sites

Hosting Capacity Q&A Break

Use Case #2 - DER Interconnection Screening

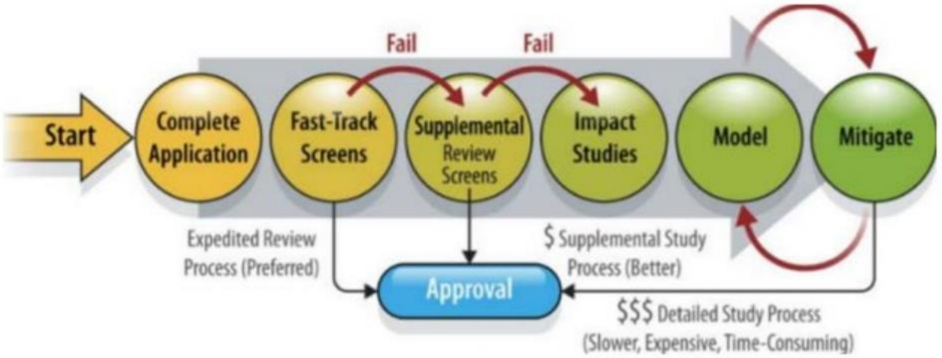
Goal: Integrate hosting capacity into the DER interconnection screening process to **<u>improve efficiency, reduce conservative assumptions, and improve screening process timelines</u>**.

Current Role in Interconnection Screenings:

- Not commonly used directly as part of interconnection screening criteria
  - Screens usually set by state codes or in utility tariffs
  - May be used to identify “restricted” or “closed” feeders
- Significant synergy between data collected for hosting capacity and data-driven screening methods
  - Use actual minimum daytime load instead of rule of thumb based on 15% of peak capacity of the feeder
  - Substation protection / reverse flow limits
  - System-wide distribution model clean-up

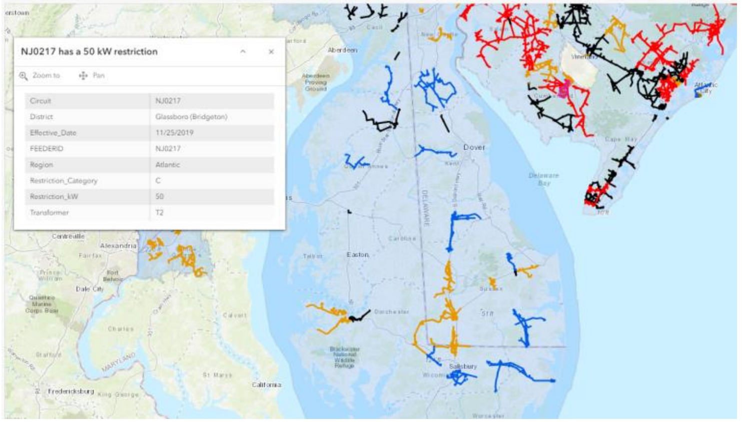
Implementation Challenges:

- Requires application/model management for queued generation and resulting system upgrades
- Models used for system-wide analysis not as trustworthy as application-specific studies (scale trade-offs)
- Difficult to account for site-specific factors (e.g., volt/var curve, co-located storage)
- Modifying screening criteria may require state-level modifications

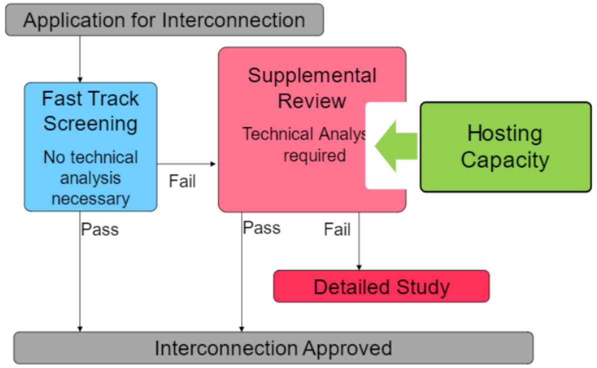


Source: NREL, Emerging Issues and Challenges in Integrating Solar with the Distribution System, May 2016.

Interconnection Screening Process



Restricted application [Example]



Source: Jeff Smith, Methods, Applications, Opportunities and Challenges, EPRI. MPSC Distribution Planning Stakeholder Meeting, June 27, 2019, p. 24.

Hosting Capacity Analysis Can Assist in Interconnection Screening

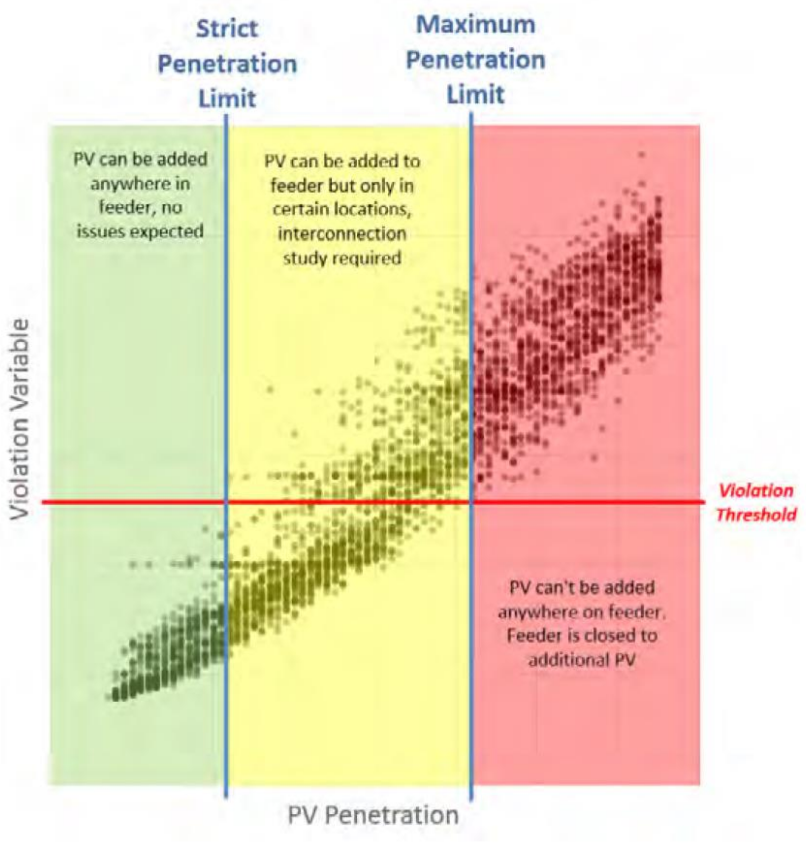
Use Case - Examples

California IOUs:

- Integrate hosting capacity information to refine the Rule 21 interconnection process
- In 2020, mandated by the CPUC to use Integration Capacity Analysis (hosting capacity) results in the interconnection process to:
  - *Determine where and when existing circuits can accommodate additional DERs without needing upgrades*
  - *Allow interconnection resources to export up to those limits [Source CPUC]*

Pepco (Washington, DC):

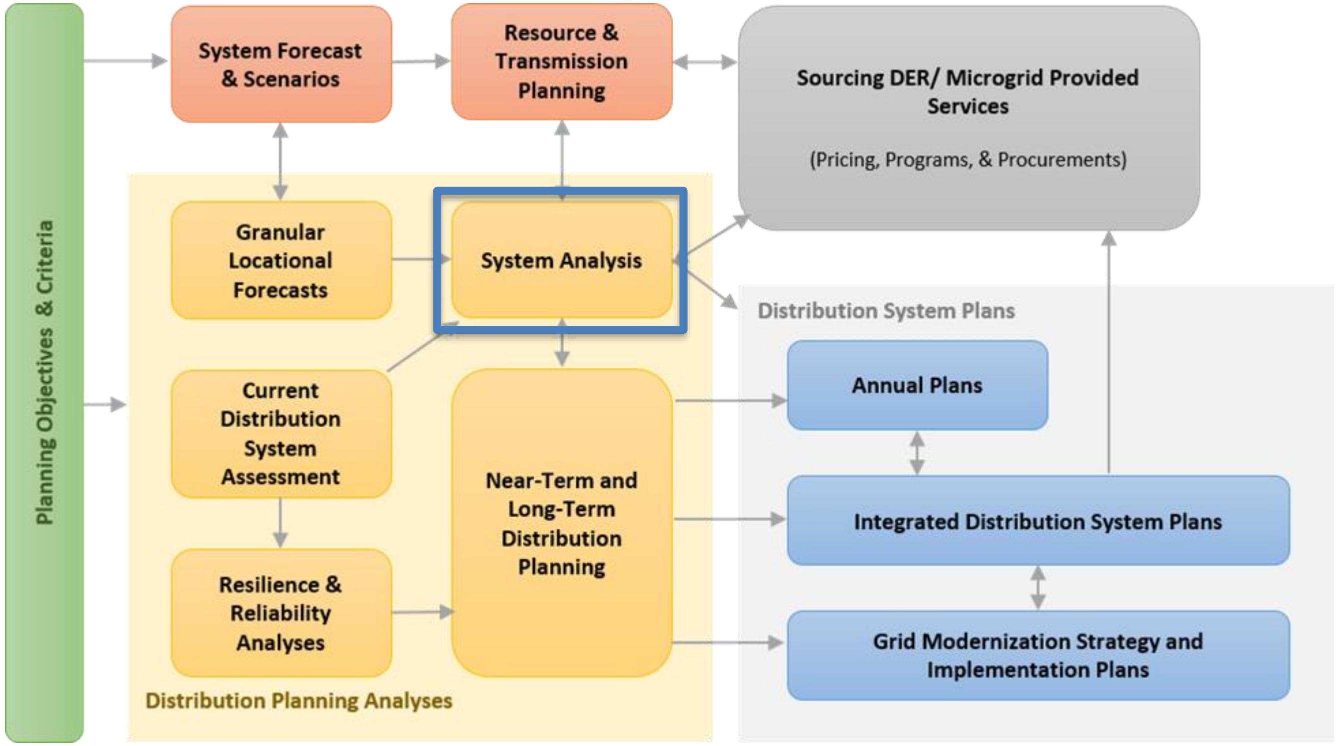
- Uses hosting capacity results along with a Heat Map to indicate existing and pending installations on feeders
- Pepco's Hosting Capacity Analysis provides customers with the ability to assess the interconnection point to estimate the available capacity on a feeder, in relation to the current and anticipated solar photovoltaic (PV) projects awaiting connection



Pepco's Definition of Strict and Maximum PV Penetration Limits – Source DE-EE0006328

Use Case #3 - Distribution Planning Tool

- Hosting capacity plays a crucial role in scenario analysis, allowing for the assessment of various 'what-if' situations concerning DER integration.
- When combined with projections of load and DER expansion, the analysis facilitates detailed evaluations of future effects on a per-feeder basis.
- Utilities can use these scenarios to consider mitigation strategies and necessary infrastructure enhancements and to conduct cost-effectiveness analyses.
- Advanced analytical capabilities will equip utilities to gauge the distribution system's readiness to leverage DER services, including non-wires alternatives, and to understand how DERs affect grid restructuring, operational tactics, and the adoption of advanced inverter technologies.



Source: Modern Distribution Grid Guidebook, DSPx Volume 4, June 2020, [PNNL: Grid Architecture - Modern Distribution Grid Project]

Use Case - Example

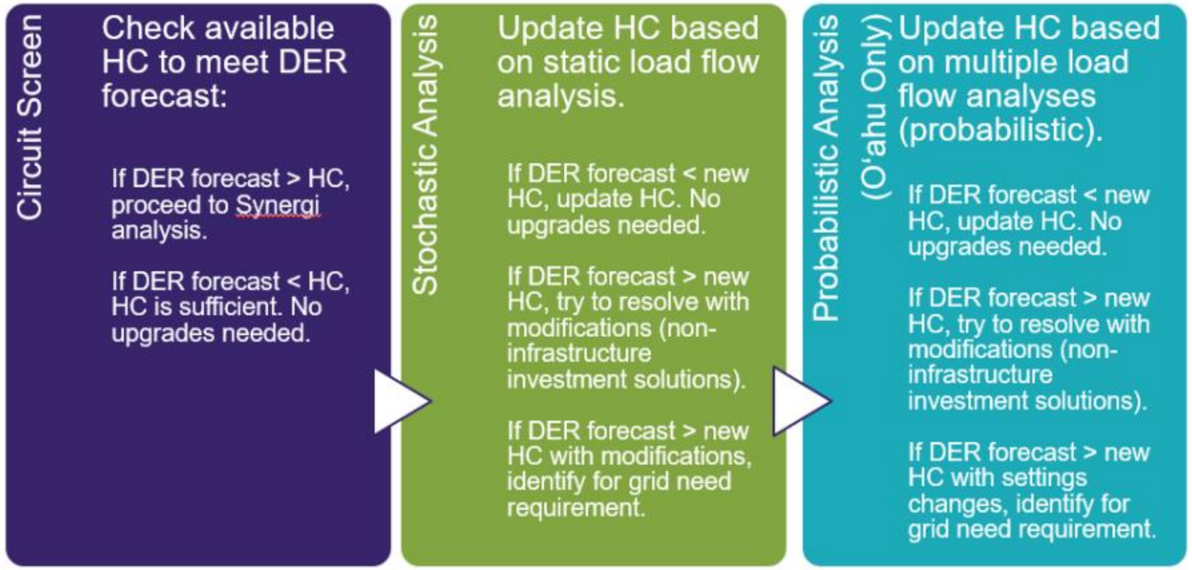
Hawaiian Electric Company:

The Hawaiian Electric Company (HECO) employs a multi-step, increasing complexity screening process to assess a circuit's capacity to host forecasted DERs through 2025.

Based on the multistep process, Hosting Capacity is categorized in the following groups by Circuit.

- **Existing Hosting Capacity Satisfies Need**: Existing hosting capacity can accommodate the total anticipated DER in year 2025. No grid needs are required.
- **Updated Hosting Capacity (Without Modifications) Satisfies Need:** Updated hosting capacity can accommodate the total anticipated DER in year 2025. No grid needs are required.
- **Updated Hosting Capacity (With Modifications) Satisfies Need:** Updated hosting capacity along with modifications that do not require infrastructure investments can accommodate the total anticipated DER in year 2025.
- **Solution Option Required:** Updated hosting capacity is unable to accommodate the total anticipated DER in year 2025. Grid need identified.

Source: HECO



Summary of Hosting Capacity Analysis – Source: HECO

Island	Total Circuits	Existing Hosting Capacity Satisfies Need (Analysis Not Required)			Total Anticipated DER in 2025 > Hosting Capacity (Analysis Required)		
		Low	Base	High	Low	Base	High
O‘ahu	384			303			81
Hawai‘i Island	137			76			61
Maui Island	88			52			36
Lana‘i	3			1			2
Moloka‘i	8			3			5
Total (All Islands)	620			435			185

Summary of Circuit Selection Screening – Source: HECO

Non-Wires Alternatives

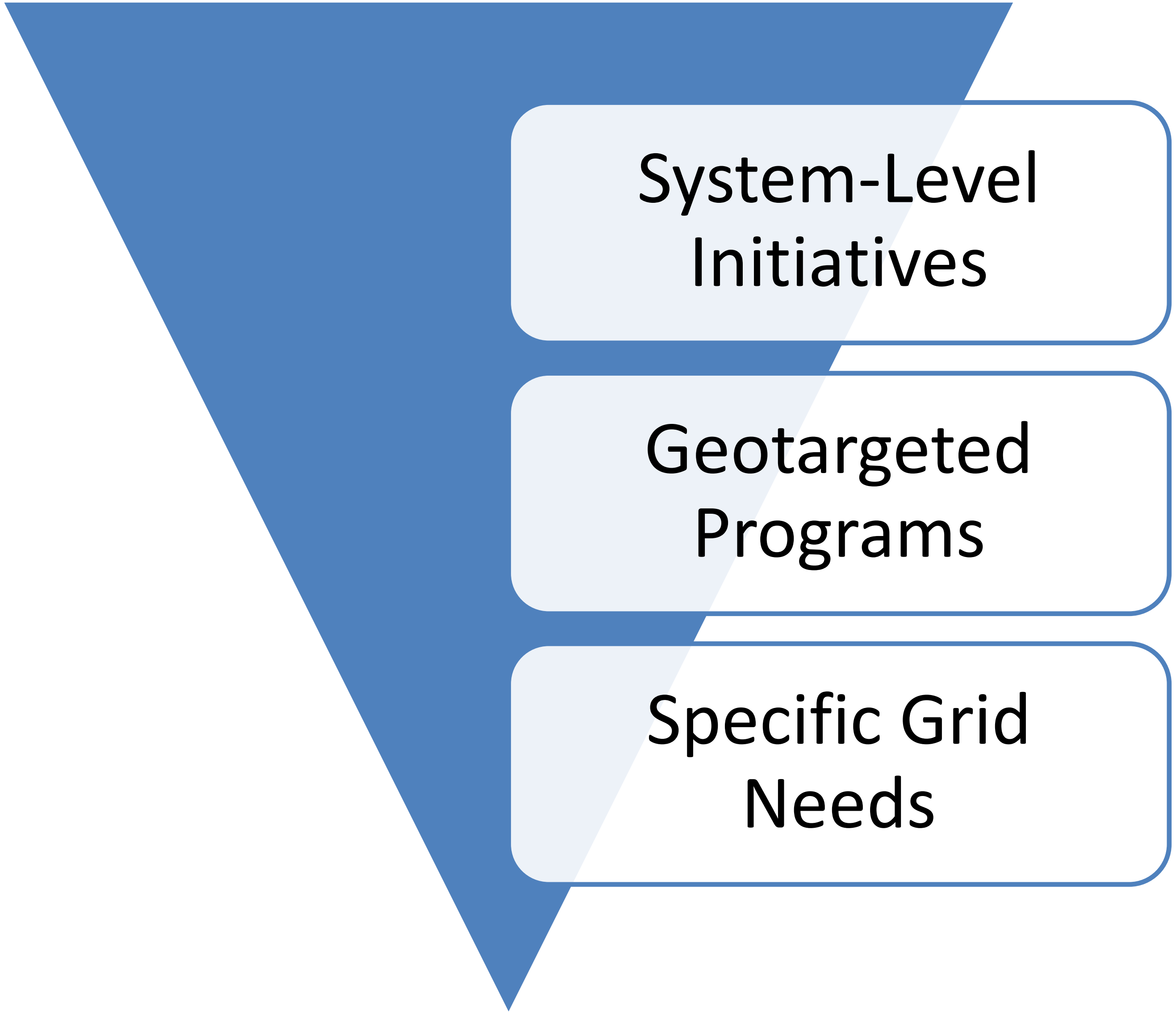
Non-Wires Alternatives

"Non-wires alternative (NWA)" is any action or strategy that uses **non-traditional** transmission and/or distribution solutions – such as distributed generation, energy storage, energy efficiency, demand response, and grid software and controls – with the intent to **defer or replace** the need for specific **energy delivery system equipment investments**. An NWA must meet energy delivery system needs and be more **cost effective** consistent with the guiding principles of sustainable, well-planned, secure, affordable, and non-discriminatory."*

NWA Benefit Category	Traditional Solutions	NWA Solution	DER Types Considered
Capacity – Reduce thermal loading on utility equipment during peak load hours to defer upgrades	Upgrade overloaded equipment, construct new circuit or substation for segmentation	Inject power locally to reduce thermal load on equipment	Grid-following DER — e.g., PV, battery energy storage system (BESS), combined heat and power
Reliability – Provide an alternate source during loss of utility supply	Build circuit ties, construct redundant substation or circuit	Intentional island to restore service to unfaulted area	Grid-forming DER (grid-forming inverter or synchronous generator)
Voltage Support – Mitigate voltage violations	Install capacitor bank or voltage regulator, reconductor	Real and reactive power injection and absorption	Inverters with Volt/Var curves, BESS, etc.

*SEPA Non-Wires Alternatives (NWA) – Incorporating NWAs into Your Grid Modernization Program

Identifying NWA Opportunities – Levels of Targeting



- No specific locational drivers; impact to specific grid needs is coincidental
- Examples: Lighting LED Conversions, Net Metering

- Tailor programs and incentives to target areas of expected future distribution needs
- Ex: Value of DER Tariffs

- Dedicated procurement of specific size/type of resource to meet known constraint
- Ex: Microgrid for reliability

Identifying Opportunities – Geotargeting

Proactive Approach to System Needs in High Growth/Constrained Areas

- **Tailored Solutions**: Geotargeting allows utilities to tailor solutions to specific areas where growth is expected to outpace the existing grid's capacity, thus preventing bottlenecks and overloads before they occur.

- **Local Resource Optimization**: Encourages the development and integration of local renewable energy sources, which can alleviate demand on the central grid and reduce transmission and distribution losses.

- **Scalable and Flexible**: Geotargeting solutions can be scaled up or down as needed, providing flexibility to adapt to actual growth patterns and changes in energy consumption behavior.

