Scenario Planning Workshop

April 22, 2025

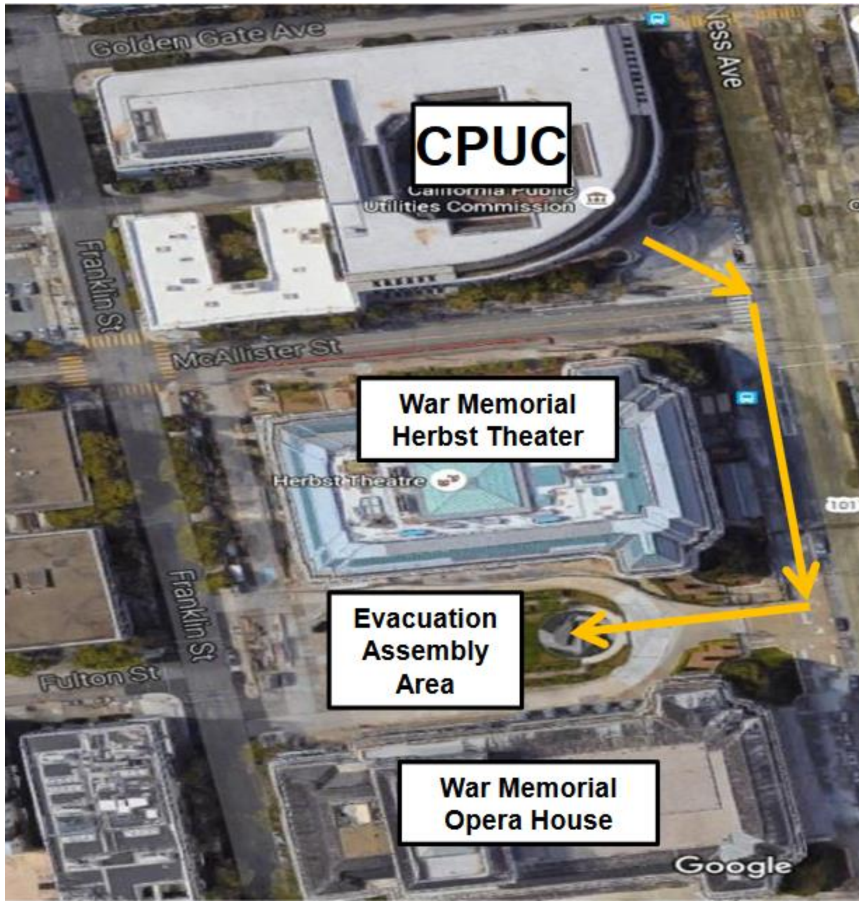
High DER Proceeding

D.24-10-030 Implementation

California Public
Utilities Commission

Safety & Misc.

- In case of an Emergency
  - Staff will call 911
  - To evacuate, proceed out of 1 of 4 exits to Civic Center Plaza
    - Exit toward Van Ness / McAllister
    - Walk past City Hall
- Bathrooms & water fountain across the Lobby



Ground Rules and Workshop Logistics

- **Ground Rules:**
  - Raise your hand for questions, both in the room and online
  - Identify yourself and your organization before speaking
  - Do not repeat what another person has already said
  - Stay on topic
- **Workshop Logistics**:
  - Workshop is being recorded and will be posted on the CPUC’s Distribution Planning webpage along with presentation slides
  - WebEx and phone participants are muted until called on. Please remember to mute yourself when finished speaking.
  - Webex participants type questions/comments in the “chat” and they will be read aloud. You may raise your hand to ask the question yourself or follow up on your question.

Please Note

- Today’s workshop will not be on the record for R.21-06-017.
- Parties may include information they discuss today in comments or protests to the Tier 3 Scenario Planning Advice Letter due 6/30/25 and to the subsequent Resolution before it is voted on by the CPUC.
- Participants who are not formal parties to the OIR may either partner with respondents or contact Energy Division staff to provide additional comments.

Agenda - Morning

Time	Agenda Item	Details
9:00 - 9:30 AM	**Welcome and Opening Remarks** •Opening remarks by Commissioner Houck •Energy Division Background and Workshop Framing slides	•Workshop logistics •Commissioner Darcie Houck to set the stage for the workshop and emphasize its purpose. •Energy Division opens with context and frames the workshop objectives
9:30 – 10:30 AM	**External Utility/PUC Presentations** •Presentations by •Minnesota PUC •Hawaiian Electric	Hear real-world examples of scenario implementation in distribution planning from a PUC and/or utility that has done so already.
10:30 - 10:45 AM	**Open Discussion for Q&A**	Reactions and questions from the morning presentations
10:45 - 11:00 AM	**Break**	Be back in 15 minutes!
11:00 – 12:45 AM	**IOU Presentations of scenario planning implementation proposals** •Presentation by IOUs •SCE •PG&E •SDG&E	Covering: •Number, combination, and purpose of scenarios •Scenario details and coordination •Selection process •Investment plan creation •Guardrails and costs
12:45 – 1:00 AM	**Open Discussion and Q&A**	Reactions and questions from the Utility presentations
1:00 - 2:00 PM	**Lunch**	Be back in 60 min!

Opening Remarks

Commissioner Darcie Houck

Background and Framing

Energy Division

Background from D.24-10-030

Requires utilities to use scenario planning to improve forecasting and disaggregation.

- Utilities must implement the use of scenario planning in the distribution planning and execution process (DPEP) beginning with the 2025-2026 DPEP cycle
- Defined scenario planning as a process in which multiple scenarios can be performed to evaluate the impact of different levels of demand, distributed energy resource adoption, and customer behaviors and integrated into a single investment plan.
- Established that results (grid needs) are not required to be identified in all scenarios in order to be included in the investment plan.

Background from D.24-10-030 continued

- Stakeholder input should be provided in scenario planning, on an annual basis, in both the Distribution Forecasting Working Group to explain the proposed scenarios and the DPAG workshop to explain how the scenario outcomes influenced the investment plan.
- Requires utilities to submit a Tier 3 Advice Letter proposal by 6/30/25 that
  - (1) summarizes the workshop;
  - (2) identifies the outcomes of the workshop;
  - (3) proposes a framework for implementation of scenario-based planning;
  - (4) identifies the steps to be taken to facilitate the transition to using scenarios and a timeline for using them

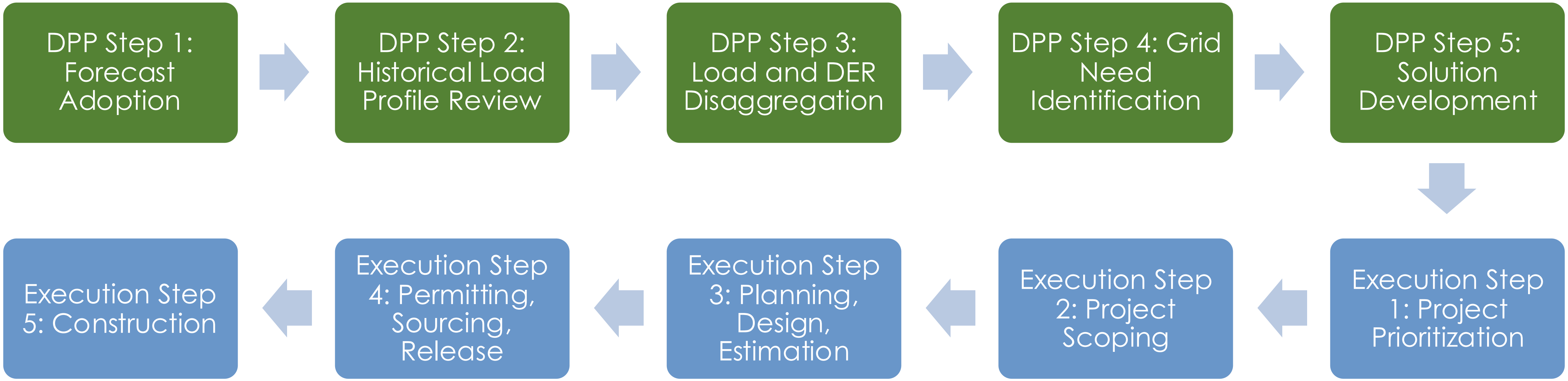
Why Scenario Planning?

- Planning for one scenario assumes the future will unfold as predicted.
- In an era of load growth, rapid change, and uncertainty, long-term planning for one scenario does not capture the range of likely outcomes.
- Scenarios can help identify, communicate, mitigate uncertainty about load and DER growth.
- Supports robust decision making by identifying grid upgrades that are needed and/or are flexible to work for multiple scenarios, i.e. "least regrets"

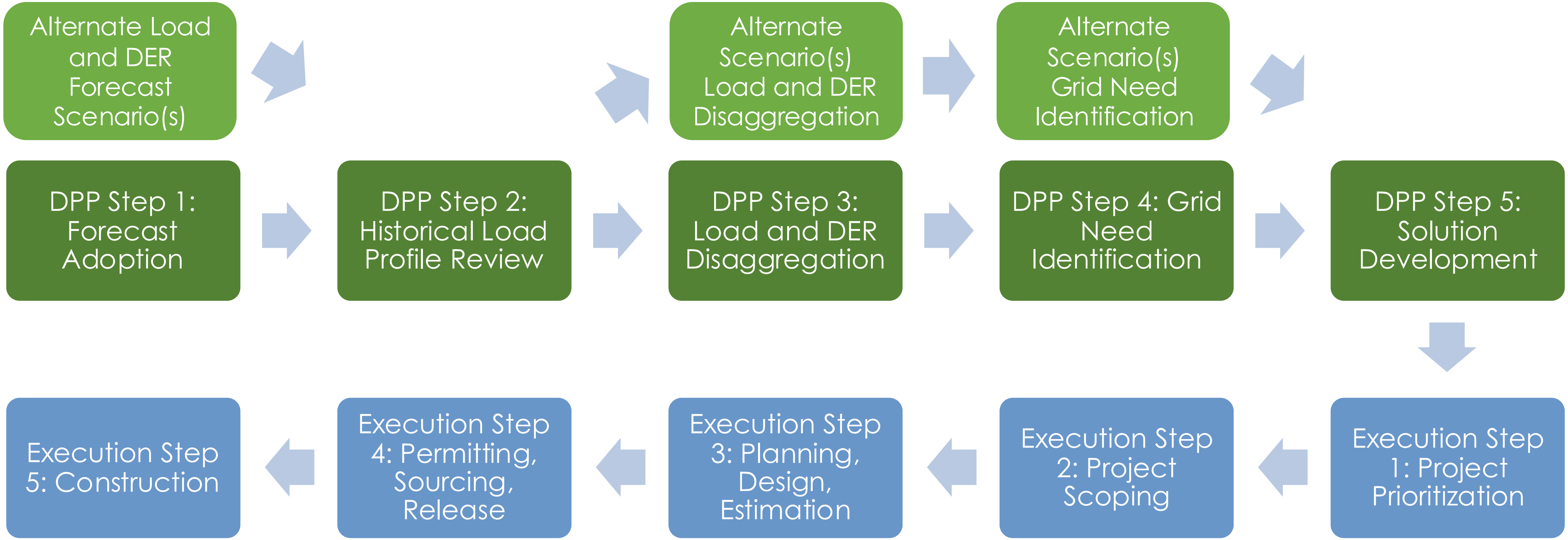
Key Risks That Scenario Planning Can Mitigate

Risk	Cause	Mitigation
Overinvestment Stranded assets and undue ratepayer costs	DER or Load growth is slower than forecast. Load management outperforms expectations	• Conservative demand / adoption scenarios with limited DER uptake or slower electrification. • Robust load mitigation scenarios. • Encourage modular or phased investments that can scale.
Underinvestment Capacity constraints, long lead times, poor reliability, service connection delays	DER or Load growth outpace the forecast	• Model futures with rapid DER adoption, load growth. • Identifies stress points to proactively design upgrades or mitigations including load flexibility. • Identify long lead time investments
Lack of Flexibility Lock in suboptimal plans or waste time and resources changing direction in the future	New policy, emerging needs, or constraints	• Compare how well different investments perform under varied futures. • Encourage flexible solutions like NWA.
Blind Spots Unaware of the vulnerabilities posed by possible but less likely scenarios	Middle scenarios do not consider edge cases	• Include bookend stress scenario that consider extreme events (weather). • Expose vulnerabilities, such as local capacity limits, that might be invisible in base-case plans.

