BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E)
ELECTRIFICATION IMPACTS STUDY PART 2 REPORT

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Dated: January 28, 2026

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Pursuant to Decision (D.) 24-10-030, Ordering Paragraph (OP) 20, and the September 24, 2025 letter from California Public Utilities Commission (CPUC or Commission) 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, Pacific Gas and Electric Company (PG&E) respectfully submits its final Electrification Impacts Study Part 2 Report.

Respectfully submitted,

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Attachment A

PG&E's Electrification Impacts Study Part 2 Report

Pacific Gas and Electric Company®

ELECTRIFICATION IMPACTS STUDY PART 2

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

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Electrification Impacts Study (EIS) Part 2

Contents

Figures

Tables

1. Acronyms and Definitions

Table 1. Acronyms and definitions

Acronym	Definition
AAEE	Additional Achievable Energy Efficiency
AAFS	Additional Achievable Fuel Substitution
AB	Assembly Bill
ALJ	Administrative Law Judge
AM	Active Management
BAU	Business-As-Usual
BE	Building Electrification
CAISO	California Independent System Operator
CARE	California Alternate Rates for Energy
CEC	California Energy Commission
CPUC	California Public Utilities Commission
DAC	Disadvantaged Communities
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management Systems
DFLEX	Demand Flexibility
DR	Demand Response
EE	Energy Efficiency
EIS	Electrification Impacts Study
EV	Electric Vehicle
EGI	Electric Generation Interconnection
FA	Forecasting Anywhere
FERA	Family Electric Rate Assistance
GRC	General Rate Case
HDV	Heavy-Duty Vehicle
HVAC	Heating, Ventilation, and Air Conditioning
IEPR	Integrated Energy Policy Report
IOU	Investor-Owned Utility
LM	Load Management
LBNL	Lawrence Berkeley National Laboratory

Acronym	Definition
LDV	Light-Duty Vehicle
MDV	Medium-Duty Vehicle
MHDV	Medium- and Heavy-Duty Vehicle
PAO	Public Advocates Office
PV	Photovoltaic
SIP	State Implementation Plan
TE	Transportation Electrification
TOU	Time-of-Use
TP	Transmission Planning
V2G	Vehicle-to-Grid
VIUS	Vehicle Inventory and Use Survey

2. Executive Summary

PG&E's **Electrification Impacts Study (EIS) Part 2** is a major research undertaking to understand how California's electrification goals will affect the electric grid, costs, and customer bills in the years ahead.

The EIS Part 2 was ordered as part of the High DER Proceeding[1] to assess distribution costs required to support California's electrification goals. The primary objectives of the EIS Part 2 are to estimate the potential costs of upgrading the primary and secondary distribution grid to meet electrification needs under multiple scenarios that provide a range of cost impacts based on different assumptions. It builds upon the foundational EIS Part 1 study, which was conducted by Kevala and focused on high-level statewide modeling. In contrast, EIS Part 2 is being executed by the state's Investor-Owned Utilities (IOUs), including PG&E, to deliver a more solution oriented and policy-aligned analysis.

Equally important, the EIS Part 2 lays forth a vision in which electrification growth can drive improved affordability for PG&E's customers by providing a downward pressure on distribution rates by as much as 25% by 2040. The EIS Part 2 finds that electrification will require between $23 billion and $31 billion of distribution electrification investments through 2040. The EIS Part 2 leverages engineering best practices and incorporation of demand response to deliver $3.4B in savings for customers and demonstrates how enhanced orchestrated demand flexibility can reduce distribution infrastructure costs for customers by an additional $1.8B through 2040[2].

The EIS Part 2 estimates PG&E's primary and secondary distribution grid upgrade costs specifically under three scenarios of electrification and distributed energy resource (DER) adoption for the years 2030, 2035, and 2040. PG&E used detailed geospatial modeling and incorporated demand forecasts from the California Energy Commission's (CEC) 2023 Integrated Energy Policy Report (IEPR). The California Public Utilities Commission (CPUC) designed three main scenarios to reflect a base case of adoption, equity-driven electrification, and enhanced demand flexibility. PG&E also includes an exploratory sensitivity analysis to test an alternative method for modeling a comprehensive EV charging network.

- In the **Base (Mitigated) Scenario**, PG&E modeled growth in electrification and DER adoption consistent with existing planning approaches.
- In the **Equity Scenario**, PG&E expanded electrification and DER adoption in disadvantaged, low-income, and Tribal communities.
- In the **Enhanced Demand Flexibility Scenario**, PG&E applied DER load shedding, shifting and peak reduction strategies.

[1] D.24-10-030 OP20

[2] The cost reduction equates to 7% of the total cost of the Base (mitigated) Scenario and 14% of the cost excluding new service connections.

