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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) ELECTRIFICATION IMPACTS STUDY PART 2 FINAL REPORT

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Dated: **January 28, 2026**

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Pursuant to Ordering Paragraph (OP) 20 of Decision (D.) 24-10-030 and the September 24, 2025 letter from CPUC Executive Director Rachel Peterson authorizing, in part, the Utilities' request for an extension of time to comply with OPs 19 and 20 of D. 24-10-030, Southern California Edison Company hereby submits its Electrification Impacts Study Part 2 Final Report.

Respectfully submitted,

WILLIAM YU

/s/ William Yu

By: William Yu

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January 28, 2026

Attachment

SCE’s Electrification Impacts Study Part 2 Final Report

ELECTRIFICATION IMPACTS STUDY PART 2

Final Report

Southern California Edison

January 28, 2026

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1.0 Executive Summary

This report presents an overview of the preliminary findings and recommendations from Southern California Edison's (SCE) Electrification Impacts Study, Part 2 (EIS 2)

The study evaluates capacity overloads and infrastructure needs for distribution substation and primary systems operating below 50 kV, as well as secondary distribution systems and the associated costs under four scenarios: a base case, an equity-driven case, and two demand flexibility cases with varying levels of customer participation. All four scenarios are evaluated across two planning horizons: 2025-2030 and 2031-2040. The base scenario has a total cost estimate of $13.1 billion.

The study employs a partially automated decision tree methodology to identify recommended mitigation measures, which differs from the traditional Distribution Planning Process (DPP) that relies on a team of engineers to select the most cost-effective solutions. While EIS 2 is designed to align with DPP outcomes, methodological differences are expected. This approach was taken in EIS 2 to allow four scenarios to be analyzed in the time it typically takes to analyze a single scenario within the DPP.

Key infrastructure needs identified in the study include upgrades and additions to distribution circuits, substation capacity expansions, new substation construction, 4 kV circuit cutovers and substation eliminations, and upgrades to secondary service transformers and conductors. The study also evaluates the integration of demand flexibility and equity considerations into the distribution planning and execution process.

The equity scenario did not result in a significant increase in new capacity projects, at an additional cost of $0.16 billion. The two Demand Flexibility scenarios showed potential to save $0.32 billion and $1.38 billion, respectively. However, the cost-effectiveness and reliability of demand flexibility require further evaluation. Based on these findings, SCE provides the following conclusions:

1. The EIS 2 scenarios provided insights into the potential grid needs and mitigation measures required under distinct assumptions. However, these scenarios are unlikely to occur in isolation. Rather, appropriate levels of DER adoption and demand flexibility will be embedded in scenarios evaluated as part of the annual Distribution Planning Process.

2. SCE acknowledges the critical importance of equity in the distribution planning process. The equity scenario evaluated in EIS 2 (Scenario 2) is a less likely DER adoption pattern barring significant policy intervention. The results of the EIS 2 Equity scenario suggest such a shift in adoption would not have significant impacts on investment requirements.

3. SCE is committed to advancing the integration of demand flexibility into its distribution planning and execution process both through enhancements to forecasting and through evaluation of its role in the solution menu.

4. Approaches tested in the EIS 2 study will inform the forthcoming Distribution Planning and Execution Process, notably the partially automated solutioning script that will be the foundation of the scenario planning decision logic, and enhancements to forecasting methodologies to more accurately reflect demand flexibility levels

2.0 Background and Context

A draft version of this study report, with preliminary results from EIS 2, was filed on October 31, 2025. The findings in the present final version have been revised based on feedback from Energy Division. Note, however, that no additional studies were conducted to bring in new data since the draft filing.

3.0 Objective and Scope

SCE conducted EIS 2 to estimate potential infrastructure needs and associated costs to upgrade the primary and secondary distribution grid under four distinct scenarios: a base case, an equity-driven case, a demand flexibility case, and an alternate demand flexibility case focused on augmented levels of demand flexibility for electric vehicles and energy storage. These scenarios were designed to reflect a range of impacts based on varying DER adoption patterns and demand flexibility.

The scope of EIS 2 includes evaluating capacity overloads and infrastructure needs for distribution substations and primary systems operating below 50 kV, and secondary distribution systems, for 2025-2030 and 2031-2040.

4.0 Scenario 1: Base Case with Typical Planning DER Dispersion

4.1 Overview

Scenario 1 is a “typical planning” reference point to compare against scenarios 2, 3, and 4. Aggregate demand in this scenario is based on the California Energy Commission’s (CEC) 2023 Integrated Energy Policy Report (IEPR) Local Reliability Scenario, while DER adoption patterns align with SCE’s 2024–2025 Distribution Planning Process (DPP). Scenario 1 is intentionally structured to closely mirror SCE’s 2024–2025 DPP. However, unlike SCE’s DPP that is performed by a team of over 100 engineers, EIS 2 utilizes a decision tree approach to identify grid needs and corresponding mitigation strategies.

4.2 Sum of Non-Coincident Circuit Peaks

The following table represents the sum of non-coincident circuit peaks for Scenario 1. Consistent with current practice in the distribution planning process, the individual non-coincident circuit peak loads were used to develop grid needs, solutions, and cost estimates.

TABLE 1: SCENARIO 1 SUM OF NON-COINCIDENT CIRCUIT PEAKS

	2030	2040
Scenario 1 Sum of Non-Coincident Circuit Peaks	38.33 GW	41.54 GW

4.3 Primary and Secondary Results

The tables below summarize the total number of mitigation projects by type identified in Scenario 1.

TABLE 2: SCENARIO 1 PRIMARY RESULTS

Timeframe	Small DCU[1]	Large DCU	New Circuits	Substation Capacity Upgrades	New Substations	4 kV Circuit Cut Over	4 kV Sub Eliminations
2025-2030	109	229	330	188	11	344	43
2031-2040	49	100	134	35	4	190	52
Total	158	329	464	223	15	534	95

TABLE 3: SCENARIO 1 SECONDARY RESULTS

Timeframe	Service Transformer Upgrades
2025-2030	22,192
2031-2040	15,859
Total	38,051

4.4 Total Costs

Costs for primary and secondary upgrades are presented below in millions of dollars.

TABLE 4: SCENARIO 1 TOTAL COSTS

Timeframe	Primary	Secondary	Total
2025-2030	$ 8,507	$ 418	$ 8,925
2031-2040	$ 3,788	$ 350	$ 4,138
Total	$ 12,295	$ 768	$ 13,063

[1] Distribution Circuit Upgrade

5.0 Scenario 2: Base Case with Equity DER Dispersion

5.1 Overview

This scenario evaluates how an equity-focused Distributed Energy Resource (DER) adoption pattern could influence grid needs and mitigations. It specifically aims to highlight differences in project requirements and associated costs when DER adoption levels in priority populations are set to match adoption levels of non-disadvantaged communities.

5.2 Sum of Non-Coincident Circuit Peaks

The following table represents the sum of non-coincident circuit peaks for Scenario 2. Consistent with current practice in the distribution planning process, the individual non-coincident circuit peak loads were used to develop grid needs, solutions, and cost estimates.

TABLE 5: SCENARIO 2 SUM OF NON-COINCIDENT CIRCUIT PEAKS

	2030	2040
Scenario 2 Sum of Non-Coincident Circuit Peaks	38.43 GW	41.82 GW

5.3 Primary and Secondary Results

The tables below summarize the total number of mitigation projects by type identified in Scenario 2.

TABLE 6: SCENARIO 2 PRIMARY RESULTS

Timeframe	Small DCU	Large DCU	New Circuits	Substation Capacity Upgrades	New Substations	4 kV Circuit Cut Over	4 kV Sub Eliminations
2025-2030	105	232	333	189	11	347	43
2031-2040	42	112	137	34	4	192	54
Total	147	344	470	223	15	539	97

TABLE 7: SCENARIO 2 SECONDARY RESULTS

Timeframe	Service Transformer Upgrades
2025-2030	22,510
2031-2040	17,751
Total	40,261

5.4 Total Costs

Costs for primary and secondary upgrades are presented below in millions of dollars.

TABLE 8: SCENARIO 2 TOTAL COSTS

Timeframe	Primary	Secondary	Total
2025-2030	$ 8,574	$ 424	$ 8,998
2031-2040	$ 3,830	$ 390	$ 4,220
Total	$ 12,404	$ 814	$ 13,218

6.0 Scenario 3: SCE's Initial Demand Flexibility Case with Typical Planning DER Dispersion

6.1 Overview

This scenario assesses the potential capital deferral benefits based on assumed levels of demand flexibility for select end uses. While DER adoption assumptions remain at typical planning levels, aggregate load shapes were adjusted using the California Energy Commission's (CEC) "Enhanced Demand Flexibility" tool (D-Flex tool). Scenario 3 evaluated the potential impacts of load shifting for end uses including light-duty EV, medium/heavy-duty EV, non-residential energy storage, residential energy storage, and HVAC-cooling.

In this scenario, demand flexibility was specifically assessed at the local circuit level rather than being extrapolated from system-level aggregation. To determine the amount of available load flexibility at each circuit, SCE began with circuit-level DER forecasts from SCE's DPP Scenario 1. These forecasts provided estimates of DER adoption and load profiles specific to each circuit. Assumptions were not taken from current and foreseeable program designs. Instead, a set of assumptions were taken from the CEC's D-flex tool—such as control eligibility, participation rate, and impact—were then applied to estimate the realistic potential for load flexibility. By focusing on the individual characteristics and resource availability of each distribution circuit, this approach enables a more accurate estimation of the realistic impacts that load flexibility can have across SCE's service territory. This localized analysis accounts for the unique peak times and distributed energy resources available in each area, providing a granular view of potential infrastructure deferral opportunities.

Implementing circuit-level demand flexibility analysis represented a novel methodology developed for this study which may provide value to similar analysis efforts in the future.

6.2 Sum of Non-Coincident Circuit Peaks

The following table represents the sum of non-coincident circuit peaks for Scenario 3. Consistent with current practice in the distribution planning process, the individual non-coincident circuit peak loads were used to develop grid needs, solutions, and cost estimates.

TABLE 9: SCENARIO 3 SUM OF NON-COINCIDENT CIRCUIT PEAKS

	2030	2040
Scenario 3 Sum of Non-Coincident Circuit Peaks	38.07 GW	40.52 GW

6.2.1 Load Reduction and Energy Shift

The following table presents a comparative analysis of load reduction and energy shift outcomes between the Base Scenario and the Initial Demand Flexibility Scenario modeled in EIS Part 2. The table quantifies the incremental benefits of demand flexibility in reducing circuit-level peak loads and shifting energy consumption to off-peak periods. These insights are critical for understanding the potential of flexible load management to defer infrastructure investments and enhance grid reliability.

TABLE 10: SCENARIO 3 LOAD REDUCTION AND ENERGY SHIFT

	Non-Coincident Circuit Peak Reduction	Annual Energy Shift/Shed
2030	265 MW	164 GWh
2040	1,021 MW	436 GWh

When quantifying the benefits of demand flexibility, it is essential to assess the sum of non-coincident circuit peaks rather than relying solely on the system's coincident peak. This approach better reflects the benefits that may be achieved by demand flexibility, as grid constraints and infrastructure needs in the DPP are often driven by localized peak demands rather than a single systemwide maximum. Demand flexibility mechanisms, such as load shifting, DER dispatch, and customer-side controls, are typically deployed at the circuit or substation level, targeting specific overloads and deferral opportunities. Thus, evaluating the aggregate of individual circuit peaks provides a more accurate representation of where and how flexibility can mitigate grid investments. This methodology aligns with planning practices that prioritize resolving distribution-level constraints and supports a more granular and actionable understanding of demand flexibility benefits.

6.3 Primary and Secondary Results

The tables below summarize the total number of mitigation projects by type identified in Scenario 3.

TABLE 11: SCENARIO 3 PRIMARY RESULTS

Timeframe	Small DCU	Large DCU	New Circuits	Substation Capacity Upgrades	New Substations	4 kV Circuit Cut Over	4 kV Sub Eliminations
2025-2030	103	223	322	183	11	338	42
2031-2040	51	94	113	38	4	189	51
Total	154	317	435	221	15	527	93

TABLE 12: SCENARIO 3 SECONDARY RESULTS

Timeframe	Service Transformer Upgrades
2025-2030	21,723
2031-2040	15,513
Total	37,236

6.4 Total Costs

Costs for primary and secondary upgrades are presented below in millions of dollars.

TABLE 13: SCENARIO 3 TOTAL COSTS

Timeframe	Primary	Secondary	Total
2025-2030	$ 8,339	$ 411	$ 8,750
2031-2040	$ 3,656	$ 340	$ 3,996
Total	$ 11,995	$ 751	$ 12,746

7.0 Scenario 4: SCE's Alternate Demand Flexibility Case

7.1 Overview

SCE further expanded the scope of EIS 2 to include Scenario 4, an additional demand flexibility scenario that assumes elevated levels of flexibility. This scenario builds upon the foundational design of Scenario 3, maintaining the same methodological framework and use of the CEC's D-Flex Tool assumptions. However, Scenario 4 expands upon the initial demand flexibility scenario by assuming full (100%) customer participation for light-duty electric vehicles (LD EV), medium- and heavy-duty electric vehicles (MD/HD EV), residential energy storage (Res-ES), and non-residential energy storage (Non-Res ES). Participation rates for HVAC cooling loads remain the same as Scenario 3. This high-participation scenario serves as a theoretical upper bound to assess the maximum potential of demand flexibility for energy storage and electric vehicles in mitigating infrastructure needs across SCE's distribution system.

7.2 Sum of Non-Coincident Circuit Peaks

The following table represents the sum of non-coincident circuit peaks for Scenario 4. Consistent with current practice in the distribution planning process, the individual non-coincident circuit peak loads were used to develop grid needs, solutions, and cost estimates.

TABLE 14: SCENARIO 4 SUM OF NON-COINCIDENT CIRCUIT PEAKS

	2030	2040
Scenario 4 Sum of Non-Coincident Circuit Peaks	37.44 GW	40.12 GW

7.2.1 Load Reduction and Energy Shift

The following table presents a comparative analysis of load reduction and energy shift outcomes between the Base Scenario and the Alternative Demand Flexibility Scenario modeled in EIS Part 2. The table quantifies the incremental benefits of demand flexibility in reducing circuit-level peak loads and shifting energy consumption to off-peak periods. These insights are critical for understanding the potential of flexible load management to defer infrastructure investments and enhance grid reliability.

TABLE 15: SCENARIO 4 LOAD REDUCTION AND ENERGY SHIFT

	Non-Coincident Circuit Peak Reduction	Annual Energy Shift/Shed
2030	891 MW	1,106 GWh
2040	1,423 MW	3,185 GWh

7.3 Primary and Secondary Results

The tables below summarize the total number of mitigation projects by type identified in Scenario 4.

TABLE 16: SCENARIO 4 PRIMARY RESULTS

Timeframe	Small DCU	Large DCU	New Circuits	Substation Capacity Upgrades	New Substations	4 kV Circuit Cut Over	4 kV Sub Eliminations
2025-2030	96	223	308	172	10	308	37
2031-2040	59	90	83	30	3	184	45
Total	155	313	391	202	13	492	82

TABLE 17: SCENARIO 4 SECONDARY RESULTS

Timeframe	Service Transformer Upgrades
2025-2030	21,210
2031-2040	15,370
Total	36,580

7.4 Total Costs

Costs for primary and secondary upgrades are presented below in millions of dollars.

TABLE 18: SCENARIO 4 TOTAL COSTS

Timeframe	Primary	Secondary	Total
2025-2030	$ 7,807	$ 402	$ 8,209
2031-2040	$ 3,146	$ 337	$ 3,483
Total	$ 10,953	$ 739	$ 11,692

8.0 Cost Estimation Methodology

Cost projections were escalated to 2030 for the 2025–2030 period, and to 2035 for the 2031–2040 period, due to an absence of cost escalation data beyond 2035. The escalation rates used are consistent with the escalation rates used in SCE's operational planning at the time of this study. Consistent with SCE's standard cost estimation practices, a contingency factor of 35% was applied to most mitigation types, and 50% for new substations. 50% contingency for initial cost estimates of projects requiring licensing is consistent with the AACE Class 4/5 standard range. Operational costs, such as construction expenses, are embedded within the capital cost estimates. Discount rate was not used in the calculation for cost estimates.

To estimate the total cost of the study, unit costs were developed for each identified mitigation type. These estimates were based on either comparable completed projects or similar ongoing projects, depending on the specific mitigation category.

For distribution service transformers, SCE developed unit costs using historical closed work order data from 2019 to 2025. The unit cost for each transformer type was calculated by dividing the total cost of a work order—including labor, indirect costs, transformer cost, secondary, and service conductor—by the number of transformers in that work order.

9.0 Visualization of Evaluated Forecasts

The figure below represents the sum of studied circuit loading for all scenarios in study year 2030 on the peak date of September 6th, 2030. The impacts of Scenario 4, the Alternate Demand Flexibility Scenario can be seen during peak hours, from approximately 3 pm to 5pm. Differences between Scenarios 1 and 2 are undiscernible, and Scenario 3 shows a modest reduction in load during peak hours.

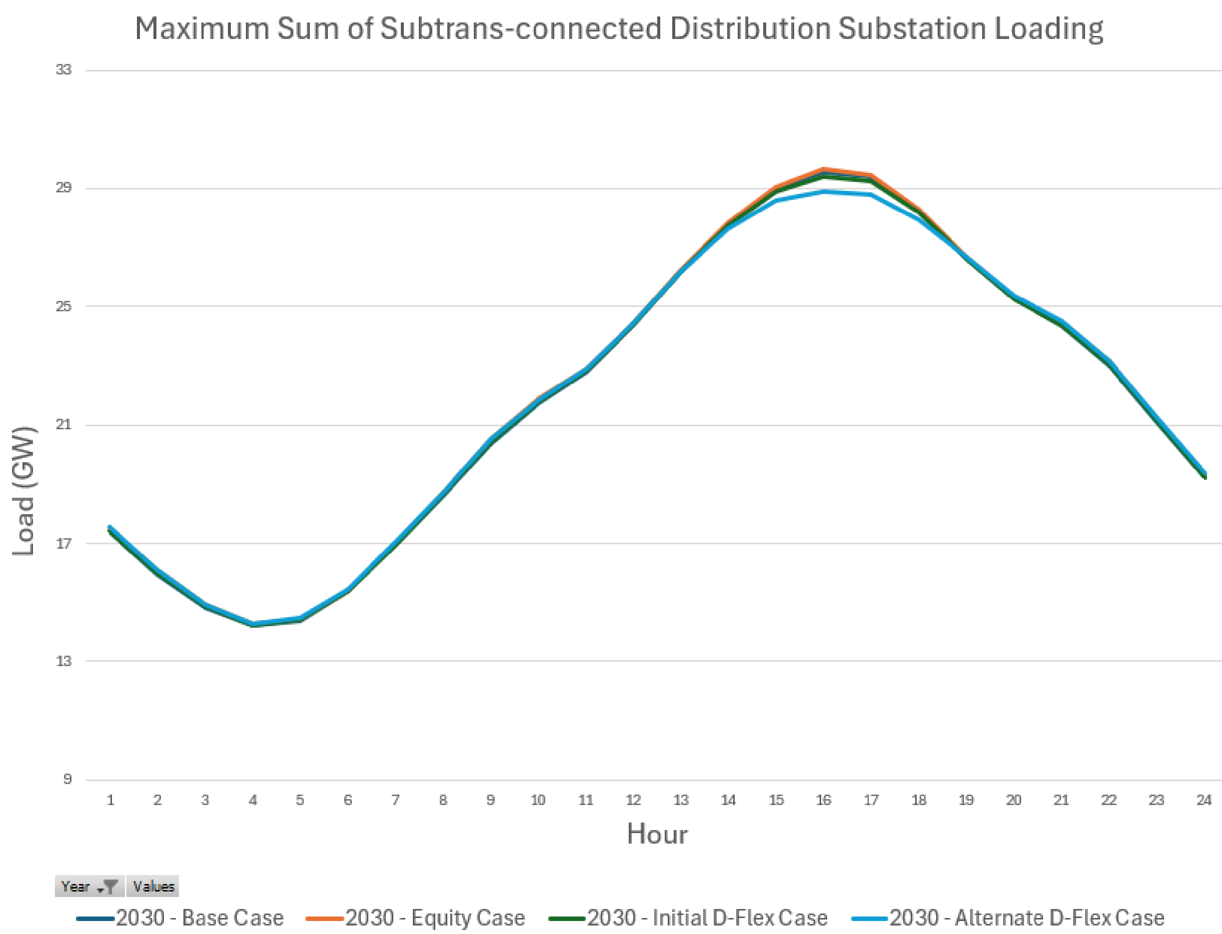


FIGURE 1: MAXIMUM SUM OF SUBTRANS-CONNECTED DISTRIBUTION SUBSTATION LOADING, 2030, ALL SCENARIOS

The figure below represents the sum of studied circuit loading for all scenarios in study year 2040 on the peak date of September 6th, 2040. The impacts of Scenario 4 are more apparent in 2040, with impacts continuing to fall between approximately 3pm and 5pm. Differences between Scenarios 1 and 2 are undiscernible, and Scenario 3 shows a slightly larger reduction in load during peak hours than in 2030.