- **Deferral of Capital Expenditure**: Can delay or eliminate the need for expensive upgrades to transformers, substations, and distribution lines by managing load growth through targeted energy efficiency and demand response and local DERs.

Example – Brooklyn Queens Demand Management Program (BQDM)

Background

- In response to rising demand for electricity in the Brooklyn-Queens area, ConEd faced the need for a significant infrastructure upgrade—a new substation costing an estimated $1 billion.

- To avoid this costly investment, ConEd launched the BQDM program in 2014, aiming to reduce electricity demand in the target area by **<u>52 megawatts (MW)</u>** through demand-side management and distributed energy resources (DERs). This included 41 MW of customer-side DERs and 11 MW of DERs directly tied to the utility distribution network.

Source: "Brooklyn Queens Demand Management Demand Response Program." Business Opportunities, Consolidated Edison Company of New York, Inc, www.coned.com/en/business-partners/businessopportunities/brooklyn-queens-demand-management-demand-response-program

Example – Brooklyn Queens Demand Management Program (BQDM)

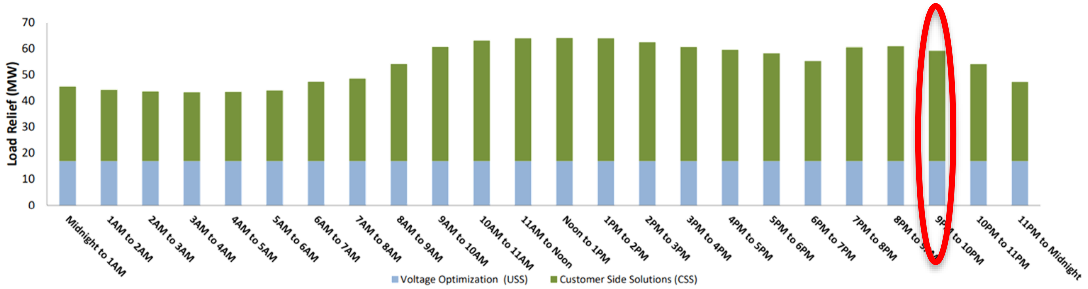
Achievements

- The BQDM program successfully met its target to reduce peak demand by 52 MW and successfully deferred the need for the new substation and provided a more cost-effective solution for managing the area's energy demand. As of Q2 2023, 61 MW of load relief was achieved at the peak (9-10 pm) including **29 MW from EE.**

Economic Impact

- With an investment of approximately $200 million—only a fifth of the cost estimated for infrastructure upgrade ($1B)—ConEd was able to achieve the required demand reduction.
- This approach offered significant savings to ConEd and its customers while still enhancing grid reliability and resilience.

BQDM PORTFOLIO	2023		
	Quarter 2	Year-to-Date	Program-to-Date
FINANCIAL ACTIVITY ($ M)			
[0] Expenditures			
Customer-sided	$ 0.53	$ 1.04	$ 107.11
Utility-sided	$ -	$ -	$ 23.74
Total Expenditures	**$ 0.53**	**$ 1.04**	**$ 130.84**
Program Cost Recovery	**$ 1.15**	**$ 2.30**	**$ 76.35**
CUSTOMER-SIDED PROGRAM ACTIVITY			
Energy Efficiency			
[1] Residential Direct Install			
Peak Hour kW reduction	-	-	4,930
[2] Bring Your Own Thermostat			
Peak Hour kW reduction	-	-	391
[3] Residential AC			
Peak Hour kW reduction	-	-	9
[4] Multifamily Energy Efficiency			
Peak Hour kW reduction	12	12	5,650
[5] Small-Medium Businesses Adder			
Peak Hour kW reduction	123	191	14,677
[6] Commercial & Industrial			
Peak Hour kW reduction	-	-	985
[7] NYCHA			
Peak Hour kW reduction	-	-	2,293
[8] DCAS			
Peak Hour kW reduction	38	38	505
Distributed Generation			
[9] Fuel Cell			
Peak Hour kW reduction	-	-	6,100
[10] Combined Heat & Power			
Peak Hour kW reduction	-	-	3,079
Energy Storage			
[11] Peak Hour kW reduction	-	-	4,000
Customer-Sided Portfolio kW reduction at Peak Hour	**173**	**241**	**42,620**



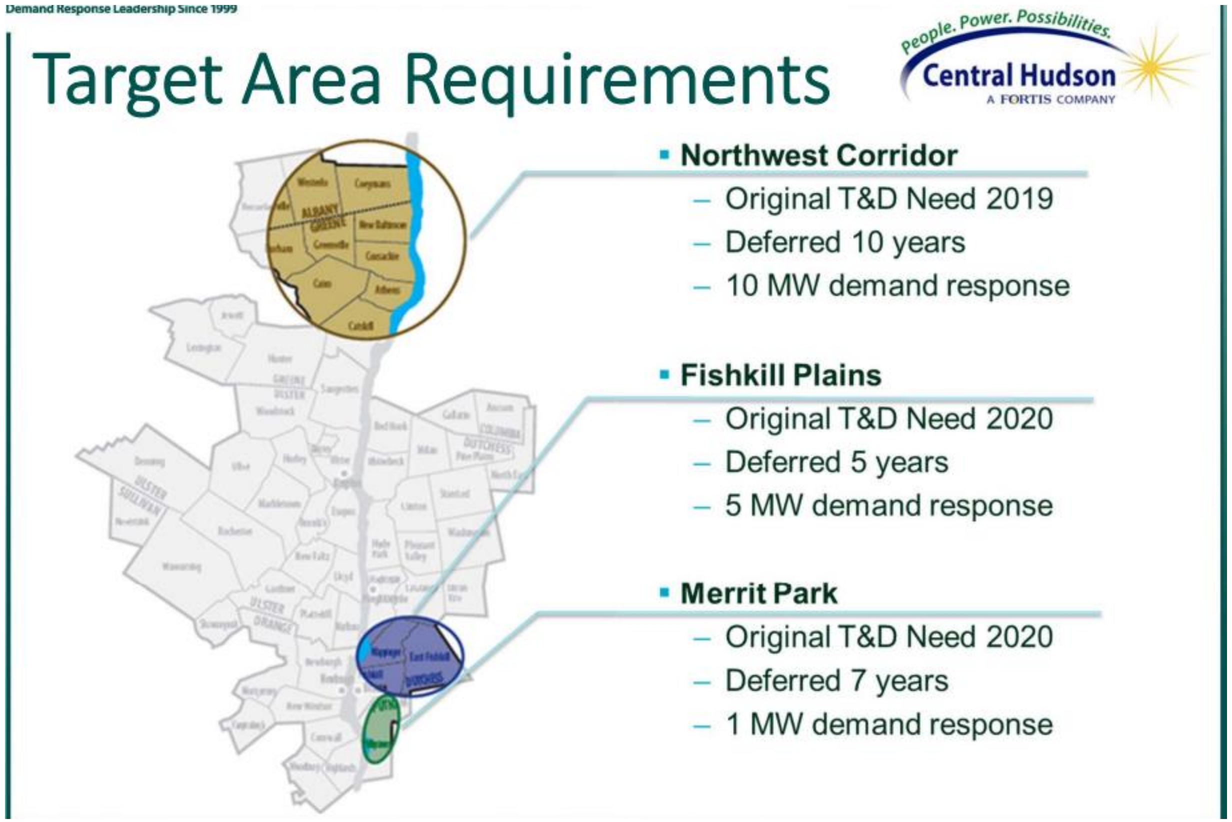
Source: Con Edison BQDM Report Q2 2023, NY PSC Order Establishing Brooklyn/Queens Demand Management Program

Example – Central Hudson Peak Perks Program

Background

- Central Hudson, serving parts of New York State, faced challenges with peak load management, especially during the summer months when energy usage spikes due to air conditioning and other cooling needs.

- The utility was looking for a way to manage these peaks more effectively without resorting to costly infrastructure upgrades in three targeted zones for 5 to 10 years.



Source: PLMA Demand Response Program [Link]

Example – Central Hudson Peak Perks Program

Overview

- Peak Perks was designed as a voluntary program that incentivizes residential and commercial customers to allow Central Hudson to install devices that can remotely cycle off air conditioning systems or adjust thermostat setpoints for brief periods during peak demand times.

- Participants receive an initial enrollment bonus and annual participation incentives.

Estimated Cost of Traditional T&D Solutions

– Actual Cost of DR Solution

+ Actual Capacity Savings

= Program Financial Benefits

70% of benefits go to rate payers by reducing future bill pressure

30% of benefits are provided to utility as incentive to achieve the program targets

Source: PLMA Award Wining DR Initiatives

Example – Central Hudson Peak Perks Program

Strategy

- The program primarily aimed to reduce peak electricity demand, which in turn could defer or eliminate the need for additional network reinforcement.

- By targeting specific areas with the highest demand or where the system was most constrained, Central Hudson could optimize its demand-side management efforts.

Outcomes

- The program exceeded the total first year MW target of all three locations, achieving **5.9 MW** of load reduction compared to 5.3 MW target.
- Overall, Central Hudson's Peak Perks program successfully curbed peak energy demand, contributing to more stable and efficient grid operation.
- Program participants contributed to a collective effort that helps to maintain reliable service and keep energy costs down for all customers.

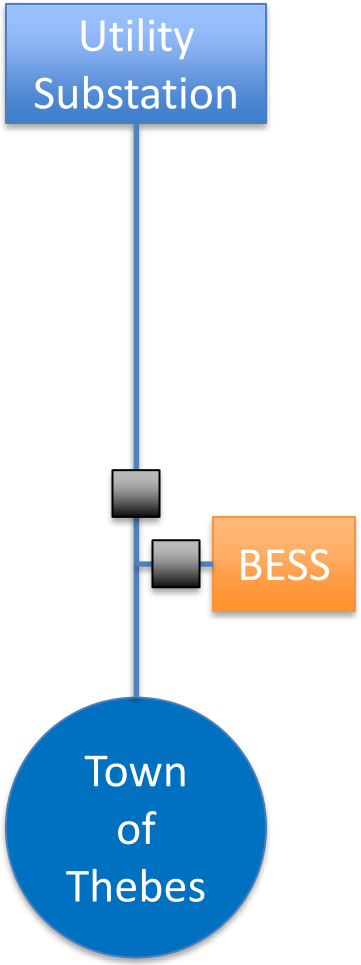
Specific Grid Needs Example – Ameren Illinois Thebes BESS

- Ameren Illinois installed a battery energy storage system to provide backup power for the town of Thebes.
  - Approximately 300 residents
  - Historically worst performing circuit for reliability
  - Served via radial supply through dense Mark Twain National Forest
  - Traditional alternate source construction not viable due to distance and trees

- **1 MW battery** installed and used as an automatic transfer voltage source for the community during an outage situation

- Estimated Cost: **$1.4M**

- This project resulted in **fewer and shorter outages with positive community feedback**.

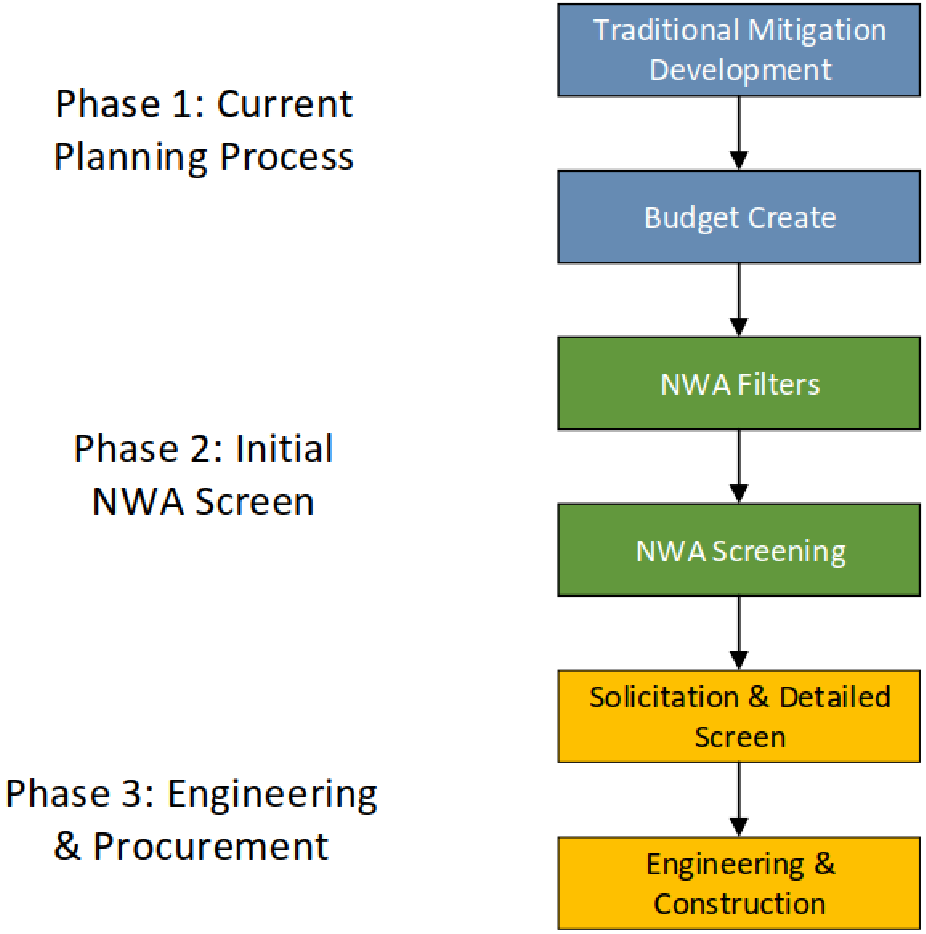


Ameren Illinois Thebes Battery [Link]

NWA Evaluation Framework – Comparison with Alternatives

Evaluating Non-Wires Alternatives requires comparing them to traditional infrastructure solutions to understand benefits and limitations of NWAs in addressing specific grid needs. This comparison is a multi-faceted comparison including, but limited to, the following factors :

- Capital and operational costs
- Time to implement
- Scalability and flexibility
- Environmental impacts
- Reliability and resiliency measures
- Regulatory and policy compliance
- Public/community impact
- Maintenance and long-term use
- Finance and business models
- Risks



Source: Xcel Minnesota 2023 Integrated Distribution Plan

NWA Evaluation Framework – Cost Benefit Evaluation

Cost-benefit analysis for NWAs scrutinizes a variety of factors to ascertain NWA economic viability compared to traditional grid upgrades, such as:

- Initial capital expenditure
- Operational expenditures
- Economic lifespan and depreciation
- Benefits and savings
- Scalability costs
- Avoided energy benefits
- Avoided capacity benefits
- Avoided non-energy benefits
- Benefit to cost ratio

Individual Cost and Benefit Calculations for an Example Project, Used to Calculate the Net Impact

Cost and Benefits Summary	
Energy Generation	$1,544,526
Generation Capacity + MISO Reserves	$473,600
Transmission Capacity	$20,332
Deferral Benefit	$800,717
GHG Emissions + Other Environmental	$2,112,750
Solar Cost	$(2,177,637)
Battery Cost	$(438,363)
Interconnection Fees	$(204,000)
Total Benefit	**$4,951,924**
Total Cost	**$(2,819,999)**
Net Impact	**$2,131,925**

Source: Xcel Minnesota 2023 Integrated Distribution Plan – NWA Appendix F, Pg 24

NWA Evaluation Framework – Resource Overcommitment Evaluation

Resource overcommitment occurs when a **single asset** is expected to **serve multiple functions simultaneously**, which might **not be feasible** due to operational constraints. This is especially relevant in the context of value stacking for NWAs, where assets like energy storage systems are expected to provide a range of services, such as demand response, load shifting, and voltage support.

To mitigate the risk of overcommitment, it is crucial to assess the following:

- **Capability Assessment -** Ensuring that each asset can handle the demands of each service it's tasked with, both individually and in combination.
- **Coordinating Scheduling and Dispatch -** This involves using advanced control systems to schedule the asset's responsibilities in a way that avoids conflicts, such as providing ancillary services during one period and reserving capacity for peak load support in another period.
- **Contractual Obligations -** When engaging resources for multiple services, the terms should reflect the physical and operational limits of the asset.
- **Robust Monitoring and Management Systems –** These systems continuously track the performance and availability of the resource, ensuring that it can meet its various functionality commitments when needed.
- **Fallback Options -** In case a resource can't fulfill all roles due to simultaneous demand, backup systems or strategies can be in place to maintain service levels.

NWA Procurement Mechanisms

Specific Grid Need
Direct Procurement

- Utility-initiated acquisition of resources to meet identified grid needs.
- Utility-owned/leased and directly controlled, offering a streamlined approach.
- The approach simplifies access to the value stack, mitigating contractual or control complexities associated with third-party operations.
- Suitable for vertically integrated utilities. More challenging for deregulated distribution utilities (ownership, market revenue, and dispatch coordination challenges).

Specific Grid Need
Distribution Services Approach

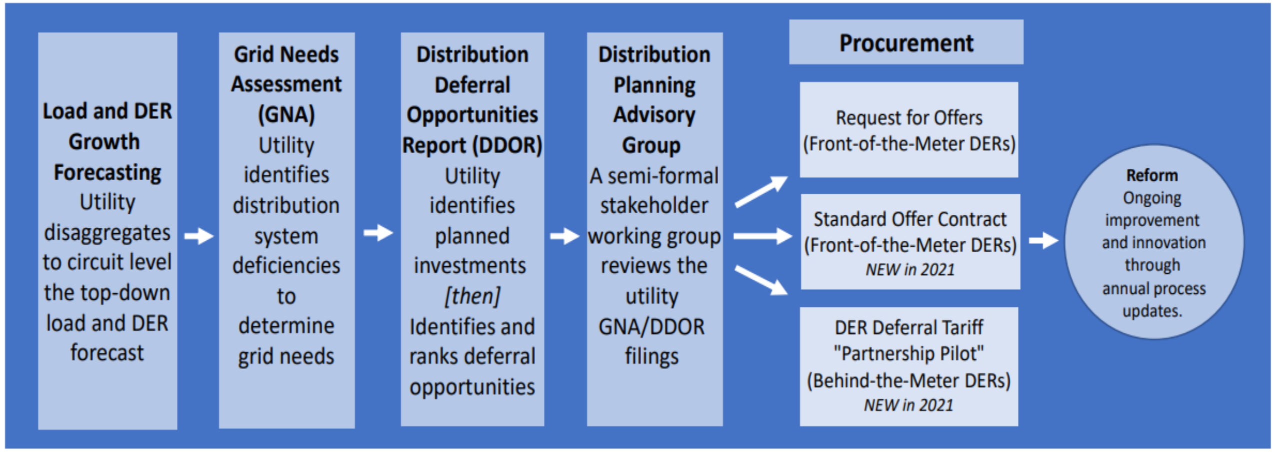
- Utility issues a call for proposals from third parties or customers for NWAs to address specific grid needs.
- Such solicitations enable the integration of customer or third-party-owned resources, which are then compensated for their services to the grid.
- These resources can be directed by the utility for distribution system needs as necessary, while otherwise participating freely in other market opportunities.

Geotargeting or System Level
Programmatic Approach

- Employ systematic studies to discern the locational value of DERs, aiming to direct them to where they're most beneficial on the grid.
- Adjust incentive levels to promote DERs in locations which can offer the greatest value/relief to the system.
- The goal is to prevent as many specific grid needs as possible by managing load growth in targeted areas, thereby reducing reliance on traditional infrastructure upgrades.

Specific Grid Needs - Distribution Services Approach - California

In 2018 the CPUC issued decision D. 18-02-004, which adopted the **Distribution Investment Deferral Framework**, creating opportunities for DERs to serve as **NWAs in lieu of traditional grid investments**.



*The California Energy Commission prepares the top-down load forecast used by the IOUs. The same top-down load forecast is used as the basis for the CPUC's Integrated Resources Plan process and California Independent System Operator's Transmission Planning Process.

