

Long-term Premise-Level Load and DER Forecast to Anticipate Grid Impacts

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Electrification Impacts Study in CA

- Electric distribution **grid requirements** and their associated costs increase significantly **beyond the traditional distribution grid planning cycle**
 - Up to \$50 billion in traditional electricity distribution grid infrastructure investments by 2035 across these unmitigated load scenarios
 - Secondary transformer and service upgrades alone are a non-negligible contribution to the total grid capacity upgrade costs

<https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K423/508423247.PDF>

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Electrification Impacts Study Part I: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates

Prepared for: California Public Utilities Commission, Energy Division

Proceeding R.21-06-017 (Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future)

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Electrification Impact Study Part 1 - Summary

The Context

- In support of a state regulatory agency, Kevala developed a hyper-granular forecast through 2035 that provides insights into **where** and **when the distribution grid will need enhancements and the potential costs** of meeting these needs exclusively with distribution assets.

Part 1

Bottom-Up Load Adoption Model and System-Level Electrification Cost

Estimate: Estimate scale of electrification impacts from the bottom up; enable premise- and circuit-specific grid integration analysis

Part 2

Electrification Grid Integration Report:

Framework for estimating localized grid investments and program enhancements; identify NWAs to mitigate electrification impacts

The Approach

- Individually **model baseline load growth, DER adoption, and DER behavior for 12 million plus calibrated to the state's current load forecast.**
- Analyze four alternate scenarios calibrated to different zero-emissions vehicle (ZEV) forecasts and two net energy metering (NEM) tariffs.

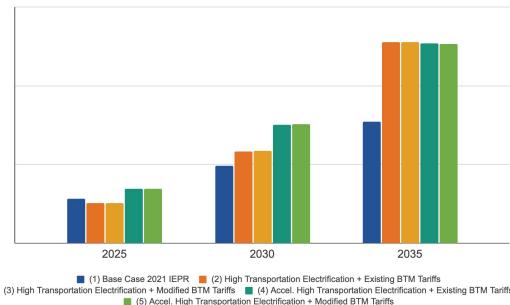
2035 Feeder-Level Capacity Overloading, Accel. High Transportation Electrification



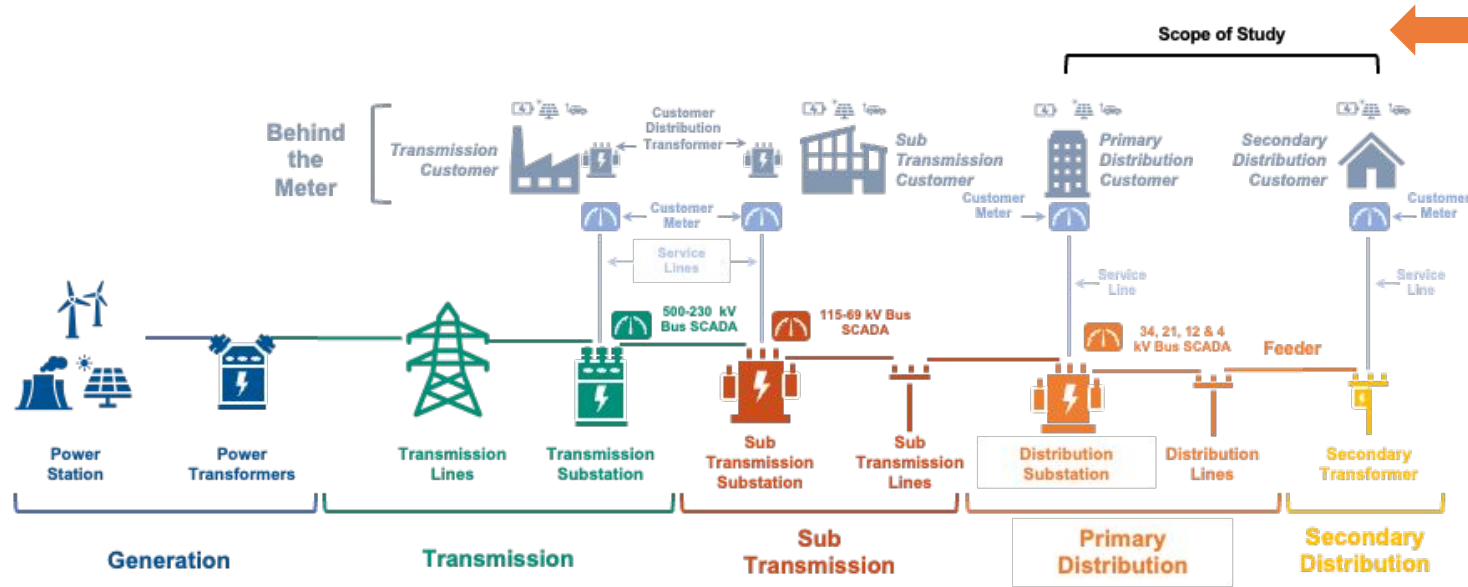
The Results

- Using current processes and without any mitigations, Kevala estimates **tens of billions in distribution investments to support electrification** through 2035.
- Utilities **risk missing the where** and the **when** of necessary distribution system upgrades without additional and continuous analysis of data and longer distribution planning horizons.