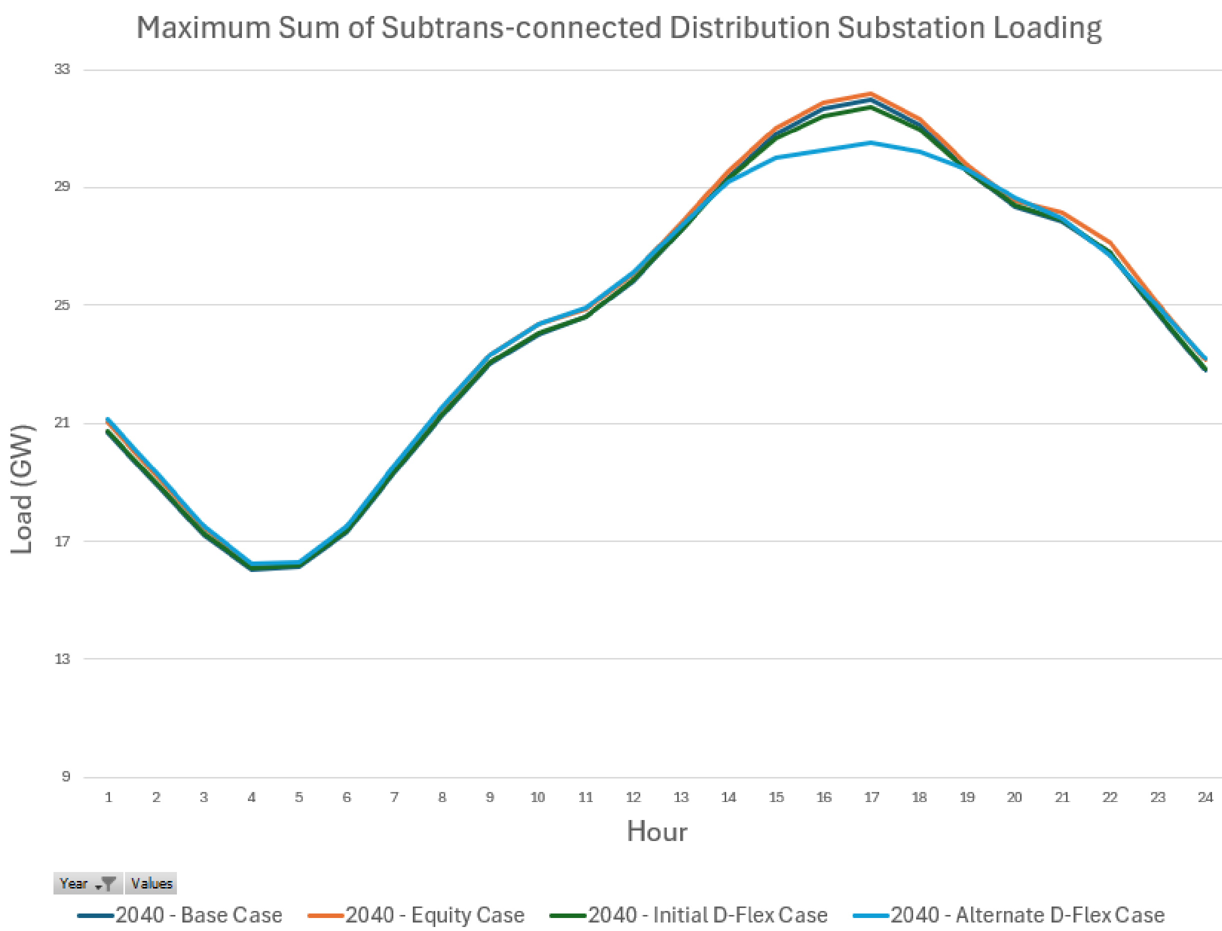
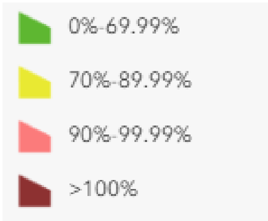


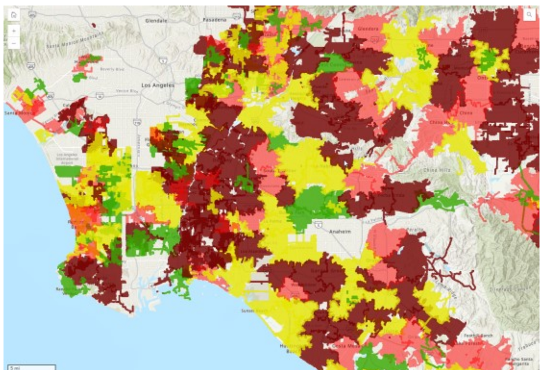
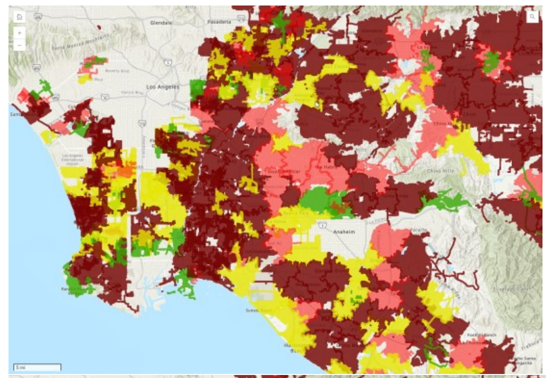
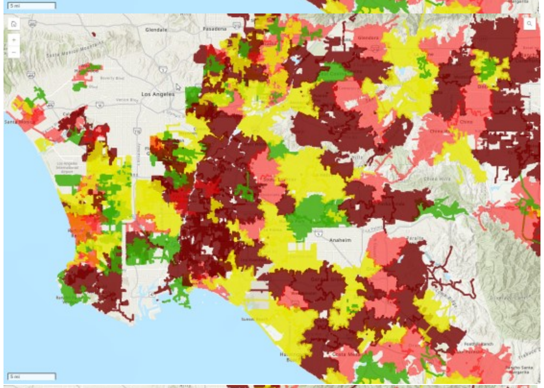
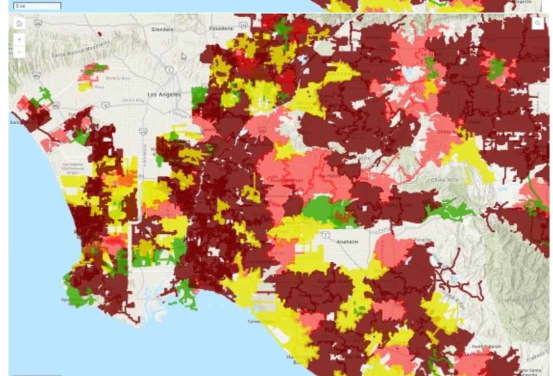
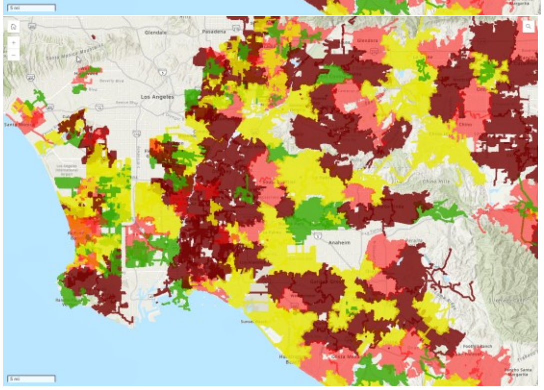
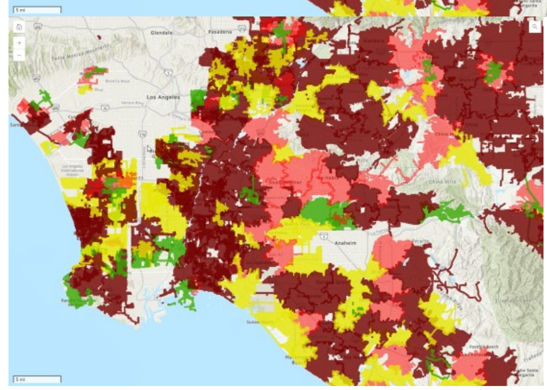
FIGURE 2: MAXIMUM SUM OF SUBTRANS-CONNECTED DISTRIBUTION SUBSTATION LOADING, 2040, ALL SCENARIOS

10.0 Geographic Distribution of Forecasted Load

This section includes GIS images representing the forecasted system utilization for each distribution substation, for a select portion of SCE's service area. Forecasted system utilization, expressed as a percentage, is the forecasted load of a distribution substation divided by its facility loading limit.

The ranges are as follows:



Scenario	2030	2040
Scenario 1: Base		
Scenario 2: Equity		
Scenario 3: Initial Demand Flex		

Scenario 4: Alternate Demand Flex

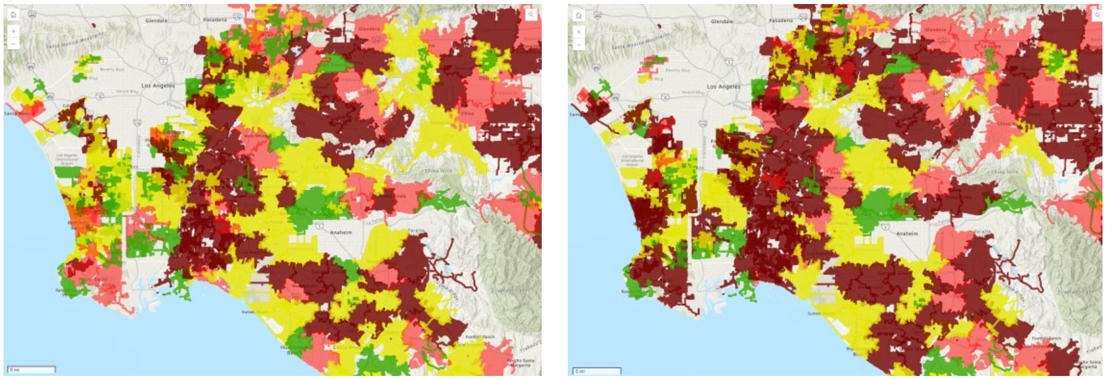


FIGURE 3: GEOGRAPHIC DISTRIBUTION OF FORECASTED LOAD

11.0 Historical Project Counts and Costs

EIS 2 identified a significant number of mitigation projects for all three scenarios, especially pronounced in the 2025-2030 timeframe. A review of SCE's completed projects from 2020-2024 highlighted the critical need to significantly accelerate capital project execution moving forward. Historically completed projects from 2020-2024 are summarized in the table below. SCE's approach to mitigating supply chain and resource constraints, which have emerged in response to a projected workload increase of up to 5-10 times in some cases, is outlined in the subsequent sections of this report. The historical completed 4 kV Circuit Cutovers captured in the table below reflect full circuit cutovers driven by the need to replace aging infrastructure, and do not include load growth driven circuit cutovers, or partial circuit cutovers. This is consistent with the circuit cutover methodology captured in Appendix 2, Table 29. The 4 kV circuit cutovers in EIS 2 reflect full circuit cutovers driven by forecasted capacity overloads.

TABLE 19: COMPARISON - PROJECT COUNTS OF HISTORICAL COMPLETED (2020-2024) AND EIS 2 SCENARIOS (2025-2030, 2031-2040)

Scenario, Timeframe	Small DCU	Large DCU	New Circuits	Substation Capacity Upgrades	New Substations	4 kV Circuit Cutover	4 kV Sub Eliminations
Historical Completed 2020-2024	19	31	41	18	1	47	18
EIS 2 Base 2025-2030	109	229	330	188	11	344	43
EIS 2 Base 2031-2040	49	100	134	35	4	190	52
EIS 2 Equity 2025-2030	105	232	333	189	11	347	43
EIS 2 Equity 2031-2040	42	112	137	34	4	192	54
EIS 2 D Flex (Initial) 2025-2030	103	223	322	183	11	338	42

EIS 2 D Flex (Initial) 2031-2040	51	94	113	38	4	189	51
EIS 2 D Flex (Alternate) 2025-2030	96	223	308	172	10	308	37
EIS 2 D Flex (Alternate) 2031-2040	59	90	83	30	3	184	45

The table below represents the total closed work order costs of historical completed projects from 2020-2024. Costs include labor and construction support but exclude maintenance, inspections, and repairs.

TABLE 20: TOTAL COSTS OF HISTORICAL COMPLETED (2020-2024) IN $M

Scenario, Timeframe	Small DCU	Large DCU	New Circuits	Substation Capacity Upgrades	New Substations	4kV Circuit Cutover	4 kV Sub Eliminations
Historical Completed 2020-2024	$2	$25	$147	$107	$44	$82	$41

12.0 Supply Chain and Procurement Impacts

SCE has observed notable improvements in the supply chain for key materials over the past few years. Materials such as conductor and distribution transformers have seen reduced lead times from their historical highs. However, these lead times remain significantly longer than industry standards prior to the COVID-19 pandemic. Additionally, SCE has observed more consistent availability for switches and pole line hardware such as elbows, connectors, and fuses.

Despite these improvements, lead-times for critical equipment such as distribution transformers, overhead conductors, underground cable, and switchgear have increased due to rising domestic and global demand. This demand is largely driven by electrification needs associated with AI data centers, EV infrastructure, and renewable energy integration. Manufacturing capacity constraints continue to impact project timelines and are expected to persist through the 2025-2040 timeframe.

Global supply chain disruptions have further exacerbated these challenges. Events such as the COVID-19 pandemic, tariffs, geopolitical tensions, extreme weather, and labor strikes have delayed the delivery of raw materials and finished goods. The United States currently relies on a single domestic manufacturer of grain-oriented electrical steel (GOES), which is essential for producing larger transformers required to meet growing electrification demands.

The market continues to face significant challenges with high-voltage equipment, including power transformers and circuit breakers. Demand for these components has outpaced supply, and lead times for certain power transformer designs now exceed four years. These delays are compounded by global demand and shortages of skilled labor. Additionally, U.S. distributors and brokers of steel, aluminum, and copper source their raw materials globally, which further impacts production downstream in the supply chain.

If electrification-driven demand continues to grow nationally and globally, the risk of material shortages is expected to intensify. This would place additional strain on manufacturing capacity and global supply chains, particularly for high-voltage equipment.

To address these risks, SCE is implementing a range of mitigation strategies that span both immediate action and long-term planning. In the near term, SCE is partnering with critical manufacturers to align production plans with project needs. The company is also expanding its pool of qualified suppliers to reduce dependency on single sources and improve procurement flexibility. For example, SCE now maintains at least three approved vendors for most critical substation equipment types, including approximately seven suppliers for substation-class transformers, four or more for circuit breakers, four or more for disconnect switches, and multiple suppliers for relays, GIS, BESS, and other major components. These suppliers are vetted through safety and performance reviews, factory inspections, QA/QC audits, and, where applicable, factory acceptance testing to ensure reliability and adherence to SCE technical standards.

Additionally, SCE is streamlining internal planning processes to enhance responsiveness and execution. For the longer term, SCE is considering long-term financial commitments with select manufacturers to secure production capacity and improve supply reliability. For example, SCE has executed on-line agreements for several categories of high-risk equipment, including capacitor banks, MEERs, disconnect switches, and air-core reactors, to ensure consistent access to critical components. For long-lead items, SCE has begun placing advanced orders for large projects to mitigate timing risks. SCE will continue to monitor the market for all available qualified sources to mitigate potential disruptions. SCE remains adaptable to evolving supply chain conditions and is prepared to deviate from standard procurement practices if necessary.

Despite the positive results that these strategies have yielded, several challenges remain in managing long-term supply chain constraints. Manufacturing capacity for certain high-voltage equipment, particularly transformers, circuit breakers, and specialized substation components, remains limited nationwide due to sustained electrification-driven demand. Lead times for these items continue to fluctuate, while market volatility, raw material constraints, and global logistics disruptions pose ongoing risks. SCE will continue to address these challenges through strengthened supplier partnerships, continued expansion of qualified vendors, long-term procurement commitments, and ongoing enhancements to internal planning processes to ensure it can reliably secure the materials needed to meet state electrification goals.

13.0 Workforce Projections

As previously noted, SCE must use a comprehensive approach for designing and building capacity mitigation projects at the levels specified by EIS 2—some areas will see project completion increase by five to ten times compared to past rates. To manage this surge, SCE is updating its workforce strategy to include benchmarking, reassessing team skills, expanding recruitment, balancing workloads, and strategic sourcing that combines hiring essential internal talent and outsourcing routine tasks. Additionally, SCE plans to boost technical efficiency through innovations such as AI-assisted design, workflow automation, and Integrated Planning, topics also addressed under High DER Track 1.

SCE assigns the proper personnel for each job, ensuring employees in roles like linemen possess interchangeable skill sets suited for their classification. They are dispatched to handle diverse assignments according to location, workload, and resource needs. When necessary, contract partners supplement SCE's workforce to match increased demand.

Other staff groups—including civil construction teams, distribution, protection, and substation engineers, project managers, permitting teams, and maintenance crews—participate in a wide range of activities. These resources are not tied to specific projects but instead support multiple functions as required.

To expand its execution capacity, SCE is focused on maintaining adequate staffing across all internal resource types. Any shortages are addressed via contractors, new hires, process improvements that enhance efficiency, and reallocation of work within the company. Additionally, SCE develops a forward-looking workforce strategy for each GRC cycle, including apprenticeship programs to grow the skilled workforce, investment in processes and tools that create efficiency, and the ability for the workforce to scale up or down annually through contractor resources. Together, these efforts help close the gap between available resources and the levels required to meet workforce demands.

The volume of projects identified in the EIS 2 study underscores the need for a robust workforce strategy. Labor demand depends on several variables, such as authorized budgets from the GRC and decisions about capital investment priorities. Consequently, total labor requirements must account for all sources of operational workload, not just those related to load growth cited in the EIS 2 study. Therefore, relying solely on project counts from this study would overlook other essential elements of workforce planning. While it was insightful to see what the potential grid investments would be across the next 16 years, the scenarios of EIS 2 are hypothetical. SCE will continue to evaluate workforce needs on a year-by-year basis and based on the results of the actual distribution planning process.

14.0 Findings & Recommendations Related to the Distribution Planning Process

14.1 Rationale on Meeting Forecasted Demand

SCE is exploring multiple efforts to increase the ability to meet forecasted demand in a timely manner. Concepts such as pending loads and scenario planning discussed in High DER Track 1 can enable a more proactive planning process. Incorporating additional sources of load growth and commencing proactive mitigation projects is expected to enable grid capacity in a way that supports timely customer energization.