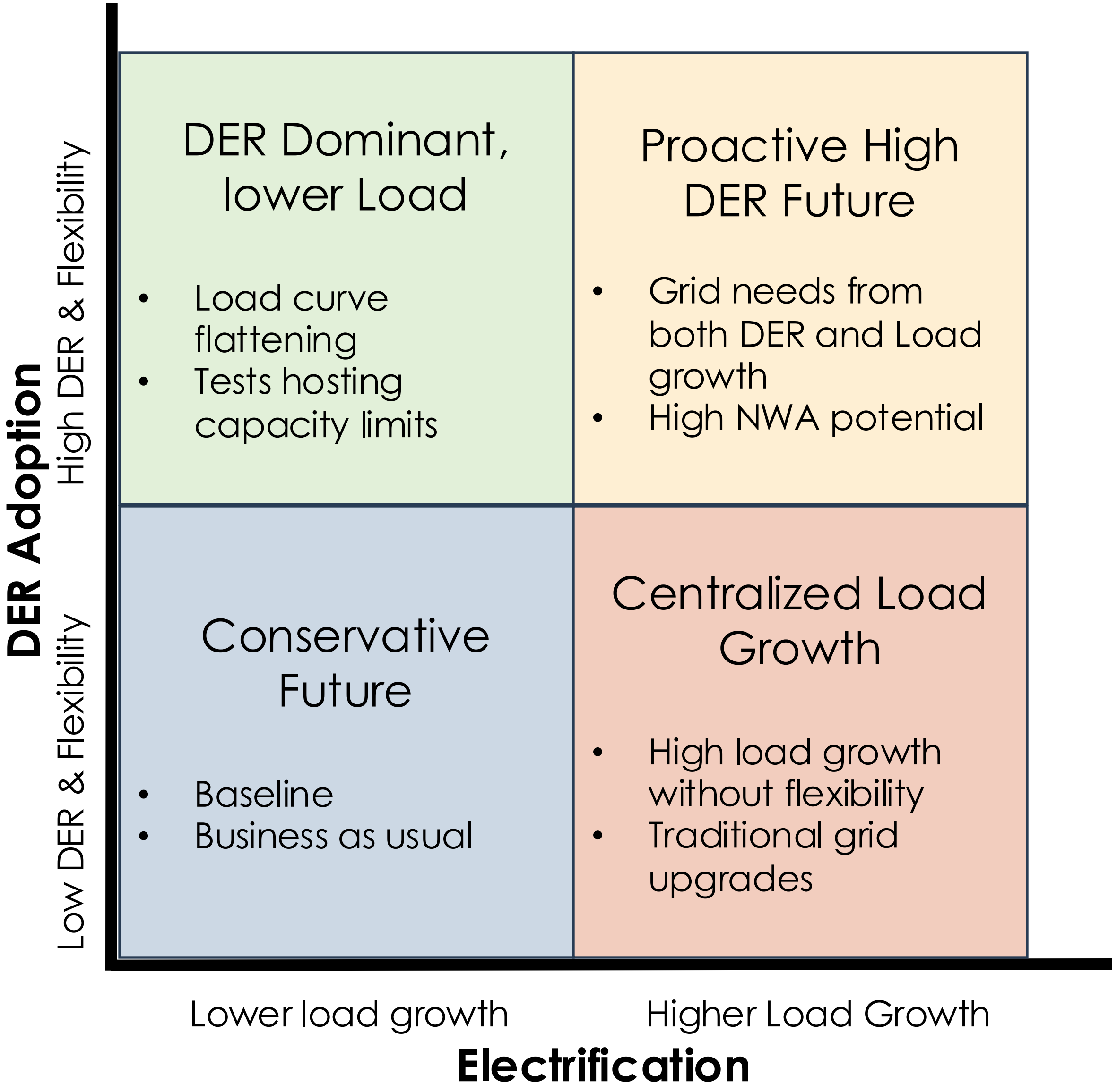
Distribution Planning and Execution Process

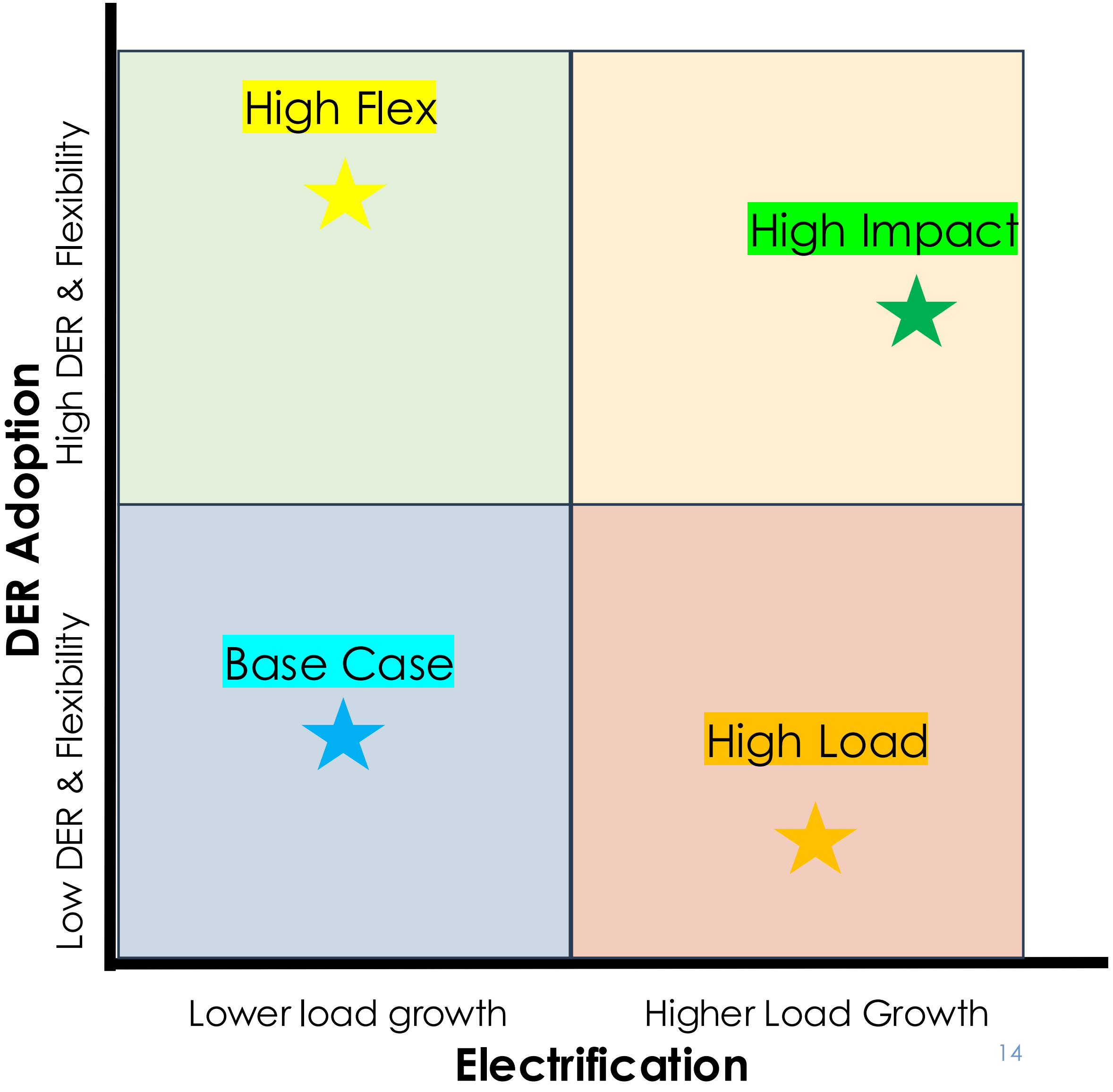


Distribution Planning and Execution Process with scenarios



Scenario Matrix and Example Scenarios





1. Base Case Scenario
What the utilities traditionally do

- Informed by Known Loads and IEPR disaggregation
- Potentially high confidence Pending Loads

2. High Load Scenario
Additional load growth and specificity

- Additional Pending Loads and Proactive TE load forecast
  - Provides locational and temporal specificity for the load growth compared to the base case.
- Identifies additional grid needs due to high load growth

3. High Flexibility

What projects can be avoided?

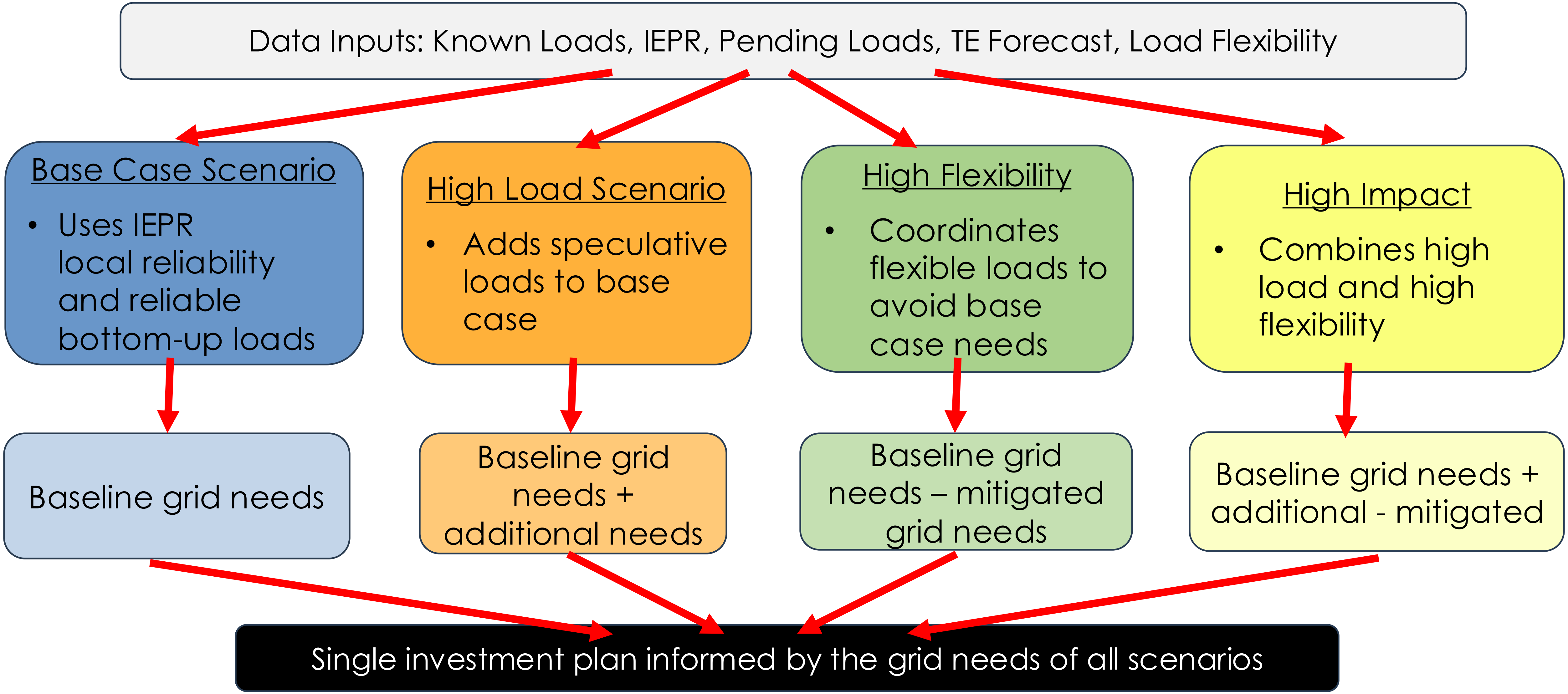
- High adoption of flexible demand technologies and managed EV charging
- Model load shifts, ramp smoothing, and local peak shaving.
- Tests whether coordinated flexibility can defer or downsize grid upgrades.

4. High Impact

High load and high flexibility

- Combines scenarios 2 and 3
- Shows what high load growth projects can be avoided by demand flexibility

Example Scenario Planning Framework



Benefits of this method

- Multiple information sources are being used to **complement and confirm** each other, not compete against each other
  - Instead of deciding to choose one scenario input over another to inform the planning process, both inputs can be used as different scenarios
  - Use the instances where multiple scenarios find a grid need to confirm each other and provide increased confidence in the need for that investment.
- Instances where a grid need is identified in only one scenario may be treated differently depending on the circumstances.
  - Consider available capacity at the location
  - Compare to a high flexibility scenario output
  - Consider NWA solutions

Challenges of this method

- Creates a critical juncture at the point where the different scenario grid needs come together to make the single investment plan.
  - Double counting is a serious concern here. Need to distinguish between data inputs to know if grid needs are overlapping or additional.
  - Substantial transparency and oversight is needed.

- The current DPP process is not set up for CPUC approval of utility plans.
  - Implement guardrails to provide sensible guidance on investment decisions
  - Status Quo: We see the results of one cycle and make changes for the next.

Iterative Reform Proposal

- Repurpose the DIDF Reform Ruling to be DPEP Reform Ruling that includes changes to the Scenario Planning framework as needed.
- Allow for expansion of scenarios, incorporation of methodology, metrics to trigger incremental grid investments, changes to the schedule or metrics as needed.

Potential Guardrails and Requirements

- **Transparent reporting:** Investments should identify what scenario(s) the grid need has been identified under.
- **Scenario justified investments**: Most investments should be identified as necessary across multiple scenarios.
- **Flex first:** Grid needs that disappear in the high flexibility scenario should first assess NWA solutions
- **Tiered investments:** Approve least regrets projects required in all scenarios. Identify trigger thresholds for projects required in some scenarios. Report fringe investments as planned solutions (not investments).