Upgrade Costs Estimates through 2035



Baseline Net-Load: Objective



Study Hypothesis: The development of a baseline net-load forecast by premise that incorporates varied assumptions of demand modifiers is needed the most accurate way to generate estimates of the **where** and the **when** of capacity needs at a secondary transformer, feeder, feeder bank, and substation across all three large IOU service territories in California

EIS Methodology

Objective

Baseline
Load
Forecast



Agriculture



Residential



Commercial



Industrial

Demand
Modifier
Forecasts



EV/EVSE



PV



EE

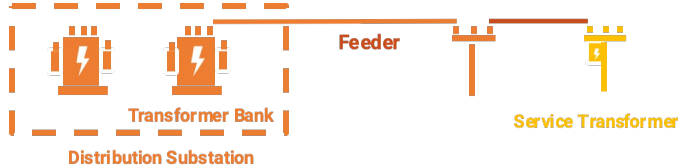


BE

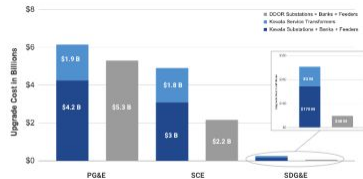


BESS

Capacity
Expansion
Grid Needs

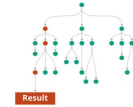


Cost
Forecast

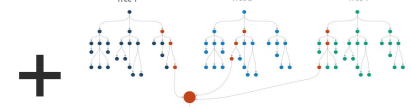


Methodology

Premise Level
Hybrid
Forecast using
AMI



Decision Tree



Extremely Randomized Forest

Adoption
Forecasts
Calibrated to a
Target



Size



Behavior

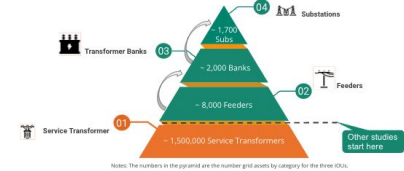


Adoption



Target

Stepwise Grid
Infrastructure
Needs
Assessment



Unit Cost
Assignment &
Aggregation



\$X



\$Y



\$Z

DER Modeling Basis



Size

- **Output** is an estimate of the capacity of the DER, such as the appropriate capacity or nameplate rating of the DER for a given premise, or percent change in premise load
- Determined based on characteristic of a premises, such as baseline load (e.g., to get to 'net zero' for PV), historical DER sizing (e.g., historical percent savings from EE) or technology adoption (e.g., Level 1 vs Level 2 charger)



Behavior

- **Output** is the hourly resolution (8760 profile) behavior of the DER over the course of a year
- Determined based on either engineering algorithms (e.g., PV based), statistical relationships (e.g. EE) or a combination of premise characteristics and customer behaviors (e.g., EV)



Adoption

- **Output** is an estimate of the likelihood that a premise will adopt the DER (specifically an adoption propensity score between 0 (definite non-adoption) and 1 (definite adoption))
- Determined using statistical modeling techniques that examine the relationships among certain premise (or customer) attributes and historical adoptions



Target

- **Input** is an estimate of the level of adoption of a DER in terms of capacity (e.g., kW of PV installed) or number DERs adopted (e.g., numbers of EVs)
- Determined using medium case scenario from Integrated Energy Policy Report 2021 mid-case forecast for base case and other targets for specific EV scenarios

Aligning Top-down & Bottom-up Forecasts

Select grid infrastructure or area to allocate appropriate number of EV chargers to align with regional EV adoption forecasts