In conjunction with its ongoing planning efforts, SCE is exploring new strategies to enable greater levels of capacity through innovative solutions. These include the use of 34.5 kV distribution voltages and compact substations, which require a smaller footprint and offer the potential for more rapid deployment compared to conventional substation designs. SCE is also evaluating new physical grid designs aimed at increasing power density and asset utilization, while enhancing safety and enabling faster deployment timelines.

To further support grid flexibility and resilience, SCE is considering the integration of Distributed Energy Storage as a flexible grid asset. This approach can provide additional capacity, improve reliability, and enhance system resilience. In parallel, SCE is assessing the role of demand flexibility, in part, enabled by Advanced Metering Infrastructure (AMI) 2.0 and flexible interconnection options. These technologies allow customer resources to be leveraged in ways that can avoid or defer traditional grid buildout, while also improving reliability and resilience.

Modernization of the grid platform is another key focus area. SCE is exploring the use of artificial intelligence to significantly improve engineering insights and accelerate work execution. These efforts are part of a broader initiative to transform grid operations and planning to meet future demands more effectively.

Integrated planning, a concept also discussed in the High DER proceeding, will play a critical role in enabling execution efficiencies. By addressing multiple drivers with holistic solutions, SCE aims to streamline project delivery and optimize resource allocation across its service territory.

The equity and demand flexibility findings in EIS 2 do not fundamentally shift SCE's ongoing multi-pronged strategic approach to meet future load growth and ensure grid readiness, due to theoretical assumptions used in EIS 2. While the scenarios considered in EIS 2 offer valuable insights into potential future conditions, they do not necessitate immediate changes to current planning or investment strategies due to the high uncertainty surrounding the likelihood and timing of these discrete scenarios materializing. SCE's strategies already incorporate more proactive changes to the planning process, as contemplated in the High DER Track 1 Proceeding, including the incorporation of pending loads and scenario planning. These changes reflect a shift away from the prior traditional DPP paradigm. However, the emergence of demand flexibility as a key resource highlights the need for SCE to begin developing a more defined strategy for integrating demand flexibility into its planning process, which may be addressed in future planning cycles or complementary studies.

SCE will comply with the pending loads and scenario planning resolutions, therefore findings in EIS 2 are not expected to inform refinements to pending loads screening and expedited processing of electrification-related load requests. The final pending loads resolution includes a definition of hot spots, which is the most appropriate mechanism for identifying and understanding where rapid electrification is likely to occur. While uncertainties in transportation electrification adoption should be effectively addressed in the IEPR, the pending loads framework is designed to fill any gaps where the IEPR may fall short. EIS 2 did not provide insights to inform refinements to expedited processing of electrification related load requests or localized grid modernization needs. SCE's annual planning process remains the most robust mechanism for evaluating and addressing these needs.

14.2 Integration of Enhanced Load Flexibility Assessment into the Distribution Planning and Execution Process

The demand flexibility scenarios in EIS 2 indicate that higher participation rates and enablement levels are associated with more material circuit peak load reductions. This reinforces that demand flexibility should be integrated through a staged pathway – expanding enablement, targeting, and operational experience – so that demand flexibility can be used with increasing confidence alongside traditional solutions over time.

SCE views demand flexibility as having an integral role in addressing grid needs and is committed to identifying a viable pathway to its incorporation into its distribution planning and execution process, both through enhancements to forecasting and through evaluation of its role in the solution menu. On the forecasting side, SCE hopes to engage with the CEC to continue its efforts related to inclusion of demand flexibility in the IEPR, while acknowledging that the timing of this inclusion depends on the CEC's schedule.

To include demand flexibility as a formal mitigation option in the solution menu, SCE seeks to better understand the reliability and cost effectiveness of delivering the required capacity reduction to mitigate localized grid needs. This will require significant progress defined by three readiness areas:

1. Reliability and Cost Effectiveness: SCE must validate, through evidence-based pilots and analysis, that demand flexibility can consistently and sufficiently reduce localized peak loading.
2. Policy Readiness: Key regulatory and policy frameworks for DER orchestration, including those being contemplated in High DER Track 2, must be resolved before a definitive timeline for implementation can be determined.
3. Technical Readiness: SCE will leverage existing pilots and, if necessary, launch new pilots that have clearly defined objectives and measurable outcomes tied to specific use cases, such as deferring traditional wires solutions or accelerating customer energization. The planned 2029–2033 deployment of AMI 2.0 will deliver granular demand and consumption data to assess the dependability of demand flexibility as a solution to address grid needs.

To develop technical readiness, pilots should target circuits with high peak loads and sufficient populations of flexible loads, such as HVAC systems, electric vehicles, energy storage, and electric water heaters. A comprehensive analysis should be conducted to define the population and appropriate composition of flexible loads, quantify their potential impact on each circuit, and realize the benefits of demand flexibility. In addition, it will be important to understand the potential impact of various strategies for managing customer loads, such as adjusting thermostat setpoints to minimize customer impact and staggering dispatch across different customer groups, to ensure these approaches can be deployed effectively at scale.

To ensure reliable planning assumptions, SCE may need to adopt an over-enrollment strategy, which is enrolling more flexible load capacity to account for variability in customer response. SCE is currently pursuing further understanding of the appropriate customer incentive levels, program establishment, and administration costs, to better inform the cost effectiveness of demand flexibility compared to other mitigation measures. In order to incorporate demand flexibility alongside traditional infrastructure upgrades in the solution menu, SCE must better understand the dependability and cost-effectiveness of demand flexibility as a mechanism to reduce peak loading conditions.

Technology solutions must be deployed to enable orchestration of demand flexibility in a way that maximizes local grid benefits. SCE expects its deployment of AMI 2.0 in 2029-2033 to enable granular usage and demand data as pilots are conducted, as well as additional capabilities that will support the integration of demand flexibility into the distribution planning process solution menu. If demand flexibility proves to be dependable, reliable, and cost-effective through pilot validation and broader analysis, AMI 2.0 will serve as a foundational component that enables further integration of demand flexibility into the distribution planning process. This integration would support SCE's continued efforts to incorporate demand flexibility as a viable alternative or complement to traditional infrastructure upgrades, helping to reduce localized peak loads, defer capital investments, and improve overall grid reliability and resilience.

While EIS 2 offers insights into the potential of demand flexibility, it did not evaluate detailed components such as demand response (DR) program design, program targeting, or the development of enabling technical capabilities. Generally, DR refers to event based, utility-initiated load reductions during peak or emergency conditions, whereas demand flexibility reflects a broader, continuous, and more automated ability for customers or devices to dynamically adjust usage in real time. Instead, EIS 2 assumed that the necessary programs would be put in place to enable the levels of demand flexibility modeled in Scenarios 3 and 4. The demand flexibility scenarios were intended to estimate the potential capital deferral benefits if such programs were already in place, not to assess whether those levels of flexibility are realistically achievable through existing or future DR programs or enabling technical capabilities.

Now that the EIS 2 is complete, SCE will turn to evaluating reasonable assumptions that can begin to be layered into distribution planning. This will begin with more granular estimates of where significant load flexibility will be available, and where that flexible capacity will most likely have the potential to drive savings. This exercise is challenging given that local load flexibility is still in its infancy, and much work is required to understand and validate the potential, as discussed above. Therefore, SCE will be evaluating reasonable assumptions of load flexibility that can be incorporated into the planning process, appropriately considering the above-mentioned uncertainty.

Although many elements remain to be explored to validate that demand flexibility is a reliable resource to reduce circuit peak loading conditions, SCE remains committed to advancing the capabilities, analyses, and supporting programs required to make cost-effective demand flexibility a practical and dependable solution.

14.3 Integration of Equity Driven Assessment into the Distribution Planning and Execution Process

The Equity Scenario was designed to explore a non–typical planning pattern of distributed energy resource (DER) adoption, with a specific focus on prioritizing DER adoption in disadvantaged communities (DACs) and other priority populations. This scenario was intended to challenge the presumption, established in EIS Part 1, that higher-income communities adopt electrification technologies at a faster rate than low- and moderate-income communities, due to greater access to capital, incentives, and enabling infrastructure.

In the annual distribution planning process, SCE develops DER adoption propensity models and updates socio-economic and demographic data to forecast the most likely DER adoption pattern. In contrast, the EIS 2 Equity Scenario artificially increased DER adoption in priority population areas until it reached parity with adoption levels forecasted for non-priority population areas. To achieve this parity, significant targeted policy intervention would be required, as this adoption pattern is unlikely to materialize organically under existing policy and programs.

Despite this forced adjustment, the results of the Equity Scenario revealed that it did not lead to a significantly greater number of new capacity projects compared to the Base Scenario, therefore, should DER adoption trends accelerate in priority population areas (e.g., in response to CPUC programs or other exogenous changes), SCE's planning process will identify the appropriate mitigation measures to address any resulting changes to grid needs. The table below summarizes the differences in project counts between Scenarios 1 and 2.

TABLE 21: COMPARISON OF EQUITY AND BASE SCENARIO PRIMARY PROJECTS, 2025-2040

2025-2040 Results	Small DCU	Large DCU	New Circuits	Substation Capacity Upgrades	New Substations	4 kV Circuit Cutover	4 kV Sub Eliminations
Base	158	329	464	223	15	534	95
Equity	147	344	470	223	15	539	97
Difference (Equity-Base)	-11	+15	+6	0	0	+5	+2

SCE attributes the reduction in small distribution circuit upgrades to the need for a slightly larger mitigation measure in the Equity scenario. Specifically, while a comparison between the Base and Equity scenarios shows a reduction of 11 small DCUs in the Equity scenario, those small DCUs were likely absorbed into large DCUs, which in turn evolved into new circuits.

The minimal variation in primary system project outcomes between the Equity and Base scenarios indicate that SCE's existing distribution system provides equitable access to grid capacity for all customers seeking to adopt distributed energy resources. Because reaching full parity in DER adoption would require substantial policy-driven support coupled with the relatively minor changes to the investment plan that would be necessary to accommodate such adoption patterns, the Equity Scenario should be viewed as illustrative rather than informing future DPEP enhancements.

15.0 Conclusion

SCE appreciates the opportunity to evaluate the potential grid needs and corresponding mitigation measures resulting from the various scenarios contemplated in EIS 2. This leads to SCE's first conclusion:

1. The EIS 2 scenarios provided insights into the potential grid needs and mitigation measures required under distinct assumptions. However, these scenarios are unlikely to occur in isolation. Rather, appropriate levels of DER adoption and demand flexibility will be embedded in scenarios evaluated as part of the annual Distribution Planning Process.

The preliminary results of the Equity Scenario revealed that it did not lead to a significantly greater number of new capacity projects compared to the Base Scenario. With this, SCE offers its second conclusion:

2. SCE acknowledges the critical importance of equity in the distribution planning process. The equity scenario evaluated in EIS 2 (Scenario 2) is a less likely DER adoption pattern barring significant policy intervention. The results of the EIS 2 Equity scenario suggest such a shift in adoption would not have significant impacts on investment requirements. Even though the equity scenario artificially increases DER adoption in priority populations to parity with non-priority populations, the incremental DER additions required to meet the equity scenario criteria were small relative to system scale. This additional DER was then distributed across many circuits, which reduces local circuit impacts and thus does not meaningfully change the number or type of projects needed to satisfy grid needs.

Scenarios 3 and 4 demonstrated a varying range of capital cost deferral, which may serve as a proxy when quantifying the potential value of demand flexibility. When compared to the base scenario, Scenario 3 resulted in a potential deferral of $0.32 B, while the more aggressive assumptions in Scenario 4 resulted in a hypothetical book-end deferral of $1.38 B.

3. SCE is committed to advancing the integration of demand flexibility into its distribution planning and execution process both through enhancements to forecasting and through evaluation of its role in the solution menu. On the forecasting side, SCE defers to the CEC on how to include demand flexibility as a potential IEPR load modifier, with recognition that the timing of this inclusion depends on the CEC's schedule. On the forecasting side, SCE hopes to engage with the CEC to continue its efforts related to inclusion of demand flexibility in the IEPR, while acknowledging that the timing of this inclusion depends on the CEC's schedule. Before demand flexibility can be included as a formal mitigation option in the solution menu, it must be demonstrated to be reliable, available when needed, capable of delivering the required capacity reduction, and cost effective. Additionally, SCE's forthcoming deployment of AMI 2.0 will enable granular usage and demand data as pilots are conducted, as well as additional capabilities that would facilitate and enhance inclusion of demand flexibility in the DPP if demand flexibility is confirmed to be dependable, reliable, and cost effective.

The approaches tested in EIS 2 will inform the forthcoming Distribution Planning and Execution Process.

4. The partially automated solutioning script, utilized and tested in EIS 2, will serve as the foundation for the decision logic used in Scenario Planning. As directed by the Scenario Planning Resolution, the decision logic will be subject to annual presentation and approval. SCE plans to incorporate methodological enhancements related to forecasting such as adjustments and validation to the level of demand flexibility in the DPEP Base Scenario to reflect existing demand management programs more accurately. In addition, the DPEP will

not consider a separate equity scenario based on the results of EIS 2, since it is unlikely that DER adoption levels in the equity scenario will materialize without significant policy intervention. SCE will continue to utilize the forecasted DER adoption from IEPR and propensity models that are shared at the Distribution Forecasting Working Group, to define the most logical adoption pattern.

Appendix 1: Forecast Methodology

1. Forecast Preparation for Primary System Analysis

1.1. Forecast Development for Primary Analysis – All Scenarios

SCE's circuit level load forecast is based on the CEC's IEPR forecast, combined with local information about new development projects and econometric data specific to each planning area.

SCE first extracts the Total Energy Consumption across the forecasting horizon from 2023 CEC IEPR Baseline forecast (Form 1.2) and then generates the annual incremental consumption forecast for its service territory, which serves as the foundation for developing the circuit level load forecast for distribution system planning.

The following section provides a high-level overview of the current circuit level load forecast process:

1. Establish Baseline Demand from Historical Profile: The baseline hourly demand is developed in the Long-Term Planning Tool (LTPT) - Structure Level Forecast (SLF) tool using recorded historical hourly demand. This baseline peak demand reflects the expected peak load under typical weather conditions for a given structure/asset.
2. Disaggregation of IEPR Base Growth: The previously developed annual incremental consumption forecast along with econometric data are leveraged to incorporate embedded Load Growth Projects (LGPs) to the distribution structure level within LTPT-SLF applying Borrow Forward methodology.
3. Disaggregation of IEPR DER Growth: The IEPR DER forecast is disaggregated to the distribution circuit level using DER adoption, customer attributes, and program participation information. This is performed in various software tools (e.g., R programming).
4. Application of Incremental Load Growth Projects: Incremental LGPs are then applied to specific structure forecasts, additive to the IEPR Base Growth. SCE consults with the CEC to determine which projects are considered incremental to the IEPR.
5. Integration of Load Growth and DER Growth: Unique hourly profiles are applied to the embedded LGPs, IEPR disaggregated DER, and Incremental LGPs. The resulting hourly load and DER forecasts are consolidated with the baseline hourly demand for each circuit, producing an 8760-hour net demand forecast reflecting IEPR base growth, DER growth, and incremental LGP impacts.
6. Establish Annual Net Peak Growth: Circuit peak times are determined by identifying the highest hourly net demand forecast. The coincident load and DER impacts are then established corresponding to the circuit peak time.
7. Determine Net Demand Forecast: This step calculates the net demand forecast.

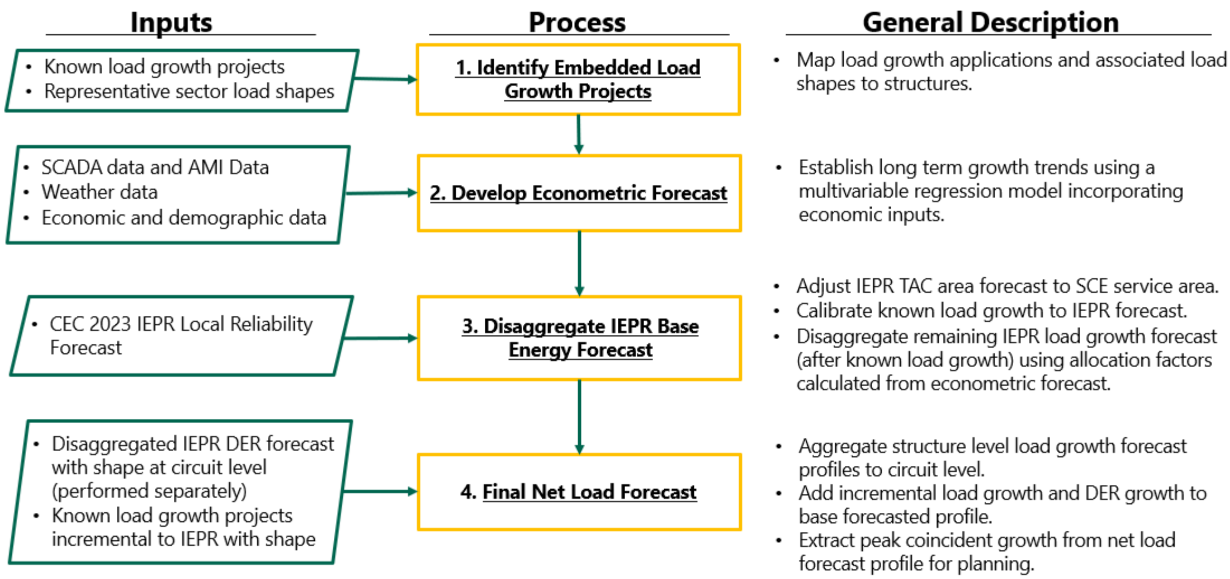


FIGURE 4: NET FORECAST PROCESS FOR ALL SCENARIOS

The SCE energy consumption forecast from IEPR includes EVs and municipalities not served by SCE's distribution system. EV energy is removed as it is disaggregated separately, and municipalities' consumptions are removed. The annual incremental energy consumption specific to SCE's system is then calculated.

Distribution planners collaborate with developers of electrification projects across all sectors (agricultural, commercial, industrial, residential, and transportation) to understand the electrical needs and timing of these projects. This collaboration helps estimate projected increases in demand on SCE's distribution system, known as LGPs. These projected demand increases are derived from developer-provided information, development progress, and institutional knowledge from similar past developments.

Most LGPs are considered embedded or captured in the IEPR total consumption forecast. However, there are some loads from new industries and loads that are not reflected in the economic indicators used to develop the IEPR forecast. For example, Commercial Electric Vehicle Chargers, Cultivation, and Temporary Power LGPs are not directly or not fully accounted for in the IEPR forecast. The load from these LGPs is added incrementally to the IEPR total consumption forecast. Both embedded and incremental LGPs are incorporated in SCE's load growth forecast.

In addition to specific load growth projects, long-term growth trends at the structure level are captured using multivariable regression. SCADA data and AMI data are used to establish historical energy usage patterns. Weather data and economic and demographic data are collected to account for climatic variations and broader context. This data helps shape regression trends.

During the IEPR base energy forecast disaggregation, embedded load growth projects are compared and calibrated with the IEPR forecast. SCE's Borrow Forward method for IEPR allocation allows load growth amounts for a given year to exceed the annual incremental IEPR. Remaining load growth from the IEPR, if any, is then disaggregated using allocation factors from the econometric forecast.

The initial disaggregation of load forecast represents the energy amount consistent with the CEC's system level forecast. To provide system planners with a more informed load and DER forecast that captures the fluctuations in energy usage patterns, SCE further applies unique hourly profiles to the embedded LGPs, DER forecast, and incremental LGPs for each circuit or structure. These profiles reflect the consumption behaviors of different customer sectors, including residential, commercial, agricultural, and industrial. SCE uses the Re|Grid Grid Analytics Tool (GAT) Curve Builder and 8760-hour historical data to develop the normalized representative load shape for different customer classes.