Implementations in other states

Minnesota Public Utilities Commission – Hanna Terwilliger

Minnesota Scenario Planning in Integrated Distribution Planning

April 22, 2025 | California PUC High DER Public Workshop on Scenario Planning

Hanna Terwilliger| Analyst Coordinator - Distribution System Planning

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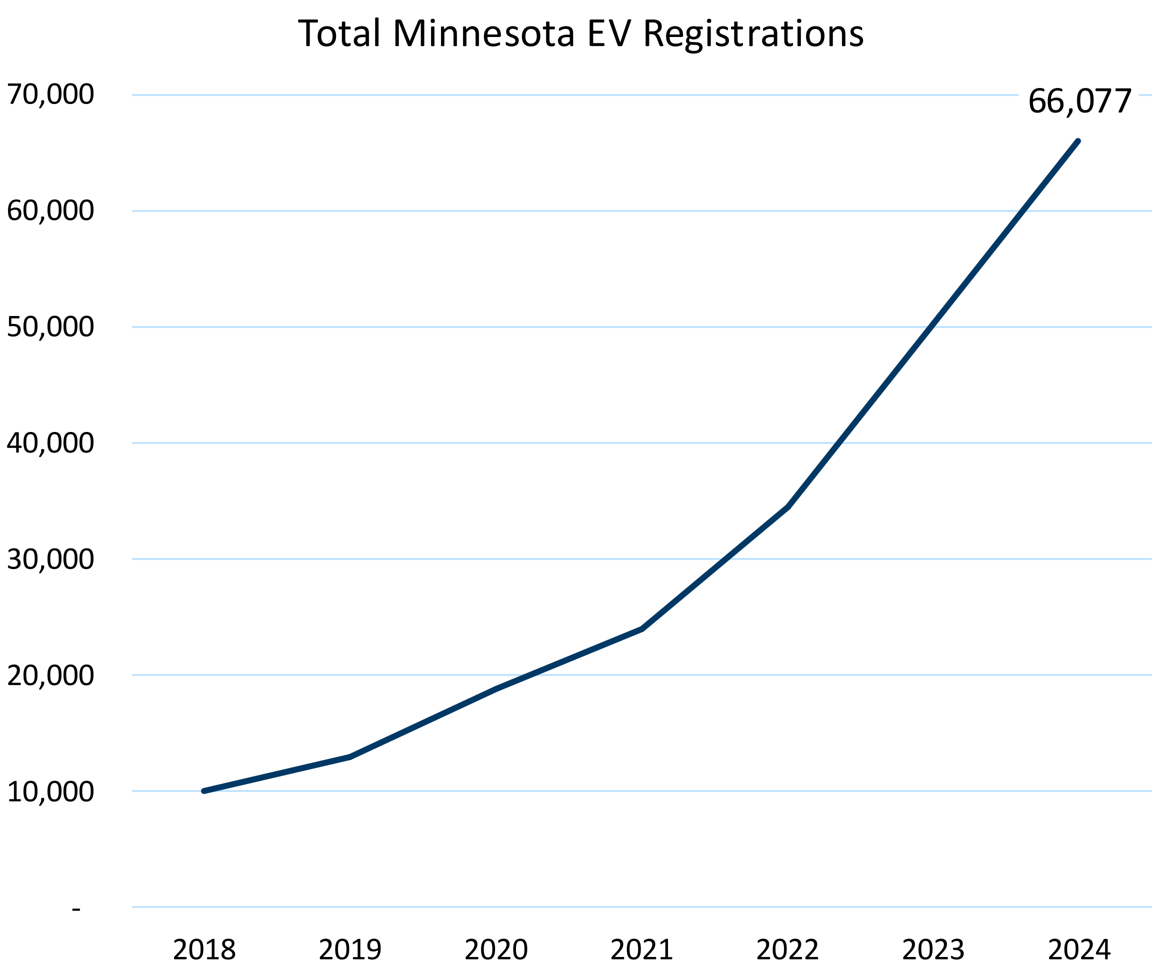
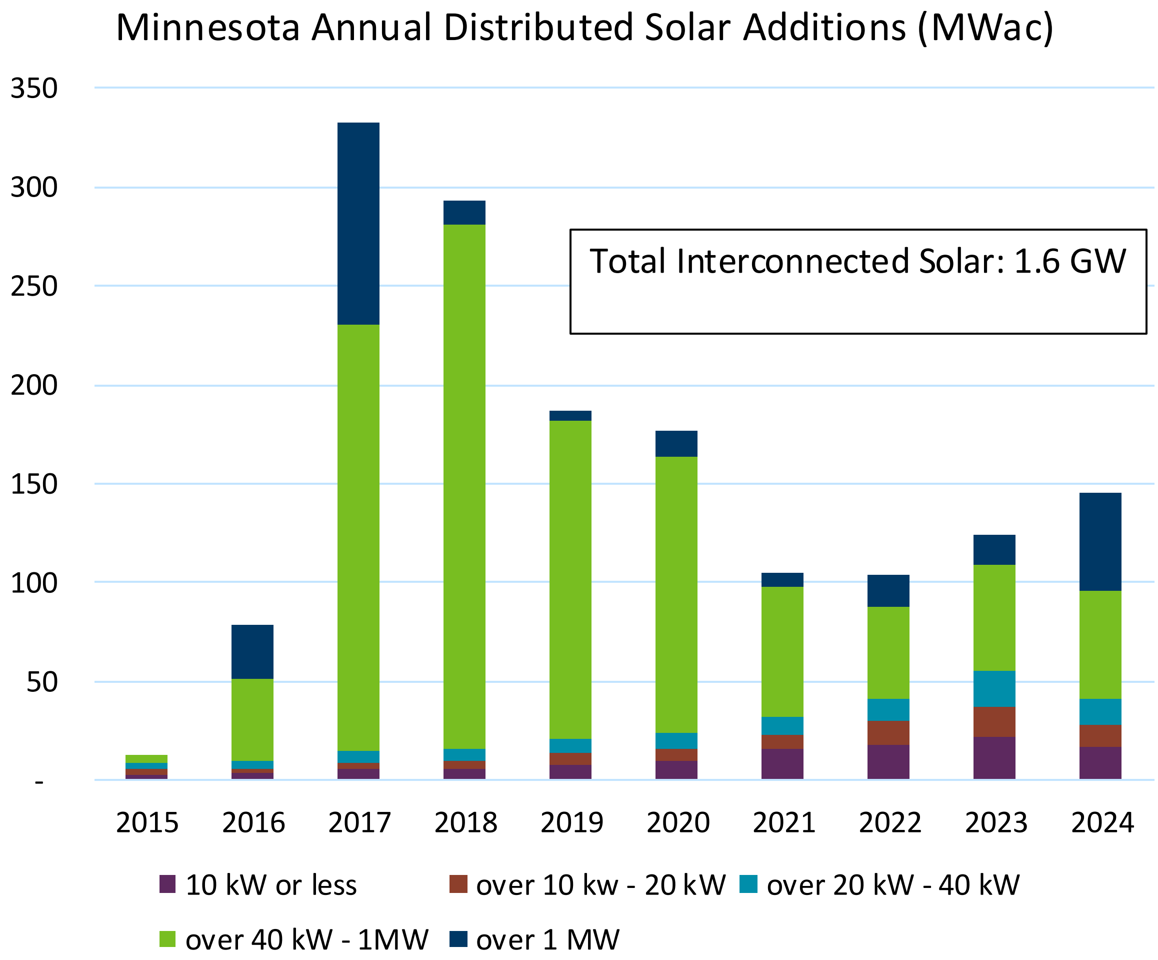
The ideas expressed are the views of the presenter, and not the Minnesota Public Utilities Commission.

Minnesota DER Snapshot





Source: MN PUC EV and DER Dashboards, mn.gov/puc

Integrated Distribution Planning Objectives

The Commission is facilitating comprehensive, coordinated, transparent, integrated distribution plans to:

1. Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;

2. Enable greater customer engagement, empowerment, and options for energy services;

3. Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies,

4. Ensure optimized utilization of electricity grid assets and resources to minimize total system costs, and,

5. Provide the Commission with the information necessary to understand Xcel Energy's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.

Integrated Distribution Plan Filing Requirements

<u>IDP Requirements</u>

1. **Timing**
2. **Stakeholder Process**

> Utilities must hold at least 1 stakeholder meeting prior to filing, covering DER Forecasts, 5-Year Investment Plan and System Capabilities

3. **Filing Requirements**

A. Baseline Data
   - System
   - Financial
   - DER

B. Hosting Capacity and Interconnection

C. DER Futures Analysis (Scenario Planning)

D. Long-Term Distribution System Investment Plan *(5 & 10 year)*

E. Non-Wires Alternatives Analysis

F. Transportation Electrification Plan (IOUs only)

DER Scenario Analysis Requirements

- Base-case, medium, and high scenarios that reflect a mix of individual and aggregated DER service types, dispersed geographically in the locations the utility expect to see DER growth take place first.
- Methodologies used to develop the low, medium, and high scenarios, including the DER adoption rates (if different from the minimum 10% and 25% levels)
- Geographic deployment assumptions
- Expected DER load profiles (for both individual and bundled installations),
- Whether methodologies and inputs are consistent with Integrated Resource Plan inputs
- Processes and tools necessary to accommodate forecasted DERs
- System impacts and benefits from increased DER adoption,
- Barriers to DER integration
- Types of system upgrades necessary to accommodate DER at forecasted levels.

Source: MN IDP Requirements, Section C: DER Scenario Analysis, September 16, 2024 Order, Docket 23-452

Scenario Definitions

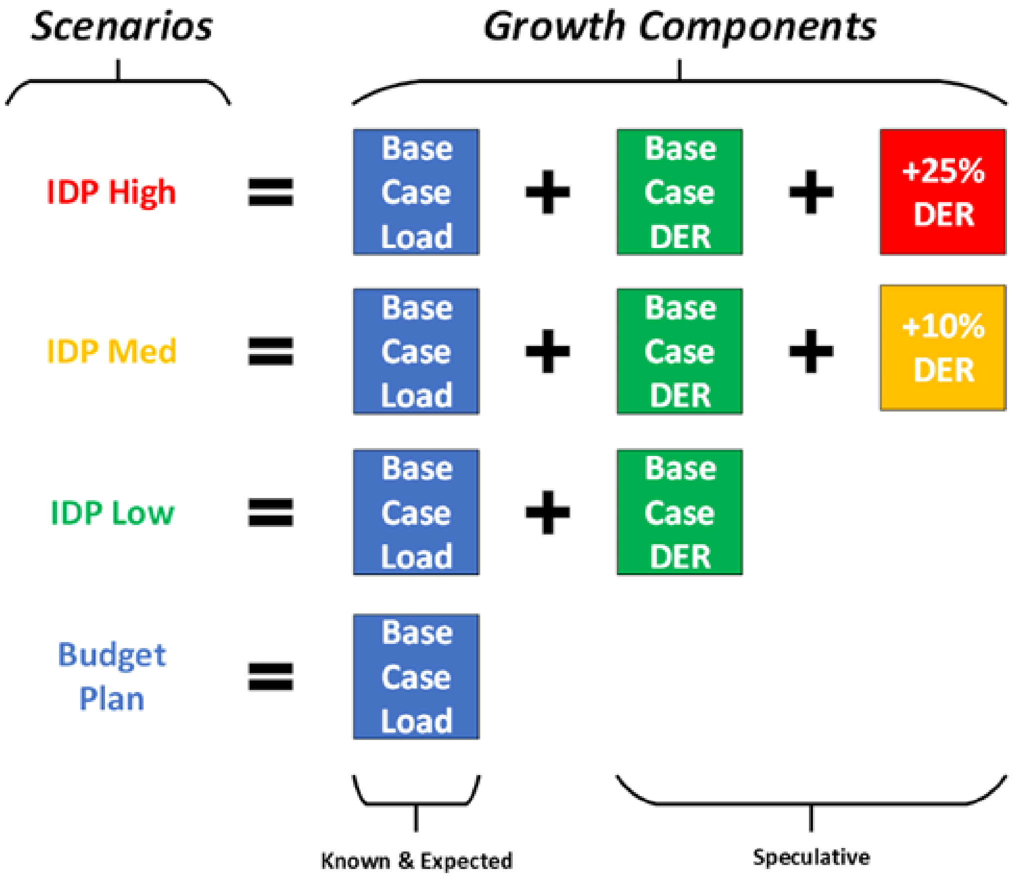
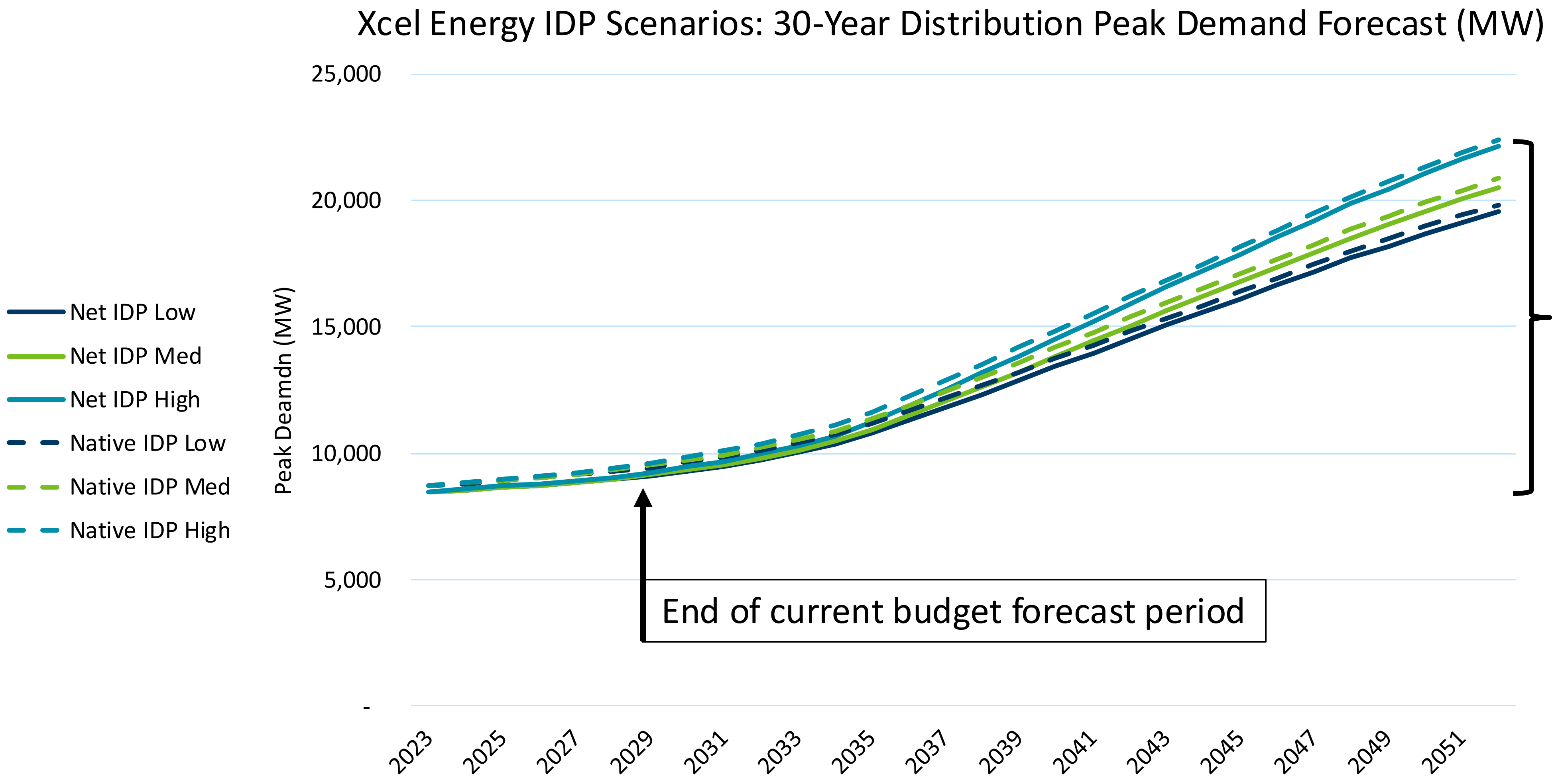