1

EV Charge Inputs

Residential Charger
Count

30

Strategy

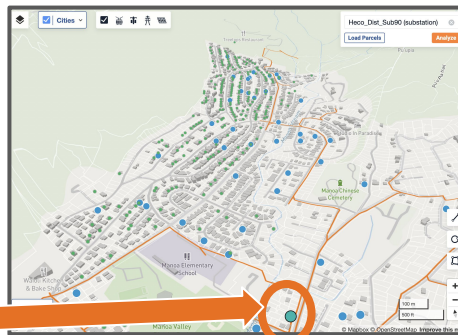
☒ Residential

☐ Commercial

Back

Cancel

Run Analysis

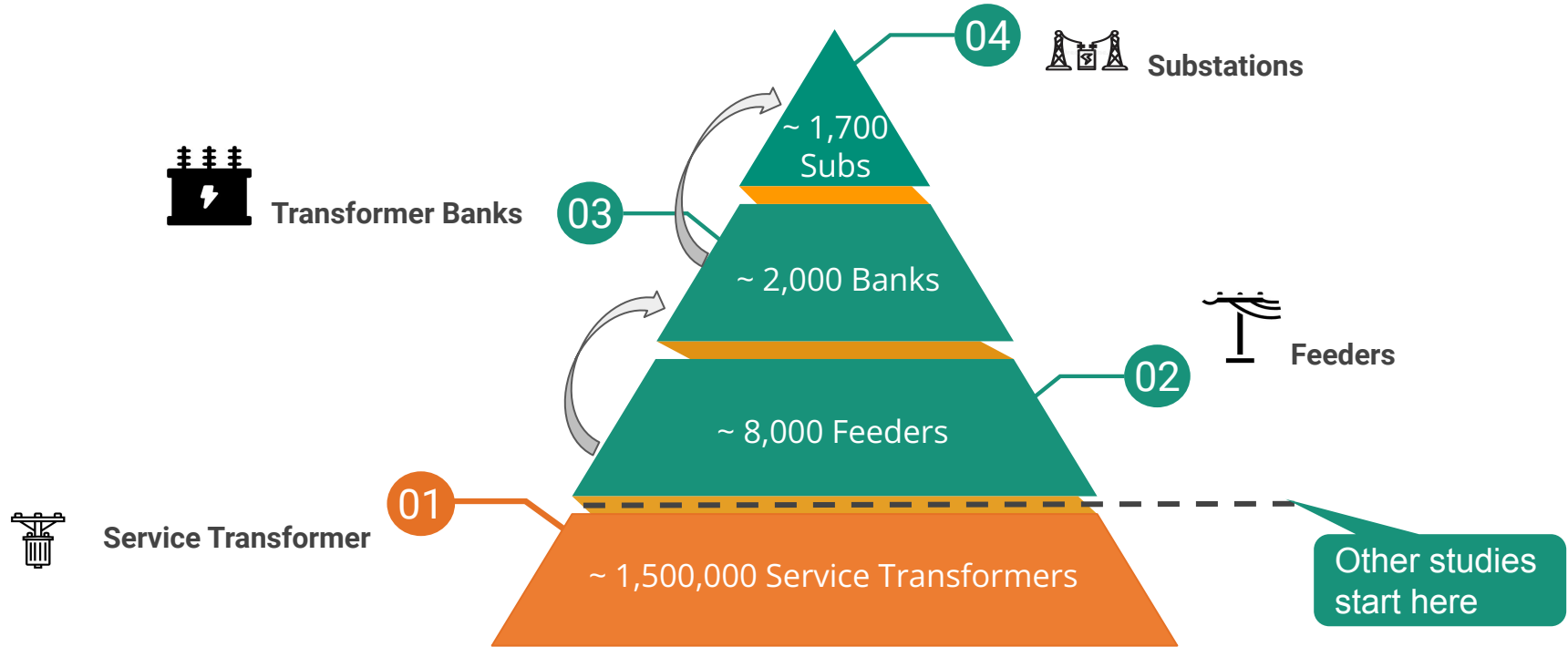


Identify the most probable locations for EV charger deployment and load impacts on a feeder, circuit, or within an area and generate time-series forecasts

2



Infrastructure Upgrade Costs Approach



Notes: The numbers in the pyramid are the number grid assets by category for the three IOUs.

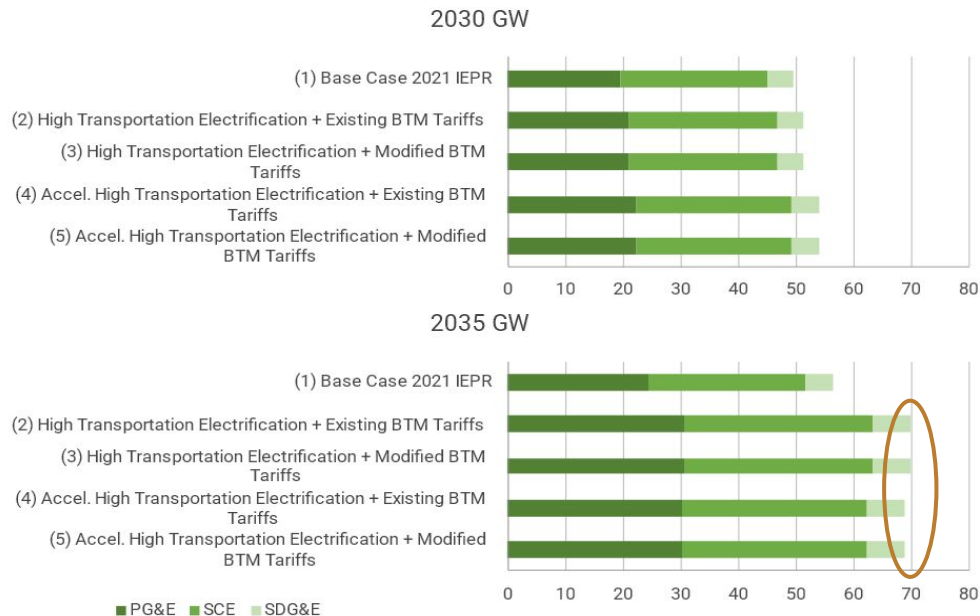
Five Scenarios Designed to Focus on the Impact of Transportation Electrification and PV BTM Tariffs