SCE then derives circuit peak times based on the maximum of the integrated hourly load forecast. Finally, SCE establishes the coincident load and DER impacts corresponding to the circuit peak time.

SCE utilizes various software to support the disaggregation and development of the distribution forecast. Historically, the SCE-developed planning software, Master Distribution Interface (MDI), allowed for end-to-end preparation of a point-based forecast. As SCE's DPP evolves, SCE continues to develop solutions as part of its LTPT to begin shifting the point-based forecast to be fully profile-based. SCE's profile-based forecast leverages statistical tools (e.g., SLF), Geographic Information System (GIS) tools (e.g., ArcGIS), and historical profile tools (e.g., SCE's GAT powered by Re|Grid).

1.2. DER Disaggregation - Scenario 1

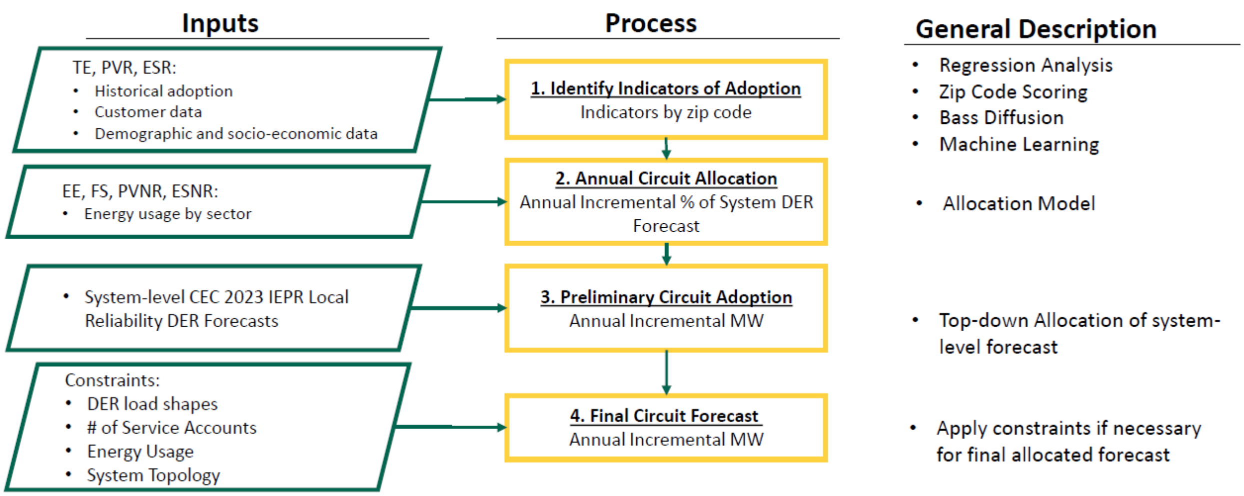


FIGURE 5: DER DISAGGREGATION PROCESS FOR BASE SCENARIO

The 2023 CEC Integrated Energy Policy Report (IEPR) forecast includes a 15-year forecast for the following DERs:

1. Energy Efficiency (EE)
2. Transportation Electrification (TE)
3. Solar Photovoltaic (PV)
4. Energy Storage (ES)
5. Fuel Substitution (FS)

SCE disaggregated the 2023 CEC IEPR DER forecasts across its 50,000 square mile service territory down to each distribution circuit. The circuit-level forecasts are then aggregated up to the substation level. This process results in a net demand forecast for all distribution circuits and substations. Generally, EE and PV reduce demand, while TE and FS increase demand. ES decreases demand during discharging periods while increasing demand during charging periods. Once the disaggregated DER forecasts are developed and integrated with the circuit-level disaggregated load forecast, the result is a managed forecast that serves as the necessary input to SCE's EIS 2.

SCE applies the 2023 CEC IEPR 8760 load shapes for EE, TE (Medium & Heavy Duty), ES, and Fuel Substitution to distribute the total annual aggregated forecasts for each DER to the hourly level. IEPR load shapes are not modified based on climate zone adjustments. For TE (Light Duty) and PV, SCE uses customized, internally developed load shapes rather than those provided by CEC. SCE uses its own load shapes for Distributed Energy Resource (DER) forecasts when it has more locationally specific or recent data—especially for electric vehicle (EV) charging. If such specific data isn't available, SCE defaults to the California Energy Commission's (CEC) DER profiles. For light-duty EVs, SCE's AMI data for Residential Separate Meter (TOU-D-PRIME) and proprietary AMI data from its Charge Ready program provide detailed insights into EV charging behavior at homes and workplaces. SCE applies these insights when developing load shapes for light-duty vehicles, as described in Appendix 1 Section 1.2.3.

SCE uses internally generated photovoltaic (PV) profiles for its Distribution Planning Process. Because PV output depends on unpredictable environmental factors like cloud cover, SCE conducts studies to determine how much solar generation can be reliably counted on—especially during high-load days. These studies help SCE manage localized variability and maintain reliable service for customers.

Below is the PV dependability shape by region across SCE's territory. The shapes remain the same for different dates and years.

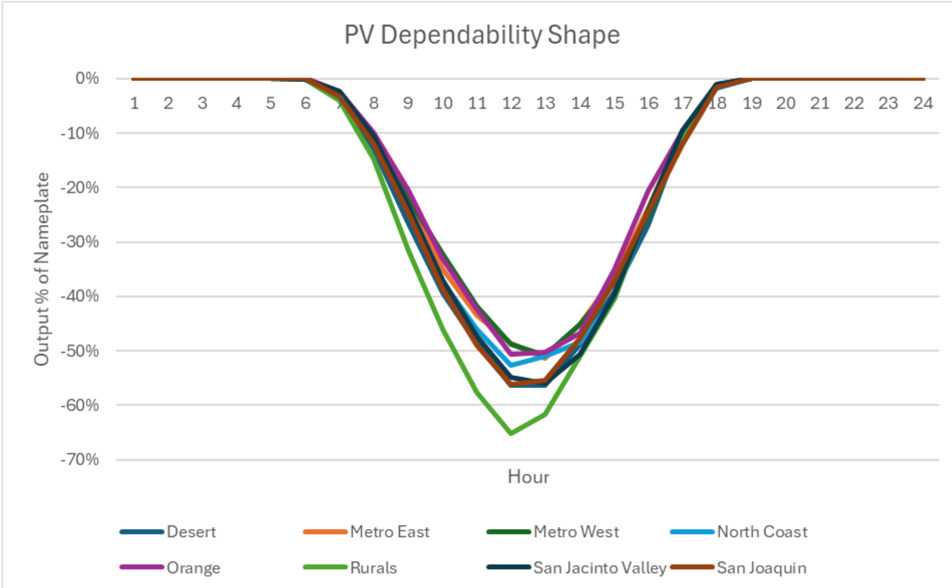


FIGURE 6: PV DEPENDABILITY SHAPES BY REGION

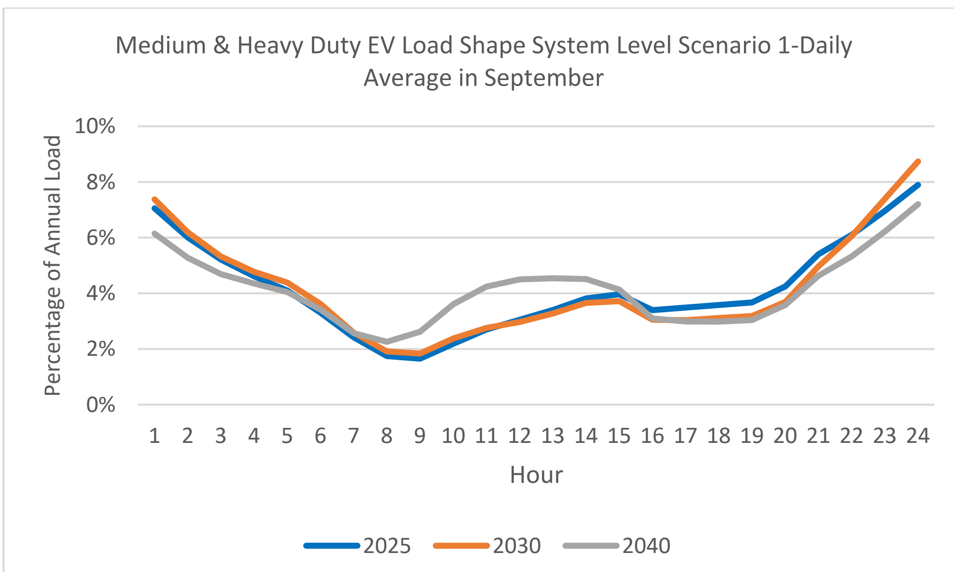


FIGURE 7: MEDIUM & HEAVY-DUTY EV LOAD SHAPES

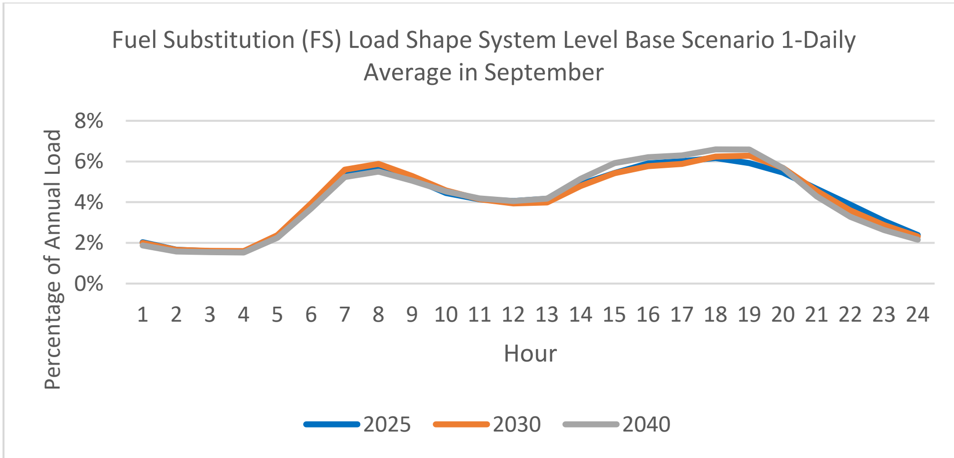


FIGURE 8: FUEL SUBSTITUTION LOAD SHAPES

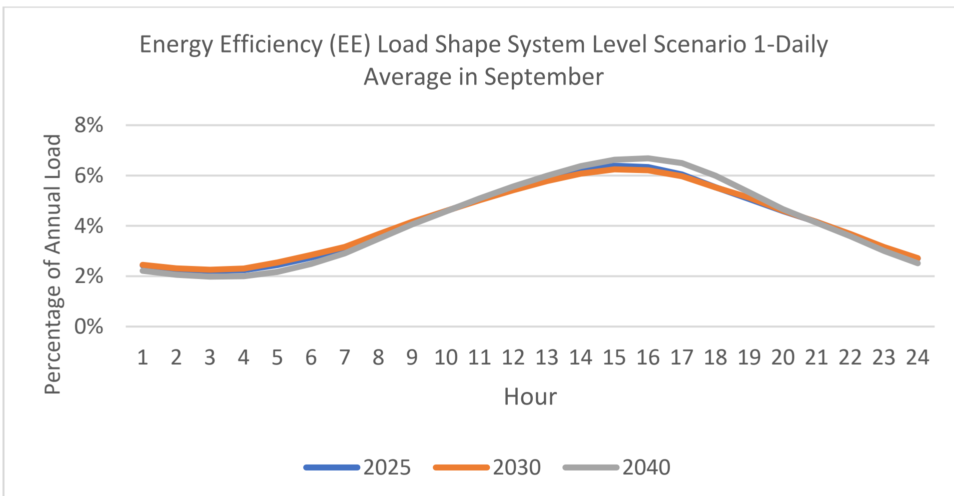


FIGURE 9: ENERGY EFFICIENCY LOAD SHAPES

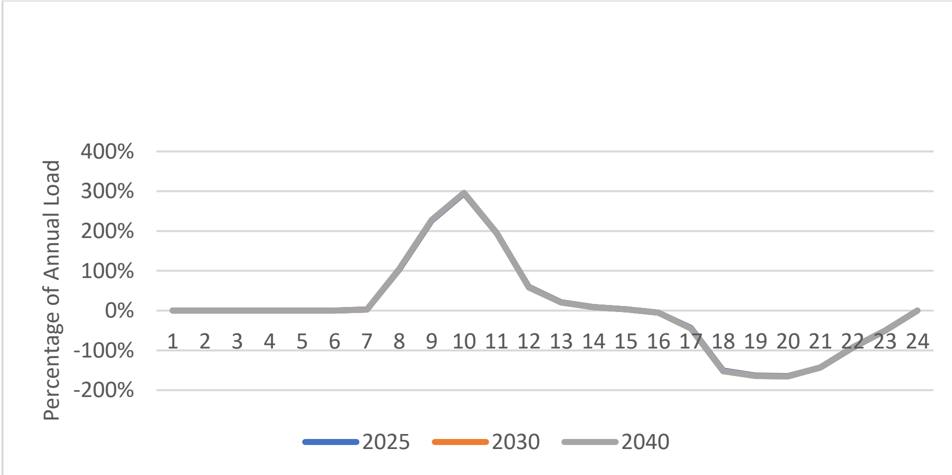


FIGURE 10: RESIDENTIAL ENERGY STORAGE LOAD SHAPES

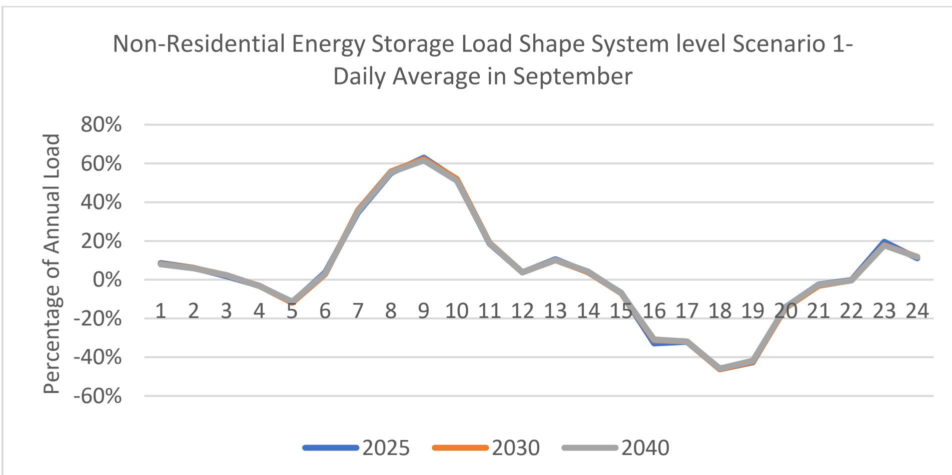


FIGURE 11: NON-RESIDENTIAL ENERGY STORAGE LOAD SHAPES

Consistent with the 2024 Distribution Forecast Working Group, the DER forecast elements used in the base scenario include:

- CEC-Adopted IEPR Vintage: 2023 IEPR Local Reliability Scenario
- Economic, Demographic, and Price: Baseline
- Additional Achievable Energy Efficiency (AAEE): Scenario 2
- Additional Achievable Fuel Substitution (AAFS): Scenario 4
- Additional Achievable Transportation Electrification (AATE): Scenario 3

The subsections below describe how each DER forecast is disaggregated from the 2023 CEC IEPR system-level to each individual circuit.

1.2.1. Energy Efficiency (EE)

SCE leveraged the 2023 CEC IEPR AAEE Local Reliability scenario forecast and used proportional scaling modeling, extracting customer-level energy use data from its billing system to scale the AAEE system-level forecast to individual circuits.

SCE disaggregates the 2023 CEC IEPR system-level AAEE forecast using proportional scaling models that assume energy efficiency (EE) adoption follows energy use. The CEC's Local Reliability AAEE scenario includes savings from EE Programs and Title 24 Codes and Standards. SCE's methodology involves three main steps: collecting circuit-level energy use data and grouping it by sector, obtaining AAEE forecasts by scenario and sector from the CEC, and disaggregating EE savings by applying sectoral energy use percentages to the IEPR forecasted savings.

SCE used the 2023 CEC IEPR AAEE system-level 8760 load shapes to convert annual hourly load shapes into hourly percentages, ensuring the annual EE savings percentage equaled 100% for each forecast year. SCE then multiplied these unitized hourly percentages by the total CEC-supplied AAEE forecast, enabling the distribution of total SCE service territory EE savings into hourly increments.

1.2.2. Transportation Electrification (TE)

SCE disaggregated the 2023 CEC IEPR forecast for both light duty and non-light duty electric vehicles. Non-light duty electric vehicles include medium & heavy-duty trucks.

1.2.3. Light Duty (LD) EVs

SCE used the following data sources to disaggregate the system-level light-duty EV forecast from the 2023 CEC IEPR forecast: ZIP Code-level EV adoption data from the CEC's New ZEV Sales in California dashboard[2], household characteristics from the American Community Survey by U.S. Census Bureau[3], median household income growth forecasts from IHS Markit and Moody's Analytics[4], customer segmentation data from SCE's market research and ZIP Code to circuit mappings from SCE's Geospatial Analysis team.

SCE disaggregated the 2023 CEC IEPR EV forecast using internally developed propensity models. The process begins with developing a propensity score for each ZIP Code, identifying key indicators of electric vehicle adoption. Using historical EV adoption data and demographic and socioeconomic data, SCE performed regression analysis to determine driving factors for EV adoption, with household income over $150,000 being statistically significant and chosen as the propensity indicator. EV potential for each ZIP Code was estimated based on the number of high-income

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[2] California Energy Commission (2024). New ZEV Sales in California. Data last updated [08-06-2024]. Retrieved [10-28-2024] from https://www.energy.ca.gov/zevstats.

[3] American Community Survey, *Household Demographic and Socioeconomic Data at ZIP Code level,* 2022 (*available at* https://data.census.gov/).

[4] IHS Markit and Moody's Analytics, Median Household Income Growth Forecast at MSA Level, October 2024 (available via subscription at https://connect.ihsmarkit.com/home and https://www.economy.com/databuffet/preview/start).

households, and median household income growth forecasts were used to reflect changes in EV adoption rates over time.

SCE then allocated the 2023 CEC IEPR EV forecast to ZIP Codes based on relative propensity scores. ZIP Codes were mapped to circuits based on circuit mileage, and circuit shares of ZIP Codes were applied to the ZIP Code level EV forecast. In addition, SCE's market research study of customer segmentation by circuits is used for including potential EV adoption from low-income customers. This resulted in the final disaggregated circuit level EV forecast.

The EV load shape was used to determine the hourly energy forecast, considering factors such as where and when EV owners charge, the duration of charging, and their residential rate classes. In Scenario 1, SCE assumes some demand flexibility within the light-duty vehicle (LDV) shapes. The modified shapes represent managed charging due to existing time-of-use (TOU) rates, additional public chargers, and potential future price signals that would shift the EV charging load from peak hours to daytime and off-peak hours. The major assumptions are:

1) EV owners charge either at home or away from home. In Scenario 1, it is assumed that in the year 2025, 76% of EV charging occurs at home and 24% occurs away from home. By 2040, SCE expects the percentage of away-from-home charging to increase due to the expansion of public chargers, resulting in 68% of charging occurring at home and 32% away from home.