Table A1 - 10: Corporate-Level DER Scenarios Used in LoadSEER Scenario Forecasts

Budget Plan	IDP Low	IDP Med	IDP High
Corp Demand	Corp Demand	Corp Demand	Corp Demand
	EV: Mid	EV: Mid +10%	EV: Mid +25%
	BE: Base/125%	BE: Base/110%	BE: Base
	Solar FTM: Low	Solar FTM: Medium	Solar FTM: High (Legislation)
	Solar Rooftop: Medium	Solar Rooftop: Medium +10%	Solar Rooftop: Medium +25%
	Battery: Mid	Battery: Mid +10%	Battery: Mid +25%

Source: Xcel Energy, 2023 Integrated Distribution Plan, Docket 23-452, Appendix A1, p. 50; 57

Scenario Forecast Results

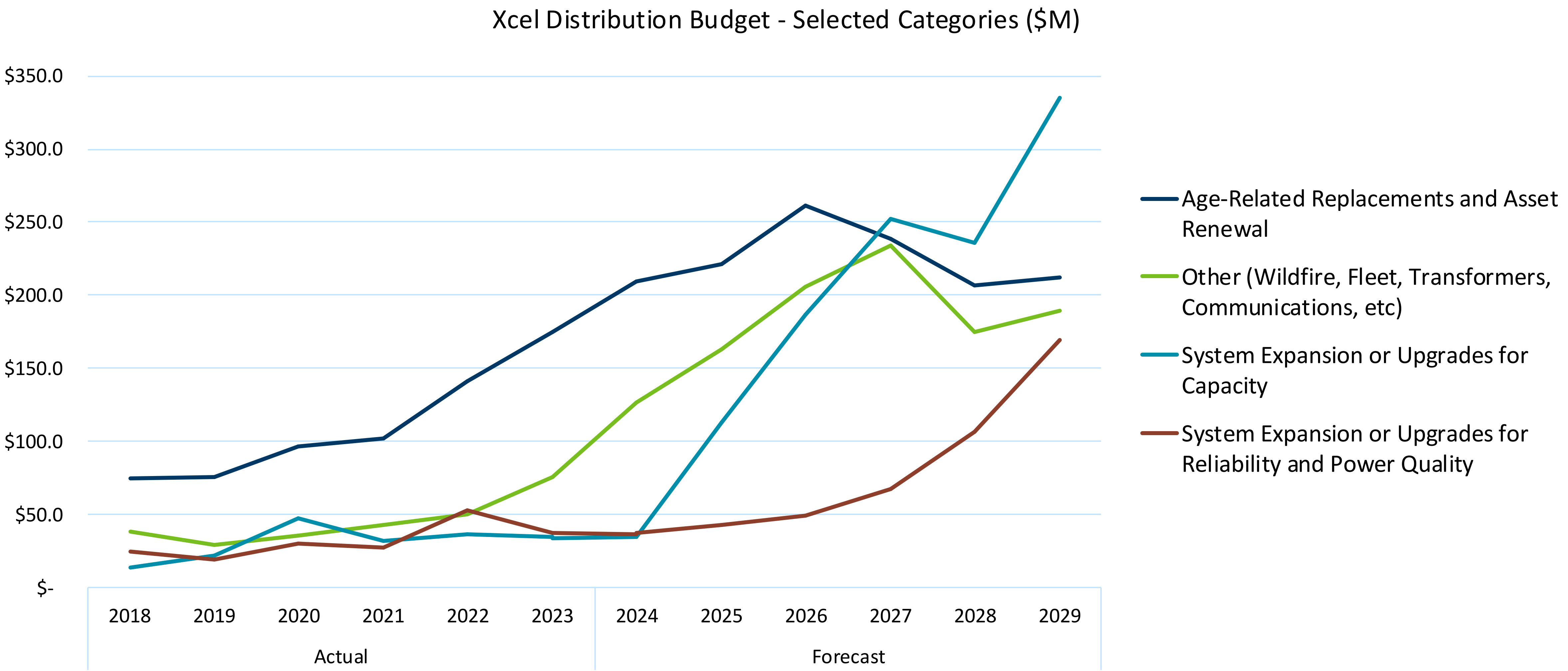


~11-13 GW* forecasted peak distribution growth – 140% increase over 2023

*accounts for distributed solar growth

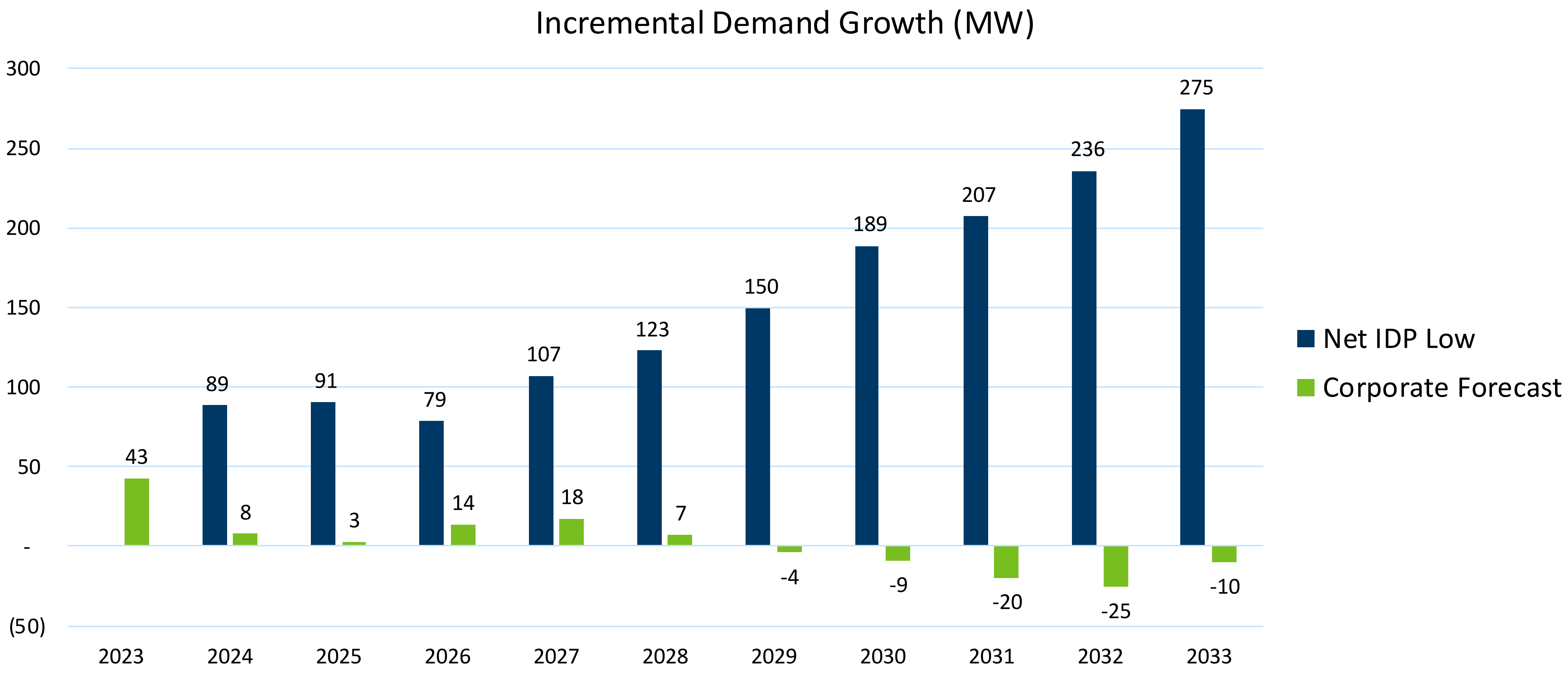
Source: Xcel Energy, 2023 Integrated Distribution Plan, Docket 23-452, Attachment M

Distribution Budget Increases



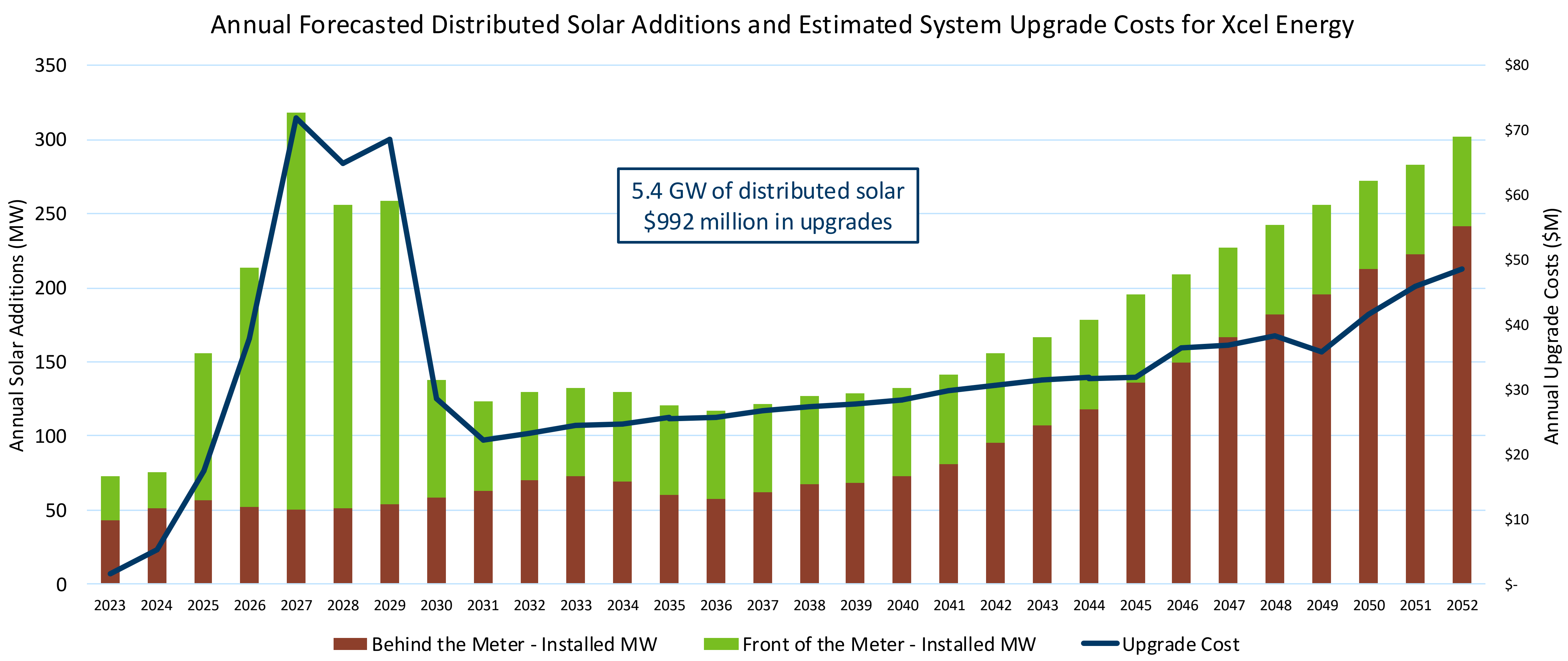
Source: Xcel Energy, 2024 Annual Update, Docket 23-452, Attachment C

Forecast and Budget Disconnect



Source: Xcel Energy, 2023 Integrated Distribution Plan, Docket 23-452, Attachment M

Proactive upgrades for increasing DERs and electrification



Source: Xcel Energy, 2023 Integrated Distribution Plan, Docket 23-452, Appendix I

Cost Allocation and Upgrades Framework

	Proactive Upgrades	Reactive Upgrades
Shared Cost Allocation	• Build distribution budgets around DER and electrification forecasts. • Assign incremental infrastructure costs via typical class cost allocation methods, e.g., in next rate case. • Benefits customers adopting DER and electrification by reducing or eliminating wait time and cost of interconnection. • Risks include deploying assets that are not used and useful if forecasts are not accurate, the potential for shifting costs of upgrades onto non-benefitting customers, and risk of inequitable investments.	• Grid upgrades are made in response to individual customer requests. • Costs assigned via typical class cost allocation methods, e.g., in the next rate case. • Benefits customers adopting DER and electrification by eliminating the cost of interconnection; benefits ratepayers by ensuring upgrades are used and useful. • Risks include continued wait-times in the interconnection process, the potential for shifting costs of upgrades onto non-benefitting customers, and risk of inequitable investments.
Individually Allocated Costs	• Build distribution budgets around DER and electrification forecasts. • Individual customers, where appropriate, pay a fee to cover their share of the upgrade at time of interconnection. • Benefits customers adopting DER and electrification by reducing or eliminating wait times for interconnection; benefits ratepayers by reducing the costs of upgrades via reimbursement over time. • Risks include deploying assets that are not used and useful if forecasts are not accurate, and the potential for shifting costs of upgrades onto non-benefitting customers if forecasts or reimbursement fees are not accurate.	• Grid upgrades are made in response to individual customer requests. • Individual customers, where appropriate, pay a fee to cover their share of the upgrade at time of interconnection. • For the most part the model in place today • Benefit is ensuring upgrades are used and useful. • Risks include wait time and interconnection costs for DER and electrification customers.