Candidate Deferral	GNA Facility Name	In-Service Date
WILLOW PASS BANK 1	WILLOW PASS BANK 1	2023
	WILLOW PASS BANK 3	2023
SAN MIGUEL BANK 2	SAN MIGUEL BANK 1	2023
	SAN MIGUEL 1104	2023
	PASO ROBLES 1107	2023
CALISTOGA BANK 1	CALISTOGA BANK 1	2023
	CALISTOGA 1102	2023
RIPON 1705	VIERRA 1707	2024
ZAMORA BANK 1	ZAMORA BANK 1	2023
GREENBRAE BANK 2*	GREENBRAE BANK 2	2023
BLACKWELL BANK 1 *	BLACKWELL BANK 1	2023

* CUSTOMER CONFIDENTIAL due to their peak loads violating the 15-15 customer privacy rule

Source: PG&E presentation on 2021 RFO for more than 19.6 MW support of local distribution capacity relief in seven areas in central California

DIDF Framework - Demand-side Alternatives To Traditional Supply-side Investments: Updated And New Approaches In California

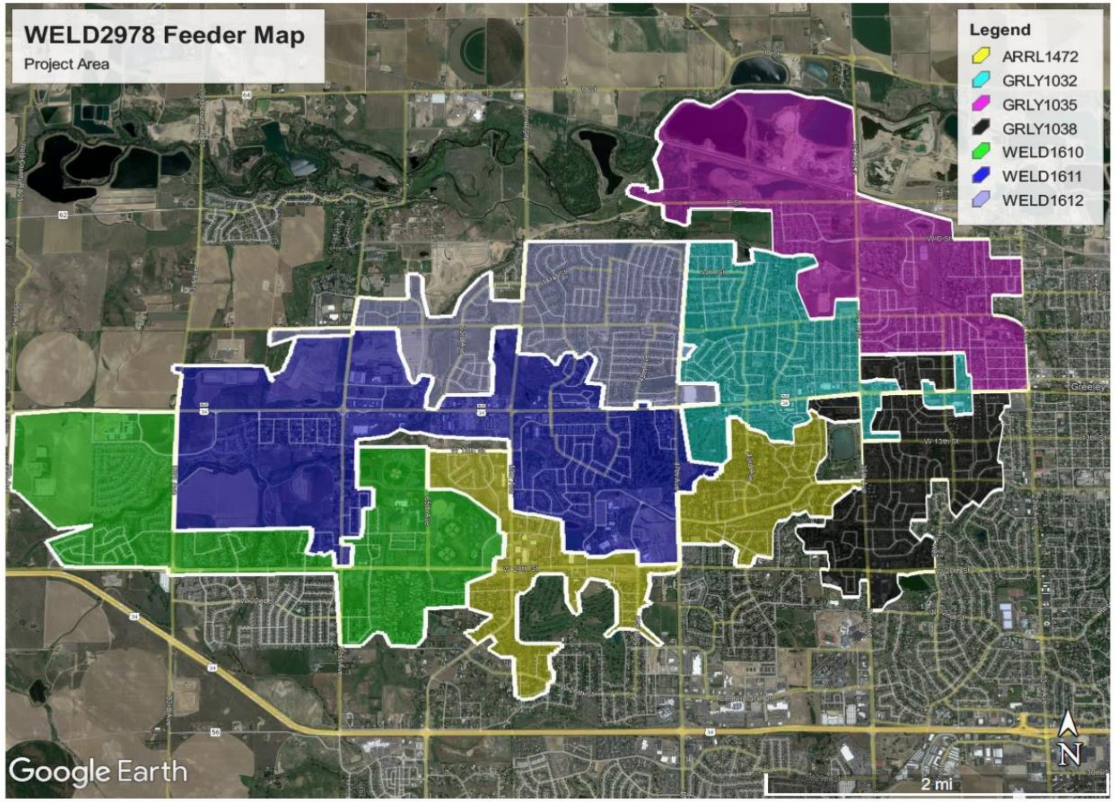
PG&E 2021 DIDF identified more then 19MW of Grid needs [Locational Value of DERs]

Specific Grid Needs - Distribution Services Approach - Colorado

In May of 2023, Xcel Energy (PSCo) issued an RFP to solicit NWA solutions for two capacity-driven projects to defer system upgrades

- Goal: Defer $4.1M for new feeder from 2025 to 2031 for each project location
- Expected to utilize demand response, energy efficiency, energy storage, and/or distributed generation

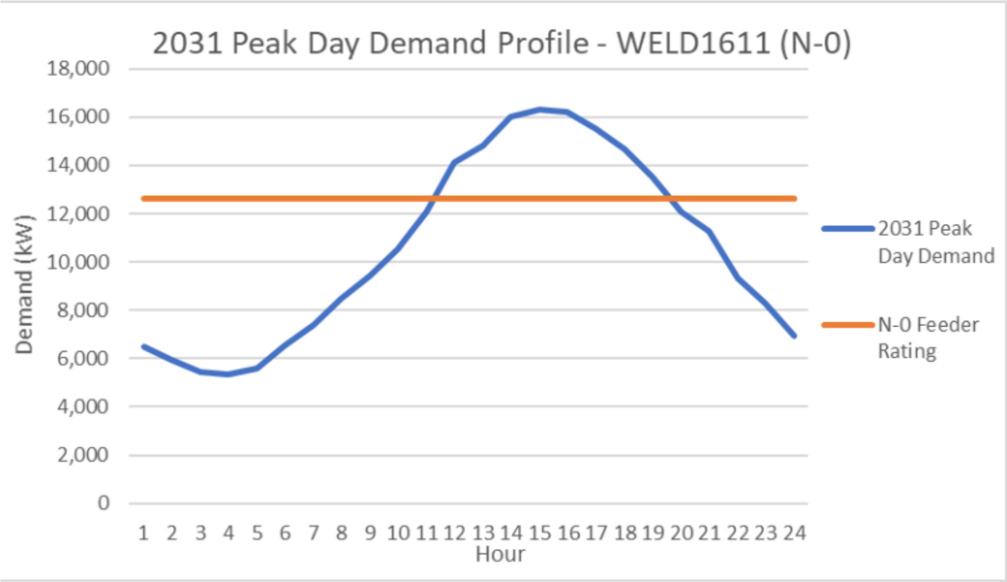
Area of Need



Timing of the Need

Asset	Capacity Need (MW)	Need Period (Hours)	Peak Hours	Deferral Period (Years)	120-Day Load Relief Period
WELD1611 (N-0)	4.6	10 hours	11:00 – 20:00	2025 - 2031	June 1st – September 28th
WELD1611 (N-1)	11.5	20 hours	4:00 – 23:00	2025 - 2031	
GRLY1032 (N-1)	7.0	21 hours	3:00 – 23:00	2025 - 2031	

Table 7: Timing for System Risk Relief Requirements



[Source]

Geotargeting and System Level – Value of DER

- **Customer-centric approach** where customers choose the size, location, and type of DER installations, such as solar panels or energy storage systems, and are **compensated based on the locational value their DERs** provide to the grid, **encouraging deployment in areas where can provide maximum benefits**.

Example: NY VDER
New York's Value of Distributed Energy Resources (VDER) program, which includes the **Locational System Relief Value**, **compensates** DER providers based on the **location-specific value** they bring. VDER also employs studies on the marginal cost of service to determine a general "**Demand Reduction Value**" applicable across **all locations**.

Ongoing Proceeding – Illinois Value of DER
Illinois is engaged in an ongoing proceeding to determine "base value" and "additive services" value of DER as a replacement for the distribution component of net metering compensation

- Driven by state legislation
- Framework to be proposed in 2024
- Workshop Materials: [Link]

Value Name	Description	Eligible DERs
Energy Value (LBMP)	LBMP is the day-ahead wholesale energy price as determined by NYISO. It changes hourly and is different according to geographic zone.	All technologies: PV, storage, CHP, digesters, wind, hydro, and fuel cells.
Capacity Value (ICAP)	ICAP is the value of how well a project reduces New York State's energy usage during the most energy-intensive days of the year. Developers can choose from three payout alternatives and most ICAP rates change monthly.*	All technologies receive ICAP. Dispatchable technologies (stand-alone storage, CHP, digesters, and fuel cells) will receive Alternative 3.
Environmental Value (E)	E is the value of how much environmental benefit a clean kilowatt-hour brings to the grid and society. The E value is locked in for 25 years.**	PV, wind, hydro, and storage charged exclusively from PV or wind energy. Stand-alone storage is not eligible at this time.
Demand Reduction Value (DRV)	DRV is determined by how much a project reduces the utility's future needs to make grid upgrades. DRV is locked in for 10 years.**	All technologies.
Locational System Relief Value (LSRV)	LSRV is available in utility-designated locations where DERs can provide additional benefits to the grid. Each location has a limited number of MW of LSRV capacity available. The LSRV is locked in for 10 years.**	All technologies. Project must be on a utility-specified substation.
Community Credit (CC)	CC is available on a limited basis to encourage the development of Community Distributed Generation (CDG) projects. CC is the successor to the Market Transition Credit (MTC) and is similar in structure. The CC is locked in for 25 years.** PV projects in utility territories that have fully expended their CC may be eligible for the Community Adder – an upfront incentive administered by NY-Sun.	Available for CDG projects including PV and digesters. Wind, hydro, and fuel cells receive CC at a derated value. Not available for stand-alone storage or CHP.

NY Value Stack Elements [Link]

Closing

Questions to Ask

- How are the impacts of DER factored into your planning and investment processes?
- How are you estimating the peak load impact of EV growth across your distribution system?
- How granular are your PV, EV, and other DER forecasts with regard to location?
- What constraints are you considering in your hosting capacity map?
- What information could be readily provided by your hosting capacity analysis that would provide value to the utility, DER developers and customers?
- What steps would be needed to incorporate hosting capacity results into the screening process for DER interconnection?
- How can geotargeting be applied to existing system-level DER programs to improve distribution benefits?
- How are Non-Wires Alternative opportunities being identified and screened?
- What challenges have you experienced or do you anticipate within the NWA adoption process?

Q&A

Questions?

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U.S. DEPARTMENT OF ENERGY

Identifying Grid Needs and Evaluating Investment Options

Training for States on Distribution System and Distributed Energy Resources Planning

Presented by Samir Succar, ICF

Western Regional Training

January 24, 2024

Agenda

Mapping technologies to objectives

Planning objectives

Utility budgets

Investment prioritization

Cost-effectiveness methods

Actions and questions

Distribution System Planning Context

Baseline information on current state of distribution system

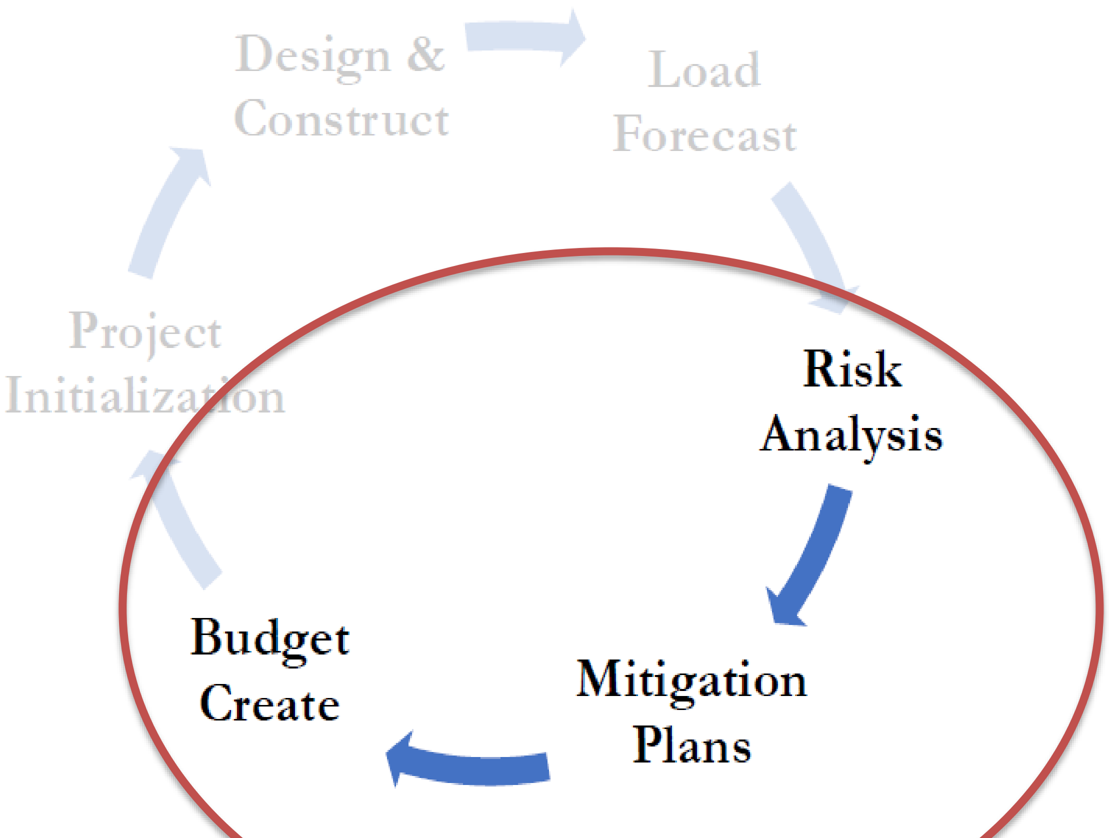
- Such as system statistics, reliability performance, equipment condition, historical spending by category

Description of planning process

- Load forecast – projected peak demand for feeders and substations
- Risk analysis for overloads and plans for mitigation
- Budget for planned capacity projects
  - Asset health analysis and system reinforcements
  - Upgrades needed for capacity, reliability, power quality
  - New systems and technologies
  - Ranking criteria (e.g., safety, reliability, compliance, financial)

Distribution operations

- Vegetation management
- Event management



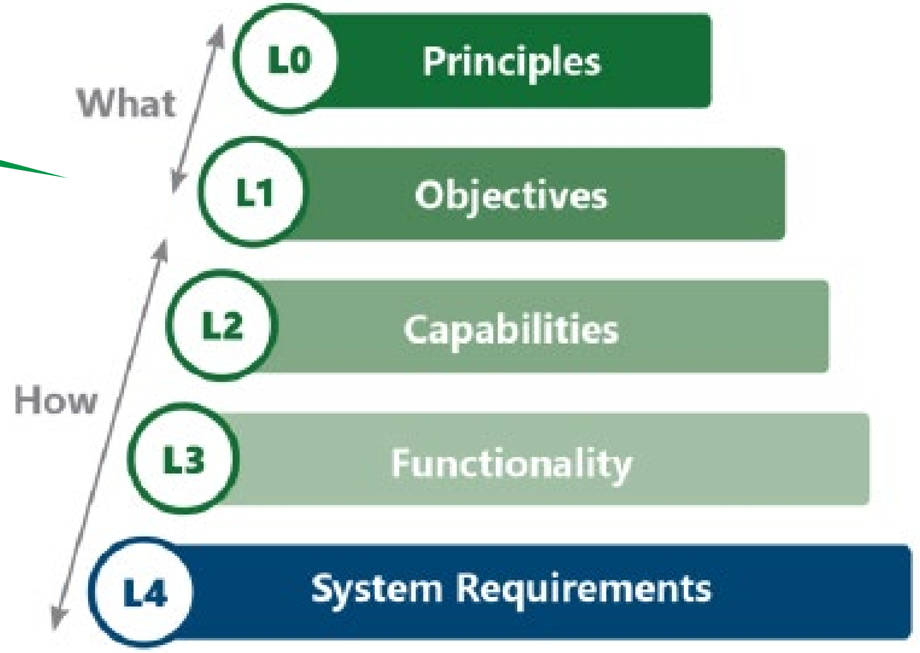
Source: Xcel Energy

Grid Modernization Strategy & Implementation Planning

Objective: An envisioned or desired result or outcome

?

System requirements: Technology solutions that can meet specific business and technical requirements



Source: *Modern Distribution Grid Guidebook, Strategy & Implementation Planning Guidebook*, Version 1.0 Final Draft, DOE Office of Electricity, June 2020; [Modern-Distribution-Grid_Volume_IV_v1_0_draft.pdf (pnnl.gov)]

Mapping Technologies to Objectives: **Reliability**

Objective	Capability	Function	Technology
Reliability improvement by reducing customer unplanned outage durations Achieve 2nd quartile CAIDI performance by 2025	Improve outage identification and customer service restoration	Fault Identification Fault Location Fault Isolation Service Restoration	Fault Current Indicators Outage Notification from Meters Outage Management System Geospatial Information System Distribution Management System and/or SCADA Automated Switches Work Management System

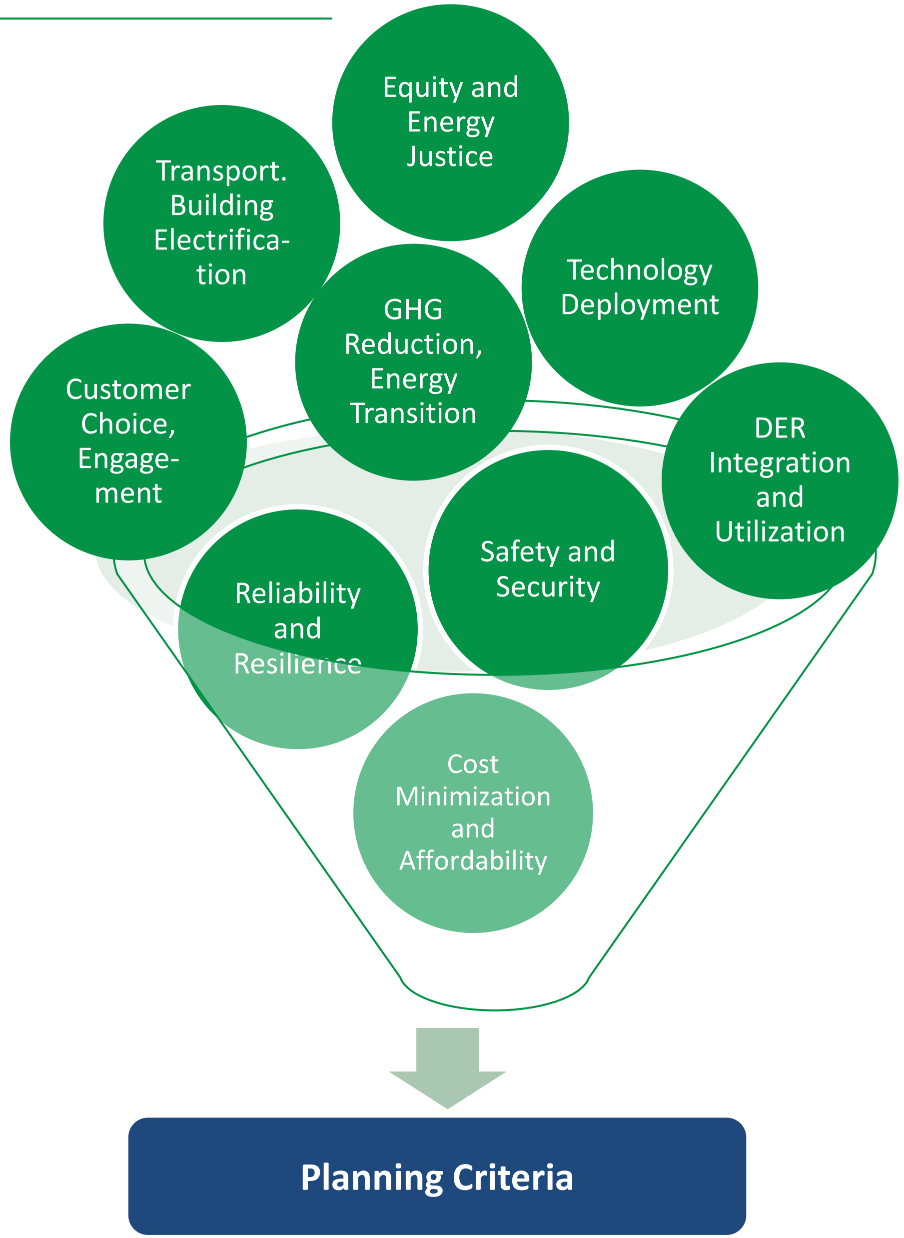
Source: *Modern Distribution Grid, Volume I: Customer and State Policy Driven Functionality, DOE, 2017;*
https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf

Mapping Technologies to Objectives: **Customer Choice**

Objective	Capability	Function	Technology
Enable customer choice by providing information to support customer decisions	Provide online customer access to relevant & timely information by 2020 for small business & residential customers	Remote meter data collection & verification Customer data management Energy management & DER purchase analysis	Customer portal Customer analytic tools Green Button Time interval metering Meter Data Management System Customer information system Data warehouse Meter communications

Source: *Modern Distribution Grid, Volume I: Customer and State Policy Driven Functionality, DOE, 2017;* https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf

Translating Objectives into Criteria



Objectives: An envisioned or desired result or outcome

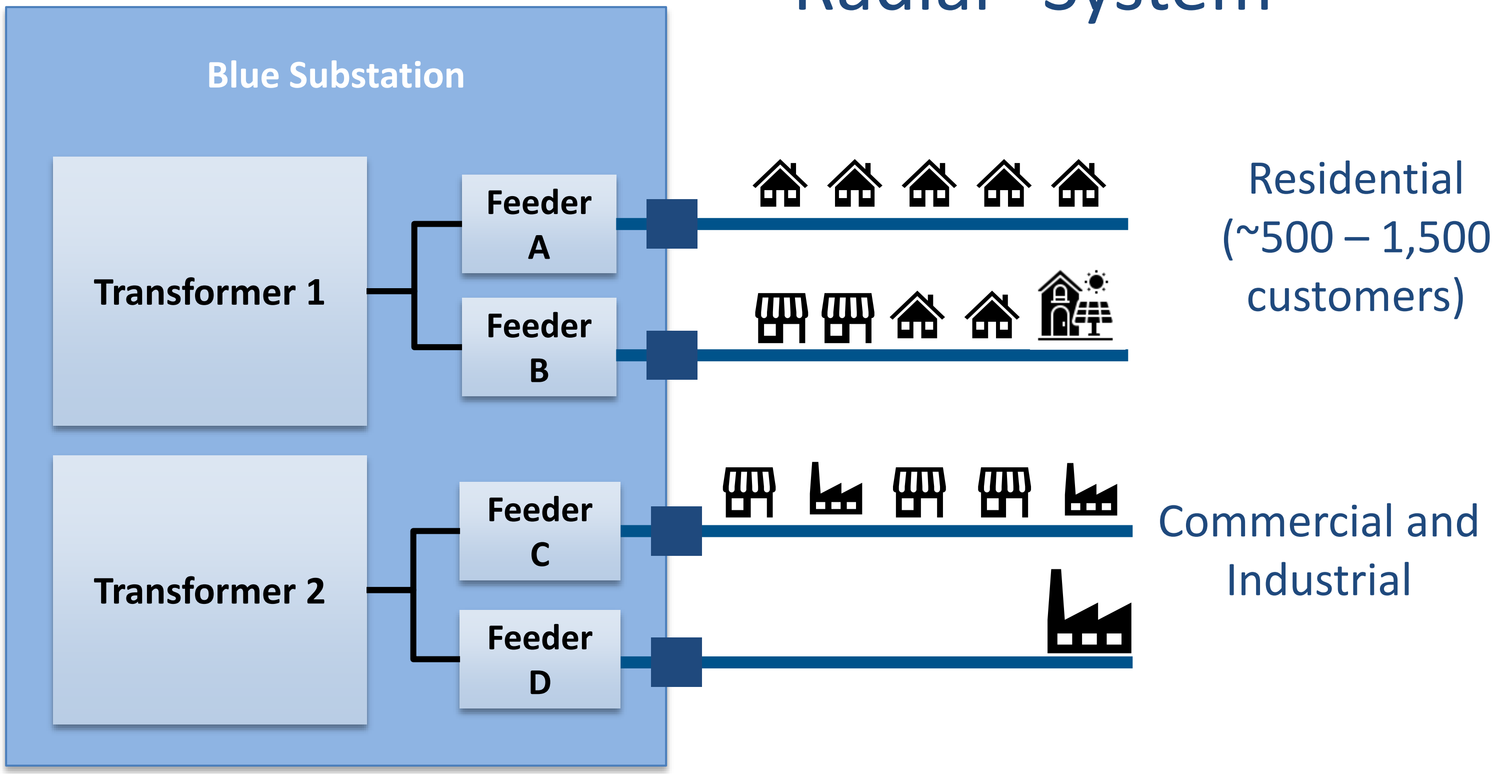
Criteria: Principles or standards by which system risks or solutions may be evaluated or prioritized

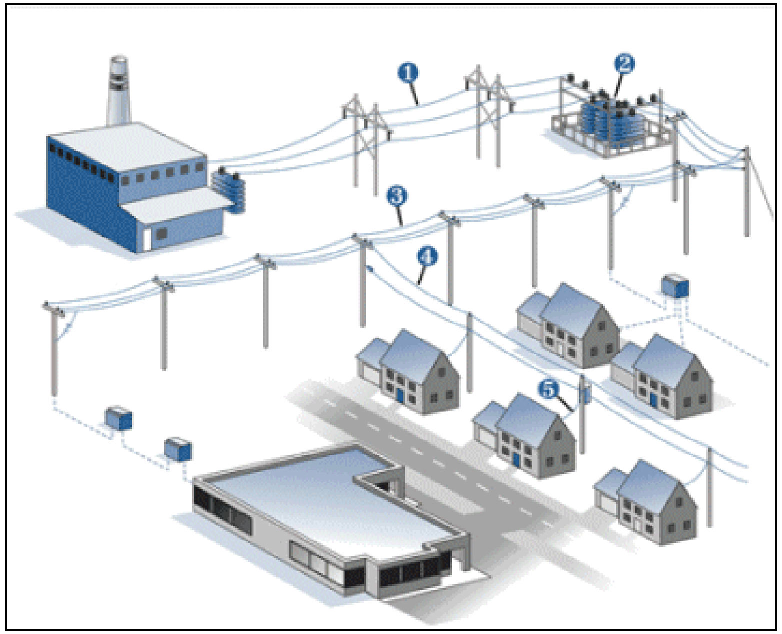
Planning for Electric Capacity

Normal Operations

Safety Reliability

“Radial” System





Credit: Ameren
https://www2.ameren.com/common/DistributionSystem.aspx

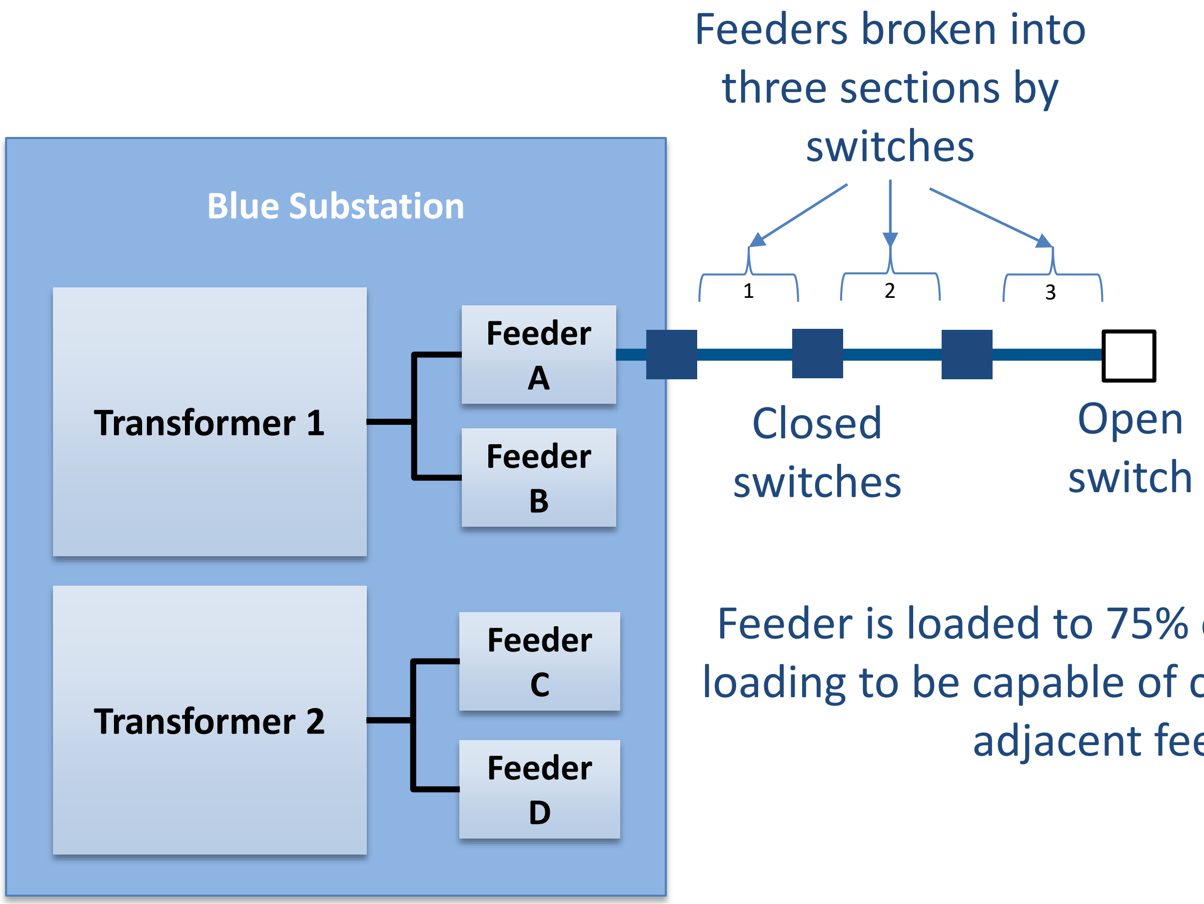
DER is analyzed for system normal configuration

Planning for Capacity

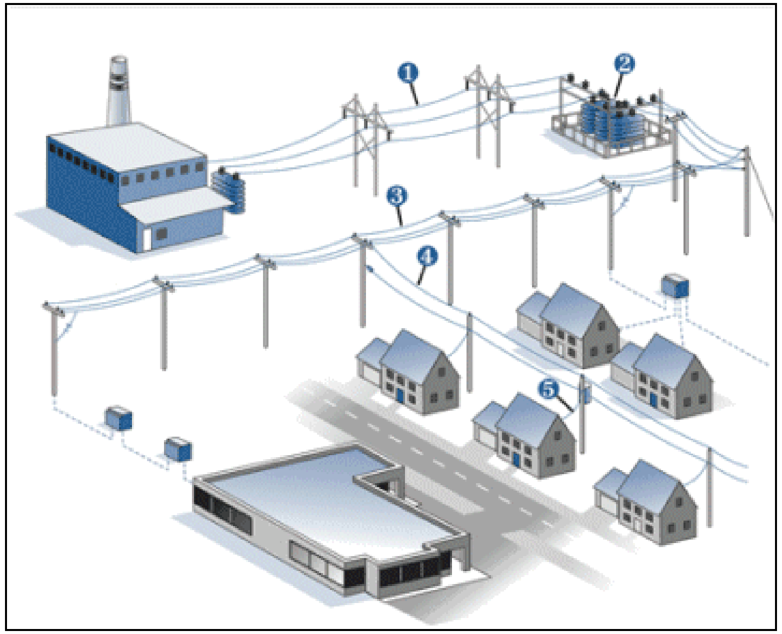
System Flexibility

Safety

Reliability



Each section carries 25% of feeder capacity



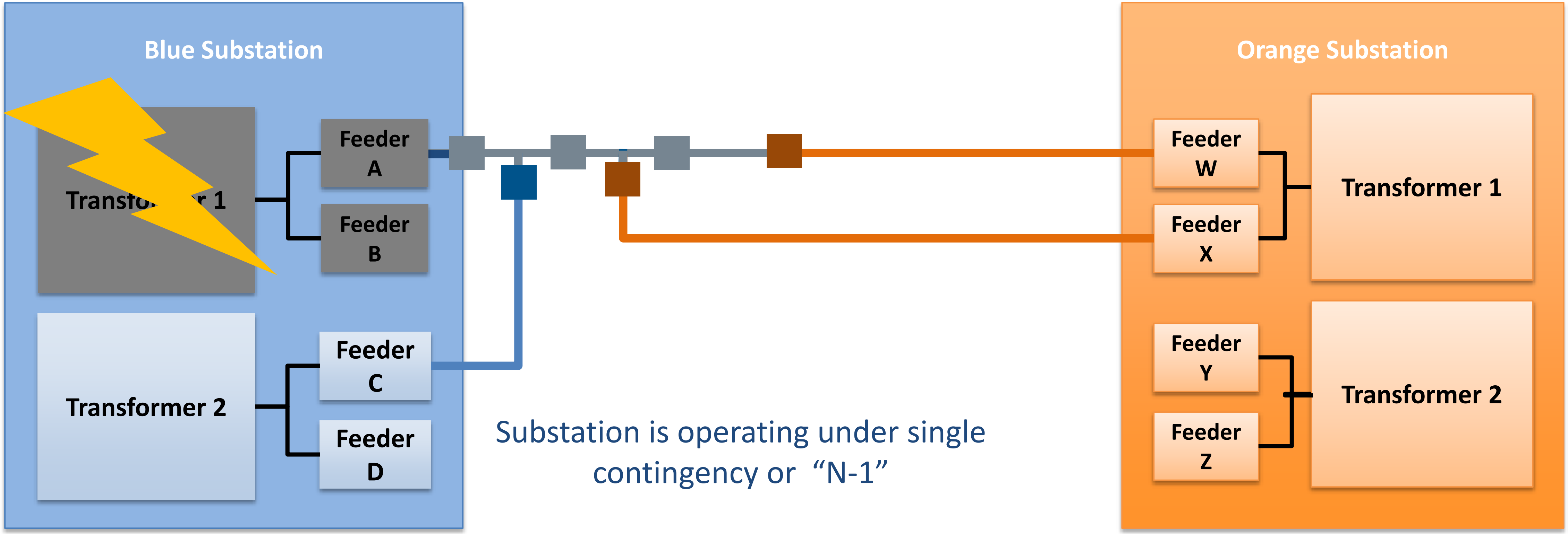
Credit: Ameren
https://www2.ameren.com/common/DistributionSystem.aspx

Feeder is loaded to 75% of capacity at full loading to be capable of carrying section of adjacent feeder

Contingency Capacity Criteria

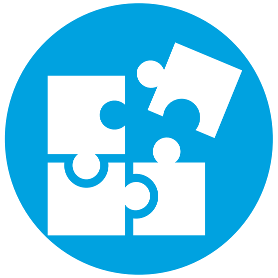
Safety Reliability

Example: Substation Transformer Outage



Substation is operating under single contingency or "N-1"

Distribution Planning Criteria – Capacity Constraints and EVs

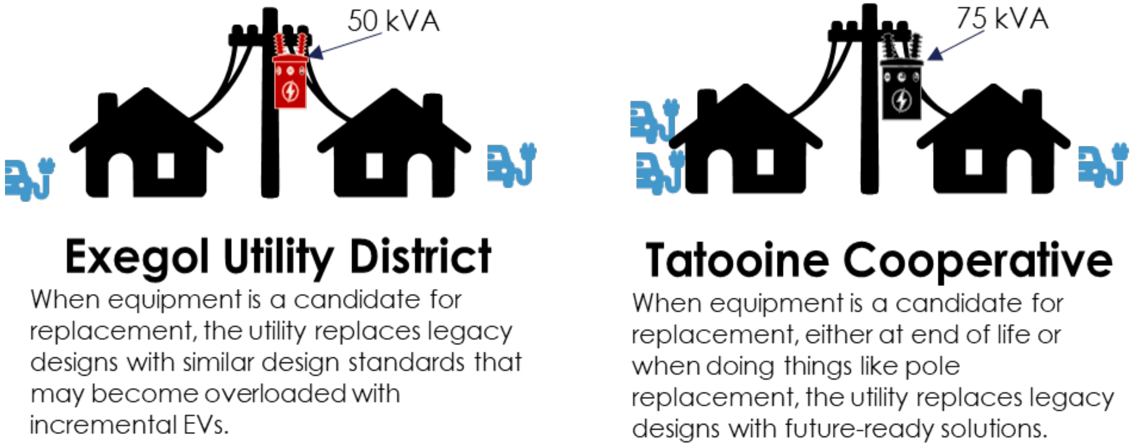


Electric Capacity
- Normal
- Contingency

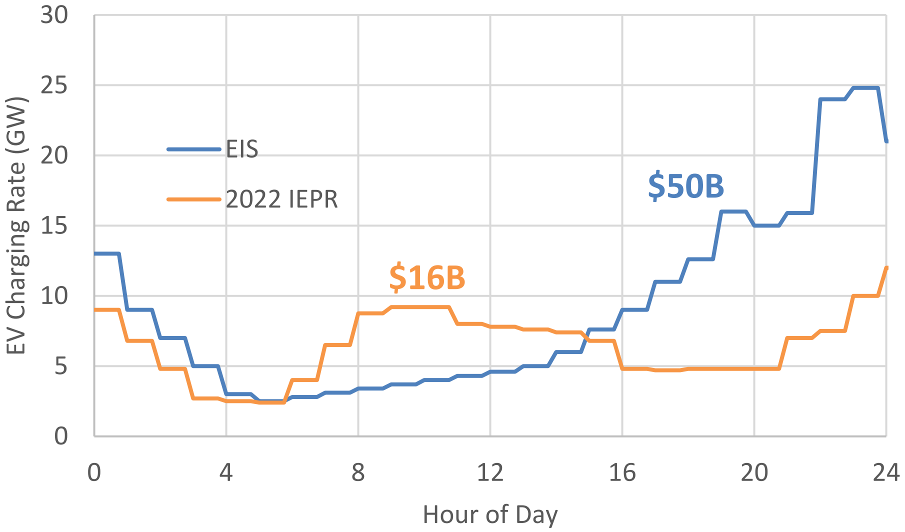
Voltage
Reliability

Source.Energy Systems Integration Group; data courtesy of Kevala, 2023; Public Advocates Office, 2023.

Transformer Replacement



Smart Charging



Differences in charging assumptions can have a large impact on the cost of distribution upgrades. Smart charging can adjust the charging profile.