*All Transportation Electrification assumptions used in the Part 1 scenarios are consistent with state agency coordinated assumptions. The Part 1 Study Base Case is based on the 2021 Integrated Energy Policy Report (IEPR) forecast assumptions as of early Q1 2022. Since that time, the CEC increased the Transportation Electrification assumptions for the IEPR.**

Scenario	(1) Base Case IEPR 2021	(2) High Electrification + Existing BTM Tariffs	(3) High Electrification + Modified BTM Tariffs	(4) Accelerated High Electrification + Existing BTM Tariffs	(5) Accelerated High Electrification + Modified BTM Tariffs
Input Name	Demand Forecast/DER Growth Forecast Calibration Target				
Transportation Electrification	IEPR 2021 Mid Scenario 4.6 million light-duty and 289,000 medium- and heavy-duty ZEVs by 2035 (statewide)	Interagency Scenario 13.1 million light-duty and 287,000 medium- and heavy-duty ZEVs by 2035 (statewide)		IEPR 2021 Bookend Scenario 12.9 million light-duty and 291,000 medium- and heavy-duty ZEVs by 2035 (statewide)	
BTM PV Rate Design	Existing BTM rate design	Existing BTM rate design	Modified BTM rate design	Existing BTM rate design	Modified BTM rate design

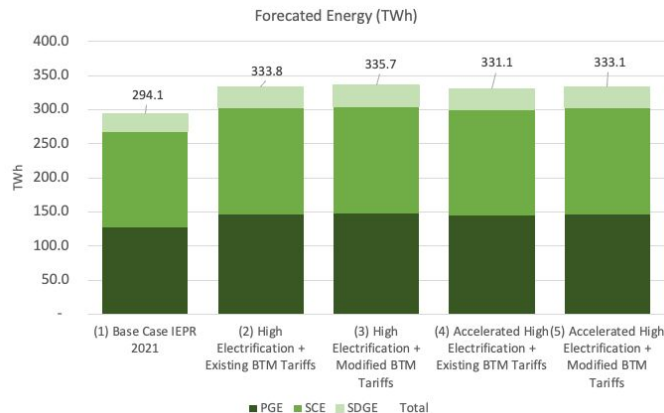
- Peak demand, energy efficiency, building electrification, solar PV, BESS are **all calibrated to 2021 IEPR mid-case**.
- Except for BTM tariffs, **rate levels and design are held constant at early 2022 levels for each IOU**; modified BTM tariffs reflect the Proposed Decision framework in R.20-08-020 issued on December 13, 2021 that was subsequently withdrawn.

Load Increases to ~70GW by 2035



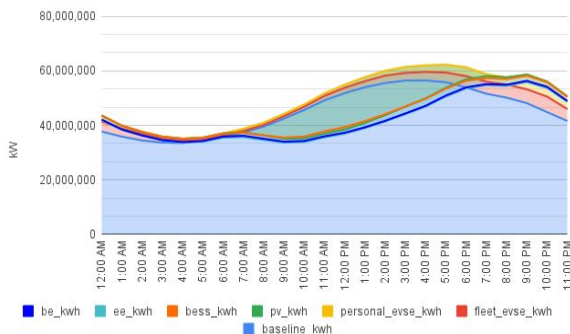
All scenarios result in peak demand increasing to between **55 and 70 GW by 2035**

- 2035 electric vehicle projections appear counterintuitive (High vs. Accel.) but are based on the adoption curves available in the agency projections applied and timing of agency projection availability, with both scenarios reaching about 70 GW by 2035.
- All scenarios increase energy use by between 180% and 210% of current, providing additional 'sales' to aid in collecting additional costs