Source: Fresh Energy Initial Comments, Xcel Energy IDP, Docket 23-452

Scenario Analysis for Proactive Distribution Upgrades
(Draft Language)

E.1 [Utility] shall provide a base case forecast, as well as sensitivities that include higher and lower adoption of DERs and electrification than expected in the base case. [Utility] shall recommend which forecast should be adopted and explain why it thinks that forecast should be the case toward which to plan and why.

E.2 Where possible, the following load and DER components shall be differentiated in the forecast data provided: distributed solar PV, CSGs, distributed energy storage, energy efficiency, demand response, electric vehicles, and electrification of space, water, and process heating.

E.3 For each of the DER components above, [utility] shall provide a discussion of each essential assumption made in preparing the forecast, including assumptions regarding customer adoption rates, cost trends, and relevant policy drivers. [Utility] should include any sensitivity analyses used to test these assumptions.

Source: Draft Proactive Distribution Upgrade Framework, April 7, 2025, Notice, Docket 24-318

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Thank You!

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mn.gov/puc

Implementations in other states

Hawaii Electric Company – Shaun Imada

Hawaiʻi Powered

Hawaiian Electric IGP: Scenario Planning in Distribution Planning

April 22, 2025

Shaun Imada
Principal Engineer, Distribution Planning

shaun.imada@hawaiianelectric.com

Agenda

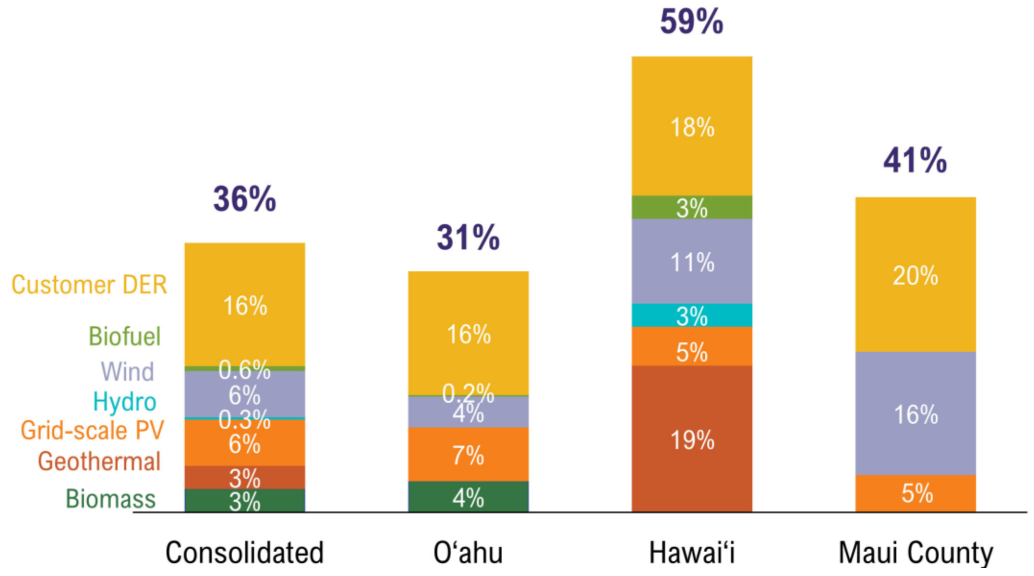
- Hawaiian Electric overview
- IGP Process
  - Forecast Scenarios
- Distribution Planning Process
  - DER Hosting Capacity
  - Location-Based Forecast

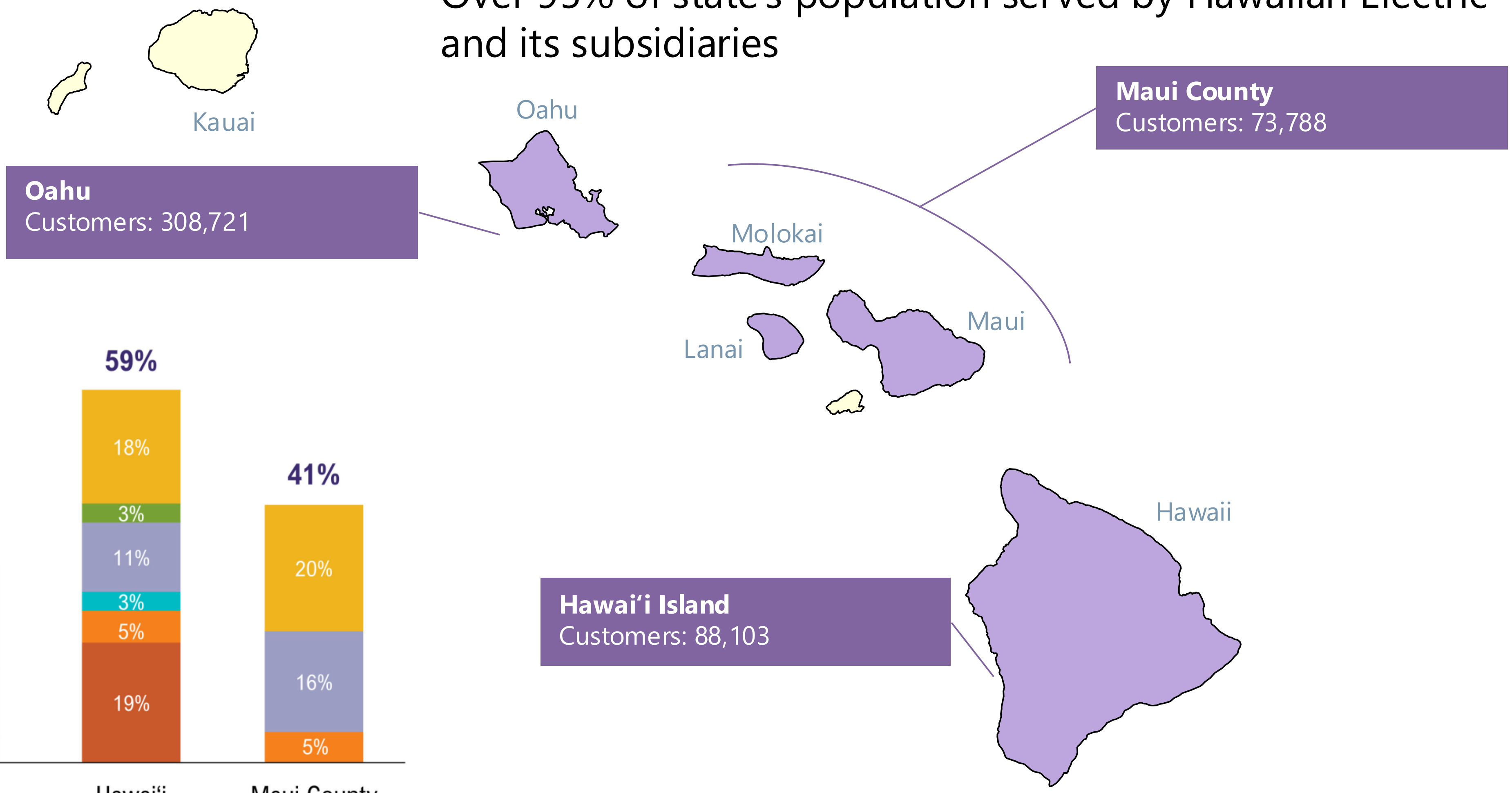
Hawaiian Electric Overview

Hawaiian Electric today

Serving the State of Hawaii for 133 years

Over 95% of state's population served by Hawaiian Electric and its subsidiaries





Note: All data as of 12/31/23 unless otherwise noted

Distribution System Info

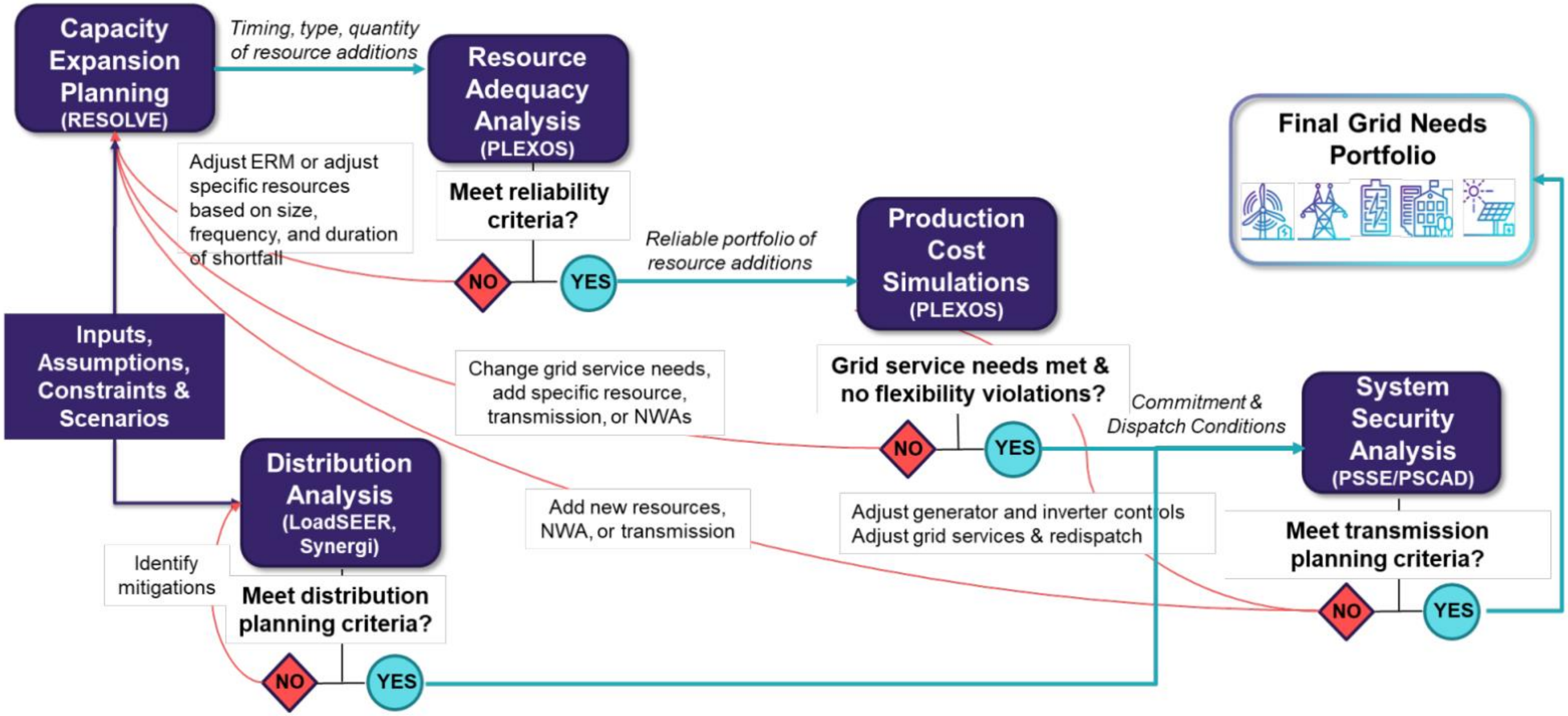
	Voltage Level	Approximate Number of Feeders/Transformers
Subtransmission (Oahu only)	Radial 46kV	60 Feeders 30 Transformers
Distribution (All Islands)	Radial 12kV, with some 2.4kV, 4kV and 25kV	650 Feeders 350 Transformers

IGP Process

IGP Process

Figure 1-2. High-level steps of Integrated Grid Planning

IGP Modeling Analysis Framework



Scenarios for Distribution Analysis

Table 1-1. Forecast Layer Mapping of Modeling Scenarios and Sensitivities

No.	Modeling Case	DER Forecast	EV Forecast	EE Forecast	TOU Load Shape
1	Base	Base Forecast	Base Forecast	Base Forecast	Managed EV Charging
2	High Load Customer Technology Adoption Bookend	Low Forecast	High Forecast	Low Forecast	Unmanaged EV Charging
3	Low Load Customer Technology Adoption Bookend	High Forecast	Low Forecast	High Forecast	Managed EV Charging
4	Fast Customer Technology Adoption	High Forecast	High Forecast	High Forecast	Managed EV Charging

Layer Forecasts

- **DER** – Cost projections, Federal/State tax credits, long term export programs, addressable residential/commercial market, etc.
- **EV** – light duty EV and electric buses
- **EE** – market potential study from PUC
- **TOU Load Shapes** – Rates, customer pool, AMI rollout, TOU rollout, TOU opt-out rate, etc.

Distribution Planning Process

Distribution Planning Process

1. **Forecast Stage**: Develop circuit-level forecasts based on the corporate demand forecast.
2. **Analysis Stage**: Determine the adequacy of the distribution system.
3. **Solution Options Stage**: Identify the grid needs requirements.
4. **Evaluation Stage**: Evaluation of solutions.