Distribution Planning Criteria – Voltage Violations and PV

Safety

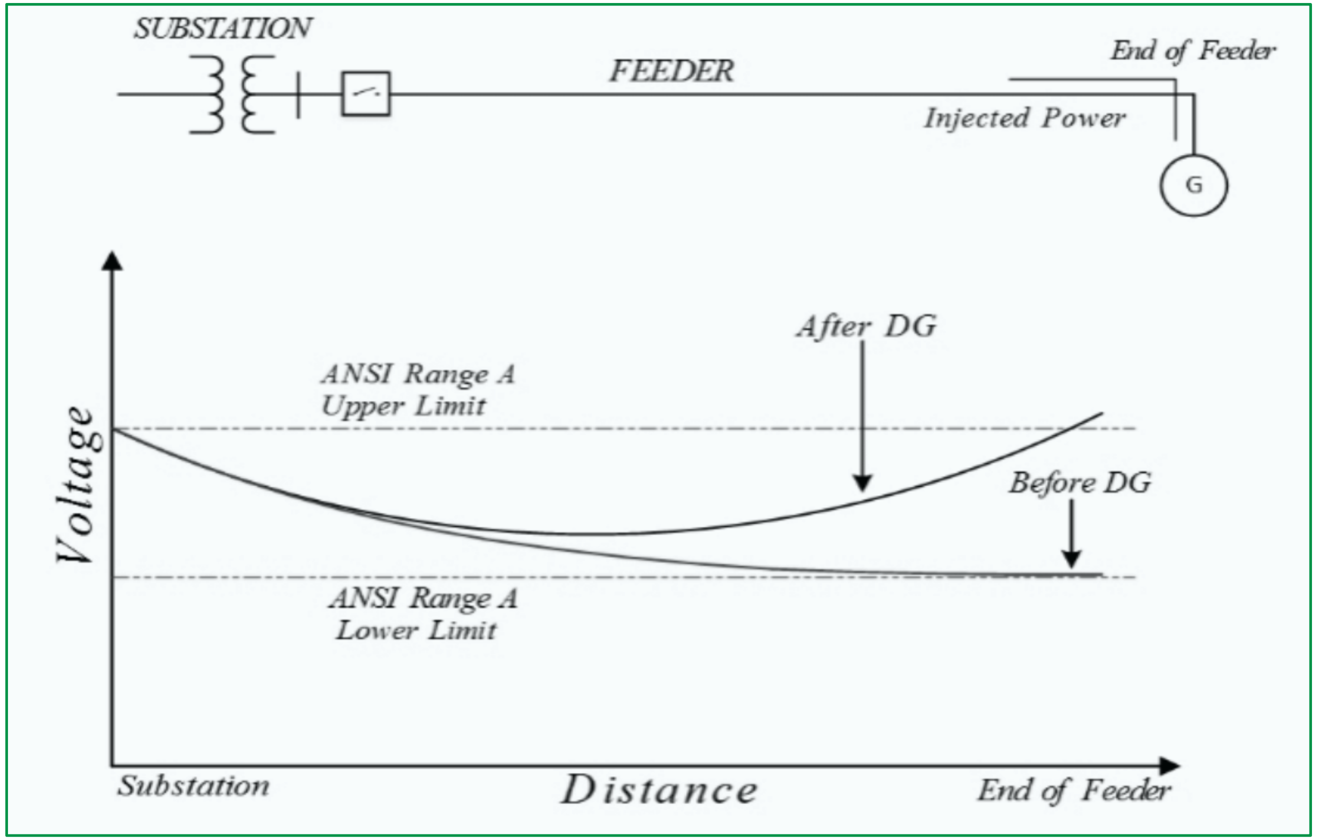
Reliability

Electric Capacity
- Normal
- Contingency

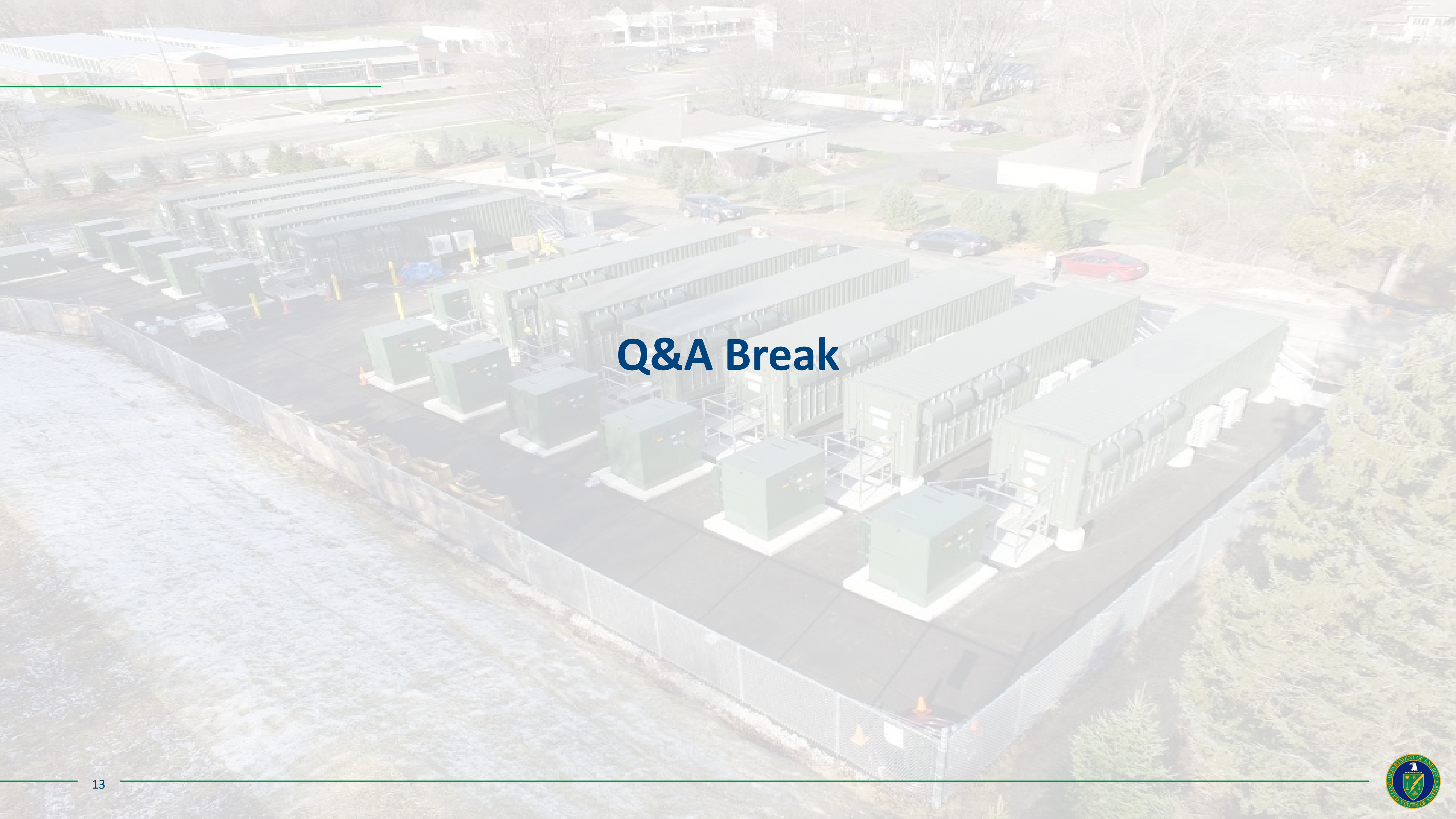
Voltage

Reliability

Illustration of Voltage Criteria



Sahito, Anwar & Memon, Zubair & Buriro, Ghulam & Memon, Sarwan & Jumani, Muhammad. (2016). Voltage Profile Improvement of Radial Feeder through Distributed Generation. SINDH UNIVERSITY RESEARCH JOURNAL (SCIENCE SERIES). 48. 497-500.



Q&A Break

Investment Categorization

Cost

- **Distribution investments are frequently lumped together in grid modernization proceedings, but for cost-effectiveness evaluation and cost allocation it's important to categorize investments according to type and drivers.**
- **In terms of type, a high-level taxonomy of investments might include:**
  - Existing infrastructure replacements and upgrades (e.g., 4 kV to 12 kV upgrades)
  - Line extension and service upgrades (e.g., new service requests, amperage upgrades)
  - Distribution capacity expansion (e.g., substation upgrades)
  - Hardening (e.g., undergrounding, steel/concrete poles, raising equipment)
  - Grid technology (e.g., grid management and monitoring hardware and software)
  - Administrative (e.g., meters and backend software, billing software)

Source: Kahrl (3rd Rail) and de Martini (Newport)

Capacity Planning

Process to plan for adequate system capacity under normal and contingency operations

Asset Health

Programs to plan the replacement of aging assets

Capacity Planning is typically an annual process to address load growth or movement of load around the system

System analyzed for normal and contingency conditions

Solutions identified and proposed to address constraints

Asset health programs contribute to system reliability and the customer experience

Different approaches to asset health

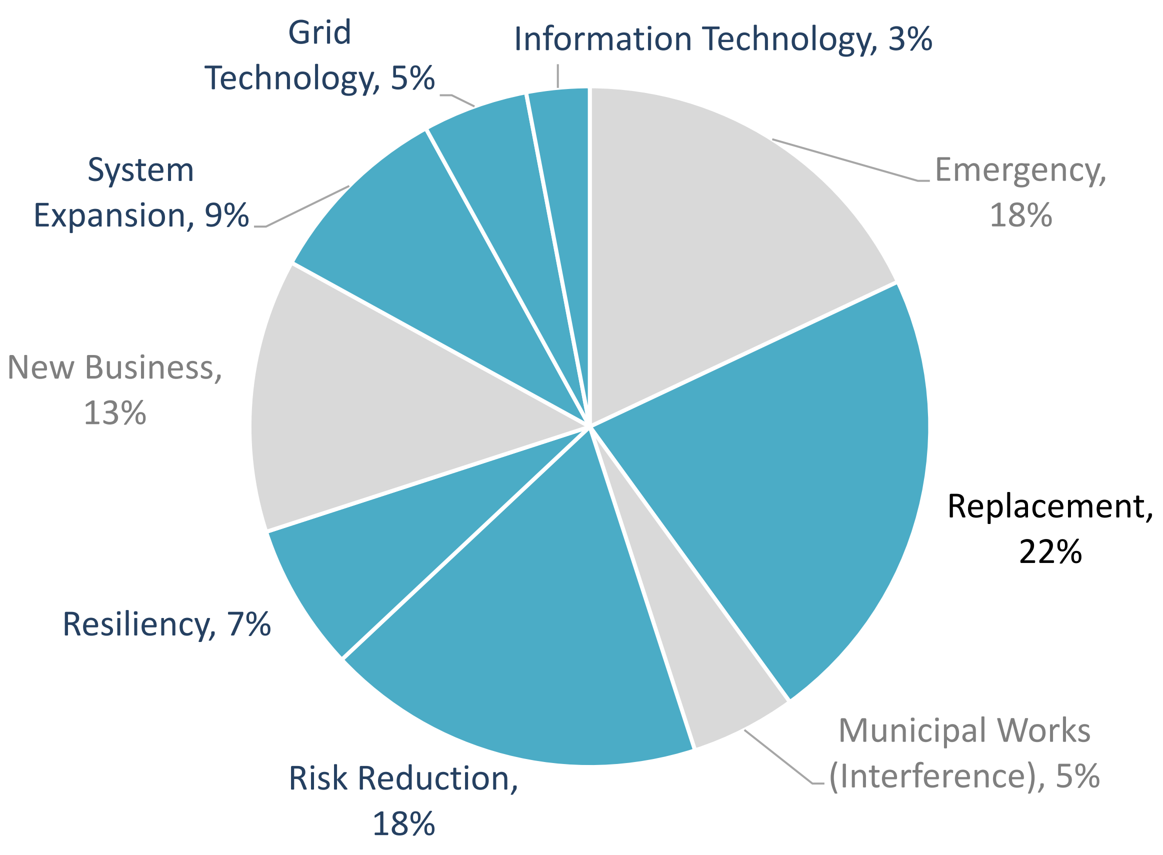
- Corrective Maintenance – replacing failed assets
- Preventative Maintenance – replacing assets prior to failure
- Reliability-Centered Maintenance – replace assets based on historic reliability records
- Condition-Based Predictive Maintenance – proactive and situational based

Utility Budgets: Discretionary vs Non-Discretionary

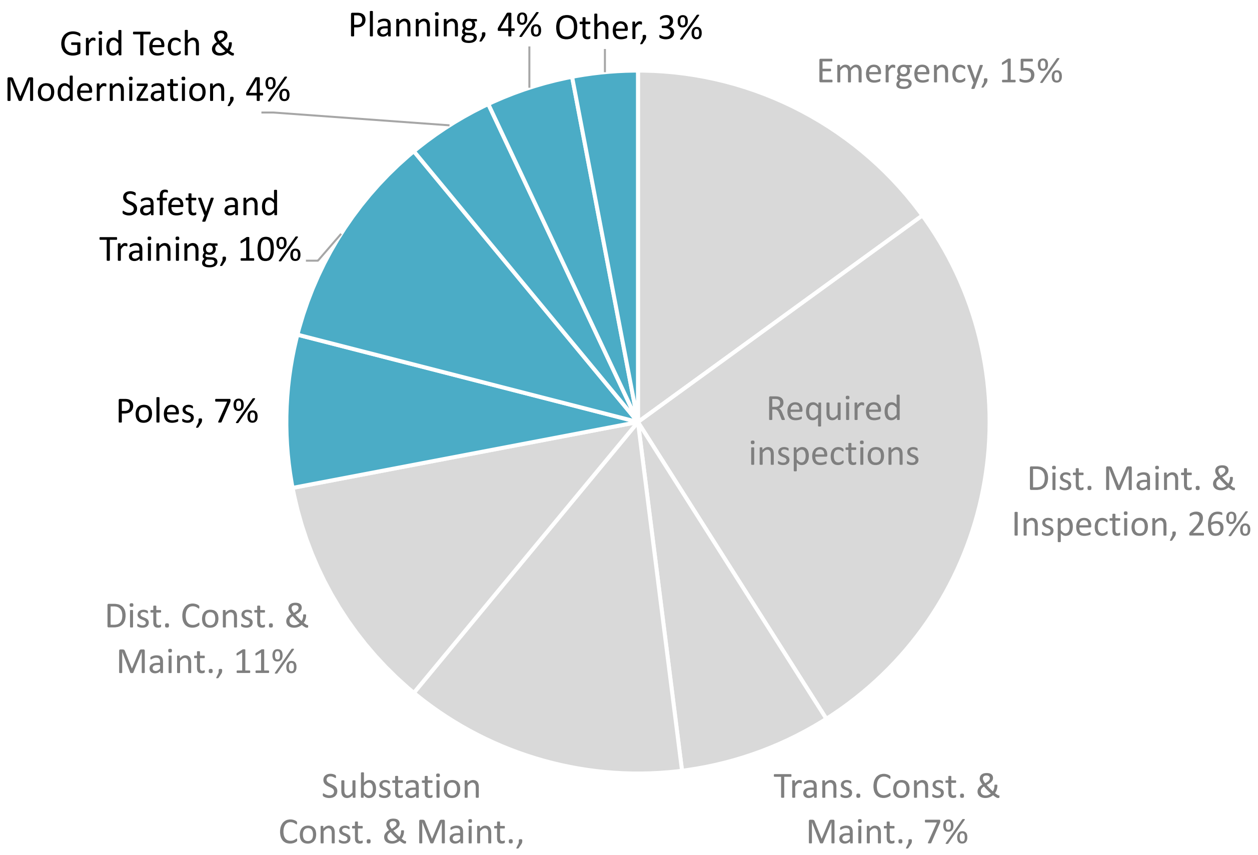
Cost

Utility capital and O&M expenditures can be deferrable or non-deferrable.

Capital



Operations and Maintenance



Development of Multi-Objective Distribution Plans

Integrated distribution planning should address the development of prioritized and optimized multi-year distribution plans.

Determine Grid Need

Assess grid health, resilience risks, customer load and DER growth needs

Identify Potential Solutions

Develop grid & non-wires solutions that address more than one objective

Evaluate C-E of Potential Solutions

Assess cost-effectiveness of grid & non-wires solutions

Develop Multi-year Plan

Prioritize & optimize expenditures with given financial and resource constraints

Planning Objectives

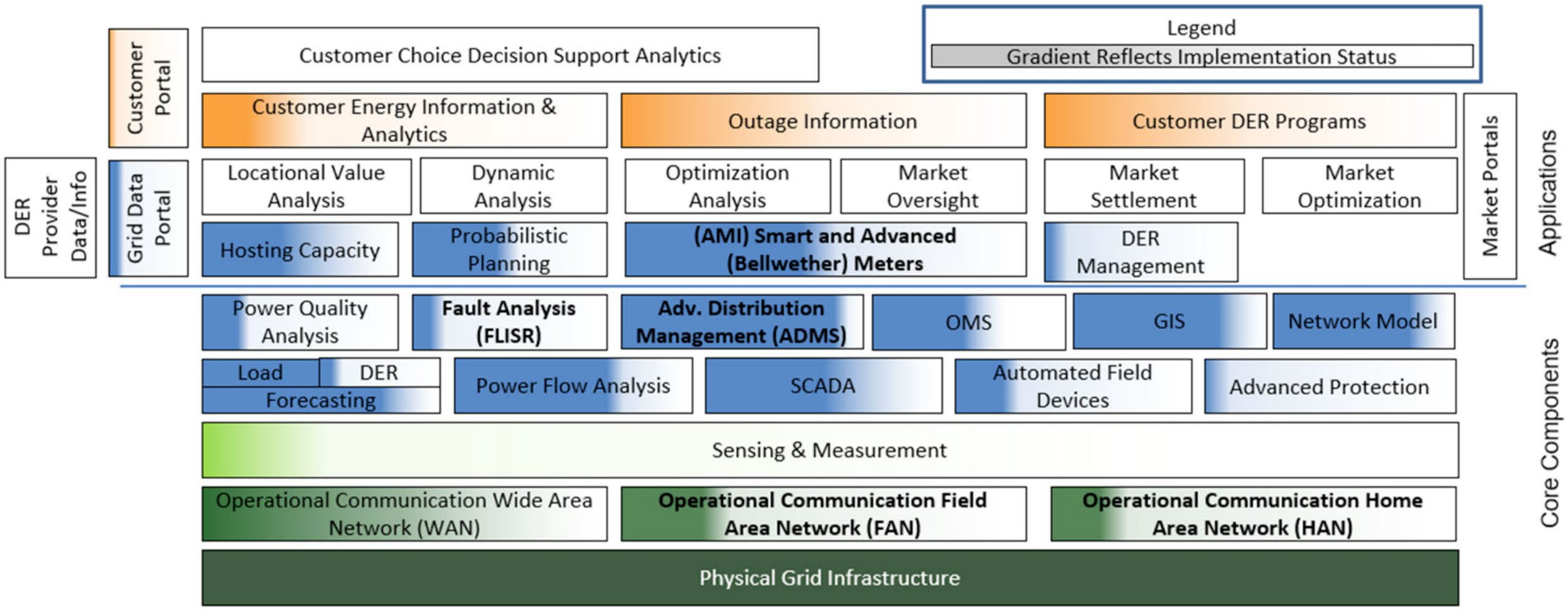
Improve Asset Health & Safety	Improve Reliability	Increase Capacity	Improve Resilience	Promote Equity
Address asset conditions that lead to failure	Reduce frequency & duration of outages	Expand capacity to address load growth & DER adoption	Address climate threat risks to critical grid infrastructure	Ensure benefits of the grid are fairly distributed

Source: Kahrl (3rd Rail) and de Martini (Newport)

State of the Grid and Gap Analysis

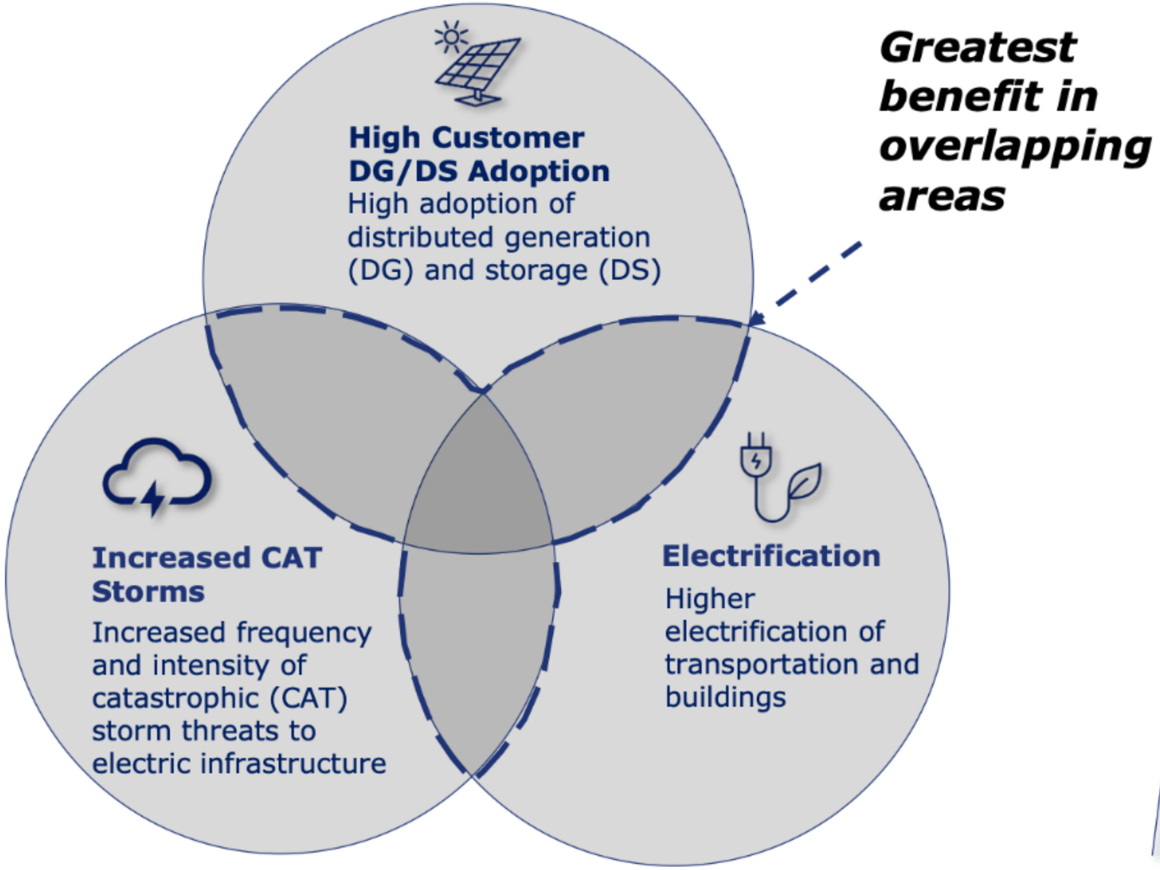
- Determine the status of current tools and capabilities
- Track progress in each area and identify where investment is most needed
- Grid modernization status provides a gap analysis according to functionality and capability
- Next: Prioritize investments delivering joint and interdependent benefits according to objectives

Xcel Grid Modernization Status (2023)



Source: Xcel Integrated Distribution Plan 2023

Scenario Analysis



Three scenarios were developed to analyze the range of potential impacts to the grid if one or multiple scenarios materialize

Scenarios are driven by unique sets of drivers that are expected to impact the grid over the next 15 years and beyond

Each scenario includes three components to determine the potential investments needed for the grid:

1. Plausible forecasts
2. Grid impacts
3. Signposts

While the Company invests in projects and programs that support individual scenarios, the **greatest benefit** is achieved by **identifying investment opportunities across multiple scenarios**

Source: DTE DGP 2023

Prioritizing Utility Investments

Goal: develop a list of **prioritized solutions** given **practical constraints**, such as budget limitations.

Steps:

1. Ranking planning objectives w/stakeholder input
2. Normalizing the value contribution of each solution in relation to one or more objectives
3. Developing a prioritized list

See example: DTE Electric Company's 2021 Distribution Grid Plan, pp. 82-90; https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000Uc0pkAAB.