2) Since customers might have different charging behaviors based on their rates, SCE assumes there will be four different rate options for home charging and two public charger dynamic pricing for away-from-home charging by the year 2040. Each rate option is assumed to drive slightly different customer behavior. Some of these rate options are not in existing SCE rates, but SCE's EV demand modelers assume additional rate options will need to be developed as more electrified transport options are adopted by businesses, government, and households.
    a. Home charging Customer rates
        i. Domestic rate: These are the customers are incentivized to charge their EVs right after arriving home from work, and SCE utilized U.S. Census data to determine when this will be. The charging peaks around 6 PM. SCE assumed 10 percent of EV owners who charge at home will be on this rate in the year 2040.
        ii. TOU rate: These are the customers who are on SCE's existing TOU rate which starts after 9 PM. SCE utilized the separately metered AMI data for TOU-D_PRIME residential customers. SCE assumed 40 percent of EV owners who charge at home will be on this rate in the year 2040.
        iii. EV "Flexible charging rate": This TOU rate structure does not currently exist. However, we assume some potential price signals will move towards a flex charging behavior which can control when EVs start charging to flatten the charging pattern at night. The charging peak is around midnight. SCE assumed 40 percent of EV owners who charge at home will be on this rate in the year 2040.
        iv. "Smart Charging" rate: This TOU rate structure does not currently exist. This is for customers who charge during the day when they are home and peaks

around noon. SCE assumed 10 percent of EV owners who charge at home will be on this rate in the year 2040.

b. Away from home charging - public charger dynamic pricing

  i. Non-Flexible charging: This represents the workplace and/or destination charging and usually starts in the morning and charging peaks around 11 AM. SCE utilized the charging load profile from the Charge Ready program for workplace charging, based on AMI data from separate meters. SCE assumed 40 percent of EV owners who charge away from home will be on this group in the year 2040.

  ii. “Flexible charging”: This dynamic pricing may exist. This is assumed price-based incentive to charge their EV in the early afternoon when they are at their workplace and/or to take advantage of high solar production in the middle of the day. Charging peaks around 2 PM. SCE assumed 60 percent of EV owners who charge away from home will be in this group in the year 2040.

3) The start time for charging is based on either historical data (for exiting rates) or internal assumptions.

The figure below represents the aggregated behavior of LDV EV customer charging (in different rate classes) in SCE territory both at home and away from home.

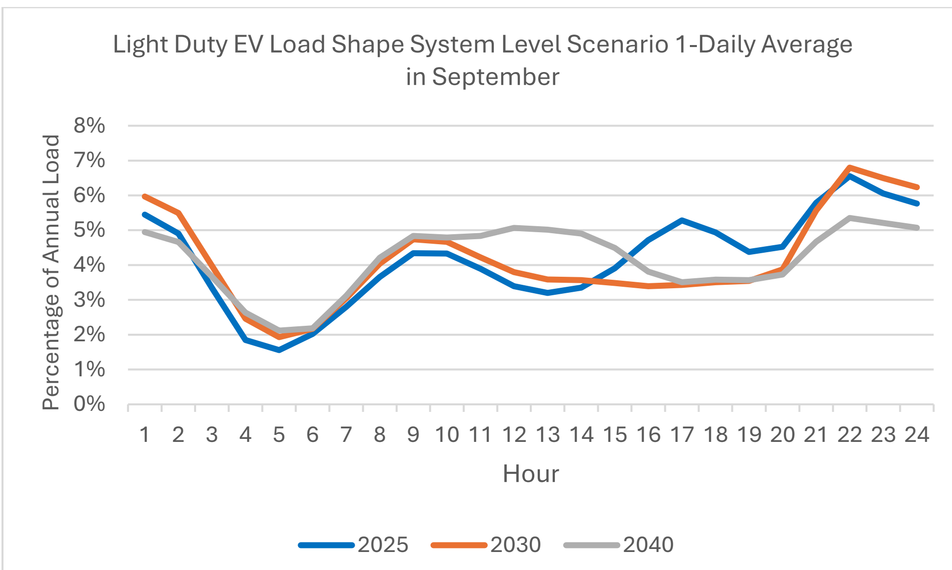

FIGURE 12: EV LOAD SHAPE SYSTEM LEVEL IN SCENARIO 1

Rates of charging at home vs away from home are included in the table below.

TABLE 22: PERCENTAGE OF CHARGING BY LOCATION

	2025	2030	2040
Home Charging	76%	73%	68%
Away from Home Charging	24%	27%	32%

1.2.4. Medium & Heavy-Duty Vehicles (MD/HD EV)

To forecast medium- and heavy-duty transportation electrification (TE) load, SCE leveraged Guidehouse's circuit-level propensity modeling. This analysis used vehicle registration data, fleet operations information, and survey responses to estimate where and when MDHD electric vehicle loads are likely to emerge across SCE's service area. The forecast also incorporated regulatory timelines and incentive-driven adoption patterns to map expected TE load growth onto SCE's distribution circuits. This study was funded through SCE's Low Carbon Fuel Standard (LCFS) TE Research and Studies portfolio — a non-ratepayer funding source authorized under CPUC Resolution E-5236.SCE utilized Guidehouse's circuit level energy (GWh) forecast at circuit level and then SCE converted those circuit level values to percentages of the SCE total system value.

SCE used the 2023 CEC IEPR Local Reliability scenario forecast for medium and heavy-duty trucks. SCE then allocated this forecast to individual circuits based on the percentage share of each circuit to total forecast developed by the Guidehouse study.

To estimate the circuit level hourly medium and heavy-duty truck forecast, SCE multiplied the 2023 CEC IEPR medium and heavy-duty truck load shape by annual medium and heavy-duty truck forecast at the circuit level.

1.2.5. Solar Photovoltaic (PV)

SCE utilized the following data sources to break down the system-level Solar PV forecast from the 2023 CEC IEPR: relationships between forecast zones and ZIP codes, ZIP code to circuit mappings, internally developed market potential at the ZIP code level, housing starts data from Moody's Analytics, permit data from the Construction Industry Research Board (CIRB), circuit length information from SCE's Geospatial Analysis team, customer-level propensity models, and non-residential energy consumption values for circuits within SCE's service territory.

For residential forecasts, SCE separated single-family (SF) new construction by leveraging housing start data and circuit distribution models, while the remaining residential forecast applied a Bass Diffusion Model for adoption trends.

1.2.5.1. Circuit Level Residential Single Family (SF) New Construction PV:

Single-family new construction applies to residential single-family new construction-related Solar PV installations. This forecast[5] is a subset of the total residential forecast and was provided by the CEC separately. Steps include:

1. Use Moody Analytics' data to estimate total housing starts in SCE's service territory based on historical percentages from CIRB permits data
2. Calculate circuit share for each county using internal GIS data
3. Generate circuit-level new construction numbers by applying the share from Step 2
4. Generate circuit-level share of new construction in SCE's service territory
5. Allocate IEPR Residential SF new construction load growth, in MW as derived in Step 4.

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[5] California Energy Commission, *CED: SCE Annual Installed PV Capacity (MW) on New Single Family Homes*.

1.2.5.2. Circuit Level Remaining Residential PV:

This section addresses the residential forecast after the residential SF new construction forecast has been subtracted. Steps include:

1. Use the Bass Diffusion Model to obtain forecasting zone parameters and applying these to each ZIP Code
2. Run the Bass Diffusion Model for each Zip Code adopting the relative forecasting zone parameter and recalculating market potential based on NREL's small building data and SCE non-CARE service account data.
3. Determine the ZIP code share of incremental installations, calculated the share of each circuit within ZIP codes, and combined these ratios to get each circuit's share of the entire SCE service territory.
4. Apply the 2023 CEC IEPR MW incremental forecast for SCE's territory to the circuit level by applying the computed share from the previous step. The forecast applied was the residential solar PV forecast, with the residential SF new construction homes first subtracted.
5. Add circuit level forecasts for residential SF new construction solar PV, to produce a total residential forecast for each circuit.

1.2.5.3. Circuit Level Non-Residential PV:

The steps below were followed for the circuit level non-residential PV forecast:

1. Allocate the 2023 CEC IEPR forecast for new construction in SCE's service territory, according to Title 24 requirements.
2. Distribute remaining non-residential existing MW across all circuits based on each circuit's energy use share.
3. Utilize an internally generated shape that incorporates dependability. To estimate the circuit-level hourly forecast, SCE multiplied its regional dependability shapes by the annual PV forecast at the circuit level. Dependable PV shapes include adjustments to account for factors including cloud cover, degradation, etc.

1.2.6. Energy Storage (ES)

SCE utilized the following data sources to break down the energy storage MW forecast from the 2023 CEC IEPR forecast: circuit-level residential PV share distribution, information from the Self-Generation Incentive Program (SGIP) Equity Resiliency Program Database, circuit-level EV allocation in SCE territory, and circuit-level peak-to-energy ratios.

1.2.6.1. Circuit Level Residential ES:

SCE observed that most residential energy storage (ES) units are paired with photovoltaic (PV) systems and used circuit-level PV share as a proxy for ES distribution. A portion of the ES forecast was allocated to high wildfire threat zones based on SGIP Equity Resiliency Program data, with future capacity forecasted from historical incentive dollars and nameplate capacity. This forecast was evenly distributed across circuits in high fire threat zones. The remaining residential ES MW forecast was allocated using weighted circuit shares for residential Solar PV and electric vehicles.

1.2.6.2. Circuit Level Non-Residential ES:

For the non-residential sector, SCE allocated the 2023 CEC IEPR new construction MW forecast based on Title 24 requirements. Observing that most non-residential customers use energy storage to reduce peak demand charges, SCE identified the top 25% of non-residential customers with the highest peak-to-energy ratios as likely adopters. Then SCE calculated the number of adopters per circuit, assigned shares to each circuit, and applied these shares to the remaining 2023 CEC IEPR non-residential storage forecast to determine each circuit's non-residential energy storage forecast.

SCE utilized separate 8760 hourly profiles for residential and non-residential customers. The 2023 CEC IEPR hourly forecasts for energy storage were normalized to 100% for each year and then multiplied by the annual MW to MWh conversion ratio to generate circuit-level forecasts for both residential and non-residential energy storage.

1.2.7. Fuel Substitution (FS)

Fuel substitution involves transitioning from one type of fuel to another, typically reducing gas use, and increasing electricity use. This section details SCE's method for disaggregating the 2023 CEC IEPR forecast for Additional Achievable Fuel Substitution (AAFS) to individual circuits, including zero-emission appliance standards from the CARB State Implementation Plan (CARB-SIP). The CEC added a load modifier for expected fuel substitution due to new zero-emission appliance policies. SCE adopted the AAFS local reliability scenario (AAFS scenario 4) and used the CEC's Fuel Substitution Scenario Analysis Tool (FSSAT) to quantify CARB-SIP impacts. Primary data sources include residential and non-residential energy consumption values, residential and commercial building stock forecasts, and the 2023 CEC IEPR hourly load forecast for AAFS.

Disaggregation of 2023 CEC IEPR system-level AAFS forecast uses proportional scaling models that assume FS adoption follows at least one of the following variables: energy use, segmentation, home vintage, housing starts, building stock. The combination of variables depends on the type of load and the sector. The CEC's AAFS load forecast can be broken into two main categories: FS Programs and CARB-SIP. FS Programs involve the CPUC working with IOUs and other entities to develop programs using ratepayer funds. CARB-SIP refers to the incremental electricity consumption from zero-emission appliances.

These two categories are further subdivided into residential and non-residential sectors, resulting in four mutually exclusive buckets for the total CEC forecast. SCE's disaggregation steps for each of these six categories are as follows: For Residential FS Programs, SCE computes allocation shares from input data, collects CEC AAFS forecasts, and disaggregates FS by applying allocation percentages to the IEPR forecasted impacts.

For Residential CARB-SIP, SCE leverages Moody Analytics housing stock forecasts, maps residential housing stock forecasts to circuits, collects CEC FSSAT results, and disaggregates CARB-SIP impacts using allocation percentages.

For Non-Residential FS Programs, SCE computes circuit allocation shares from energy usage, collects CEC AAFS forecasts, and disaggregates FS by applying allocation percentages to the IEPR forecasted impacts.

Finally, for Non-Residential CARB-SIP, SCE extends Dodge building stock forecasts, maps commercial building stock forecasts to circuits, collects CEC FSSAT results, and disaggregates CARB-SIP impacts using allocation percentages. This comprehensive methodology ensures that the CEC's system-level AAFS forecast is accurately disaggregated to individual circuits, considering several factors such as energy use, customer segmentation, building vintage, housing starts, and building stock.

SCE used the 2023 CEC IEPR Local Reliability system-level hourly forecast to convert the AAFS hourly load modifier forecast into hourly percentages for each forecast year, ensuring the total FS load percentage equaled 100% annually. SCE then multiplied these unitized hourly percentages by the CEC-supplied AAFS + CARB-SIP annual forecast, allowing SCE to distribute the total FS impacts across hourly increments for their service territory.

1.3. DER Disaggregation - Scenario 2

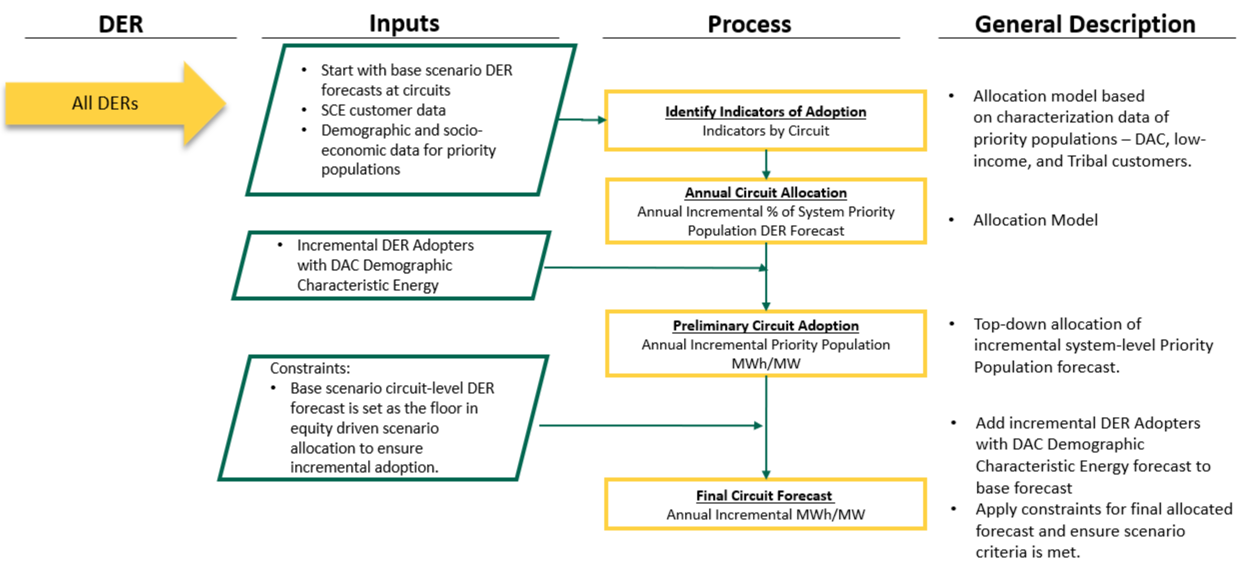

FIGURE 13: DER FORECAST METHODOLOGY FOR SCENARIO 2

SCE utilized work conducted by California Climate Investments on Priority Populations within the southern California region. Their mapping tool and associated data are publicly available: California Climate Investments Priority Populations 4.0[6]. The priority populations identified in their analysis fall into three categories:

- **Low-income community** – Census tracts that are at or below 80% of the statewide median income, or within the threshold designated as low income by the California Department of Housing and Community Development's Revised 2021 State Income Limits.

- **Disadvantaged community: CES** – Disadvantaged communities based on CalEPA's identification using CalEnviroScreen.
- **Disadvantaged community: Tribal land** – Identified by CalEPA as lands under the control of federally recognized tribes.

These groups may overlap, and many census tracts contain one or more of these communities. Additionally, the map identifies census tracts that do not fall directly within these communities but are within ½ mile of one. Table 23 outlines the metrics used by the California Climate Investments to characterize the priority populations across California's census tracts.

TABLE 23: DATA DICTIONARY PROVIDED BY CALIFORNIA CLIMATE INVESTMENTS THAT CHARACTERIZES PRIORITY POPULATIONS ACROSS CALIFORNIA'S CENSUS TRACTS

Key (Columns)	Definition
Disadvantaged Communities; COMPLETELY COVER Census Tract	Census Tracts designated as Disadvantaged Communities are marked "Yes" in this column. These are CalEnviroScreen 4.0 scoring census tracts along with some tribal land area representations covering an entire census tract.
Disadvantaged Communities; PARTIALLY WITHIN Census Tract	Census Tracts where a portion of the tract area overlaps a disadvantaged community are marked "Yes" in this column. These are CalEPA Tribal Land Area Representations. CalEnviroScreen 4.0 scoring census tracts are not partially within, but a tribal land area can be within a CalEnviroScreen scoring tract.
Low-Income Communities; COMPLETELY COVER Census Tract	Census Tracts designated as Low-Income Communities are marked "Yes" in this column.
Low-Income half-mile Buffer Communities; COMPLETELY COVER Census Tract	Census Tracts designated as Low-Income Communities whose entire boundary falls within a half-mile of a Disadvantaged Community (Buffer) are marked "Yes" in this column.
Low-Income half-mile Buffer Communities; Partially Within Census Tract	Census Tracts designated as Low-Income Communities where a portion of the tract area includes an area within a half-mile of a Disadvantaged Community (referred to as "Buffer") are marked "Yes" in this column.
Low-income Household Only half-mile Buffer; COMPLETELY COVER Census Tract	Census Tracts corresponding to areas falling completely within a half-mile of a Disadvantaged Community which are not otherwise designated as Low-Income Communities, but where a low-income household is eligible for Buffer benefits are marked "Yes" in this column. Low-income Household designations fall anywhere within the State of California.
Low-income Household Only half-mile Buffer; PARTIALLY WITHIN Census Tract	Census Tracts where a portion of the area falls within a half-mile of a Disadvantaged Community which are not otherwise designated as Low-Income Communities, but where a low-income household is eligible for Buffer benefits are marked "Yes" in this column. Low-income Household designations fall anywhere within the State of California.
Tribal Lands Present	Tribal land that Completely Covers or is Partially Within the boundary of land controlled by Federally Recognized Tribes are

	considered Disadvantaged Communities and are marked "Yes" in this column.

1.3.1. Disaggregation Methodology

SCE developed a six-step process that assigns priority population scores to each circuit, determines the amount of DER growth allocated to priority populations in scenario 1, determines how much incremental DER growth is required to meet the CPUC criteria, and allocated the additional incremental growth to the circuits. SCE considered the same set of DER types as those in Scenario 1, except for the Medium/Heavy-Duty vehicle portion of the TE forecast since the load type was determined not to fit the scope of the scenario. Adoption constraints such as building type, charger access availability, or rooftop PV feasibility were not considered in the assumptions.

Step 1: Derive Composite Score from All Priority Population Factors

The initial step involves defining and deriving a “Priority Population Score” for each census tract within the targeted region. California Climate Investments has made available resources on priority populations which includes a comprehensive list of every census tract in California and which type of priority populations exists in those tracts based on the various categories defined in the table above.

Each cell contains either "Yes" or "No," denoting whether the tract meets the criteria for that category. For the Tribal Lands Present column, "Yes" values are further categorized as "Yes: Full Tract" or "Yes: Partial Tract," indicating the extent of coverage by tribal lands.

SCE then converts these categorical values into numerical scores:

- A “Yes” value indicating complete coverage assigns a score of 1 to the census tract.
- A “Yes” value indicating partial coverage assigns a score of 0.5.
- A “No” value assigns a score of 0.

The final priority population score for a census tract is computed as the maximum numerical value appearing in any of the priority population metrics. Thus, the overall score for each census tract is either 0, 0.5, or 1.

Step 2: Map Census Tract to Circuits

This step involves mapping the composite census tract score to the circuit composite score. Each circuit will be associated with at least one or potentially multiple census tracts. In instances where there is a direct one-to-one mapping between a circuit and a census tract, the circuit is assigned the same composite score as that census tract.

When a circuit spans multiple census tracts, the composite scores of all relevant tracts are averaged, weighted by the number of customers residing within each tract. This results in the composite score for each circuit in the distribution plan, which ranges between 0 and 1.