Forecast

- Collection of Historical Data
- Load & DER Forecasts
- Load & DER Profiles

Analysis

- Distribution Planning Criteria
- Hosting Capacity
- Contingency Analysis
- Grid Needs Identification

Solution Options

- Solution Requirements
- Wires Solutions
- Non-Wires Solutions

Evaluation

- Evaluation of Solutions
- Solution Sourcing
- Solution Selection

DER Hosting Capacity Grid Needs

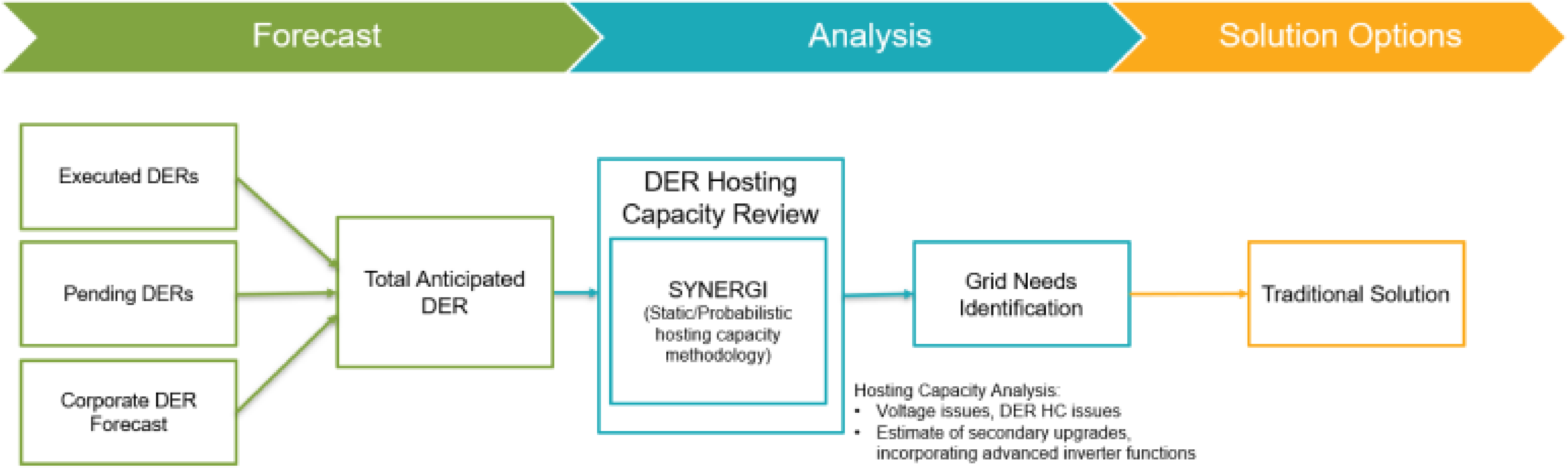


Figure 3: Hosting Capacity Grid Needs Identification Stages

DER Hosting Capacity - Analysis

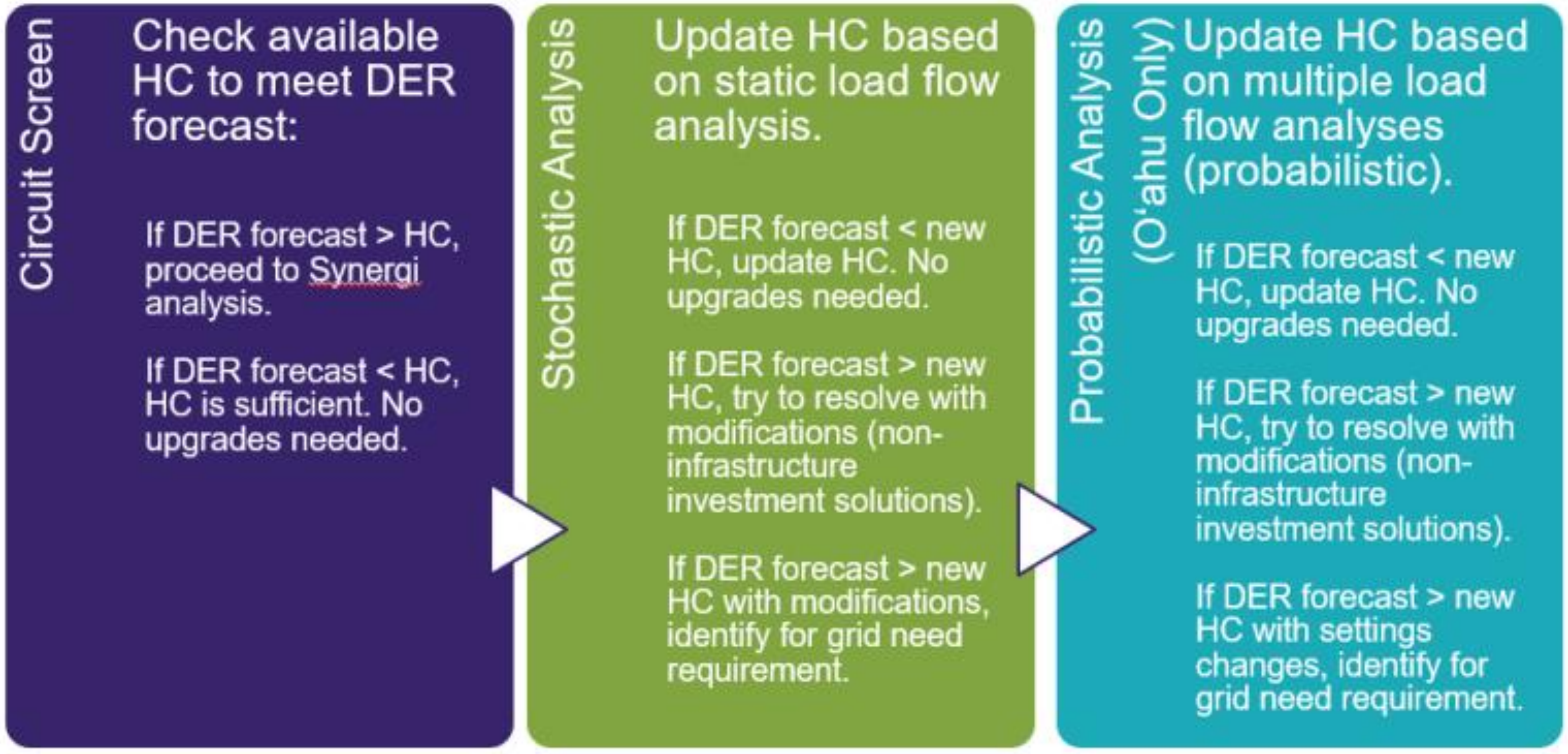


Figure 6. Summary of Hosting Capacity Analysis

Fail Circuit Screen (% of Total Circuits)		
High DER	Base DER	Low DER
30%	18%	17%

Grid Need Identified (% of Total Circuits)		
High DER	Base DER	Low DER
5%	3%	2%

Location-Based Forecasts Grid Needs

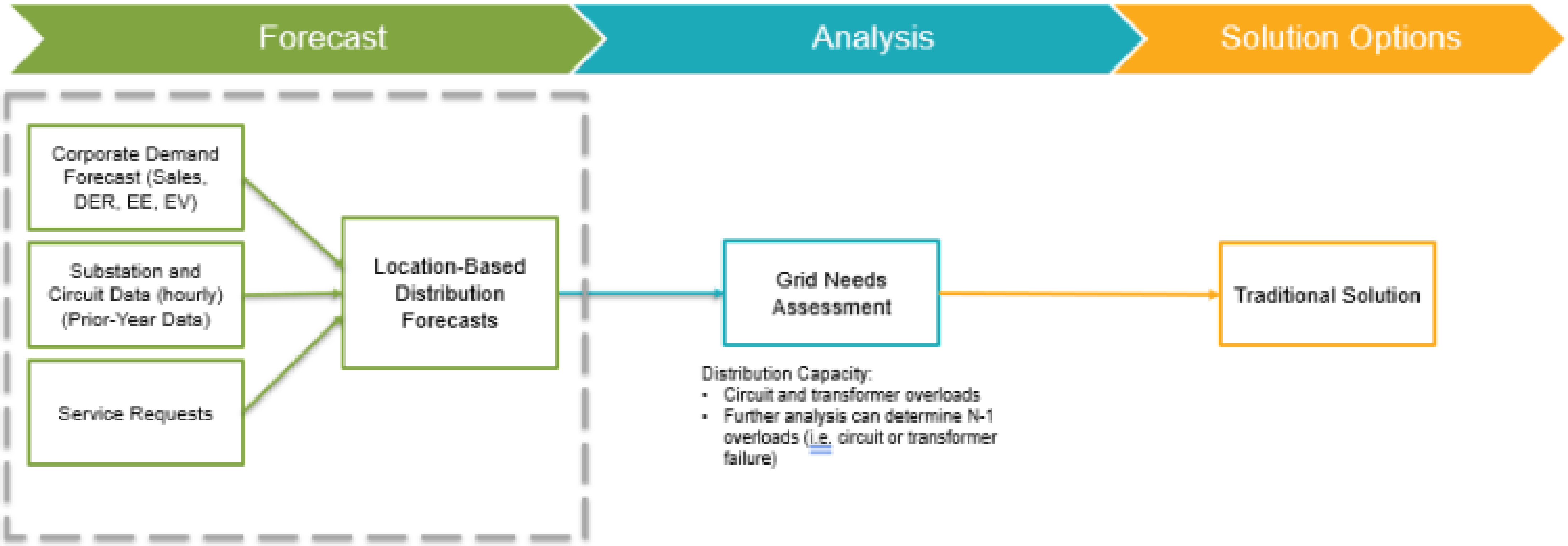


Figure 1-2 Location-Based Distribution Grid Needs Identification Stages

Location-Based Forecasts - Analysis

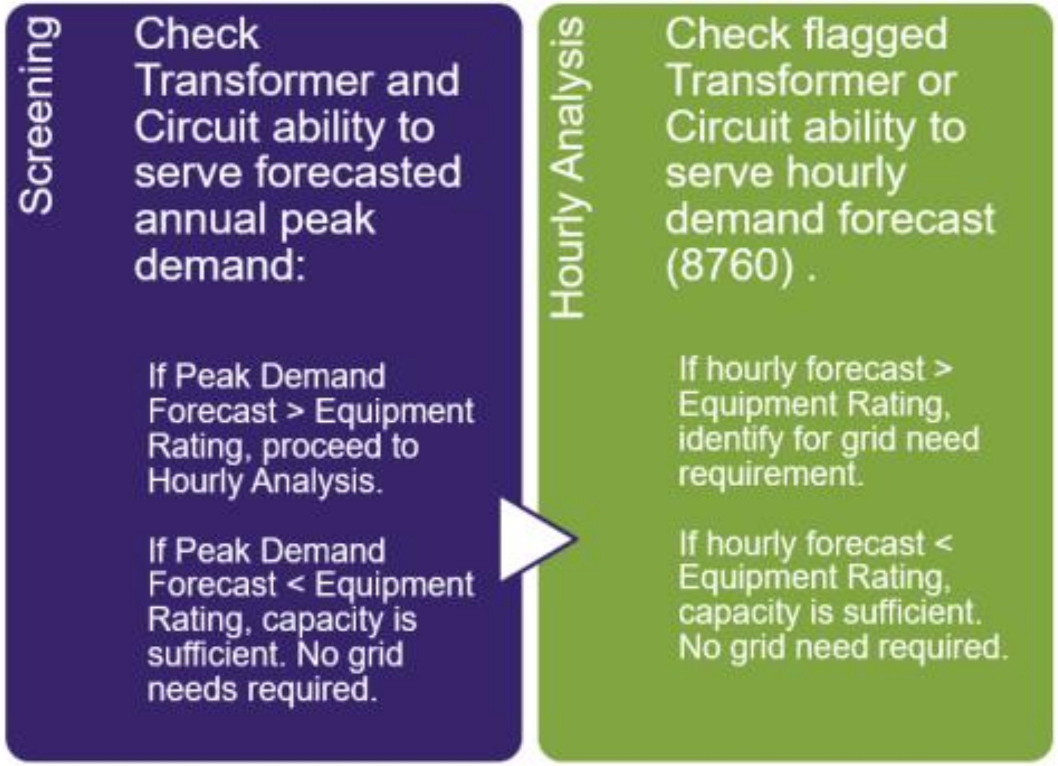


Figure 2-2: Summary of Screening and Hourly Analysis Process

Fail Screen (% of Total Circuits and Tsfs)			
High Load	Base	Low Load	Fast Adoption
19%	10%	10%	13%

Grid Need Identified (% of Total Circuits and Tsfs)			
High Load	Base	Low Load	Fast Adoption
3%	2%	1%	2%

Grid Needs Summary – Solution Options

Total Cost Estimate of Wires Solutions for <u>DER Hosting Capacity</u> Grid Needs ($M)		
High DER	**Base DER**	**Low DER**
$10	$6	$6

Total Cost Estimate of Wires Solutions for <u>Location-Based Forecast</u> Grid Needs ($M)			
High Load	**Base**	**Low Load**	**Fast Adoption**
$70	$50	$51	$59

Summary and Takeaways

- Distribution Planning Process
  - Adopted new tools and analyses for new process
  - Increased workload and complexity
  - Potential to utilize more of existing capacity with probabilistic analyses
- Scenario Planning
  - Provides bookend scenarios
  - Identification of solutions to address potential issues may start earlier
  - More closely aligns with Generation and Transmission analyses
  - Required robust stakeholder input to identify scenarios

Mahalo for your time

Any questions?