Illustrative Value-Spend Efficiency Method

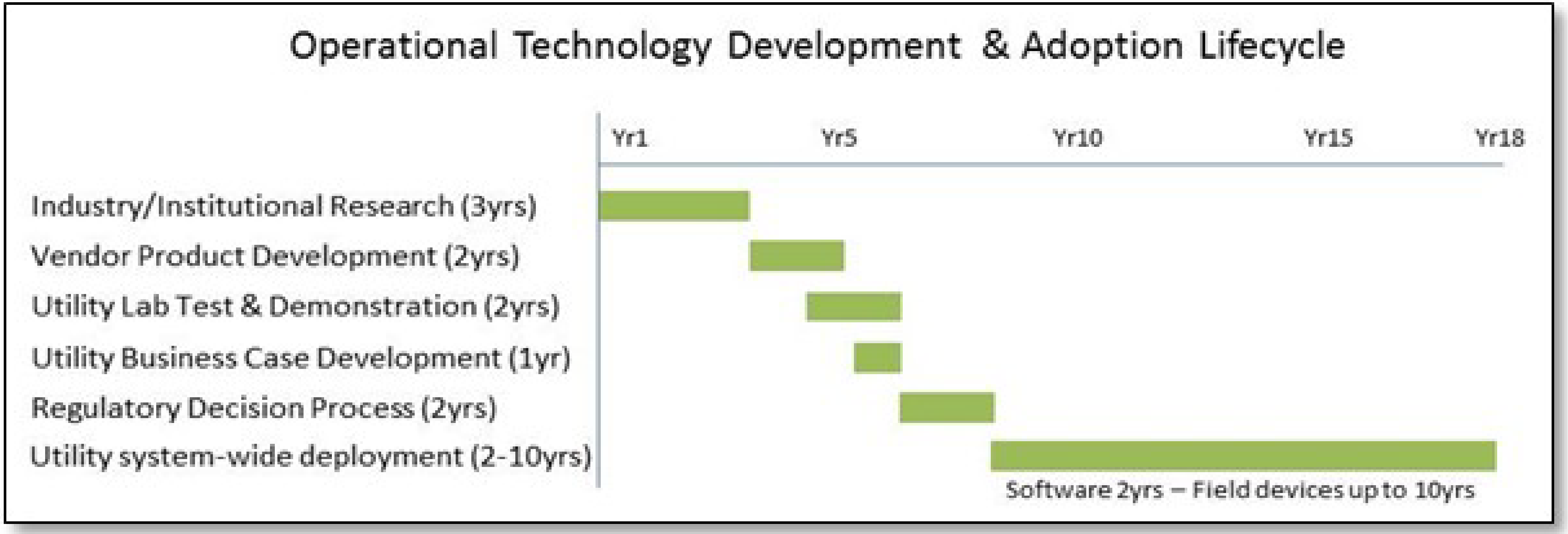
	Planning Objectives Ranked (1-5)									
Specific Projects	Safety (5)	Service Compliance (5)	Reliability (3)	Resilience (4)	Electrification (3)	DG/DS Integration (3)	Equity (4)	Score	Cost ($mm)	Spend Efficiency (S/C)
Tree Trimming[1]	5		3	3				11	$2.5	4.4
Undergrounding[2]	3		3	4	1	1	2	14	$5.0	2.8
Pole/Tower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

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

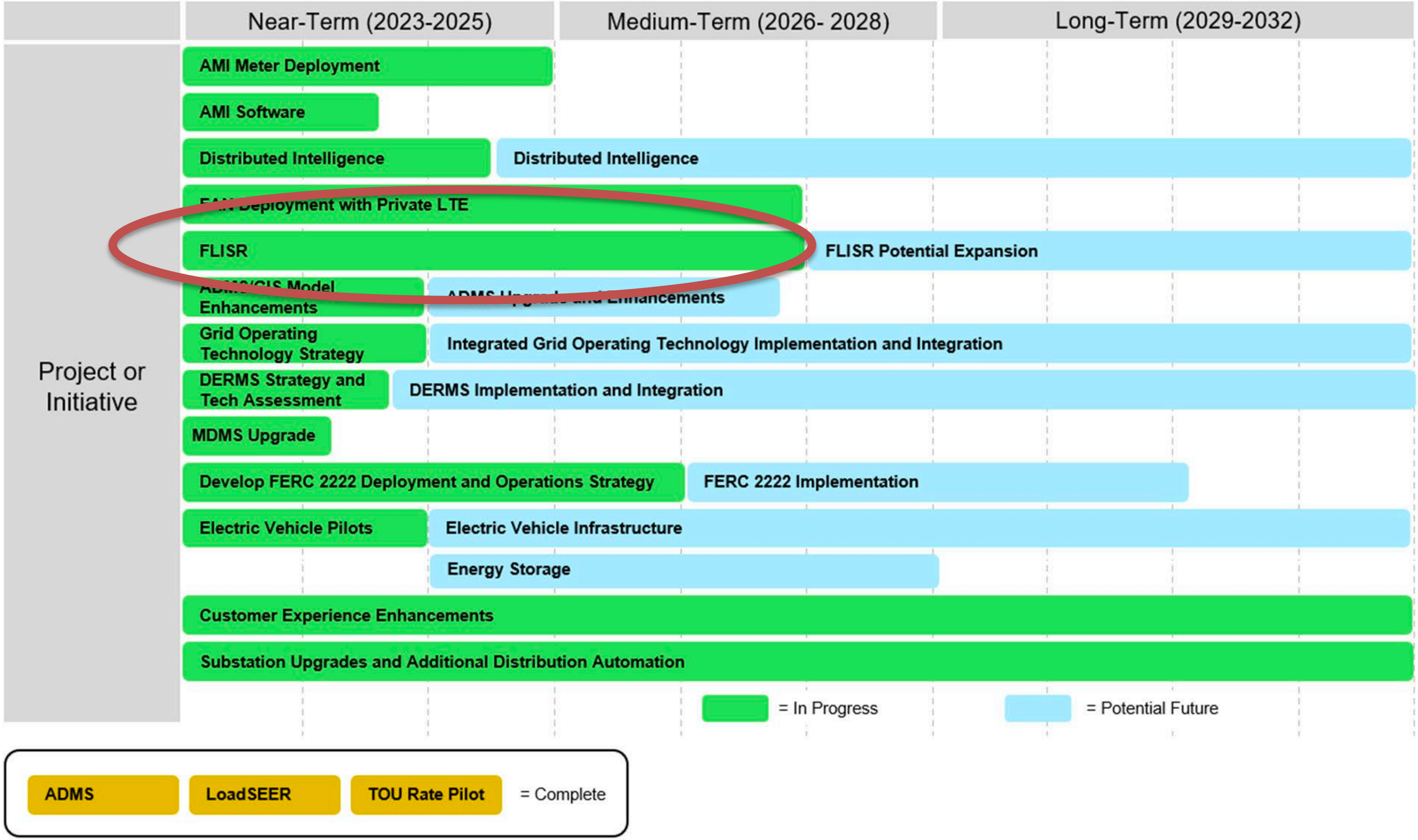
Source: Integrated Resilient Distribution Planning, by P. De Martini, J. Taft, A. De Martini, and M. Hall, PNNL-32883, May 2022. Available at: https://gridarchitecture.pnnl.gov/media/advanced/Integrated_Resilient_Distibution_Planning.pdf.

Technology Adoption Timing Considerations

Required efforts to develop, demonstrate, test, and deploy new technologies are incorporated into an IDSP grid modernization strategy



Example Technology Roadmap



Source: Xcel Energy (2023)

Mapping Technologies to Objectives: **Reliability**

Objective	Capability	Function	Technology
Reliability improvement by reducing customer unplanned outage durations Achieve 2nd quartile CAIDI performance by 2025	Improve outage identification and customer service restoration	Fault Identification Fault Location Fault Isolation Service Restoration	Fault Current Indicators Outage Notification from Meters Outage Management System Geospatial Information System Distribution Management System and/or SCADA Automated Switches Work Management System

Source: *Modern Distribution Grid, Volume I: Customer and State Policy Driven Functionality, DOE, 2017;* Available online at: https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf

Example: Fault Location Isolation and System Restoration (FLISR)

Benefits

- Improve reliability - Two-thirds reduction in the number of customers who experience a sustained outage because of a fault

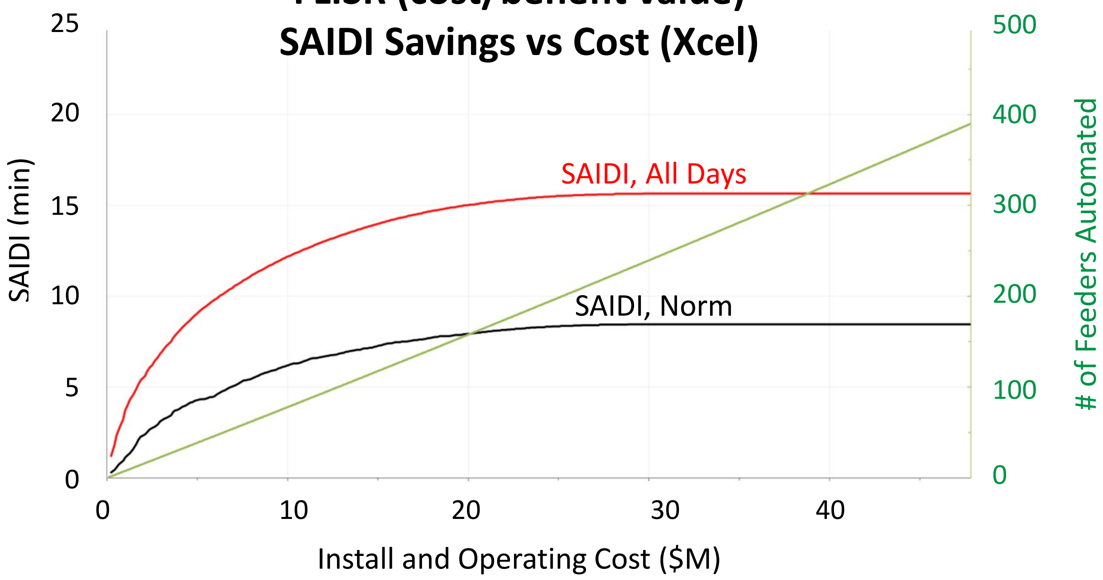
Phased Deployment

- Deployed on ~200 feeders over 5 years, focusing on lower reliability performance and/or circuits with existing field devices
- Phased functionality: Local mode, fault location prediction, open loop, closed loop

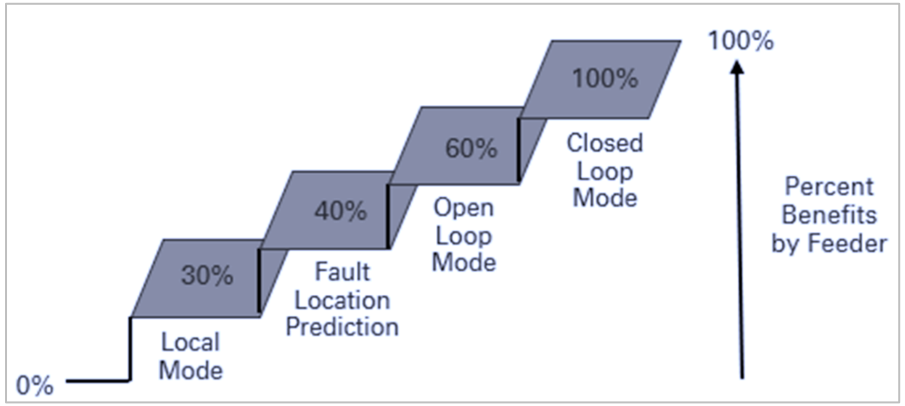
Challenges in quantifying benefits

- Sustained outage indices (SAIDI, SAIFI) might improve while performance of momentary outages (MAIFI) declines
- Customer average interruption duration index (CAIDI) performance might decline as shorter interruptions are mitigated

FLISR (cost/benefit value)
SAIDI Savings vs Cost (Xcel)



Phases of FLISR Functionality and Benefits (Xcel)



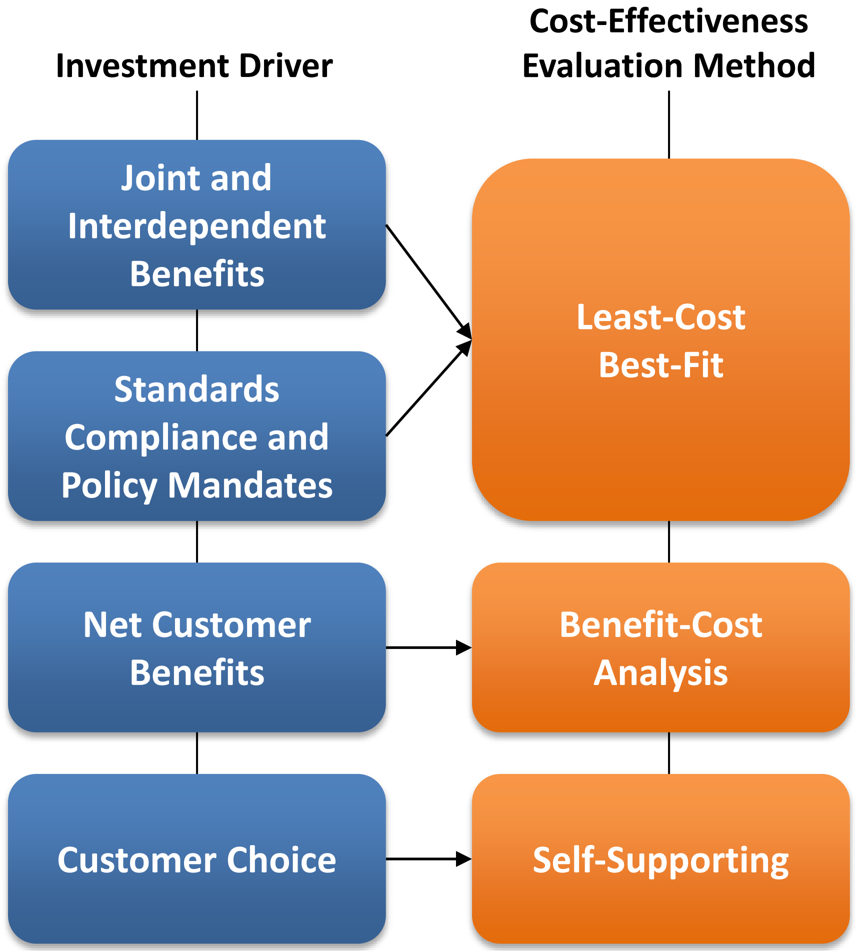
Source: Xcel Energy (2023), Xcel Energy (2023)

Investment Drivers and Cost-Effectiveness Evaluation Methods

Investments can be grouped under four key drivers:

1. **Joint and interdependent benefits** — core platform investments that are needed to enable new capabilities and functions in the distribution grid (e.g., distribution management systems)
2. **Standards compliance and policy mandates** — utility investments that are needed to comply with safety and reliability standards or to meet policy mandates for proactive investments to integrate DER (e.g., replacements and upgrades)
3. **Net customer benefits** — utility investments from which some or all customers receive net benefits in the form of bill savings (e.g., advanced metering infrastructure)
4. **Customer choice** — utility investments triggered by customer interconnection, opt-in utility programs, and customer-driven reliability improvements, paid for by individual customers (e.g., line extensions, hardening)

The investment driver points toward an appropriate cost-effectiveness evaluation method (right side of figure).



Source: Kahrl (3rd Rail) and de Martini (Newport)

Applying Economic Evaluation Methods

Least-cost best-fit (LCFB) and benefit-cost analysis (BCA) are used in different situations and answer different questions.

LCBF – used for most distribution infrastructure investments and platform software investments

- *Given that we want some functionality/capability on the distribution system or that we want to meet some safety, reliability, or regulatory goal, what is the lowest cost way to do so?*

BCA – used for investments in advanced meters (often but not always), non-wires alternatives, utility resource procurement and programs

- *Will an investment enhance welfare (benefits > costs) for all or a subset of customers?*

There may be an overlap between BCA and self-supporting investments, which historically have been addressed through cost-sharing mechanisms (e.g., free footage allowances for line extension).

Source: Kahrl (3rd Rail) and de Martini (Newport)

Example: Applying Cost-Effectiveness Methods

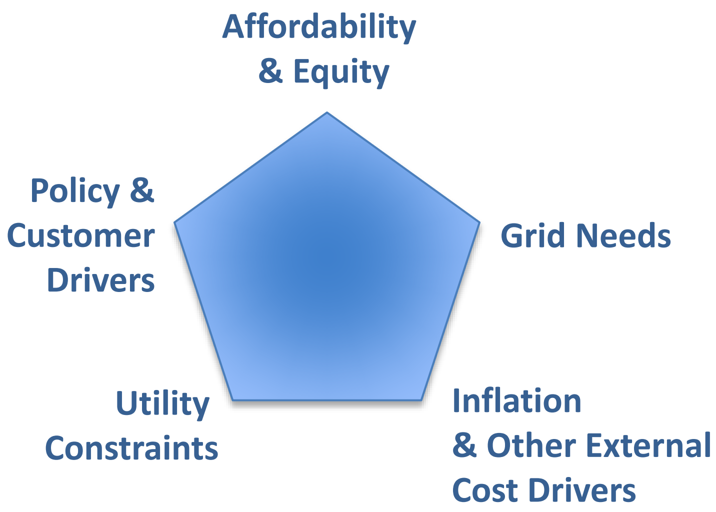
- **A state legislature develops a new statute requiring distribution utilities to meet minimum performance standards (e.g., outage frequency and duration, service restoration times) during extreme weather events.**
- **The PUC orders regulated utilities to review performance standards and approaches and propose spending to meet these standards. The order also requires utilities to integrate microgrids that several communities have proposed.**
- **Evaluation and cost allocation**
  - **LCBF**: The law deems major hardening investments (e.g., raising substations in flood zones) to be in the public interest and that taxpayers will pay for them, up to a specified dollar cap.
  - **LCBF**: Investments that exceed the cap and more minor investments that are needed to meet the standard are financed by the utility, included in the utility's rate base, and paid by the utility's customers, if the Commission determines the costs are prudently incurred.
  - **BCA**: Net of wholesale benefits, the utility finds that microgrids are not a least-cost approach to meeting the performance standard.
  - **Self-supporting**: The utilities file a tariff for microgrid exports based on avoided costs. The PUC approves the tariff. Microgrid customers pay for net microgrid costs (incremental costs minus tariff revenues) and the higher reliability that it provides.

Source: Kahrl (3rd Rail) and de Martini (Newport)

Distribution Expenditure Evaluation Challenge

Evaluate utility distribution expenditure plans within a holistic frame

- **Transformation of energy use from fossil fuel to clean electricity will place considerable demands on the electric grid.**
- **Distribution systems will require expenditures, both capital investments and operational expenses (e.g., software as a service and non-wires alternatives), to enable policies and meet customer needs.**
- **Nearly all grid expenditures result in incremental costs* and related rate impacts, as most are not offset by utility operational savings.**
- **External factors such as inflationary effects on equipment and labor costs create an additional challenge.**
- **This requires navigating several interrelated factors (see figure) that will ultimately shape a financially reasonable trajectory to address desired outcomes.**



* While non-wires alternatives may avoid capital costs, they typically require utility payments to DER aggregators or directly to participating customers. These payments are usually treated as operating expenses. Both traditional and non-wires solutions are incremental costs that impact retail rates, although capital investments impact rates differently than operating expenses.

Source: Kahrl (3rd Rail) and de Martini (Newport)

Project vs. Portfolio Cost-Effectiveness

Project cost-effectiveness is the first step to evaluate an overall distribution plan.

However evaluation of individual grid modernization projects is insufficient to determine whether an overall distribution expenditure plan is reasonable.

It is also necessary to consider whether the proposed portfolio of expenditures:

- Clearly addresses more than one identified statutory or regulatory objective
- Represents an integrated set of projects that are complementary
- Represents a set of projects that are part of a series of expenditures to address identified statutory or regulatory objectives
- Represents a prioritized set of expenditures given the urgency of grid needs that address identified statutory or regulatory objectives and utility financial and resource constraints
- Represents an optimized set of expenditures respecting customer affordability and equity considerations

Distribution expenditure plans require a multi-objective decision-making framework to evaluate these considerations.

The objective is to achieve the highest value per dollar expended – "value-spend efficiency"

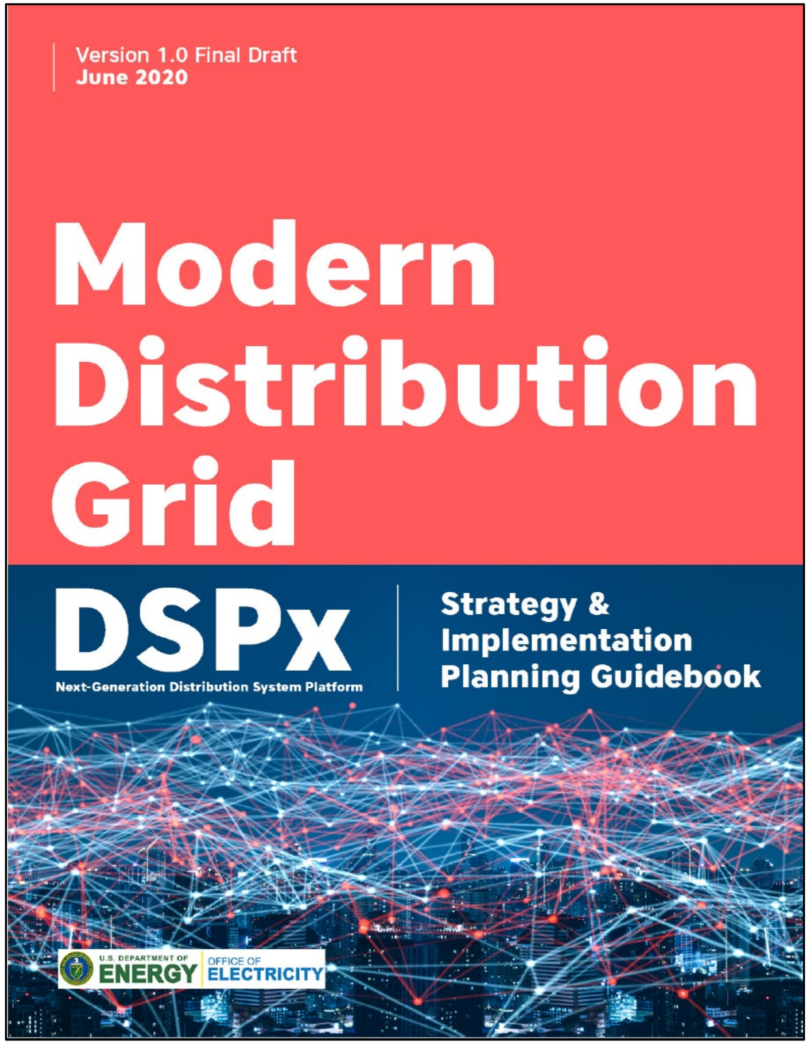
Source: Kahrl (3rd Rail) and de Martini (Newport)

DOE's Modern Distribution Grid Guidebook

Volume IV of the guide includes an economic evaluation framework for grid modernization investments.