Step 3: Calculate Composite Score for Circuit and Allocate Scenario 1 Load and SCE Customer Counts

Step 2's result is utilized to determine the amount of DER adoption already allocated to priority populations in scenario 1. This is achieved by multiplying the circuit’s composite score by the load allocated in Scenario 1. Hence, the composite score represents the share of forecasted DER load for priority population customers. The composite score is also used to determine the proportion of SCE customers on a specific circuit belonging to a priority population by multiplying the score by the customer count.

Step 4: Aggregate Priority Population Load to System-Level

The forecasted DER loads assigned to priority population customers at the circuit level are aggregated to obtain the system-level forecasts allocated to such customers.

Step 5: Evaluate Scenario 1 DER Load Using CPUC Criteria

This Scenario 1 forecast is assessed against CPUC criteria to evaluate the allocation efficiency of DER disaggregation to priority populations. The expression provided by CPUC:

$$\frac{Customers\ with\ DAC\ Demographics}{All\ Customers} \leq \frac{DER\ Adopters\ with\ DAC\ Demographics}{All\ DER\ Adopters}$$

The right-hand side of this expression suggests a customer-based model for DER adoption, which was not central to SCE's Scenario 1 analysis. Therefore, SCE adapted the expression to use a more readily available metric—energy consumption.

$$\frac{Customers\ with\ DAC\ characteristics}{All\ Customers} \leq \frac{Portion\ of\ IEPR\ DER\ Forecast\ Allocated\ to\ DAC\ Customers}{Total\ IEPR\ DER\ Forecast}$$

To determine the incremental energy that is required to meet the criteria, the expression below was utilized:

$$\begin{aligned}&Incremental\ DER\ Adoptors\ with\ DAC\ Demographic\ Characteristic\ Energy\\ &\quad = Equity\ Case\ DER\ Adoptors\ with\ DAC\ Demographic\ Characteristic\ Energy\\ &\quad - Scenario\ 1\ DER\ Adoptors\ with\ DAC\ Demographic\ Characteristic\ Energy\end{aligned}$$

Step 6: Allocate Remaining DER

If the criteria are not satisfied, allocate remaining DER needed to satisfy criteria using the circuit composite scores calculated in Step 1, normalized by the scores across the circuit to derive an allocation factor.

Results

Table 24 outlines the load or energy incremental to scenario 1 required to meet the equity scenario criteria. Among the DERs in the 2023 CEC IEPR forecast, only Light-Duty EV, Residential ES, and PV did not meet the initial criteria and required additional load/capacity to be distributed. The incremental load was distributed by the normalized priority population composite scores.

TABLE 24: ADDITIONAL LOAD OR ENERGY REQUIRED TO MEET EQUITY CRITERIA

DER	Incremental Load or Energy Required to Meet Equity Criteria in 2030	Incremental Load or Energy Required to Meet Equity Criteria in 2040

Light Duty EV	732,381 MWh	2,245,000 MWh
Residential Energy Storage	76 MWh	100 MWh
Photovoltaic	17 MW	31 MW

1.4. DER Disaggregation - Scenario 3

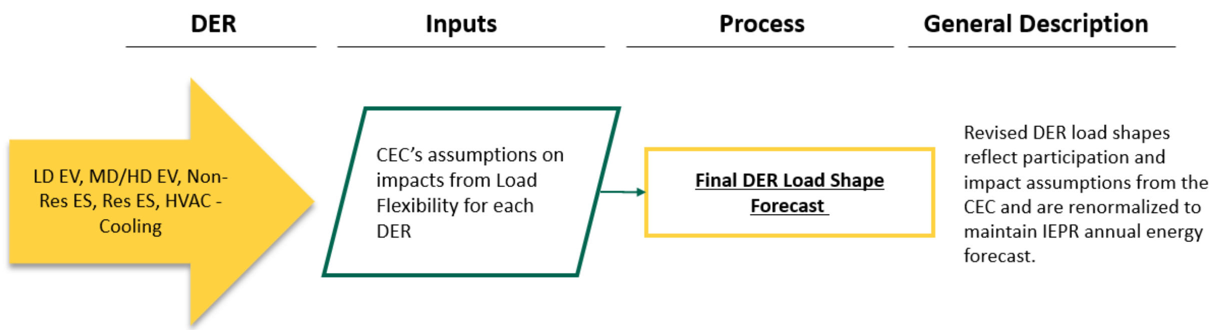

FIGURE 14: FORECAST METHODOLOGY FOR SCENARIO 3

The CEC's D-flex tool does not prescribe dispatch outcomes but offers a standardized reference for estimating flexibility availability. Following inter-agency coordination and acquiring data from the CEC, SCE derived an hourly flexibility profile tailored to the distribution circuit level, identifying where demand flexibility could help defer or mitigate infrastructure upgrades.

This scenario serves as a mitigation case to Scenario 1 in the EIS Part 2 analysis, quantifying the potential value of demand flexibility in deferring conventional distribution investments.

The load flexibility results from the CEC's D-flex tool in support of the Demand Scenarios project were not available at the time of the EIS 2 scenario development. Instead, the CEC provided a workbook that contained the assumptions that are the basis of the D-Flex tool. These assumptions were used as the basis for the EIS 2 scenario development to satisfy the CPUC scenario requirements.

For the EIS load flexibility scenario, SCE evaluated the following end uses for demand flexibility potential:

TABLE 25: SUMMARY TABLE OF KEY D-FLEX END USES AND IEPR COMPONENTS

End Use	Based on the 2023 CEC IEPR
Light-Duty EV (LD EV)	Yes
Medium/Heavy-Duty EV (MD/HD EV)	Yes
Non-Residential Energy Storage	Yes
Residential Energy Storage	Yes
HVAC - Cooling	No

The end uses were selected in part based on CEC's considerations in the Demand Scenarios project and SCE's assessment of which DERs would contribute most significantly to demand flexibility. SCE also considered how well each methodology aligned with existing processes already established in scenario 1. The first four reflect DER sources directly from the 2023 CEC IEPR forecast. HVAC-cooling was included after careful consideration because it is a large portion of the average SCE customer's load and therefore can be an important component to the demand flex solutioning. Since HVAC-cooling is not a component to the IEPR DER forecast, this end use was inferred as a portion of a circuit's forecasted gross load.

Neither of SCE's demand flexibility scenarios accounted for the following factors that could influence the results beyond the assumptions made by LBNL and CEC staff on end use flexibility potential. The study did not separately consider the mix of price responsive behavior versus program-based demand response that customers might exhibit, nor did the assumptions explicitly reflect AMI 2.0 or future telemetry capabilities. It also did not separately incorporate empirical data, such as AMI data or program data beyond what LBNL or CEC staff may have, to calibrate expected response behaviors to EV charging or HVAC cycling. Scenarios 3 and 4 did not consider any specific programs for customer adoption of enabling technologies, such as smart thermostats or controllable EV chargers.

Accordingly, EIS 2 should be interpreted as estimating potential bounds based on CEC's D-Flex tool assumptions. Future work leveraging AMI 2.0-enabled data, targeting, and operational capabilities is expected to improve the fidelity and achievable performance of DF as either a peak-shaping input and/or a localized mitigation option.

1.4.1. Methodology

The CEC workbooks, titled "D-Flex PCM NonEV Inputs & Assumptions Workbook" and "D-Flex PCM EV Inputs & Assumptions Workbook"[7], provides the inputs and assumptions used to calculate impact potential used in the CEC's D-Flex PCM tool. These workbooks describe the methodology for calculating the impact of demand flexibility at a particular hour using the following expression:

$$\begin{aligned} MW\ Impact = {} & End\ Use\ Annual\ Consumption\ (MWh) * Normalized\ Loadshape \\ & * Control\ Strategy\ Eligibility * Unit\ Impact * Participation \end{aligned}$$

Each factor that contributes to the amount of demand flexibility is defined in Table 26. Multiplying these three factors with the forecasted demand for each end use at a given hour results in the amount of demand flexibility. While the CEC's workbooks provided highly detailed inputs and assumptions at specific end-use and sector levels, this granularity was not directly aligned with the forecast structure SCE had established in the Scenario 1 analysis. To effectively incorporate these assumptions into the EIS 2 framework, SCE simplified the CEC's data by averaging similar end-uses and sector categories to match the IEPR forecast components used in SCE's analysis. This approach

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[7] California Energy Commission. *Demand Analysis Working Group (DAWG) Meeting: Overview of CEC's Demand Flexibility Tool (D-Flex Tool)*. February 28, 2025. https://www.energy.ca.gov/event/meeting/2025-02/demand-analysis-working-group-dawg-meeting-overview-cecs-demand-flexibility

allowed generalized factors to be derived that could be applied in analysis while maintaining the integrity of the load flexibility evaluations.

The resulting simplified factors, derived from the CEC workbooks, are detailed within Table 26. This table includes the control strategy eligibility, participation rate, and unit impact values used to quantify demand flexibility for each hour for the end uses considered in this scenario. To the extent that the CEC includes existing or planned demand response, time-of-use, and transportation electrification programs, those elements are included in the factors derived from the CEC workbooks.

TABLE 26: CEC ASSUMPTIONS FOR DETERMINING THE LOAD FLEXIBILITY AVAILABLE AT A GIVEN HOUR

Load Flexibility Assumption	Description
Control Strategy Eligibility (CSE)	The control strategy eligibility (CSE) represents the % of participants with a particular end use that are eligible to curtail load using particular control strategies. In other words, this represents technology saturation that enables control for a given end-use category.
Participation	Participation (%) indicate what fraction of the technically suitable and controllable load that is assumed to enroll in DR/DF programs. All values except for batteries were obtained from Lawrence Berkeley National Laboratory (LBNL) Phase 4 DR Potential study [8]for specific years. Battery percentages derived by Guidehouse[9] in alignment with CA's 2030 Load Shift Goal.
Unit Impact	Unit impact values indicate the percent of the enrolled load that could be shed during an event. Values obtained from the LBNL Phase 4 DR potential study.

The estimation of HVAC-cooling DER was inferred from the forecasted hourly gross load before applying the IEPR DERs. As HVAC-cooling is not a specific load modifier within the 2023 CEC IEPR forecast, it was necessary to estimate its contribution from broader load trends. Within a given day, HVAC-cooling consumption is assumed to constitute some fraction of the gross load. This fraction was determined using building simulation data from NREL's Restock dataset—a freely available resource which represent simulated energy usage patterns for residential buildings across the United States.

The NREL data includes information specific to buildings located within southern California and the CEC climate zones serviced by SCE. This subset enabled the estimation of a percentage capturing

[8] Gerke, B. F., Smith, S. J., Murthy, S., Baik, S. H., Agarwal, S., Alstone, P., Khandekar, A., Zhang, C., Brown, R. E., Liu, J., & Piette, M. A. *The California Demand Response Potential Study, Phase 4: Report on Shed and Shift Resources Through 2050*. Lawrence Berkeley National Laboratory, May 21, 2024

[9] California Energy Commission. SB 846 Load Shift Goal Commission Report. TN250357, May 26, 2023

the proportional share of HVAC-cooling across each hour of a typical year. The percentage derived represents the contribution of HVAC-cooling to the overall load for a typical residential structure in southern California. These percentages were applied to each circuit's gross load forecast to estimate the HVAC-cooling load available for load flexibility.

Once a circuit's HVAC-cooling load was established, the following steps were taken to generate the net impact for each DER flexible load:

- Step 1. Identify circuit's daily peaks from scenario 1.
- Step 2. Apply the CEC's assumptions for the eligible loads to determine the amount of load reduction at a given hour.
- Step 3. Renormalize the resulting load profile to generate new daily load shape.
- Step 4. Distribute DER's daily consumption to new load shape.
- Step 5. Calculate the net impact from the flexible demand.

The load flex algorithm for Scenarios 3 and 4 evaluated each distribution circuit independently. As mentioned in Appendix 1 Section 2.2 DER Disaggregation for Secondary Analysis, load shift profiles were optimized for circuit-level load reduction, not to alleviate constraints at the service transformer and/or service conductors. For every day in the forecast horizon, SCE identified that circuit's three highest net-load hours in the Scenario 1 profile and treated that three-hour window as the shiftable event. SCE then multiplies the three CEC D-Flex factors (control eligibility, participation, unit-impact) to the circuit's LDEV, MD/HD EV, ES and HVAC-cooling load components at each of the three hours to determine the amount of flexible load reduction. The final steps involve renormalizing the resulting DER profile and multiplying the original daily energy consumption across this modified profile. The result of this step distributes the load reduction from the three hours to the other hours of the day and preserves the total daily energy from scenario 1 results. Modeling treated the flexible loads independently and the amount of load flexibility for one DER had no impact on the availability for another DER. This logic is not limited to circuits with base case overloads; it is calculated for all circuits to estimate potential.

TABLE 27: SCENARIO 3 DEMAND FLEXIBILITY ASSUMPTIONS

End Use	Year	CSE	Participation	Impact
LD EV	2030	100%	6.47%	90%
	2040	100%	7.86%	90%
MD/HD EV	2030	100%	51.7%	50%
	2040	100%	51.5%	50%
Non-Residential Energy Storage	2030	100%	20%	100%
	2040	100%	20%	100%
Residential Energy Storage	2030	100%	23.33%	100%
	2040	100%	23.33%	100%
HVAC - Cooling	2030	25.96%	13.7%	61.05%
	2040	28.07%	13.5%	61.05%

1.5. DER Disaggregation - Scenario 4

For Scenario 4, the participation rates were adjusted to 100% for all DER types except HVAC – Cooling.

TABLE 28: SCENARIO 4 DEMAND FLEXIBILITY ASSUMPTIONS

End Use	Year	CSE	Participation	Impact
LD EV	2030	100%	100%	90%
	2040	100%	100%	90%
MD/HD EV	2030	100%	100%	50%
	2040	100%	100%	50%
Non-Residential Energy Storage	2030	100%	100%	100%
	2040	100%	100%	100%
Residential Energy Storage	2030	100%	100%	100%
	2040	100%	100%	100%
HVAC - Cooling	2030	25.96%	13.7%	61.05%
	2040	28.07%	13.5%	61.05%

2. Forecast Preparation for Secondary Analysis – All Scenarios

This section described the preparation of sub-circuit level forecasts for all scenarios. These forecasts were used to perform analysis of service transformers and conductors, collectively referred to as Secondary Analysis.

As part of the EIS 2 Secondary Analysis, SCE developed a methodology to disaggregate the 2023 CEC IEPR DER forecast from the circuit level to individual meters. The objective was to assess the impact of DER adoption on the distribution service transformers and service lines between the distribution service transformers and customer meter. This disaggregation process considers both customer type and historical peak demand and was applied consistently across scenarios. Priority population scores and participation rate of the demand flexibility were not additionally incorporated.

The analysis leverages Advanced Metering Infrastructure (AMI) data and Python to proportionally disaggregate based on customer account type, historical peak demand and DER adoption at each feeder. Approximately 5.15 million individual service accounts are aggregated according to their associated service transformer structures

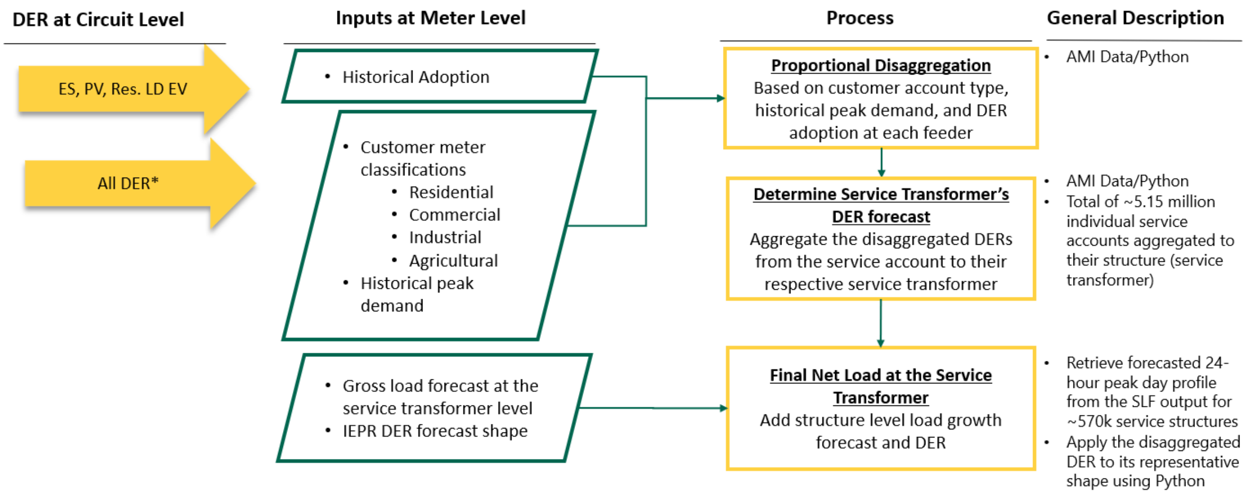

FIGURE 15: DER DISAGGREGATION AND NET FORECAST DEVELOPMENT TO THE STRUCTURE FOR ALL SCENARIOS

2.1. Net Forecast Development at the Structure

SCE's forecasting process utilizes historical profiles from AMI to generate the gross demand forecast for each structure. In this context, "structure" refers to the distribution service transformer, which often serves multiple customer meters. For the EIS Part 2 Secondary Analysis, the SLF output serves as the base for accumulating disaggregated DERs.