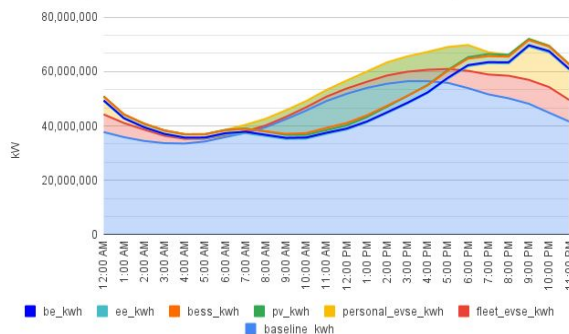


Peak Load Change Driven by EV/EVSE

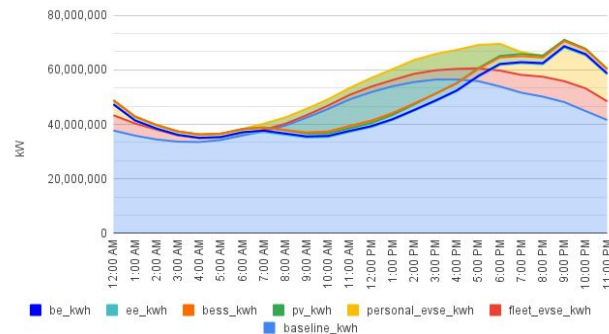
Base Case - Total Load - 3 IOU Peak Day - 2035



High Electrification - Total Load - 3 IOU Peak Day - 2035

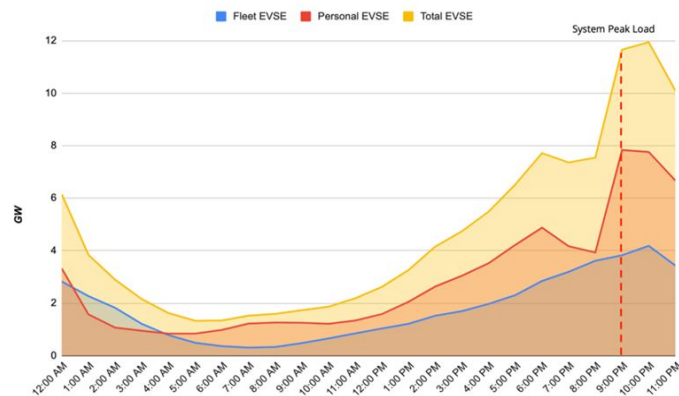


Accelerated High Electrification - Total Load - 3 IOU Peak Day - 2035



- The study assumed **adherence to existing time-of-use (TOU) periods** through 2035 to study what may be a worst-case scenario for peak load impacts from vehicle charging (*orange chart area*).
- As a result, the **system peak shifts to 9 pm**, which is the current end of the peak period for most of the IOU's TOU rates
- EIS Part 2 is expected to explore alternative assumptions about customer charging behavior

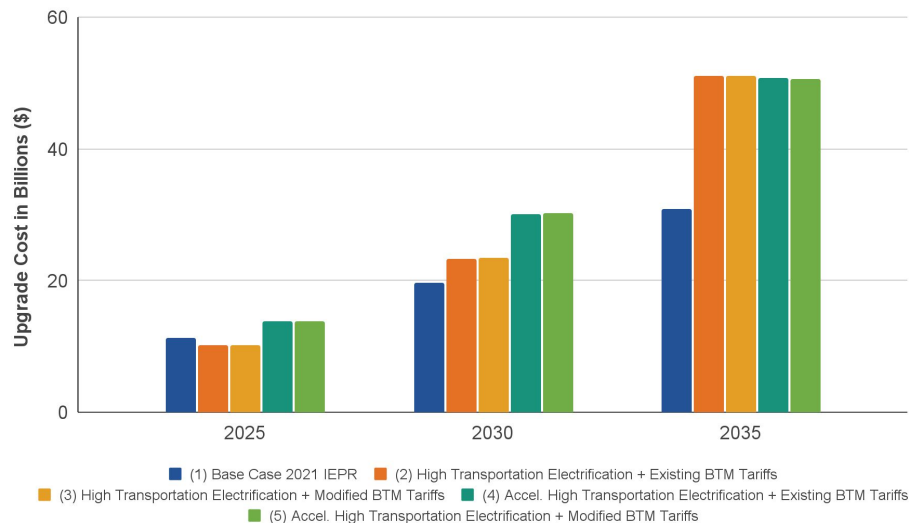
PG&E hourly Electric Vehicle Support Equipment load profile