- Aims to inform approaches to evaluating economics and managing costs and risks of grid modernization investments

No textbook approach — multiple reasonable paths to achieving the same broad goals



U.S. Department of Energy. *Modern Distribution Grid Volume IV: Guidebook*

Actions State Agencies Can Take

State agencies can help ensure planned utility investments meet state objectives and priorities. For example:

State regulators can provide guidance to utilities on:

- Translating state goals to standards for evaluating grid needs and investments
- Mapping investment priorities to state objectives and requirements
- Prioritizing investments that deliver multiple benefits according to objectives
- Quantifying benefits from grid modernization investments
- Expectations for cost-effectiveness evaluation — cost-benefit analysis vs. least-cost, best-fit approaches
- Considerations for proposed cost allocation

State Energy Offices* can:

- Develop state plans and conduct analysis to inform grid needs analysis and investment prioritization
- Facilitate or participate in stakeholder processes to discuss proposed investments
- Participate in regulatory proceedings, including contributing to frameworks that govern DSP

Utility consumer advocates can:

- Participate in stakeholder meetings convened by utilities, commissions, or State Energy Offices to review grid needs and investment options
- Review analysis of customer impacts, including costs and benefits, for rigor and comprehensiveness

*State Energy Offices' Engagement in Electric Distribution Planning to Meet State Policy Goals

Questions to Ask

Have clear objectives been established in policy or regulation, or proposed by the utility?

What are the appropriate planning objectives and criteria for your state's distribution systems?

What is the utility's grid modernization strategy and roadmap, and how will they meet state objectives?

What is the appropriate investment prioritization model recognizing multiple objectives and multiple benefits?

What level of oversight and transparency is required to facilitate stakeholder buy-in and ensure objectives are achieved?

How does the plan address uncertainty in the pace and scope of change — e.g., in technologies and policies — over the planning period, and how do the grid mod strategy and roadmap address the needs?

Contact

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Recovering and Allocating Costs

Training for States on Distribution System and Distributed Energy Resources Planning

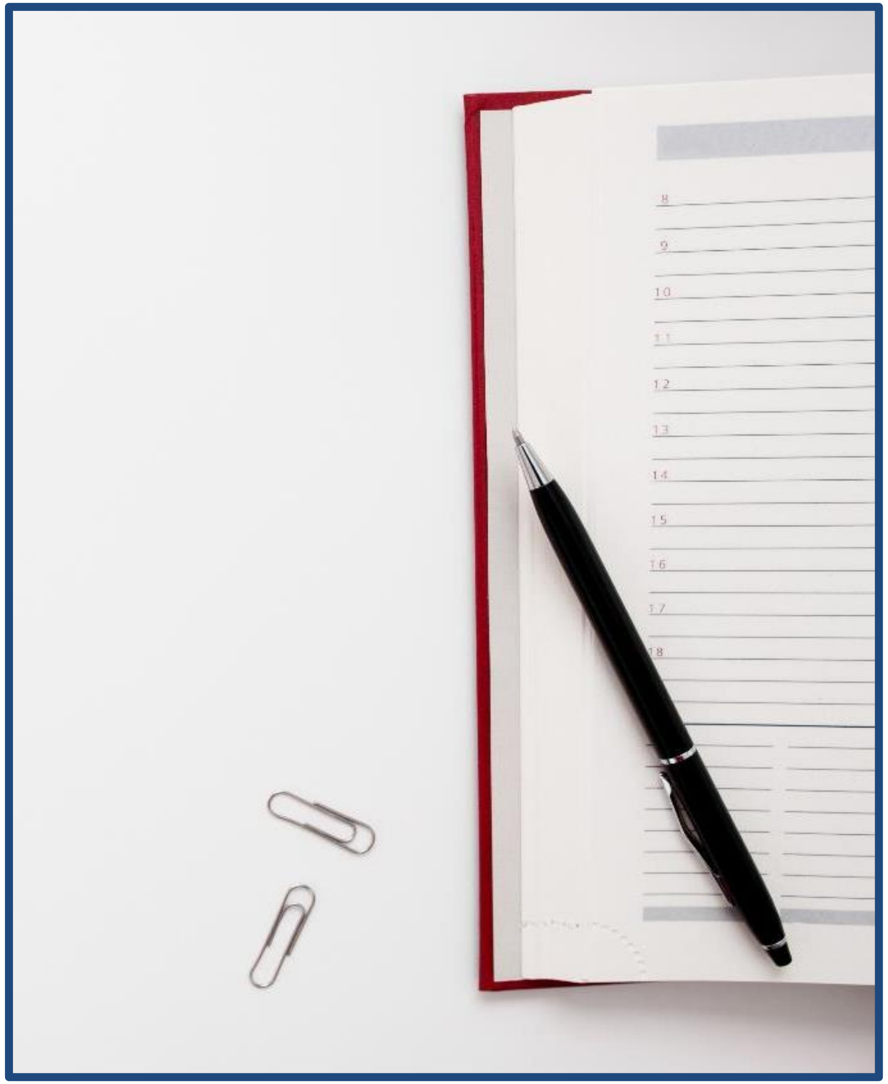
Presented by Ronny Sandoval, Regulatory Assistance Project

January 24, 2024

Western Regional Training

Agenda

- Introduction and level-setting
- Regulatory challenges
- Proactive distribution upgrades for distributed energy resources and electrification
- Treatment of projects that receive federal funding
- Ratepayer vs. taxpayer funding
- Resilience investments



“Allocation of costs is not a matter for the slide rule.

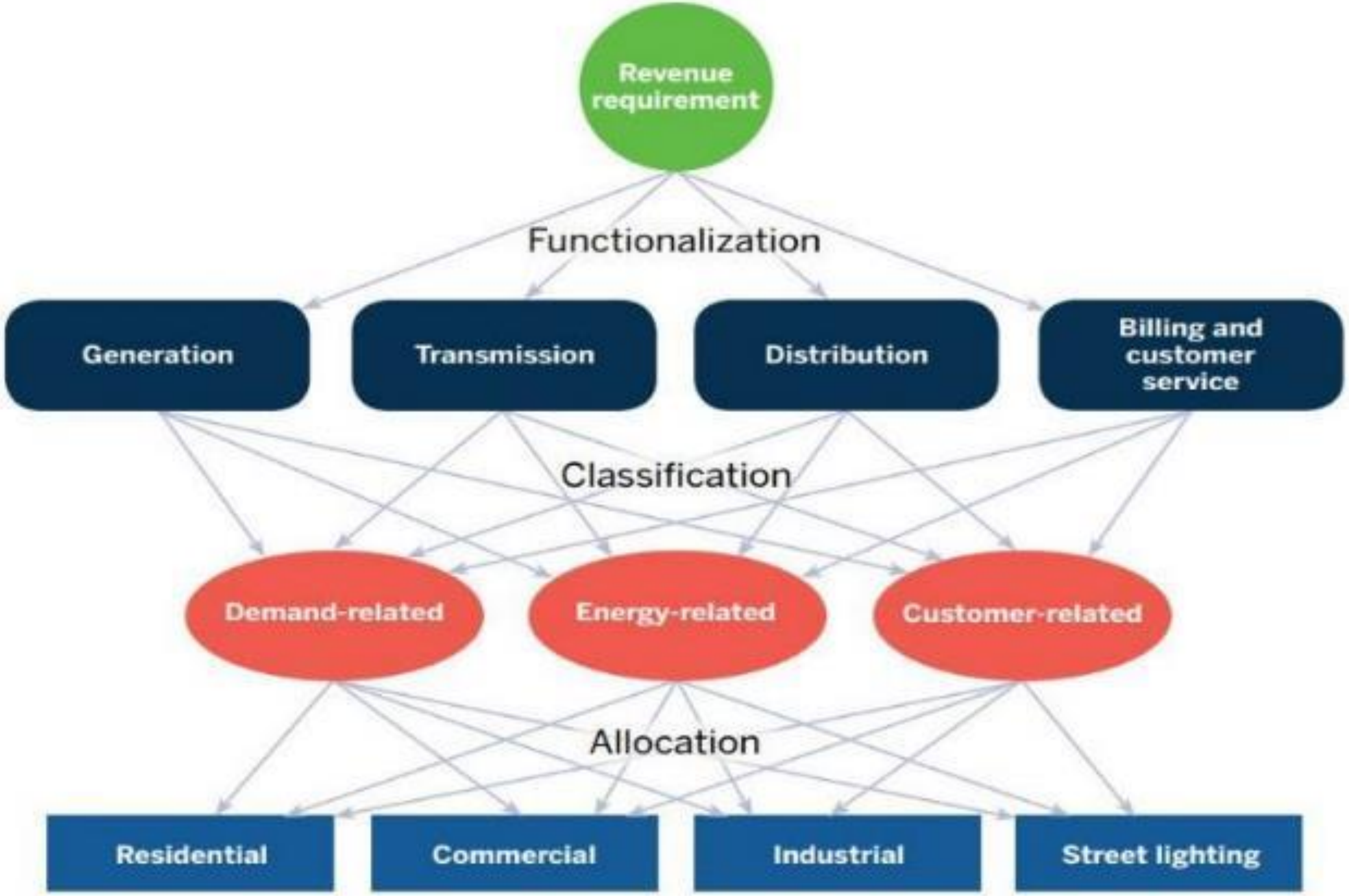
It involves judgment of a myriad of facts. It has no claim to an exact science.”

Justice William O. Douglas, U.S. Supreme Court
Colorado Interstate Gas Co. v. Federal Power Commission,
324 US 581, 589 (1945)

Elements of the Ratemaking Process

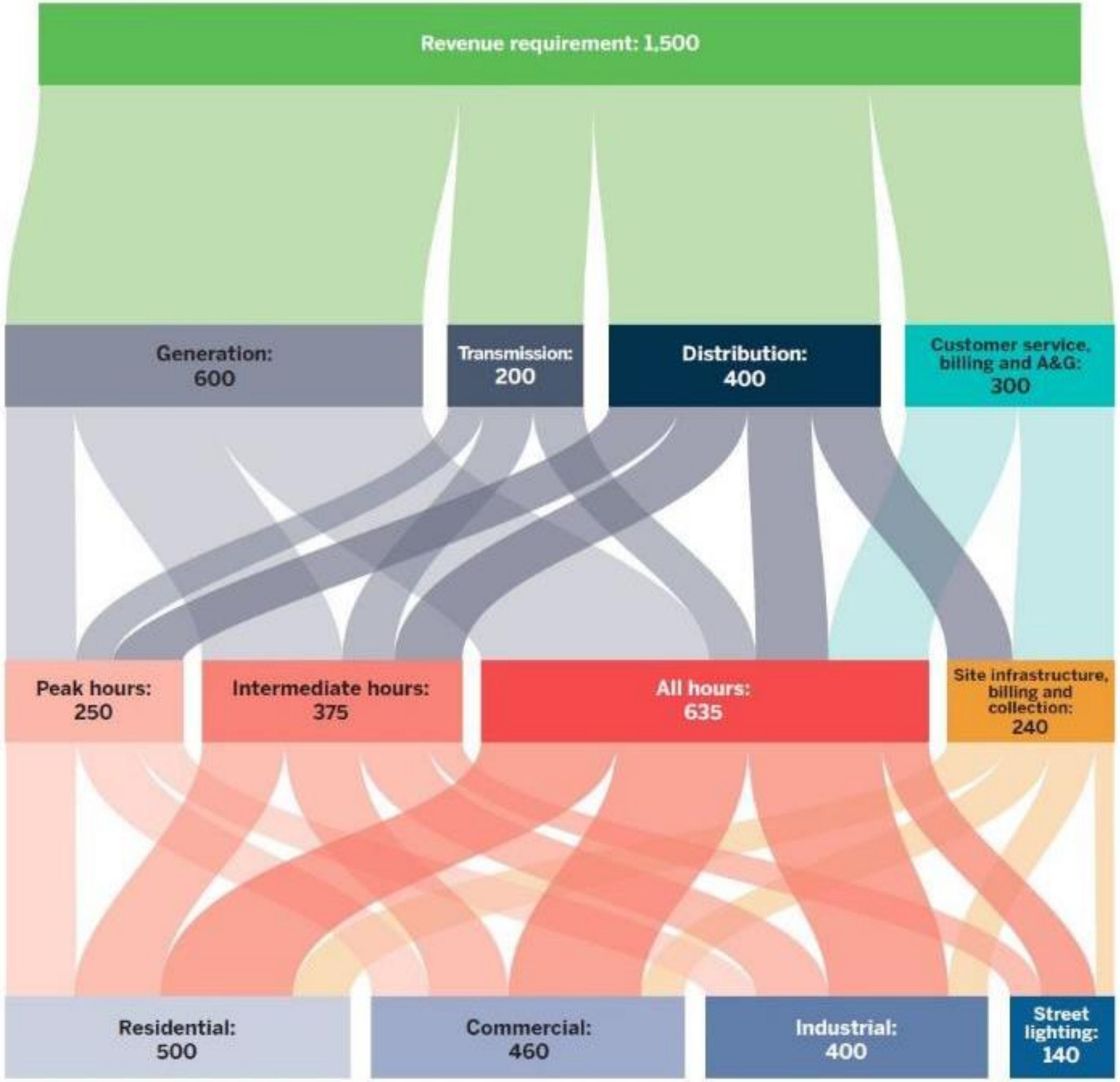
- **Revenue requirement for utility expenditures in providing electric service**
  - (Capital, O&M, Utility Rate of Return, other expenditures)
- **Functional cost categories**
  - (Generation, transmission, distribution, customer service)
- **Classification of costs**
  - (Customer-related vs. energy-related vs. demand-related)
- **Allocation of costs across customer classes**
  - (Residential, commercial, industrial, street-lighting)

Embedded Cost of Service Allocation



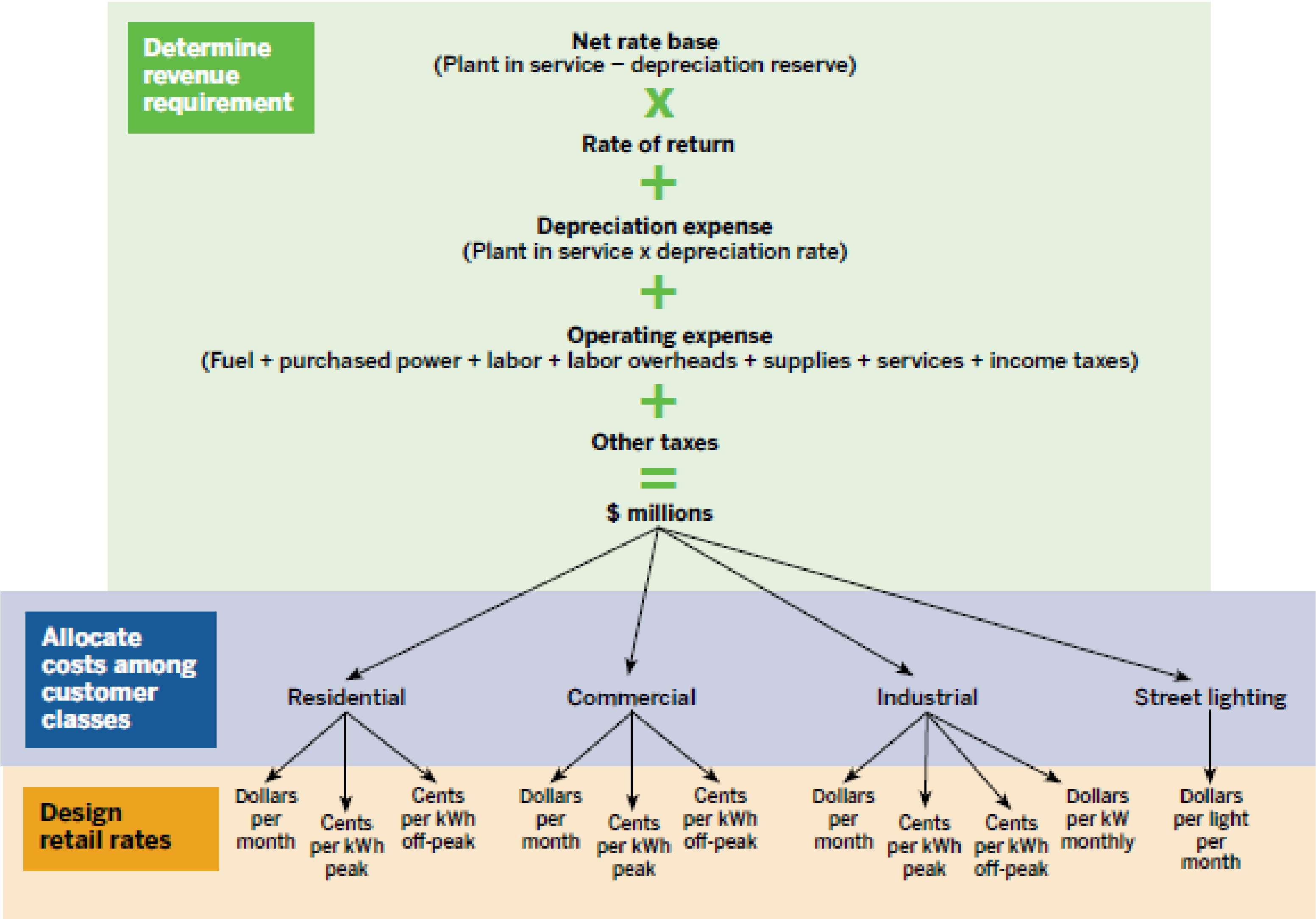
Source: Regulatory Assistance Project |2020 | Electric Cost Allocation for a New Era: A Manual

Diagram for Modern Embedded Cost of Service Study



Source: Regulatory Assistance Project |2020 | Electric Cost Allocation for a New Era: A Manual

Simplified Ratemaking Process



Source: Regulatory Assistance Project |2020 | Electric Cost Allocation for a New Era: A Manual

Regulatory Challenges Associated with Traditional Investments

- **The cost recovery and allocation process involves more than a just an economic exercise**
- **Advancing priorities such as customer affordability and attracting businesses to a desired location requires intentionality**
- **There are trade-offs involved in every aspect of rate design**
  - Simple rate options can be easy to understand, but don’t provide incentives to adjust consumption in a way that makes the best use of customer and system resources
  - Complex rate options (with little use of technologies that automate customer response) can result in customer confusion and limited opportunities to drive intended shifts in behavior
  - Opt-in rates provide customers options for intentional participation in time-variant rates, but may primarily benefit only natural “winners”
- **At some point in the process, a decision must be made on who covers what portions of the costs across the energy system and what rate structures (demand charges, volumetric rates, etc.) will be used to recover these costs**
- **Cost allocation continues to be the foundation of equitable rate design, with additional policy priorities overlayed**
  - Additional priorities, such as support for income-qualified customers, create shifts in this allocation
- **Emerging priorities such as support for electrification and local resilience can create added complexity, as these involve new cost causers and introduce different demand interactions with existing system load shapes**
- **Projects that serve multiple service territories require additional care to ensure customer fairness**

Regulatory Challenges Associated with Distributed Energy Resources

- Customer adoption of distributed energy resources (DERs) that significantly impact distribution system energy flows and congestion can create large costs for the broad customer base
- Distribution system investments may be deployed with demand flexibility tools (such as time of use rates) to relieve local congestion and meet changing energy demand needs
- However, these investments and programs responsive to local demand needs can take some time to deploy at scale
- Unanticipated demand impacts associated with electrification of customer end-use equipment and variable DERs may make it challenging to ensure these demand relief solutions are deployed in time
- Proactive distribution system investments may be made in anticipation of DER and load growth impacts to ensure these assets are in place when needed, however attempting to allocate these costs across customer classes raises questions on the:
  - Adequacy of forecasts to accurately reflect DER growth levels and their location
  - Fairness of allocation decision (Customer cost vs. System Cost)
  - Prudency of proactive investment if the need does not ultimately materialize
  - Contribution from other funding sources, including taxpayer funds

Proactive distribution upgrades for DERs and electrification

Maintain Reliability

Upgrades required to maintain reliability as energy demand and supply becomes more dynamic and distributed

- System monitoring - Advanced Distribution Management Systems, line sensors, Advanced Metering Infrastructure (including communications network)
- System modeling - Using field data obtained from monitoring sources
- Controls – Automatic Circuit Reclosers, voltage optimization equipment, Distributed Energy Resource Management Systems

Optimize Supply and Demand

Upgrades required to optimize the supply and demand profiles of DERs, allowing more value-based customer transactions with the grid

- Utility programs and incentives to shift customer consumption and generation during system constraints
- Market programs to manage market prices, manage demand, and provide ancillary services
- Revenue grade metering for transactions that require it
- Additional customer equipment to maximize participation

Support DER Flexibility and Growth

Upgrades required to accommodate additional DERs and provide flexibility for customers to adopt locally-sited energy solutions

- Hosting capacity analyses
- Energy storage deployments
- Advanced load forecasting capabilities
- Demand flexibility – price signals (including time variant rates and incentives), demand response, load shaping

Who Pays for these Investments?