The following section provides a high-level overview of how the net forecast profile is created at the structure level:

1. <u>Extract the Gross forecasted profile for each structure:</u> Retrieve the forecasted 24-hour peak day profile from the SLF output for applicable structures (service transformers)
2. <u>Determine the DER forecast at a service transformer:</u> Aggregate disaggregated DERs from individual meter accounts to their corresponding structure (service transformer)
3. <u>Integrate DER growth into the SLF to generate the NET forecasted profile:</u> Apply the disaggregated DER to its representative shape and incorporate it into the gross structure-level forecast

2.2. DER Disaggregation for Secondary Analysis

This section details the data sources and methodology used to disaggregate the circuit-level 2023 CEC IEPR DER forecast to individual customers. Load shift profiles were optimized for circuit-level load reduction, not to alleviate constraints at the service transformer and/or service conductors. As noted, the following DER include:

- Solar Photovoltaic (PV)
- Energy Storage (ES)
- Energy Efficiency (EE)
- Fuel Substitution (FS)
- Transportation Electrification (TE)

2.2.1. Solar Photovoltaic (PV)

SCE utilized the internal records of historical PV adoption for each meter account to exclude customers who have already installed PV from further disaggregation of the 2023 CEC IEPR PV forecast. For customers without existing PV, their historical peak demand is aggregated at the circuit level according to their customer classification—Residential or Non-Residential (comprising Commercial, Industrial, and Agricultural sectors). This aggregated peak demand is then used to proportionally disaggregate the circuit-level PV forecast based on each customer's historical peak demand and classification.

$$\frac{Max(Customer\ Demand_{noPV})_{Class}}{\sum Max(Customer\ Demand_{noPV})_{Circuit,Class}}\ x\ PV\ Forecast_{Circuit,Class} = PV\ Share_{Class}$$

$$\frac{Peak\ of\ a\ Res\ Customer\ w/o\ PV}{\sum Peak\ of\ Res\ w/o\ PV\ at\ the\ circuit}\ x\ IEPR\ PV\ Res\ at\ the\ Circuit = Disaggregated\ PV\ at\ a\ Res\ Customer$$

$$\frac{Peak\ of\ a\ NonRes\ Customer\ w/o\ PV}{\sum Peak\ of\ NonRes\ w/o\ PV\ at\ the\ circuit}\ x\ IEPR\ PV\ Non\_Res\ at\ the\ Circuit = Disaggregated\ PV\ at\ a\ NonRes\ Customer$$

2.2.2. Energy Storage (ES)

SCE utilized the internal records of historical ES adoption for each meter account to exclude customers who have already installed ES from further disaggregation of the 2023 CEC IEPR ES forecast. For customers without existing ES, their historical peak demand is aggregated at the circuit level according to their customer classification—Residential or Non-Residential (Commercial, Industrial, and Agricultural sectors). This aggregated peak demand is then used to proportionally disaggregate the circuit-level ES forecast based on each customer's historical peak demand and classification.

$$\frac{Peak\ of\ a\ Res\ Customer\ w/o\ ES}{\sum Peak\ of\ Res\ w/o\ ES\ at\ the\ circuit}\ x\ IEPR\ ES\ Res\ at\ the\ Circuit = Disaggregated\ ES\ at\ a\ Res\ Customer$$

$$\frac{Peak\ of\ a\ NonRes\ Customer\ w/o\ ES}{\sum Peak\ of\ NonRes\ w/o\ ES\ at\ the\ circuit}\ x\ IEPR\ ES\ Non\_Res\ at\ the\ Circuit = Disaggregated\ ES\ at\ a\ NonRes\ Customer$$

2.2.3. Energy Efficiency (EE)

The historical peak demand of all customers on the circuit was aggregated at the circuit level. This aggregated demand is then utilized to proportionally disaggregate the circuit-level EE forecast to the individual meter account.

$$\frac{Peak\ of\ a\ \ Customer}{\sum Peak\ of\ all\ the\ customer\ at\ the\ circuit}\ x\ IEPR\ EE\ at\ the\ Circuit$$
$$= Disaggregated\ EE\ at\ a\ Customer$$

2.2.4. Fuel Substitution (FS)

The historical peak demand of Residential and Non-Residential customers (Commercial, Industrial, and Agricultural sectors) is aggregated at the circuit level. This aggregated demand is then utilized to proportionally disaggregate the circuit-level FS forecast based on each customer's historical peak demand and type.

$$\frac{Peak\ of\ a\ Res\ Customer}{\sum Peak\ of\ Res\ at\ the\ circuit}\ x\ IEPR\ FS\ Res\ Forecast\ at\ the\ Circuit$$
$$= Disaggregated\ FS\ Forecast\ at\ a\ Res\ Customer$$

$$\frac{Peak\ of\ a\ NonRes\ Customer}{\sum Peak\ of\ NonRes\ at\ the\ circuit}\ x\ IEPR\ FS\ Res\ Forecast\ at\ the\ Circuit$$
$$= Disaggregated\ FS\ Forecast\ at\ a\ NonRes\ Customer$$

2.2.5. Transportation Electrification (TE)

2.2.5.1. Light Duty EV - Residential

SCE utilized internal Load Research data to analyze historical billing records and detect potential electric vehicle (EV) adoption of residential customers. This data improves the accuracy of circuit-level EV forecast disaggregation by ensuring that customers that may have already adopted EVs are excluded from further disaggregation of the 2023 CEC IEPR EV Forecast. For residential customers without existing EVs, their historical peak demand is aggregated at the circuit level. This aggregated demand is then used to proportionally disaggregate the circuit-level EV forecast based on each customer's historical peak demand.

$$\frac{Peak\ of\ a\ Res\ Customer\ w/o\ EV}{\sum Peak\ of\ Res\ Customer\ w/o\ EV\ \ at\ the\ Circuit}\ x\ IEPR\ EV\ Res\ Forecast\ at\ the\ Circuit$$
$$= Disaggregated\ EV\ at\ a\ Res\ w/o\ EV\ Customer$$

2.2.5.2. Light Duty EV – Commercial

The historical peak demand of commercial customers is aggregated at the circuit level. This aggregated demand is then utilized to proportionally disaggregate the circuit-level light duty EV forecast based on each customer's historical peak demand and type.

$$\frac{Peak\ of\ a\ Commercial\ Customer}{\sum Peak\ of\ Commercial\ Customer\ w/o\ EV\ \ at\ the\ Circuit}\ x\ IEPR\ EV\ Commercial\ Forecast\ at\ the\ Circuit$$
$$= Disaggregated\ EV\ at\ Commercial\ Customer$$

2.2.5.3. Medium/Heavy Duty EV

Historically, Medium/Heavy Duty EV customers' applications have often requested for new service due to the required charger demand and the availability of various incentive programs. Thus, the Medium/Heavy Duty EV forecast is excluded from disaggregation to the existing secondary assets, and remains at the circuit and substation levels.

Appendix 2: Grid Needs and Mitigation Methodology

Grid Needs and Mitigation Identification

The grid needs and mitigation identification in EIS 2 were designed to closely mirror SCE's Distribution Planning Process (DPP). However, differences in outcomes are anticipated due to variations in methodology. While the DPP relies on a team of over 100 engineers to identify and select the most cost-effective mitigation measures, to enable the analysis of four scenarios in a compressed timeline, SCE utilized a partially automated decision tree approach to recommend solutions in EIS 2. Although EIS 2 aims to align with DPP outcomes, it was not intended to replicate the full depth of engineering evaluation. The partially automated script is designed to identify and recommend necessary mitigations, following the typical engineering practices from the least to most costly solutions. This automated solutioning methodology was applied consistently across all four scenarios evaluated in the study.

The study identifies required mitigations such as distribution circuit upgrades (DCU), new distribution circuits, substation capacity upgrades, new substations, 4 kV circuit cutovers, 4 kV substation eliminations, and upgrades to secondary transformers and associated secondary service conductors.

SCE validated the automated script by comparing its outputs with the project types and counts from the 2025 DPP. Project counts for larger projects, such as new circuits, bank upgrades, and new substations, were 20–30% higher than those shown in the DPP. This provided confidence that the script output was within the expected range. Unlike the DPP, the solutioning script separates DCU projects into small and large categories and cannot identify mitigation measures for underground cable temperature criteria violations. Therefore, DCU project counts in EIS 2 exclude underground cable system upgrade projects driven by thermal overloads. Additionally, for 4 kV circuit cutover projects, the DPP accounts for partial 4 kV circuit cutovers, whereas the solutioning script only evaluates full 4 kV circuit cutovers and substation eliminations. Due to this the script results cannot be directly compared to the total project count figures in DPP. Despite these limitations, SCE concluded through validation that the script is suitable for use in EIS 2, as the intent of the study is to compare the outcome across the study's evaluated scenarios. The partially-automated script does not consider construction feasibility or panel/service limitations for secondary analysis. Minimum loading threshold is considered, see Table 29 in this section.

For distribution mitigations, non-coincident circuit peaks of each EIS 2 scenario are used consistently in the evaluation of grid needs and mitigation projects. This approach is consistent with how SCE performs the annual planning process and ensures the most constrained conditions are evaluated. Appendix 1 Section 1 Forecast Preparation for Primary System Analysis describes how the forecast elements are combined on a time-series basis prior to the identification of the non-coincident circuit peak.

For substation mitigations, the substation loading is compiled by taking the sum of circuits fed by that substation, then identifying the coincidence based on the substation peak. System level coincidence peaks were not used in EIS 2 for grid needs and mitigation development.

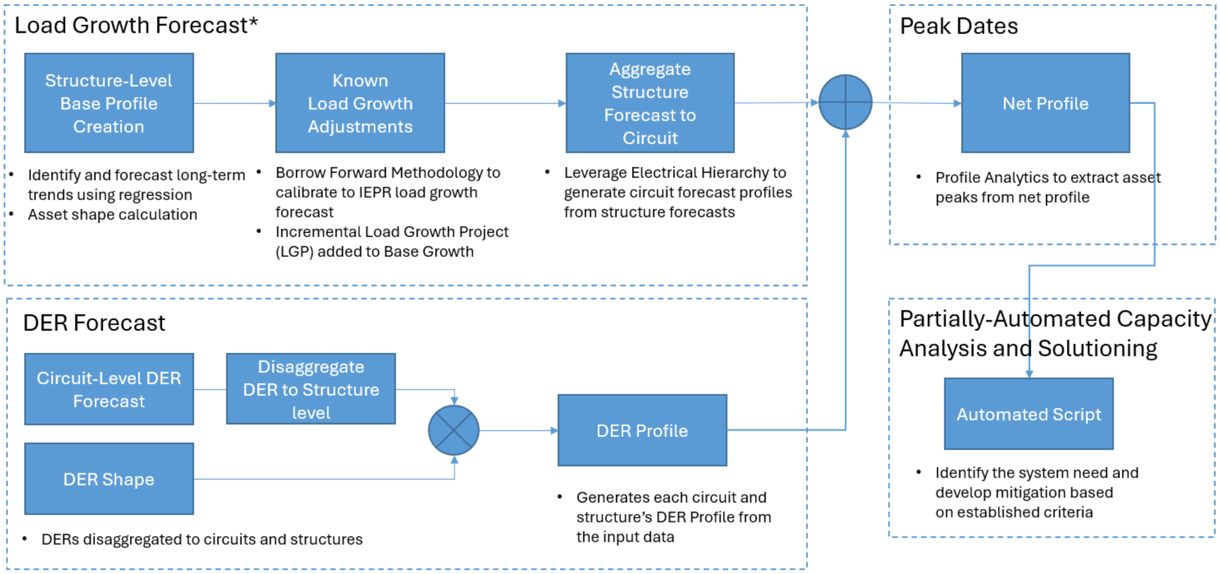

FIGURE 16: EIS 2 FORECAST PROCESS AND SOLUTIONING OVERVIEW

The figures below illustrate SCE's partially-automated solutioning scripts for identification of primary and secondary mitigations. A pre-processing function mimics the current annual planning process of cutover/elimination of the 4 kV system when the load surpasses the Planned Loading Limit (PLL) or requires significant infrastructure replacement. It evaluates circuits and substations with high-side voltage greater than 55 kV (e.g., 66/4 kV). If a cutover need is identified, the script automatically transfers the Criteria Projected Load (CPL) of affected circuits or entire substations to the nearest non-4 kV system. This process excludes 4 kV systems connected to lower-voltage distribution systems on the high side (e.g., 12/4 kV or 16/4 kV). For these configurations, the script assumes their demand will be cut over to the associated high-side distribution system.

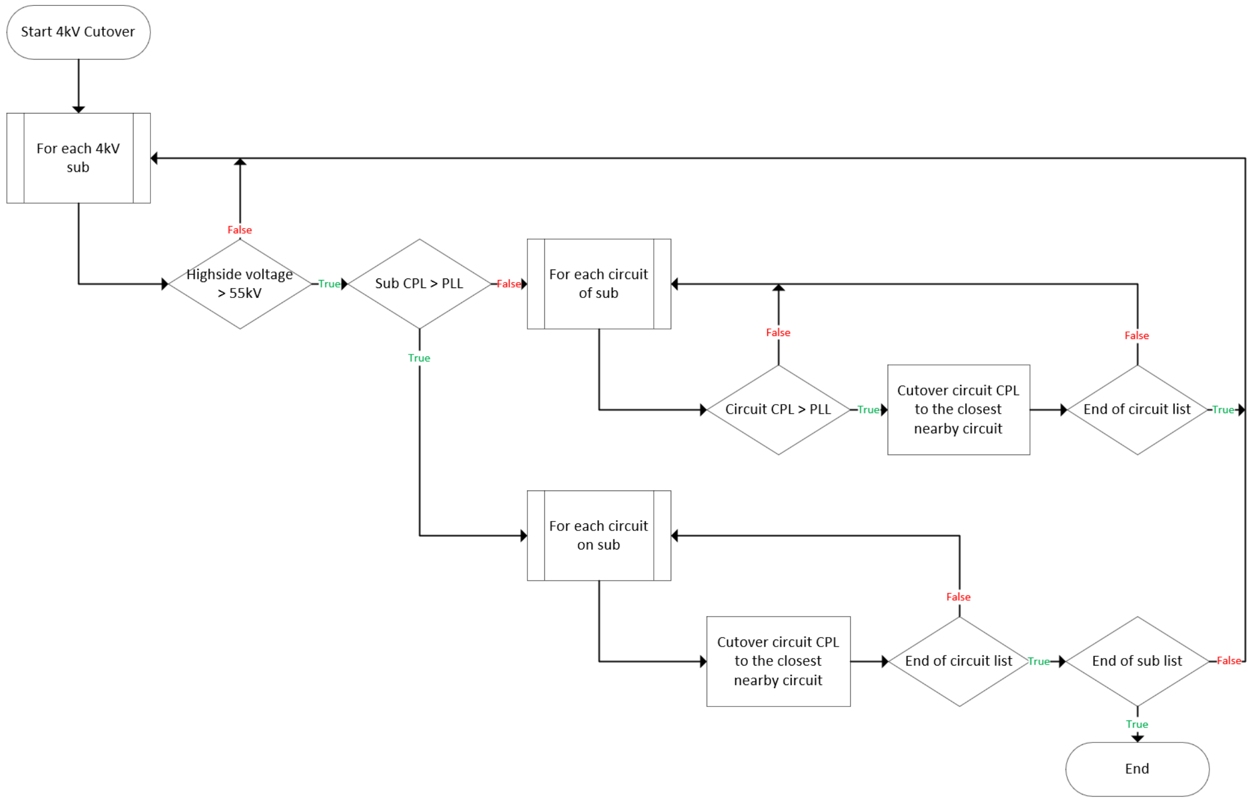

FIGURE 17: 4 KV CUTOVER PRE-PROCESSING BLOCK DIAGRAM

The main function of the solutioning script evaluates several criteria to determine when and how capacity upgrades are needed. The table below summarizes the typical infrastructure upgrade scope associated with each mitigation type. While this analysis identifies the mitigation type and general scope of work, it does not typically estimate quantities or specific assets—such as the number of service transformers, miles of new or upgraded conductors, or the average MW headroom added per project. Transformer quantities are included in the secondary analysis, but service conductor types are not quantified.

TABLE 29: OVERVIEW OF DISTRIBUTION GRID MITIGATION TYPES, TYPICAL SCOPE OF WORK, AND REQUIRED TRIGGERS

Mitigation Type	Typical Scope of Work	Required Triggers
Small Distribution Circuit Upgrade (DCU)	Smaller projects to increase circuit to standard capacity limit (e.g. <1-mile reconductor, new fuses)	12 kV, 16 kV, and 33 kV circuits with projected loading that exceeds their existing capacity limits, where those existing limits are below the standard capacity thresholds.

Large Distribution Circuit Upgrade (DCU)	Larger projects to build ties between circuits, line extension, large reconductors (>1 mile), automation addition	Cumulative circuit loading at a given distribution substation does not exceed the total circuit capacity limit, and fewer than 50% of the circuits exceed their standard capacity limit. Example: If 4 out of 9 circuits at a B-bank have negative reserve capacity, this represents 44%—which is below the 50% threshold.
New Distribution Circuit	New 12, 16, or 33 kV distribution circuits targeting 440 A	Cumulative circuit loading at given distribution substation exceeds cumulative circuit capacity by more than 50 A **or** if more than 50% of circuits at given distribution substation exceed standard capacity limit **or** if large DCU count at a given distribution substation is greater than 3
Distribution Substation Capacity Upgrade	Add 28 MVA transformer(s) and relevant equipment	Projected substation load exceeds its existing capacity limit but remains within the maximum allowable substation build-out capacity.
New Distribution Substation	Install new distribution substation with two 28 MVA transformers, two 4.8 MVAR capacitors, two subtransmission lines, distribution circuits, other relevant equipment, licensing, real properties	Projected load of a substation exceeds its maximum build-out capacity, or number of distribution circuits exceeds design criteria, and there is insufficient area capacity, including at nearby substations.
4 kV Circuit Cutovers	Cutover 4 kV circuitry to higher voltage	Projected load at 4 kV circuit or substation exceeds capacity limits
Substation Elimination	Eliminate substation and cutover 4 kV circuitry to higher voltage	Projected load at 4 kV substation exceeds capacity limits
Service Transformer/ Secondary Upgrade	Upgrade service transformer and secondary conductors	Projected load at the service transformer exceeds capacity limit based on its removal point (customer type, load factor, climate zone, structure type, kVA size)

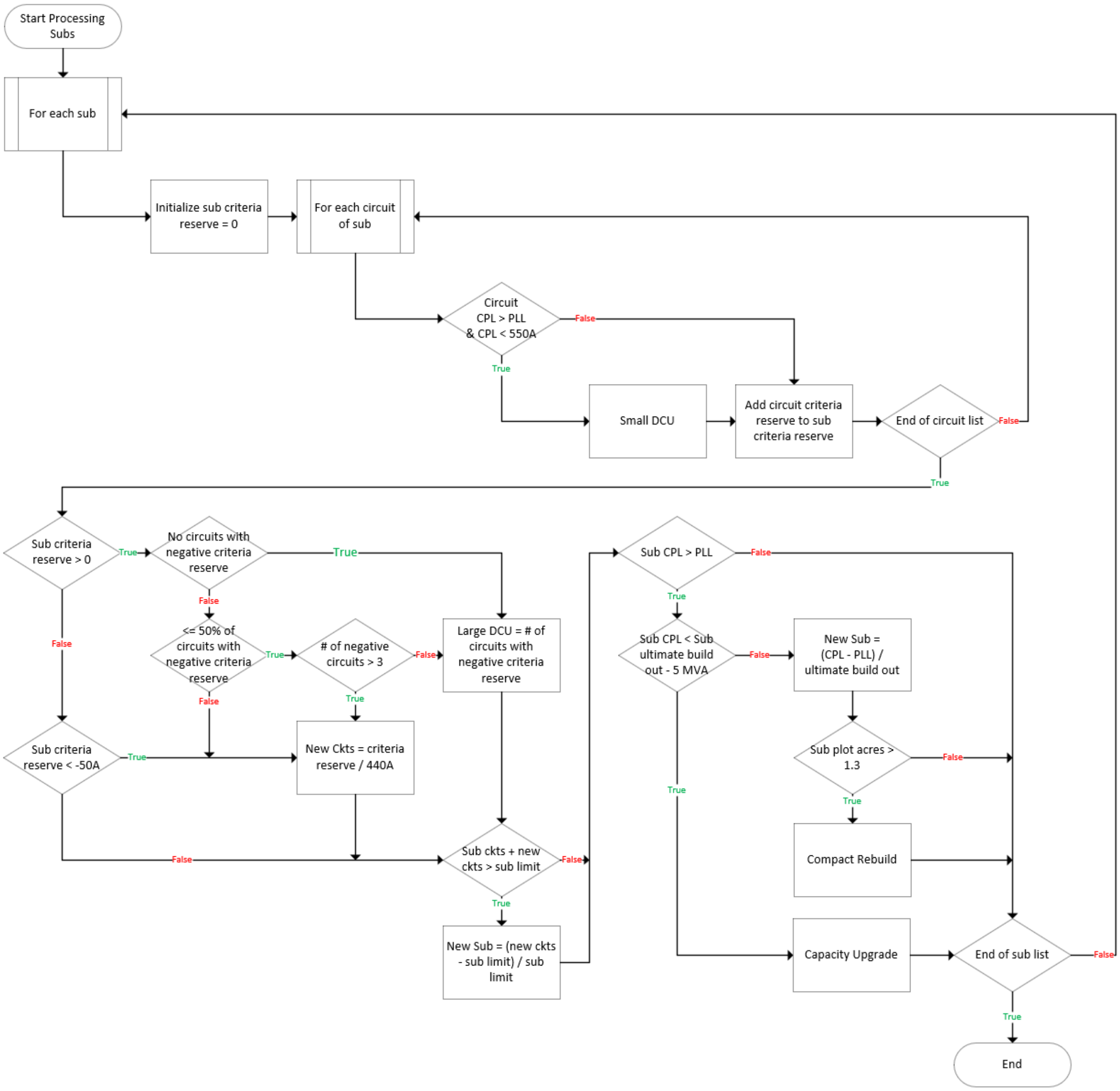

Figure 18: Main Solutioning Block Diagram

A final function then reviews the first 10 years of needs for each substation holistically and advances Large DCUs or New Circuits to replace Small DCUs or promote New Circuits to replace Large DCUs. For instance, if Small DCUs are identified as needed in 2028, 2029, and 2030, but a Large DCU is required in 2031 and 2032, the function consolidates the need by removing the Small DCUs and instead showing a Large DCU as needed from 2028 through 2032. This approach aims to identify the most cost-effective solution to address a multi-year range of needs.