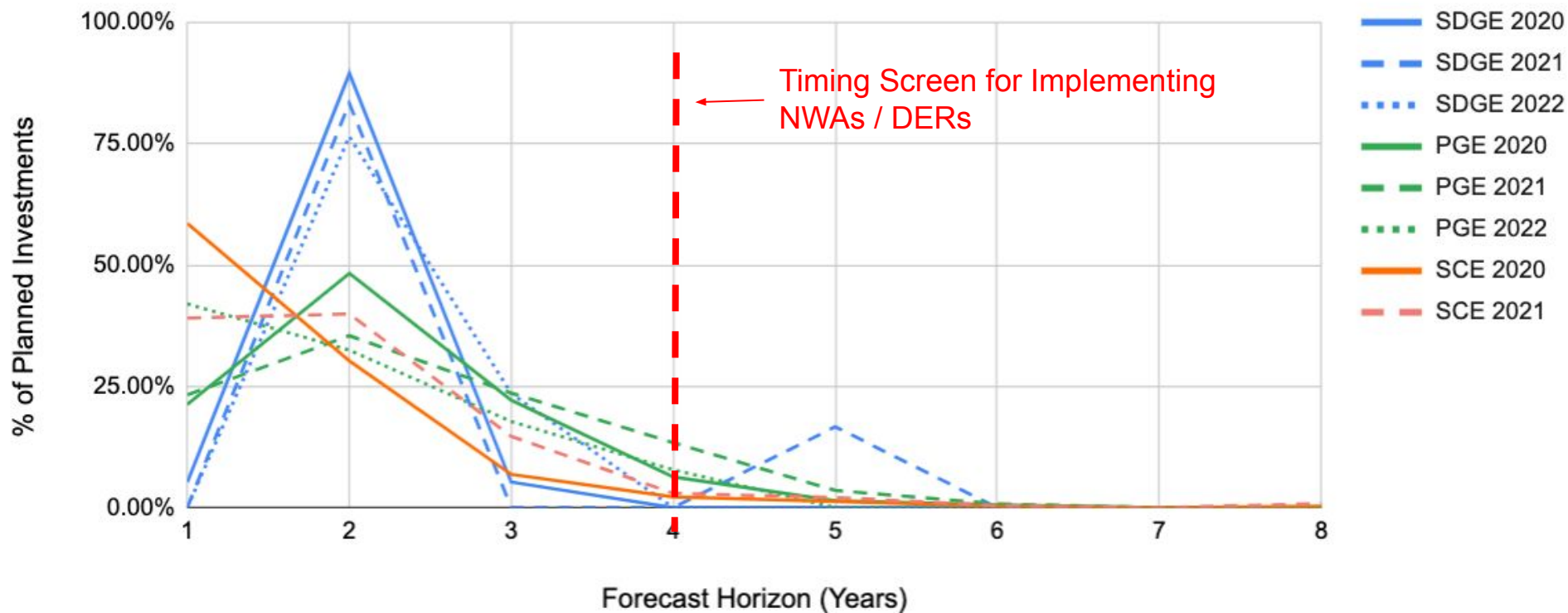
Long-Term Upgrade Costs of IEPR 2021 and Electrification Scenarios

- IEPR 2021 Base Case shows significant upgrade costs in 2030 and 2035
- All four electrification scenarios result in similar total upgrade costs in 2035
 - Key difference is the impact of the “Accelerated electrification” scenario in 2030
- Initial estimate of service transformer upgrades costs shows significant electrification impacts on secondary systems