- **Private investment at customer sites**
- **Tax credits and government incentives**
- **Ratepayers in a manner set by utility regulators**

Treatment of projects that receive federal funding

- Identification of funding opportunities that advance customer and local priorities
- Assessment of funding requirements and performance obligations
- Ensuring proposed responses to federal funding opportunities reflect projects that can demonstrate prudency and are in the best interests of ratepayers
- Securing support for use of ratepayer funds to meet cost-sharing obligations
- Managing implementation risk – meeting obligations for grant agreements and customer cost recovery

Select ARRA Project Awards Addressing Resilience

Resilience Dimension	Selectee	State(s)	Project Description	Federal Cost Share	Recipient Cost Share
Adaptive Control Technologies	NSTAR Electric Company	MA	Expand the system's distribution automation capabilities by implementing "self-healing" functions on the grid that will reduce the impact of outages on the system and the power quality and efficiency of the distribution grid.	$10,061,883	$10,061,883
	Hawaiian Electric Co. Inc	HI	Automate high load distribution circuits feeding eastern Oahu, reducing outage duration and community impacts.	$5,347,598	$5,347,598
	Oklahoma Gas and Electric Company	OK, AR	Deploy a smart grid network and implement advanced distribution automation technologies that will facilitate "self-healing" and power restoring properties on the grid.	$130,000,000	$163,201,332
Monitoring and Control / Adaptive Control Technologies	CenterPoint Energy	TX	Strengthen the reliability and self-healing properties of the grid by installing more than 550 sensors and automated switches that will help protect against system disturbances like natural disasters.	$200,000,000	$439,187,435
	Florida Power & Light Company	FL	By incorporating intelligence into the transmission, distribution and customer systems, the utility will be able to anticipate and respond to grid disturbances, empower customers through alternative rate programs, and enable the integration of renewable and on-site energy sources	$200,000,000	$378,963,325
Monitoring and Control	Navajo Tribal Utility Association	AZ, NM, UT	Integrate the smart grid system as part of the distribution network, which will help quickly identify any system outages.	$4,991,750	$5,620,099
	Sioux Valley Energy	SD, MN	Install a smart grid network across the full customer base that will allow for automated electricity readings and additional monitoring of the system in case of outages or disruptions.	$4,016,368	$4,016,368
	Woodruff Electric	AR	Install smart meters that will provide time-of-use data, help monitor demand and reduce outages.	$2,357,520	$2,658,480
	Avista Utilities	WA, ID	Implement a distribution management system, intelligent end devices, and a communication network to reduce distribution system loses, enable automatic restoration to customers during outages, and allow for the integration of on-site generating resources.	$20,000,000	$20,048,996
	Idaho Power Company	ID, OR	Modernize the electric transmission and distribution infrastructure, implementing an outage management system and irrigation load control program that will reduce peak and overall energy use and improve system reliability.	$47,000,000	$47,000,000
	City of Auburn, IN	IN	Integrate and modernize multiple components within the electrical system, including installing a smart meter network, enhancing reliable and fast communication capabilities, upgrading cyber security technologies, expanding grid monitoring and improving responses to power outages.	$2,075,080	$2,075,080

***Source:** Adapted from Recovery Act: Smart Grid Investment Grant (SGIG) Program Projects | U.S. Department of Energy – Office of Electricity| Accessed November 21, 2023 | https://www.energy.gov/oe/recovery-act-smart-grid-investment-grant-sgig-program

Summary of 2023 Grid Resilience Project Awards

Resilience Dimension	Selectee	State(s)	Project Name	Federal Cost Share	Recipient Cost Share
Microgrids	Kit Carson Electric Cooperative	NM	Building a Modern, Intelligent Distributed BESS for Resiliency in Northern New Mexico	$15,430,118	$7,715,580
	Jamestown Board of Public Utilities	NY	Jamestown Board of Public Utilities Microgrid	$17,377,945	$5,792,648
System Hardening / Microgrids	PECO Energy Company (PECO)	PA	Creating a Resilient, Equitable, and Accessible Transformation in Energy for Greater Philadelphia (CREATE)	$100,000,000	$156,761,176
	Entergy New Orleans, LLC (ENO)	LA	Line Hardening and Battery Microgrid in New Orleans, LA	$54,828,178	$54,828,178
	Electric Power Board of Chattanooga	TN	EPB Chattanooga Grid Resiliency Upgrades: Network Conversions & Microgrids	$32,375,691	$32,375,691
System Hardening	Sumpter Electric Cooperative	FL	Improving Reliability through Grid Hardening in Florida	$52,857,560	$17,619,190
	Southern Maryland Electric Cooperative		SMECO Transmission, Distribution, and Communications Resiliency Initiative	$33,567,016	$15,642,000
	Fort Pierce Utilities Authority	FL	Mitigating Impacts of Extreme Weather and Natural Disasters Through Increased Grid Resiliency	$5,828,993	$2,907,882
	Consumers Energy	MI	Sectionalization and Circuit Improvements to Mitigate Outage Impacts for Disadvantaged Communities	$100,000,000	$100,310,996
System Hardening / Wildfire Mitigation	Hawaiian Electric Company Inc.	HI	Climate Adaption Resilience Program	$95,313,716	$95,313,718
Wildfire Mitigation	Xcel Energy	CO, MN, NM, TX, WI	Wildfire Mitigation and Extreme Weather Resilience for Xcel Energy	$100,000,000	$142,020,463
	Tri-County Electric Cooperative	SC	Electrical Grid Modernization and Wildfire Reduction in South Carolina	$4,665,803	$2,332,903
	PacifiCorp	CA, OR, UT	PacifiCorp's Equity-aware Enhancement of Grid Resiliency	$99,633,723	$106,105,519
	Mora-San Miguel Electric Cooperative, Inc.	NM	Three-Part Wildfire Damage Mitigation Project	$11,270,193	$3,756,731
	Midwest Energy, Inc.	KS	Transmission Line Rebuild/Replacement for Wildlife Mitigation and Renewable Resource Access	$96,942,707	$47,717,412
	Holy Cross Energy	AZ, CA, CO, ID, KS, MN, MO, ND, NE, NM, OK, OR, SD, UT, WA, WY	Wildfire Assessment and Resilience for Networks (WARN)	$99,328,430	$45,762,816

***Source:** Adapted from Grid Resilience and Innovation Partnerships (GRIP) Program Projects | U.S. Department of Energy – Grid Deployment Office | Accessed November 21, 2023 | https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program-projects

Cost Recovery Process for Grid Investments Seeking Grants

Process Overview

1. Company Develops Project for Consideration of Grant Award
2. Applicant Files Application for Approval of Project before Commission
3. Commission Evaluates Project and Issues Order Approving Subject to Receipt of Award
4. Company Submits Grant Application
5. Notification of Grant Award and Company Files Ratemaking Petition
6. Commission Issues Order Approving Ratemaking Treatment for Project

Regulatory Decision Example

Central Maine Power – Advanced Metering Infrastructure

- **June 2008** - Maine Public Utilities Commission reviews Central Maine Power's Advanced Metering Infrastructure (AMI) project.
  - Commission defers decision on project, but examination of cost-benefit issues continues
- **February 2009** – American Recovery and Reinvestment Act is enacted
- **February – July 2009** - Commission and parties carry out a series of meetings and technical conferences on the AMI project
- **July 2009** – Commission issues Order approving AMI installation, subject to receipt of a "substantial" DOE grant award
- **August 2009** – Utility submits a grant application to DOE
- **October 2009** – DOE notifies utility of $95.9M grant award (project costs at this time estimated at $192M)
- **January 2010** – Utility submits testimony in support of AMI project
- **February 2010** – Commission issues Order Approving utility's AMI project and associated ratemaking treatment

***Source:** Order Approving Installation of AMI Technology | Docket No. 2007-215(II), Maine Public Utilities Commission, Feb. 25, 2010

Ratepayer vs. taxpayer funding

- **Potential for taxpayer funds to defray costs that would otherwise be borne by ratepayers**
  - Awards made through federal and state funding opportunities are conditional and come with certain performance requirements that must be met to maximize funds received
  - Funding opportunities are often structured to advance projects that have not already been authorized or are underway – however, projects that have been contemplated and planned to some extent are often allowed and encouraged
  - Awards are subject to negotiation and any cost-share using ratepayer funds requires Commission approval
- **Potential for taxpayer funds to reduce utility returns**
  - Utilities earn a return on their invested capital
  - Grants can reduce the required invested capital by utilities and reduce the utility's absolute return from these projects
  - However, many projects may not have advanced without these awards and may ultimately result in a net-positive return position for utilities
- **Opportunities to optimize ratepayer and taxpayer funds to advance shared goals and minimize redundant costs**
  - Federal and state opportunities often allow various types of entities to apply for funding
  - There may be opportunities to collaborate with other entities to pool together resources for greater impact, including through joint planning, deployment, and funding (formula + competitive grants)
  - Developing funding strategies with partners that harness their respective areas of strength and advance mutual priorities can maximize impact, with more judicious use of resources

Case Study: CenterPoint Energy Distribution Automation

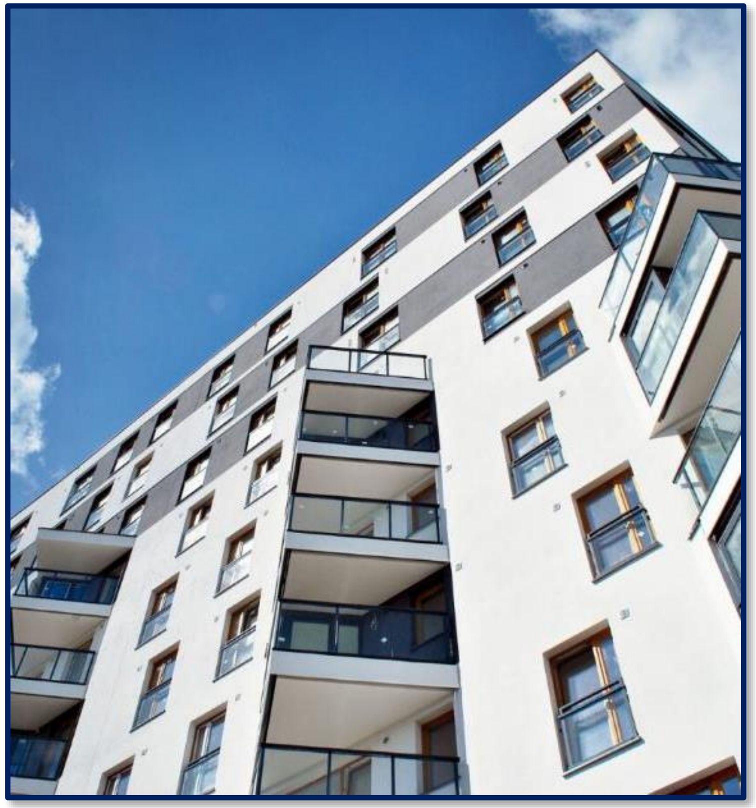
- In 2017, Hurricane Harvey brought 52 inches of rain to Texas and Louisiana
- Distribution automation, including intelligent switches, helped CenterPoint energy isolate power quickly – avoiding 41 million outage minutes for customers
- Other technologies including smart meters provided increased visibility and efficiency of response

Functionalization	Classification	Allocation
Distribution	Energy-related	All Classes

Source: Corporate Responsibility Report | CenterPoint Energy |2017 | 2017-Corporate-Responsibility-Report.pdf (centerpointenergy.com)

Case Study: New Jersey Energy Resilience Bank

- The NJ ERB provided grants and loans to critical facilities to enhance resilience following Superstorm Sandy
- Operated by the New Jersey Economic Development Authority using $200 M awarded to the State from Community Development Block Grant Disaster Recovery Funds
- Higher grant allocations covering “resilience costs” with project costs not explicitly tied to enhancing resilience supported by smaller cost-share and loans



Functionalization	Classification	Allocation
Distribution and Customer	Customer-related	Commercial and Industrial

Source: ERB Financing Program Guide | New Jersey Board of Public Utilities and New Jersey Economic Development Authority |2014| ERB Financing Program Guide (state.nj.us)

Case Study: Xcel Energy Resilience as a Service Pilot

- Program designed for commercial and industrial (C&I) customers seeking energy resilience and business continuity through power outages
- Xcel Energy of Wisconsin pays most of the upfront costs of these systems and is paid back by participant over 10 years
- As of year-end 2022, one government project was under construction, with additional projects at manufacturing, wastewater, airport, and other facilities in the study stage
- Technologies include solar, storage, microgrids and back-up generators

Functionalization	Classification	Allocation
Distribution and Customer	Customer-related	Commercial and Industrial

Source: Resilience as a Service Program Annual Compliance Report | Xcel Energy |2022 | 4220-TE-106 RaaS Annual Report 2022.docx (wi.gov)

Case Study: Connecticut Green Bank – Energy Storage Solutions

- Program that helps Commercial, Industrial, and Institutional customers install energy storage to maintain operational continuity through power disruptions
- Ratepayer funded program administered by the CT Green Bank and State IOUs
- Upfront and annual performance-based incentives provided, with additional incentive adders for small businesses, critical facilities, and other strategic applications

Functionalization	Classification	Allocation
Customer	Customer-related	Commercial and Industrial

Source: Energy Storage Solutions| Connecticut Green Bank| Accessed April 24, 2023| Energy Storage Solutions - CT Green Bank | Accelerating Green Energy Adoption in CT

What is Resilience?

- "Resilience is the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions."

- "Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents."

- High-impact disruptions can create challenges for meeting critical services, as well as result in large economic losses due to a lapse in business continuity

Source: Presidential Policy Directive / PPD-21: Critical Infrastructure Security and Resilience | 2013 | *Cybersecurity & Infrastructure Security Agency*

Measures for Mitigating the Impact of Disruptions

- Hardening of power lines, facilities, substations, and other systems
- Undergrounding of electrical equipment
- Vegetation and fuel-load management
- Monitoring and control technologies
- Use or construction of distributed energy resources for enhancing system adaptive capacity during disruptive events, including microgrids and battery-storage
- Adaptive protection technologies
- Advanced modeling technologies

- **Source:** Grid Resilience and Innovation Partnerships Program| U.S. Department of Energy | Accessed April 24, 2023 | Grid Resilience Utility and Industry Grants Fact Sheet (December 2022).pdf (energy.gov)

Examples of State Resilience Investments and Cost Recovery

Lead Entity	Program Offering	Grid Dimension	Description	Why It's Notable
CenterPoint Energy	Distribution Automation	Electric Grid	Distribution automation, including intelligent switches supported by smart meters, increased visibility and efficiency of outage response	Investments beyond system hardening avoided 41 million outage minutes for customers during record-breaking Hurricane Harvey
Arizona Public Service	Microgrid Program	Microgrid	Provides support for microgrids, battery storage, solar power and low-emission generators to enhance resilience of large customers	Provides planning, construction, site monitoring, maintenance, and reporting services depending on customer needs
Xcel Energy Wisconsin	Resilience as a Service Pilot	Microgrid	Utility program to enhance C&I customer resilience through solar, storage, microgrids, and back-up generator installation	Utility pays most costs of resilient systems upfront and is paid back by participant (not ratepayers) over 10 years
Connecticut Green Bank	Energy Storage Solutions	Customer	Energy storage offering for C&I customers administered together with IOUs to maintain operational continuity	Upfront and annual performance-based incentives provided, with additional incentive adders for small businesses, critical facilities, and other strategic applications
Alabama Power	Connected Communities	Microgrid	Utility-owned microgrid including energy efficiency, solar, storage, and natural gas generators supporting single-family homes	Can operate independently of the grid to provide community energy service through outages; additional new home construction to have microgrid services at the outset
New Jersey Economic Development Authority	Energy Resilience Bank	Microgrid	Provides grants and loans for critical facilities to enhance resilience following Superstorm Sandy	Leveraged federal funding allocated for recovery to seed bank and offer facility specific support for resilience costs
New Jersey Transit	TransitGrid	Microgrid	Microgrid provides critical transportation services through power disruptions	Leveraged $400M in federal transportation funding to enhance resilience and create 4,000 new jobs

Questions to Ask

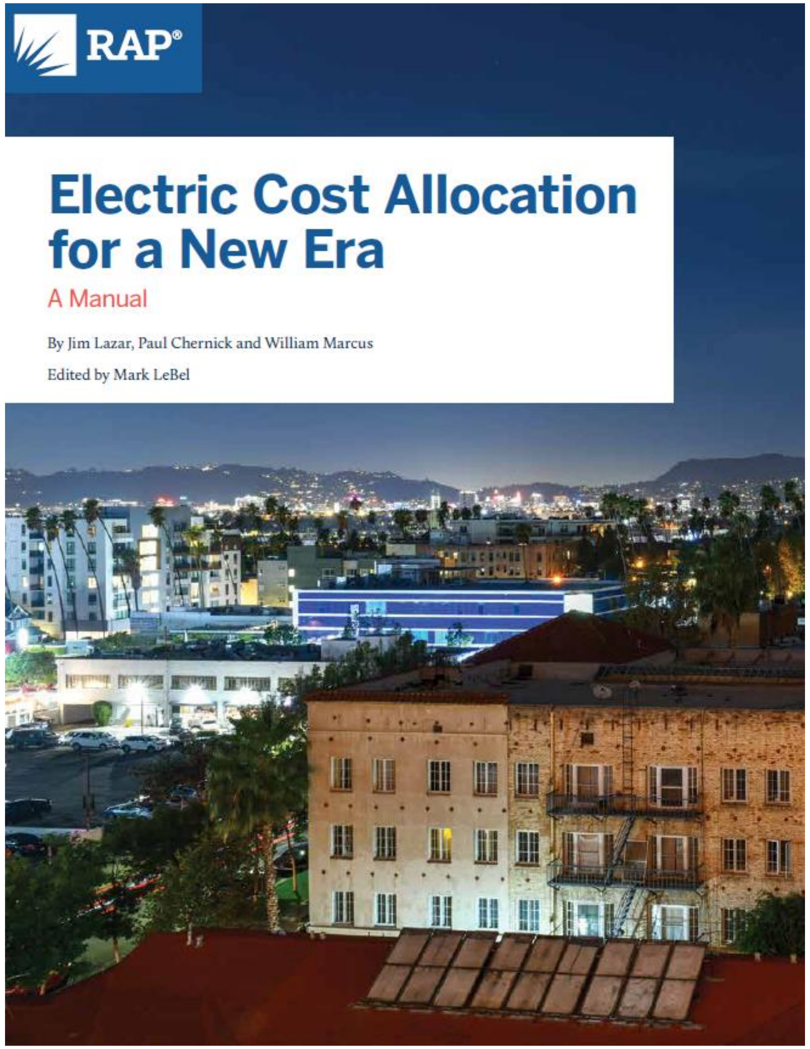
- Do the existing cost recovery processes in the state accurately account for the value that grid modernization, distribution system-enhancing, and resilience investments provide? To which entities does this value accrue?

- Do the current cost recovery and allocation processes in the state advance or hinder local priorities, such as ensuring customer affordability, supporting economic growth, and creating a more resilient energy system?

- For investments that create clear societal benefits beyond those provided to energy customers (such as enhanced resilience across life-saving and critical facilities), is there an appropriate role for taxpayer contributions to support their deployment?

- Ratepayers, taxpayers, and private entities all make investment decisions that impact resilience and the level of DERs across the state. Do existing planning processes and stakeholder activities ensure that these investments are coordinated and complementary?

Electric Cost Allocation for a New Era Manual



Source: Electric Cost Allocation for a New ERA | Regulatory Assistance Project |2020 | Electric Cost Allocation for a New Era: A Manual - Regulatory Assistance Project (wpengine.com)

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