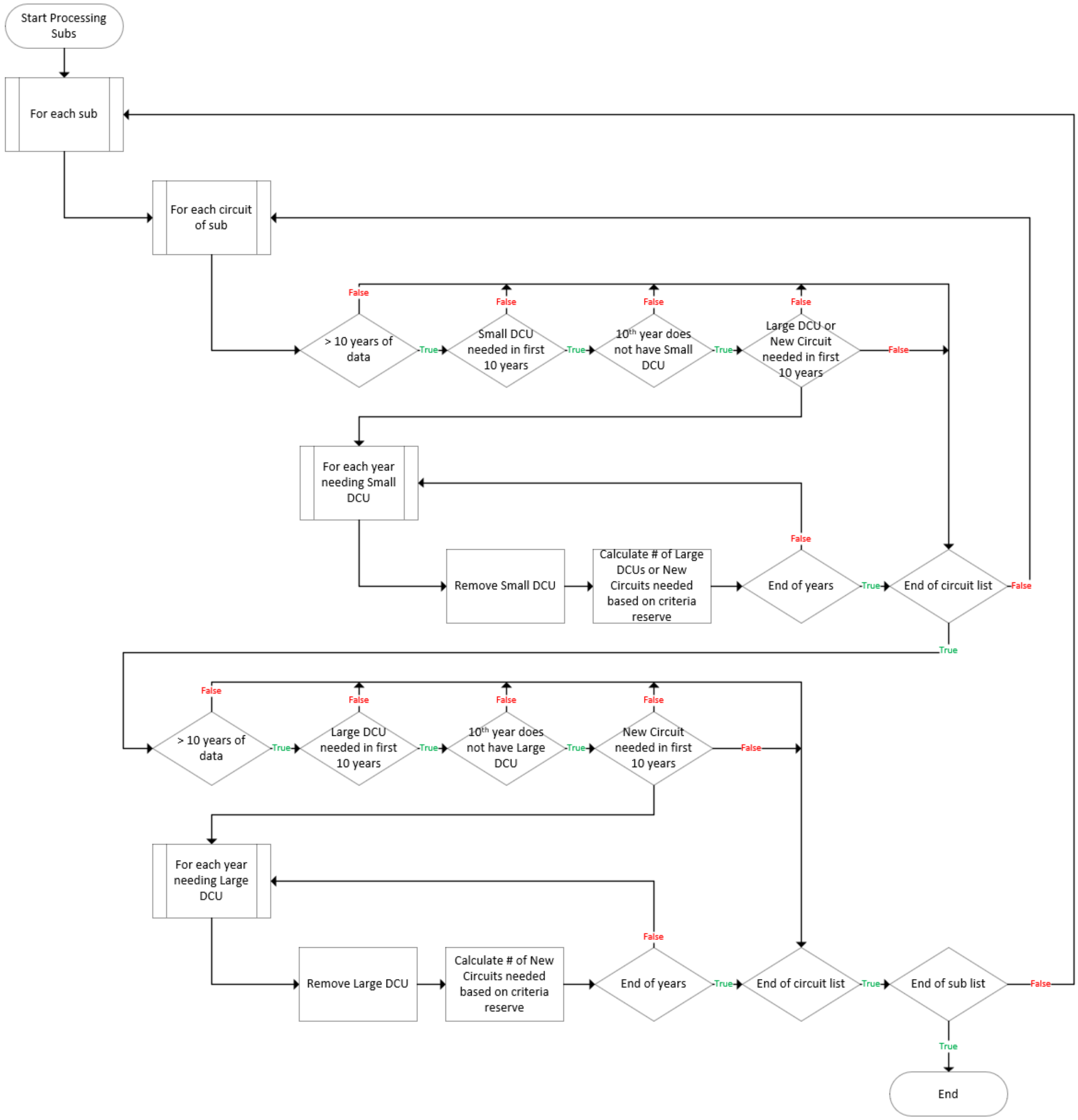

FIGURE 19: PROJECT CONSOLIDATION POST-PROCESSING BLOCK DIAGRAM

The secondary solutioning script disaggregates the DER forecast from the circuit level to individual meters. The meter data is then aggregated to their upstream transformer, and the DER contribution is added to the forecasted 24-hour peak day load profile. The service transformer is flagged for upgrade if the projected load exceeds the capacity limit based on its removal point.

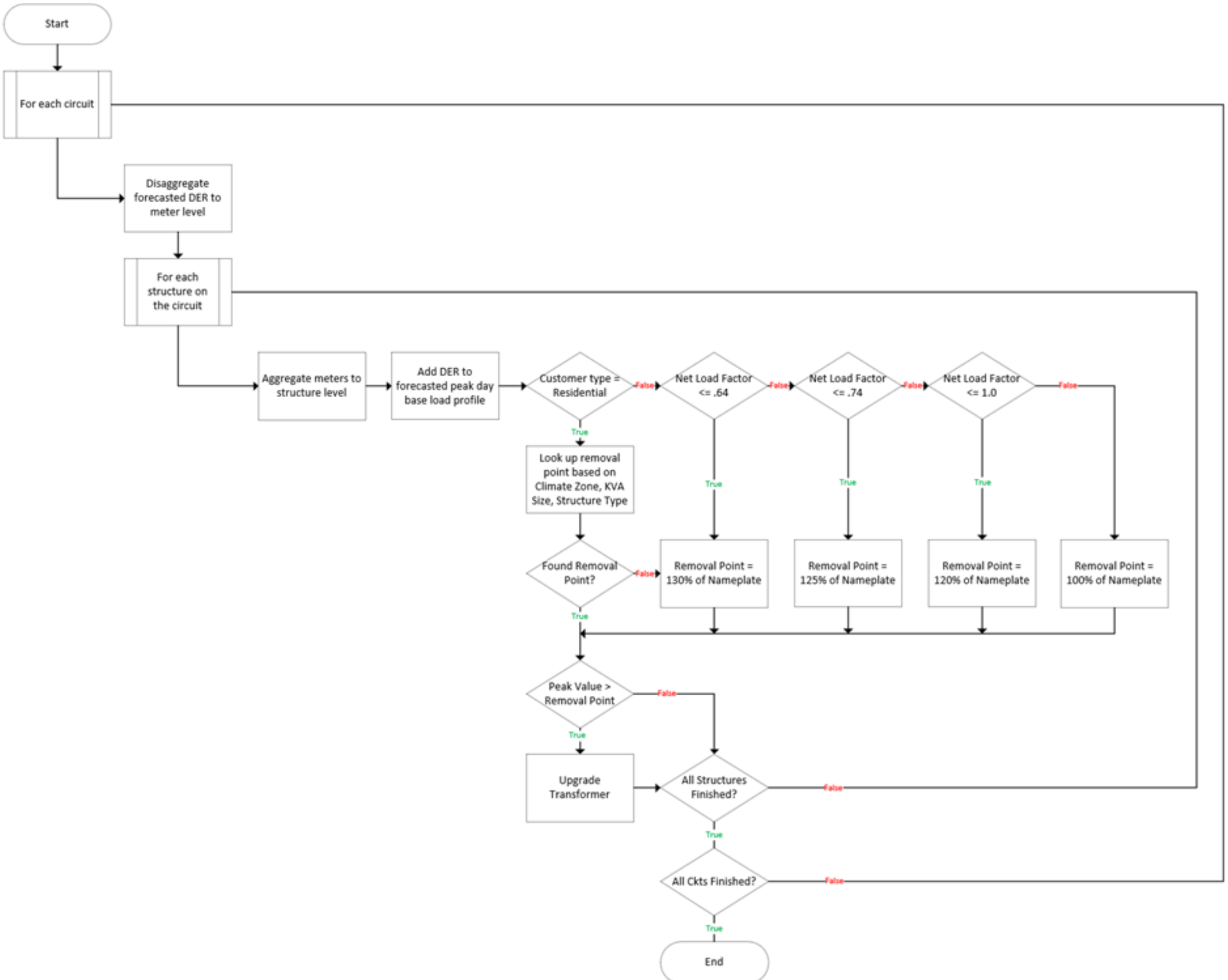

FIGURE 20: SECONDARY SOLUTIONING BLOCK DIAGRAM

Appendix 3: Responses to Energy Division Feedback on SCE's EIS 2 Draft Report

<table>
<tr><th>ED Comment</th><th>SCE Response</th></tr>
<tr><td><u>Results</u>
Energy Division appreciates the clear presentation of results across four scenarios (Base, Equity, and two demand flexibility cases) and two planning horizons (2025–2030 and 2031–2040). This structure is helpful for comparing near- and longer-term outcomes. Given that many of the observed differences across scenarios appear modest, Energy Division recommends that:

a) SCE provide additional narrative explaining the relative contribution of transportation electrification, building electrification, and DER adoption to peak formation under each scenario, including how these contributions evolve over the two planning horizons.

This clarification would help stakeholders understand why scenario outcomes converge or diverge.</td><td>a) Addressing this feedback would require additional analysis that cannot be completed by the deadline for the final report.</td></tr>
<tr><td><u>Results</u>
The draft suggests relatively modest differences in infrastructure costs across scenarios, particularly between the Base and Equity case. Given the policy importance of equity, it would be useful to:
b) more fully explain why the equity-driven DER dispersion does not meaningfully change the number or type of capacity projects,
c) and how this finding should be interpreted for equity planning.
d) In the final report, please also clarify whether spatial clustering of electrification in priority populations results in localized increases in secondary system needs even when primary system impacts remain limited, as such clarification would help contextualize the distribution of costs across asset classes.</td><td>b) Section 15.0 part 2
c) Section 15.0 part 4
d) Appendix 1 Section 2</td></tr>
<tr><td><u>Results</u>
SCE's conclusion that demand flexibility scenarios can defer between roughly $0.32 and $1.38 billion of investments, but may require very high participation rates, is an important result. However:
e) additional clarity around what range of participation SCE views as realistic under current and foreseeable program designs would help set expectations.</td><td>e) Section 6.1
f) Addressing this feedback would require additional analysis related to ED Comment item (a) and cannot be completed by the deadline for the final report. The end-uses that drive the</td></tr>
</table>

f) In the final report, it would be helpful to the reader to identify which end-uses (such as EV charging, heat pumps, water heating, or commercial load management) drive the majority of modeled peak reductions and g) specify whether the underlying technology assumptions reflect currently deployed capabilities (e.g., controllable EVSE, AMI-enabled DR). These clarifications would assist stakeholders in evaluating the feasibility of achieving the modeled reductions.	majority of peak reductions are directly a function of that end-use to peak. The amount of flexibility is calculated by the load at the peak hours by the percentages found in Appendix 1, Section 1.4.1. These percentages can be found in the tables of Appendix 1 Sections 1.4 and 1.5. g) Appendix 1, Section 1.4
Results In addition, Energy Division recommends that: h) SCE briefly indicate whether secondary system constraints were a binding factor in limiting achievable flexibility impacts a. and if not, how the modeling ensured that load shifting did not unintentionally create new overloads in non-peak hours. Transparency on these interactions will improve understanding of the practical boundaries of flexibility-driven cost reductions.	h) Appendix 1 Section 1.4.1 Appendix 1 Section 2.2
Results The projected increase in distribution capacity mitigation/upgrade projects is substantial and, while SCE has provided some high-level discussion of supply chain and workforce activities, the draft report does not provide sufficient detail or evidence demonstrating that they are prepared to address these upcoming challenges. It would be helpful for SCE to address the following issues: i) In Section 12, SCE indicates that they are partnering with manufacturers to address potential supply chain constraints, streamlining internal planning processes, and that "these efforts have yielded positive results." Provide more detail on SCE's activities, provide detailed support for the claim that these efforts have yielded positive results **a.** and discuss any issues that remain to be addressed to manage near-term supply chain constraints. activities, provide detailed support for the claim that these efforts have yielded positive results, j) In Section 13, SCE discusses high level efforts to plan for a workforce to meet projected needs. The section argues that SCE needs a robust workforce strategy, that labor demand depends on several factors beyond	i) Section 12.0 j) Section 13.0

those identified in EIS Part 2. Please explain how SCE is accounting for all these factors and workforce needs in its workforce planning, and provide detailed evidence that SCE is prepared to address all its forecasted workforce challenges.	
<u>Methodology</u> The automated decision-tree approach for solutioning is a notable innovation relative to the traditional DPP engineer-driven process. The draft acknowledges that differences between EIS2 and DPP outcomes are expected. a) Additional explanation of how SCE validated the automated solutions (for example, through sample comparison with conventional DPP analyses) would help readers understand the reliability of the results. b) Additionally, please describe whether the automated solutioning logic incorporates constraints such as construction feasibility, minimum loading thresholds, or panel/service limitations, as these factors are often identified through engineering judgment in the traditional DPP process.	a) Appendix 2 Section 1 b) Appendix 2 Section 1
<u>Methodology</u> The use of "sum of non-coincident circuit peaks" in several parts of the analysis is understandable for EIS2's scope, but Energy Division recommends that the final report clearly distinguish between: c) system-level coincident peaks, d) non-coincident circuit peaks, e) how each metric is used for cost estimation and planning, and f) how reliance on non-coincident peaks interacts with TE-driven load clustering, particularly in areas where EV adoption may shift peak-hour diversity factors, g) whether non-coincident peaks were used consistently across all scenarios or whether certain scenarios required adjustments to reflect changes in load shape diversity.	c) Appendix 2 Section 1 d) Sections 4.2, 5.2, 6.2, Section 7.2 Appendix 2 Section 1 e) Appendix 2 Section 1 f) Appendix 2 Section 1 g) Appendix 2 Section 1
<u>Methodology</u> **For the demand *flexibility scenarios***, the methodology section could more clearly describe: h) how load reduction and energy shift are modeled at the feeder and circuit level, i) how participation rates and controllability assumptions were derived from the CEC D-Flex tool and other sources,	h) Appendix 1 Section 1.4.1 i) Appendix 1 Section 1.4.1 j) Appendix 1 Section 1.4.1 k) Appendix 1 Section 1.4.1 l) Appendix 1 Section 1.4.1 m) Appendix 1 Section 2.2 n) Appendix 1 Section 1.4.1 o) Section 8

<table>
<tr><td>j) whether interactions with existing or planned DR/TOU/TE programs are explicitly captured or assumed exogenous, and
k) how SCE modeled end-use specific differences in flexibility potential (e.g., managed EV charging vs. HVAC cycling),
l) whether the modeling accounted for any saturation or diminishing returns when multiple flexible loads act simultaneously on the same circuit,
m) whether secondary transformer or service-level constraints were explicitly considered when applying load shift profiles.
n) please also clarify how its solutioning logic handled cases where load was shifted into hours that could interact with non-coincident peak conditions on specific circuits. This would improve understanding of the fidelity of the flexibility modeling under real-world constraints.
o) Explain how all future costs are accounted for, including treatment of inflation and future cost discounting. If inflation and / or discounting are not considered, justify this modeling choice and why it aligns with best practice within your organization.
a. If these factors are considered, justify your choices for the inflation and / or discount rate.</td><td></td></tr>
<tr><td><u>Data and Inputs</u>
The report confirms that the study relies on CEC 2023 IEPR forecasts and CEC demand flexibility potential, however:
a) the connection between these inputs and SCE's internal forecasting and DER adoption assumptions could be more explicitly described (for example, through a summary table listing key IEPR and D-Flex parameters used in each scenario).
b) It would be helpful if SCE also indicated whether IEPR load shapes were modified using SCE-specific data such as climate zone adjustments, observed AMI data, or empirical EV charging patterns.</td><td>a) Appendix 1 Section 1.2
Appendix 1 Section 1.4
Table 25
b) Appendix 1, Section 1.2
Appendix 1 Section 1.2.3</td></tr>
<tr><td><u>Data and Inputs</u>
For the Equity Scenario, Energy Division requests additional documentation on:
c) the specific equity criteria used (for example, DACs, priority populations, CARE/FERA, Tribal communities),
d) how those criteria translate into adjustments to DER and electrification adoption across circuits and substations,</td><td>c) Appendix 1
Section 1.3 Table 24
d) Appendix 1 Section 1.3.1
e) Appendix 1 Section 1.3.1
f) Appendix 1 Section 1.3.1</td></tr>
</table>

e) whether adoption constraints, such as building type, charger access availability, or rooftop PV feasibility, were included or assumed unconstrained, and f) how overlapping equity categories (e.g., DAC + CARE/FERA, DAC + Tribal lands) were handled when allocating incremental DER adoption.	
<u>Data and Inputs</u> ***For the demand flexibility scenarios***, more detailed information would be helpful on: g) technology-specific load shapes (EVs, building electrification, storage), h) the mix of price-responsive versus programmatic DR assumed, i) any interactions with AMI 2.0 and future data/telemetry capabilities that are embedded in the modeling, and j) whether SCE relied on empirical AMI or program data to calibrate expected response behaviors for EV charging or HVAC cycling, k) the assumed relationship between customer adoption of enabling technologies (e.g., smart thermostats, controllable EVSE) and the flexible load potential incorporated into the model.	g) Details on each factor contributing to load reduction in demand flexibility scenarios are described in Appendix 1 Section 1.4.1. As described in Section 1.4, the demand flexibility scenarios serve as a mitigation case to Scenario 1. Technology specific load shapes for each DER type from Scenario 1 are described in Appendix 1 Section 2. h) Appendix 1 Section 1.4 i) Appendix 1 Section 1.4 j) Appendix 1 Section 1.4 k) Appendix 1 Section 1.4 l) Appendix 1 Section 1.2.3
<u>Data and Inputs</u> Energy Division additionally recommends that: l) SCE specify whether IEPR-supplied EV shapes were supplemented with SCE's own EV load research (e.g., Charge Ready datasets, pilot data, or AMI-based load studies). This would strengthen understanding of TE-related data assumptions.	l) Appendix 1 Section 1.2.3
<u>Other Observations and Requests</u> Energy Division appreciates SCE's discussion of how EIS2 findings relate to ongoing efforts in integrated planning, pending loads treatment, and grid modernization. To support alignment with D.24-10-030, it would be helpful if SCE could more explicitly map: a) which EIS2 learnings SCE expects to incorporate into the next one or two DPP cycles, b) which topics it views as requiring additional pilots or complementary studies before informing DPEP changes, and	a) Section 14.1 Section 15.0 part 4 b) Section 14.2 c) Section 14.0 d) Section 14.2 e) Section 14.1

c) how TE-related scenario results will inform the prioritization of circuits undergoing rapid electrification growth, d) whether flexibility insights from EIS2 will influence future DR program design, program targeting, or the development of DERMS capabilities, e) how SCE plans to incorporate uncertainties in TE adoption and flexible load potential into long-term planning efforts using an adaptive or iterative planning framework.	
<u>Other Observations and Requests</u> Given the statement that EIS2 scenarios do not fundamentally shift SCE's multi-pronged strategy, it may be useful to: f) specify which, if any, elements of that strategy are most influenced by the EIS2 demand flexibility and equity findings (for example, TE planning, DR program design, or targeted distribution upgrades). g) Also, it would be helpful that SCE clarify whether EIS2 findings are expected to inform refinements to its pending loads screening, expedited processing of electrification-related load requests, or localized grid modernization needs.	f) Section 14.1 g) Section 15.0 part 4
<u>Other Observations and Requests</u> Finally, Energy Division recommends that SCE: h) provide a brief explanation of how approaches tested in the EIS2 study will complement or differ from those used in its forthcoming Distribution Planning and Execution Process filings, including any anticipated methodological enhancements related to forecasting, flexibility analysis, or equity evaluation.	h) Section 15.0 part 4