Total Capacity Upgrades Costs - PG&E, SCE and SDG&E



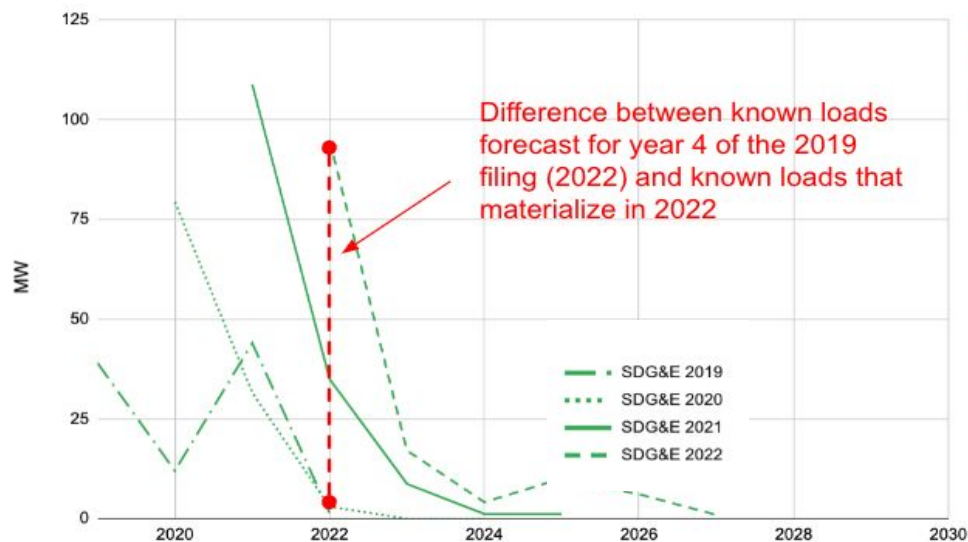
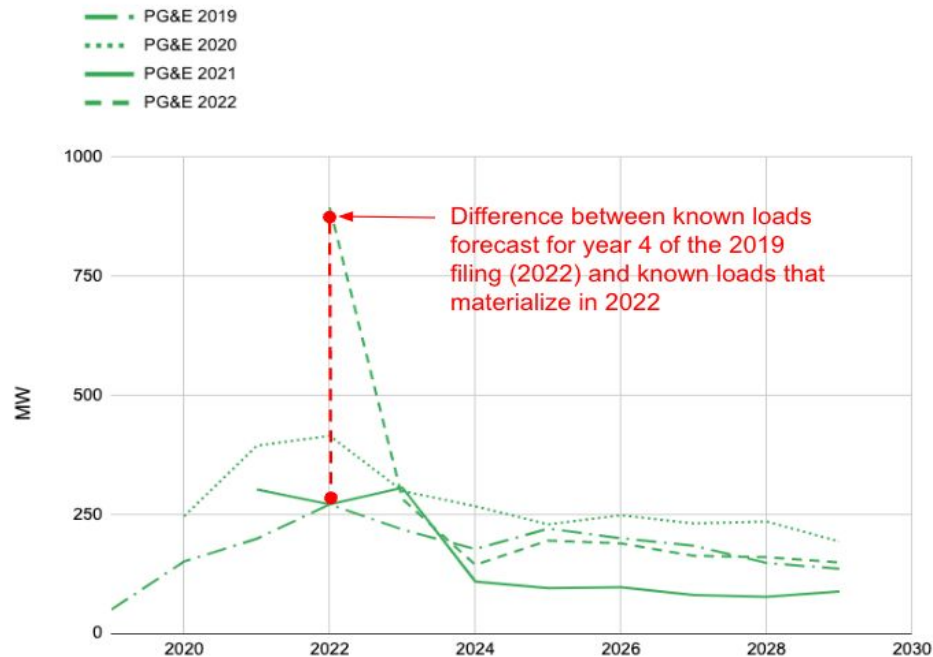
Historical Investments in CA



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

*SCE 2022 GNA delayed until Jan. 2023

Known Loads* Driving Investments is Reactive



*“Known loads” is used to mean load growth for new or additional load that is based upon customer request for new service

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

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Distribution Investment Deferral Framework: Evaluation and Recommendations

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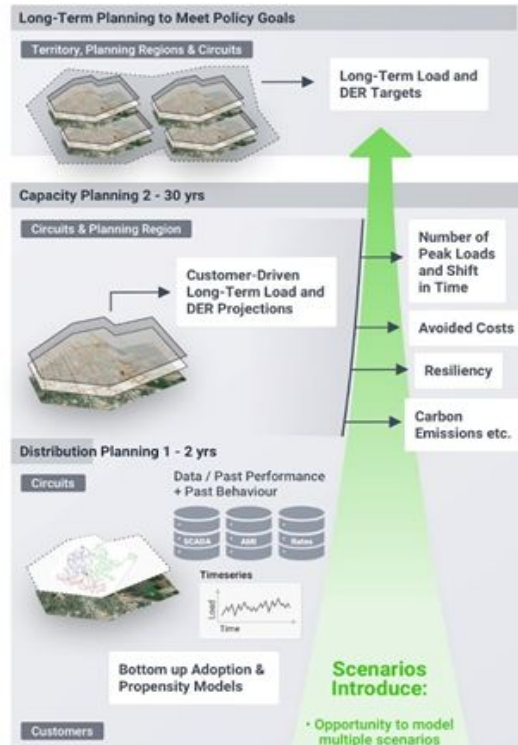
November 14, 2022

Gaps and Opportunities

- Load and DER Forecasting
 - High spatial and temporal resolution
 - Longer term forecast
- Scenario and Probabilistic Methods
- Objectives and Metrics
 - N-1 thermal
 - Cost
 - + Resilience, hosting capacity, equity, energy efficiency and carbon emissions