Open Discussion
Q&A

15 Minute Break

10:45 – 11:00 AM

Utility Presentations

Pacific Gas & Electric

Southern California Energy

San Diego Gas & Electric

High DER: Scenario Planning Workshop

Joint Presentation by PG&E, SCE, and SDG&E

April 22, 2025

Agenda

Topic	Presenter	Time
Introduction/Agenda (Joint)	Zach Branum (SDG&E)	11:00 – 11:05
Regulatory Requirements	Zach Branum (SDG&E)	11:05 – 11:10
SCE's Proposal and Q&A	Ari Altman and An Tran (SCE)	11:10 – 11:35
PG&E's Proposal and Q&A	Mark Jimenez and Tom Huynh (PG&E)	11:35 – 12:00
SDG&E's Proposal and Q&A	Yi Li and Wassim Alsafi (SDG&E)	12:00 – 12:25
Joint IOU Wrap-up of Topics in the Decision	Yi Li (SDG&E)	12:25 – 12:35
Q&A (Joint)	All	12:35 – 12:45

Regulatory Requirements

Regulatory Overview

- High DER Decision (D.)24-10-030, issued on Oct. 23, 2024, set forth that scenario planning would be included in the IOUs' distribution planning processes (DPP) for the 2025-26 cycle, but that certain elements were to be established through a stakeholder workshop and subsequent advice letter process
- As defined by Ordering Paragraph 7 of the Decision, 11 elements must be addressed in this Workshop, which have been incorporated into this presentation
- The Commission acknowledged that scenario planning can benefit the analysis of distributed energy resource (DER) adoption and customer behavior, but involves significant complexity
- Purposes of today's workshop:
  (1) Discuss barriers to use of multiple scenarios in the DPP
  (2) Determine how to integrate various scenarios into single investment plan
  (3) Develop an implementation plan, considering costs and affordability

Regulatory Timeline

April 22

Scenario Planning Workshop

May 9

Joint IOU Proposal on IEPR scenarios for the 2025 – 2026 DPP cycle

Week of May 19

Distribution Forecast Working Group

June 30

Tier 3 AL on Scenario Planning

July/August

Potential Approval of IEPR scenarios

Aug/Sep

Potential Approval of Tier 3 AL

Aug.-Oct.

Beginning of 2025-2026 DPP

SCE Scenario Planning Proposal

Why Scenario Planning?

- **Status Quo: a single deterministic forecast**
  - Sufficient when load growth was relatively modest and predictable
  - Customer energization requests adequately captured short-term growth
  - Significant deviations from the CEC's IEPR statewide forecast were rare and manageable given modest overall growth and long lead times for traditional large customer projects
- **The issue: the status quo does not address the new paradigm of accelerated load growth**
  - California, including in SCE's territory, is experiencing a high volume of large load requests, which leads to energization timeline concerns
  - Limiting planning to a single forecast based on historical loads will be insufficient in a number of areas
- **SCE's proposal: scenario planning based on at least two forecasts**
  - Allows the utility to proactively plan to anticipate *high load, short-lead time customer requests*
  - Enables procurement of long lead items, acquiring land in advance, adapting quickly to emerging customer needs, right sizing at the outset to prevent the need for immediate or repeated modifications
  - Creates framework to evaluate less certain and emerging load types, and to reasonably incorporate their potential grid impacts into the investment plan.
  - Addresses affordability by implementing a reasonable approach to risks and creating a single least-regrets investment plan

How SCE Approaches the Risk Trade-Offs of Scenario Planning

- **The Challenge:**
  - Scenario planning seeks to ensure grid readiness while avoiding unnecessarily early capital deployment
- **Why the Math Works Out:**
  - ***Timing*: Adding a mitigation project to the plan does not mean immediately spending all capital dollars to construct the project**
    - Land acquisition, design, permitting, equipment procurement, etc. may take years prior to initiation of construction, so bulk of costs accrue late in process
    - Completing early project phases allows for reduced lead times while preserving flexibility
  - ***Nature of Risk*: the impact of "getting it wrong" is asymmetrical**
    - The impact of customer energization requests materializing slower than expected can be mitigated:
      - ❑ If necessary, a project may be modified, delayed, or potentially cancelled, avoid unaccrued costs
      - ❑ Even if construction is already underway, infrastructure may be reallocated to serve other customer projects
    - The impact of insufficient grid capacity is daunting:
      - ❑ Opportunities to accelerate projects are limited and will come at higher cost
      - ❑ May cause significant customer delays, discourage customers from building, and in turn impact entire sectors and slow the achievement of key state policy objectives

SCE's Scenario Planning Implementation in the 2025-2026 Plan Cycle

- Develop Base and High forecasts:

Forecast	Known Loads	Pending Loads
Base	Customer Energization requests (same as 2024-2025 plan cycle)	Category A (same as previous cycle) Partial Category B (per SCE proposal)
High	Same as base	Same as base + broader Category B

- Identify grid needs and high-level solutions for both forecasts, territory-wide, for the 13-year planning horizon

- Apply decision logic to identify consistent and incremental least-regrets and low-risk solutions from the high scenario that can be bundled with base scenario solutions

Scenario Planning Decision Logic (1 of 2)
Overview and General Approach

- **Initial comparison:** The Decision process begins by comparing high-level solutions from the Base and High scenarios *within limited geographic areas,* each of which is typically served by a single substation.
- The comparison will have one of two broad outcomes:
  - **Consistent solution set**
    - If the high scenario and the base scenario require the *same solution* (e.g., a new circuit) within a predetermined timeframe of each other, this is considered a *consistent solution*; solution will be planned to the earlier need date.
      - ❑ There is high certainty the infrastructure is needed; the cost associated with risk of early deployment is small.
  - **Incremental solution set**
    - If the high scenario has *additional solutions*, (e.g., more circuits than base scenario) or the same solution but *more than the predetermined timeframe*, this is considered an *incremental solution*, and the "Detailed Decision Logic" applies (see next slide for examples)
- Note that, as in SCE's current planning process, all needs and all solutions are re-evaluated on an annual basis, and any investment may be modified, delayed, or cancelled if grid needs have significantly changed.

Scenario Planning Decision Logic (2 of 2)
Illustrative Examples for Incremental Solutions (Under Development)

- The table below provides selected examples of how SCE will develop a single investment plan where the initial comparison described on the previous slide resulted in "incremental solutions."
- This table provides selected cases where the base case identifies no solutions or modest solutions, and the high case has greater solutions. SCE plans to develop similar tables for other cases.

Base Scenario Solution	High Scenario Solution	Solution for Single Investment Plan	Benefits
No grid need	Sub-circuit solution	**Reassess next planning cycle**	• No risk of early capital deployment
	New circuit or more	**Potentially plan partial construction** • If grid need is within year 1-5 → plan to build out to first switch • If grid need is within years 6-10 → reassess next planning cycle	• Reduces lead time of future new circuit(s) by ~1-2 years • Built assets could be repurposed for other load growth-driven needs and increased operational flexibility if original needs do not materialize
New Circuit(s)	Base Case + X New Circuit	**Plan to build new circuit(s) to include Base Case need plus additional construction:** • If location of the high case's load growth is known → plan new circuit mainline toward load • Otherwise → plan out to first switch	• Reduces lead time of future new circuit(s) by ~1-2 years • Built assets could be repurposed for other load growth-driven needs and increased operational flexibility if original needs do not materialize
	Base Case + X New Circuit + Substation Capacity Upgrade	**Solution for circuits above, plus potential substation work:** • If substation utilization is less than approximately 60-90% → design and procure equipment for substation capacity upgrade • If substation utilization is more than 90% → plan to build substation capacity upgrade	• Substation capacity upgrade lead time ~4 years • Design and procurement reduces lead time of substation capacity upgrade by ~1 year • Built assets could be repurposed for other load growth-driven needs and increased operational flexibility if original needs do not materialize
	Base Case + X New Circuit + New Substation	**Circuit and Sub Solution above, plus potential land development** • Identify potential locations for new substation • If land highly constrained → may acquire land	• Advanced planning for land procurement

SCE's Long-Term Vision for Scenario Planning

- SCE recommends evolving its approach to scenario planning based on insights gained in the 2025-2026 plan cycle, and as more robust technical capabilities are implemented.
- The future state of scenario planning is envisioned to include:
  - **Probabilistic forecasting** with a distribution of forecasts generated by statistical methods
    - Multiple scenarios selected from this distribution
  - **Develop alternative investment plans** to meet grid needs from each selected scenario, and compare across all forecasts to understand the expected value of each alternative investment plan
  - **Select optimal investment plan that best balances overall customer impact and societal cost of unserved energy** (e.g., lost value due to energization delays, unrealized regional economic development)

Evolution of Scenario Planning

SCE plans to implement changes to better incorporate uncertainty into the 2025-2026 Plan Cycle, while working toward the long-term vision for subsequent planning cycles.

Current Process

Deterministic forecasting	Generate preliminary high-level solutions	Investment-grade plan
Single forecast determined from best available load information	Identification of overloads from single forecast Initial list of least-cost solutions meeting all overloads	Develop investment-grade buildout plan for detailed scoping

Initial Scenario Planning Implementation

Base Forecast	Grid Needs	High-Level Solutions	Decision Logic	Investment-grade plan
High Forecast	Grid Needs	High-Level Solutions		

Long-term Vision Using Probabilistic Forecasting

Forecast #1	Grid Needs & High-Level Solutions #1	Estimate of benefits & costs of solutions #1	Select optimal plan	Investment-grade plan
Forecast #2	Grid Needs & High-Level Solutions #2	Estimate of benefits & costs of solutions #2		
…	…	…		
Forecast #n	Grid Needs/Solutions #n	Estimate of B&C of #n		
Develop **forecasts with probability weightings** as the basis to develop and evaluate high-level solutions	Use rules-based model to generate preliminary versions of **high-level solutions for different forecasts**	Estimate performance of each solution set in each scenario.	Use predetermined **decision criteria** to select a solution set that is optimal across the range of scenarios.	Develop investment-grade buildout plan for detailed scoping

PG&E Scenario Planning Proposal

PG&E Scenario Planning Purpose and Objectives

Purpose: To inform PG&E's distribution capacity investment choices and to create projects to allow our system to adapt quickly to different scenarios while meeting customer needs (e.g. energization timelines) and supporting safety, reliability and affordability.

Detailed Objective: PG&E believes there are 3 components of this purpose – Efficient cost spending, confidence in cost spending, and supporting timely project completion for customer energization of both present and future applications. Each of the below objectives are tied to one or multiple pieces of the purpose.

- Approved purchases of long-lead materials (Transformer Bank, Substation Equipment, etc.)
- Proactive planning and design of PG&E substation, transmission, and distribution systems (higher nominal voltages, more ties, etc)
- Installing assets that can scale to higher scenario growth
- Initiating permits and land purchase negotiations early to push through any challenges to support timely energization
- Project planning and gating for construction and execution - "The right scope at the right time"
- Develop one set of actionable solutions to inform a single investment plan

Framework of Scenario Planning: The framework for PG&E's scenario planning involves 3 forecasts that are different at these levels –

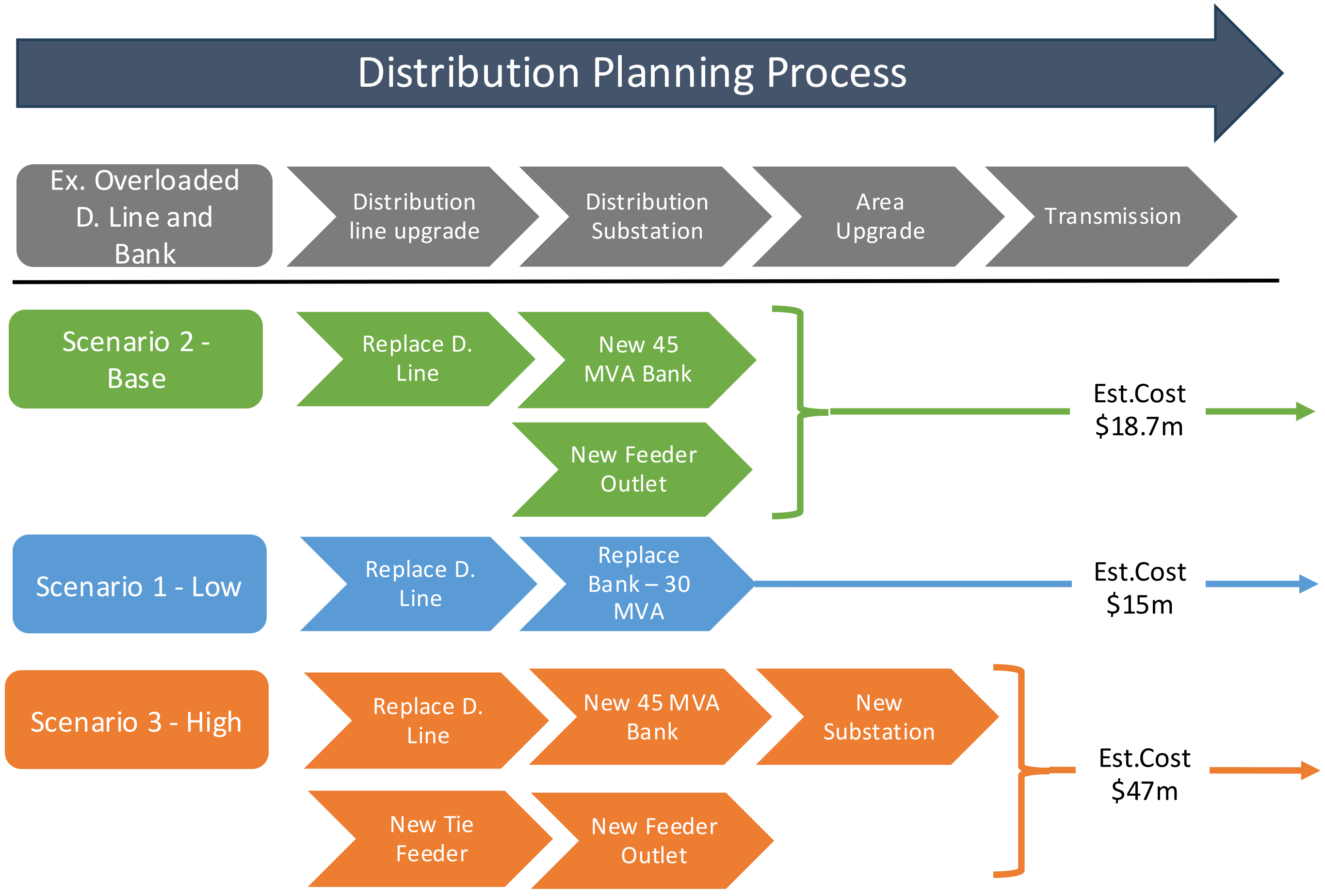
- Feeder and Bank Load Base
- IEPR / DER Category Selection
- Pending Loads Treatment In a Scenario