<https://www.nrel.gov/docs/fy23osti/83892.pdf>

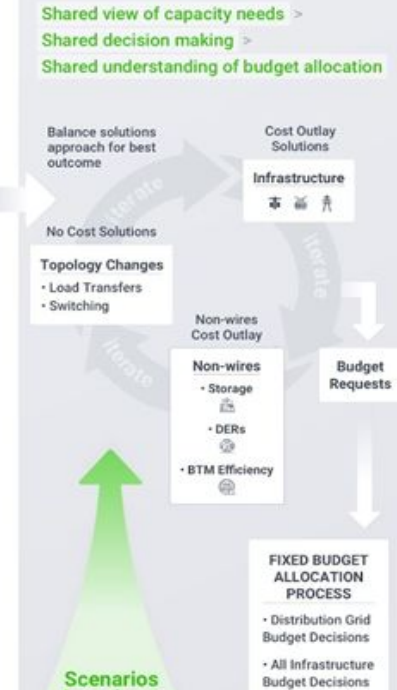
ONGOING PLANNING STREAMS



Future Scenarios at Territory, Region, Distribution Levels



COORDINATED SOLUTIONS & STRATEGIES & BUDGETS



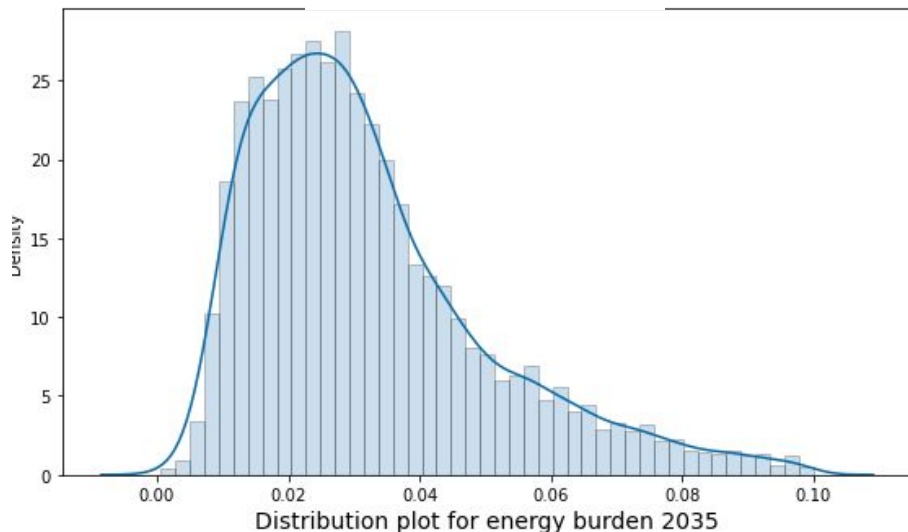
Additional

- Explore influencing behavior at address-level:
- Rates Programs
 - DR Programs
 - Other Incentives

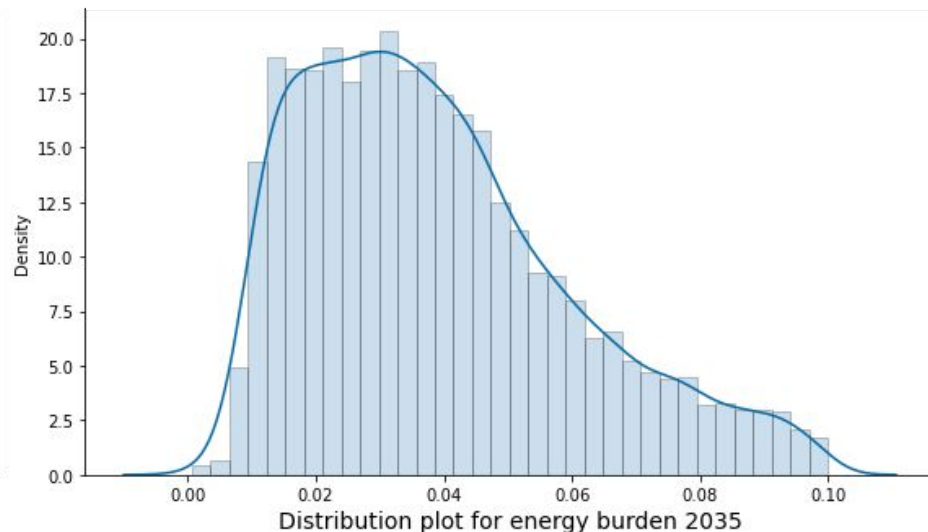
Distribution of Electricity Burden

Accelerating electrification could increase electricity burden

(1) Base Case 2021 IEPR



(4) Accel. High Transportation Electrification + Existing BTM Tariffs



Caveat: This analysis does not include other factors such that would affect the household income and share of electricity costs (fuel costs, heating costs, etc.)

New tools are needed to evolve how we incorporate supply and demand into planning processes

Premise-level approach provides unique insights about what, where, when, and how much distribution grid enhancements are needed.

- The variability and dynamism of customers is accelerating
- We are entering an era from deferral to **capacity expansion** for electricity grid infrastructure
 - A different kind of load growth will be driving planning
 - Transmission and distribution system constraints will affect the size and behavior of DERs
- All of this needs to become more aware of the **address-specific impacts of electrification** - including how rates, bills and carbon can be mitigated

Thank you!

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