PG&E's Scenario Planning Proposal

Scenario	Feeder and Bank Load Percentile	IEPR DER Scenario Selection	Use of Known Load/Pending Load	Purpose / Use	Single Investment Strategy
Scenario Base	• 95th percentile base	• Reliability Forecast	• Known Load • Category A Pending Loads* • Category B Pending Loads (Capped at IEPR)	Design solution set according to the Base Scenario	PG&E will develop solutions using the base scenario and then adapt the plan using the low and high scenarios to support short, mid and long-term needs while considering likelihood of needs materializing, alternate solutions and least-cost, no regret projects. Meeting customer timelines for energization will be key in Scenario Low. Scenario Medium and High will provide confidence in longer-term spending to support customer energization with the goal of minimizing additional work.
Scenario Low	• 50th percentile base	• Custom Forecast**	• Known Load • Category A Pending Loads*	Ensure necessary investment in short-term, minimum required work to meet customer load and drive investment prioritization. Assess Base Scenario solution with lower forecast	
Scenario High	• 95th percentile base • Forecast includes Base Scenario projects	• Reliability Forecast	• Known Load • Category A Pending Loads* • Category B Pending Loads (Can exceed IEPR)	Adapt and drive efficient use of mid-term and long-term investment. Forecast includes Base Scenario projects. Assess Base Scenario solution with high forecast	

* Refer to Pending Loads Workshop and Deck for how Category A Pending Load are treated.
**Custom forecast at minimum considers known loads and minimum forecast to meet customer applications and needs
May incorporate additional load flexibility beyond the Base Scenario

Distribution Planning Process with Scenario Planning Example
Deciding Whether to Modify the Base Solution



Purposes within Scenarios	Does it prioritize near-term customer energization?	Does it prioritize long-term cost efficiency?	Is the utility confident in the scenario and spending?
Scenario 2	Yes	Yes	Yes
Scenario 1	Yes	No, focused on short term energization	Yes
Scenario 3	No, focused on long-term investments	Yes	Yes, for proactive long-term investments

Distribution Planning Process with Scenario Planning Example (Continued) Benefits/Risks Leading to Scoring on Purposes

Purposes	Risk Assessment
Does it support customer energization?	Can project timelines be met in order to energize known load timely?
	Can project timelines be met in order to energize Pending Load A timely?
	Can project timelines be met in order to energize Pending Load B customers timely?
	Are any customers flexible with their timelines or have they stated there is risk on their side?
Does it support cost efficiency for current and future?	Does the project scope include minimum upgrades?
	Is there incremental costs to perform grid upgrades that allow for significant capacity?
	Is the grid upgrades required in the next 5 years?
	Are there other benefits of the capacity upgrades? (Reliability or Operational Flexibility)
Is the utility confident in the scenario and spending?	Are any of the solutions the same throughout all 3 scenarios?
	Can PG&E design to specific "stages" of the ultimate design to minimize risks?
	If one or multiple customers withdraw, is the project scope still supported?
	Has customers been in contact with PG&E within the last year?
Other	Does the project scope support a single customer or multiple customers?

Benefits and Risks	Scenario 1 - Low	Scenario 2 – Base	Scenario 3 - High
Benefits	Meets customer timelines and is high confidence in customer load materializing	Meets customer timelines and is high confidence in customer loads and pending loads materializing Costs for incremental work would be significantly less than undertaking additional projects in subsequent years	Meets all current and future needs
Risks	Not meeting future customers timelines and may accrue significant upgrade costs if other loads materializes	Low risk in consideration for pending loads but also may need additional upgrade if all Pending Loads materialize	Customer timelines may not be met due permit timeline for larger design requirement. Costs can be significantly higher, especially if customer loads do not materialize.

Selected

PG&E's Scenario Planning Risks and Guardrails

- PG&E's risk in the proposed Framework for Scenario Planning lies in the following:
  - Pending load categorization and confidence
  - Accuracy of the IEPR base
  - Customer application withdrawal
- PG&E's guardrails will also rely in Pending Loads Categorization guardrails, but PG&E may also scope and design to the Mid and High scenarios, allowing projects to be descoped or cancelled prior to construction if Known Loads/Pending Loads withdraw or the IEPR does not meet the expectation.

SDG&E Scenario Planning Proposal

SDG&E's Scenario Planning Approach

Boosts implementation efficiency by optimizing tools and processes

Streamlines the process to minimize cost impacts to support affordability

Enhances grid readiness to meet the electrification needs of communities

Scenarios and Purposes[1]

Base Scenario

- **Description**: Base scenario will be selected based on IEPR Scenarios with an alternative load modifier.
- **Purpose**: This scenario will serve as the base forecast for the distribution planning process. A full distribution model will be created based on this scenario.

Scenario 1: Base Scenario with Alternative Equipment Thermal Capacity

- **Description**: This scenario will be assessed for the first three years to identify near-capacity needs before reaching 100% of equipment thermal capacity.
- **Purpose**: It aims to flag the needs identified in the Base Scenario that warrant additional assessments.

Scenario 2: Alternative IEPR Scenario

- **Description**: This scenario will be selected based on alternative IEPR Scenarios.
- **Purpose**: It aims to flag the needs identified in the Base Scenario that warrant additional assessments.

1. Scenarios created in accordance with SDG&E's pending load proposal

Solutioning for Multiple Scenarios

- Focus on circuit and bus needs
- Base scenario developed by comparing different IEPR DER scenarios and selecting the most appropriate for SDG&E
- Base scenario serves as foundation
- Scenarios 1 and 2 used to flag needs that warrant additional assessment
- Additional assessment based on case-by-case reviews
  - High Growth Areas
  - Community Development and Expansion
  - System Configuration
  - Historical and Future Customer Requests
- Create planning solutioning for needs identified in the Base Scenario (as informed by Scenario 1 and 2)

Potential Implementation in 2025 – 2026 DPP

Scenario	Forecasts	Upgrades Horizon		
		Line Segments	Circuits	Bus
Base Scenario	2024 IEPR Forecast Elements reconciled with known loads and pending loads	3 Years	10 Years	10 Years
Scenario 1	Base Scenario evaluated against 90% equipment thermal capacity	N/A	3 Years	5 Years
Scenario 2	For the 2025-2026 DPP cycle, SDG&E does not identify sufficient variation within IEPR to propose an alternative scenario.			

Joint IOU Wrap-up of Decision Topics

Scenario Planning Process – Current and Future Cycles

For this year, utilize the workshop and Advice Letter process defined in OPs 7 and 8 to adopt scenario planning framework and forecast scenarios for inclusion in the 2025-2026 cycle.

IOUs propose to discuss updates to non-base scenarios in the existing Distribution Forecast Working Group (DFWG). IOUs propose ED would approve non-base scenarios through the existing process used to approve IEPR base case selection.

IOUs will review scenario planning results, answer questions, and receive feedback in the existing Distribution Planning Advisory Group (DPAG).

Scenario planning framework is designed to have sufficient guardrails and guidance to enable appropriate flexibility to meaningfully incorporated a variety of future forecast scenarios. IOUs may recommend changes to the framework, if needed, in the context of DFWG.

Q&A

Open Discussion
Q&A

Break for Lunch

1:00 – 2:00 PM

Agenda - Afternoon

2:00 – 2:30 PM	Stakeholder perspectives on benefits, risks, safeguards, and reporting requirements. • Presentation by Stakeholders • Cal Advocates	Stakeholders will present considerations related to scenario planning and propose methodologies, safeguards, and reporting requirements to ensure effective and secure implementation.
2:30 – 3:15 PM	Open Discussion	Reactions and questions from stakeholder presentations
3:15 – 3:30 PM	Closing Remarks and Next Steps	Summary of key takeaway, closing remarks, and next steps

Stakeholder Presentations

Cal Advocates

Richard Khoe

Marc Hutton

Scenario Planning Workshop

Perspectives on Scenario Planning

Richard Khoe, Supervisor

Marc Hutton, Utilities Engineer

April 22, 2025

Affordability is a key issue

Residential average rates have significantly increased

	Average Rate ($ per kWh)	**3-year Change** Jan 2022 to Feb 2025	**10-year Change** Jan 2015 to Feb 2025
PG&E	$0.380	↑ 41%	↑ 101%
SOUTHERN CALIFORNIA EDISON	$0.316	↑ 26%	↑ 85%
SDGE	$0.397	↑ 5%	↑ 71%

https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/250218-public-advocates-office-q4-2024-rates-report.pdf

Overview of our position

- **Overall position:**
  - Scenario planning offers the potential to ensure grid planning accommodates a range of future distribution planning possibilities.
  - However, choosing only aggressive scenarios risks a bias towards aggressive load forecasts and, as a result, overbuilding.
- **Cost impact analysis**: Cal Advocates **analyzed cost impacts** under various distribution planning scenarios, including using our Distribution Grid Electrification Model (DGEM).
- **Ratepayer impact**: The results illustrate the **potential costs of overbuilding** resulting from a bias towards aggressive load forecast scenarios.

Methodology

Methodology

- DGEM is a model which disaggregates the 2023 Integrated Energy Policy Report (IEPR 2023) forecasts onto individual circuits in the three major IOUs' service territories.
- DGEM uses DMV vehicle data and Census data to estimate the locations of future EV loads on the grid, combining that with historic loads, ratings, and cost data provided by the utilities to estimate overloads and then grid upgrades costs to address overloads.
- Cal Advocates’ DGEM methodology is described at the following link: https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/230824-public-advocates-distribution-grid-electrification-model-study-and-report.pdf

Baseline scenario

- IEPR load shape scenario included in DGEM October 2024 preliminary results
- Major assumptions:
  - Vehicles charge at their registration address
  - All feeder overloads are addressed with new feeders
  - EV load shapes adhere to the IEPR's forecasts
- **All IOUs total cost through 2035: $22.7 bn**

Aggressive scenario 1

- Electrification Impact Study (EIS) load shape scenario included in DGEM October 2024 preliminary results
- Changed assumption compared to Baseline scenario:
  - EV load shapes adhere to the Electrification Impacts Study Part 1 forecast
  - This load shape has a much higher afternoon and evening peak
- All IOUs total cost through 2035: $36.2 bn
- **Incremental cost: +13.5 bn**

Aggressive scenario 2

- Aggressive EV adoption scenario developed from DGEM October 2024 preliminary results
- Changed assumption compared to Baseline scenario:
  - An additional 20% electric vehicle adoption beyond what was predicted by the IEPR 2023
- All IOUs total cost through 2035: $25.8 bn
- **Incremental cost: +$3.1 bn**

Load management scenario

- Load shape optimization scenario included in DGEM October 2024 preliminary results
- Changed assumption compared to Baseline scenario:
  - All vehicles adhere to an IOU-wide heavily managed load shape on system peak days
  - This scenario represents a lower bound on peak load added by EVs
- All IOUs total cost through 2035: $16.6 bn
- **Incremental *savings*: -$6.1 bn**

Findings

Findings

- **Upward forecast bias**: Scenario planning allows potential for **bias toward aggressive load forecasts** used in forecasting and investment planning if it focuses on adoption of aggressive scenarios.
- **Estimated ratepayer impacts**:
  - About $3 bn to $13 bn of *additional costs* to ratepayers through 2035 if aggressive scenarios are implemented.
  - Up to $6 bn of *savings* to ratepayers through 2035 if load management is optimized.
- **Cost of investments based on selected range of scenarios**:
  - Different scenario planning assumptions results in a very large range of costs.
  - Only aggressive forecast scenarios: **$22-36 bn**.
  - Full range of possible scenarios: **$16-36 bn**.

Recommendations and Issues for Further Discussion

Recommendations and issues

- **Scenario development / selection**: Which organization should develop scenarios to be used in annual distribution planning process?
  - Options:
    - CEC/IEPR scenarios could be used (as is currently done); and/or
    - Commission / Energy Division could direct scenarios for IOUs to evaluate (similar to Electrification Impact Study 2.0).
  - Where IOUs have studies or other information to inform scenarios, these could be provided to the CEC to support CEC scenario development.
- **Scenario consistency**: Need to have consistency between scenarios across all IOU service territories.

Recommendations and issues

- **<u>A robust process for scenario selection is essential</u>**: need transparency and stakeholder engagement in developing/applying key scenarios/assumptions, which significantly impact forecast, including EV load profiles and adoption rates.
- **<u>Current process looks reasonable</u>**:
  - IOUs propose which CEC/IEPR scenarios to apply (early May)
  - Distribution Forecast Working Group discusses scenarios (late May)
  - Party comments on IOU proposal(s) (late June)
  - Energy Division approval or modification (early August)
- **<u>Transparency at GNA/DUPR Stage:</u>**
  - Utilities should describe in their Grid Needs Assessment (GNA) or Distribution Upgrade Project Report (DUPR) how they have used the scenarios in planning

Questions?

Open Discussion
Q&A

Next Steps

June 30, 2025: The Utilities shall file a Tier 3 Advice Letter:

1. Summarizes the workshop;
2. Identifies the outcomes of the workshop;
3. Proposes a framework for implementation of scenario-based planning; and
4. Identifies the steps to be taken to facilitate the transition to using scenarios and a timeline for using them in the 2025-2026 DPP cycle.

There will be a 20-day comment period on the Tier 3 Advice Letter.