- In the **EV Capacity Demand Sensitivity**, PG&E modeled the localized capacity demand to identify the secondary capacity impacts of increased EV charging.

PG&E estimated distribution primary upgrades in a manner analogous to current distribution planning practices, while introducing new techniques such as scenario planning that will be incorporated into future distribution plans. In contrast to the EIS Part 1's unmitigated scenario, all scenarios (including the Base Scenario) in the EIS Part 2 Study are "mitigated." This means that distribution engineers developed low-cost solutions where feasible (e.g., load transfers)[3] and load profiles incorporated existing and future customer behaviors. These advancements led to lower primary costs than Part 1, which is further explored in the key findings.

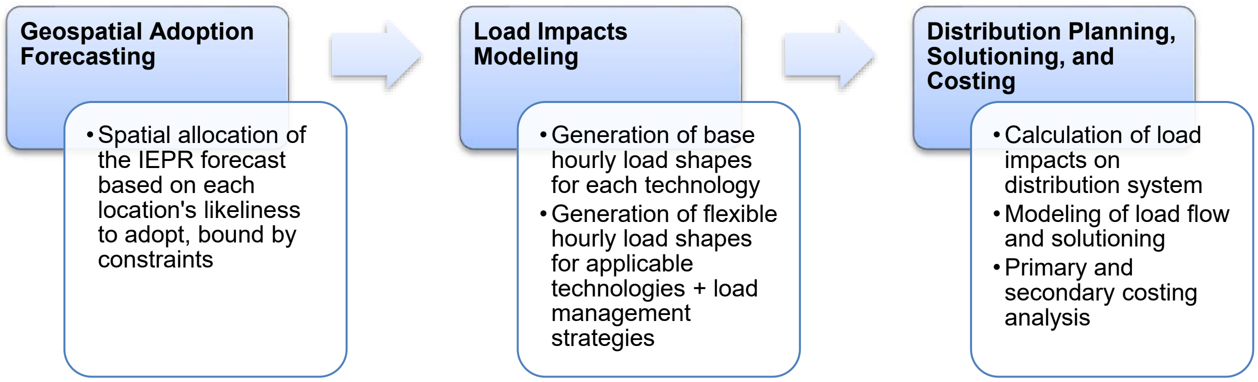
The EIS Part 2 also represents a first of its kind, data-driven evaluation of secondary service planning and costing, establishing a foundational framework to optimize secondary investments to serve load energizations. The EIS Part 2 expands upon the EIS Part 1 study[4] to model the full scope of secondary service planning costs to energize customers in a high electrification future. Lastly, the EIS Part 2 includes an Enhanced Demand Flexibility Scenario which explored the impacts of orchestrated flexible load through various load management techniques beyond those included in the Base (Mitigated) Scenario.[5] Since the Base Scenario is already mitigated and includes some load management, this Enhanced Demand Flexibility Scenario represents the benefits of *additional* orchestrated load management.

2.1. Methodology Overview

PG&E developed a three-step modeling framework to estimate distribution grid upgrade costs through 2040 under the EIS electrification scenarios. PG&E collaborated with Energy and Environmental Economics (E3) and Integral Analytics (IA) to implement this methodology using advanced geospatial and engineering tools.

[3] For example, PG&E identified more than 1,000 load transfers resulting in the reallocation of more than 300 MW of load across substation and distribution systems, allowing for optimized utilization of existing infrastructure and minimizing the need for new capital investments.
[4] Part 1 of the EIS estimated costs of service transformer capacity upgrades. The EIS Part 2 expanded the scope to consider the costs of providing secondary service to serve electrification growth (i.e., service planning).
[5] The Base (Mitigated) scenario considers the impact of load flexibility consistent with current distribution planning processes, whereas the Enhanced Demand Flexibility Scenario considers additional, orchestrated demand flexibility.

Figure 1. Overview of methodology



Step 1: Geospatial Adoption Forecasting

PG&E forecasted customer adoption of electrification and DER technologies by allocating CEC's 2023 IEPR to specific geographic areas, considering adoption likelihood and technical constraints. The analysis included electric vehicle (EV) chargers, building electrification, energy efficiency, solar PV, and battery storage.

Step 2: Load Impacts Modeling

PG&E and E3 developed hourly load shapes for each technology to simulate their impact on the grid. The team used various sources including PG&E's meter data to generate base and flexible load profiles. For the Enhanced Demand Flexibility Scenario, PG&E incorporated advanced load management strategies such as dynamic pricing, active charging management, vehicle-to-grid (V2G) capabilities, and demand response (DR) for building electrification and battery storage.

Step 3: Distribution Planning, Solutioning, and Costing

PG&E evaluated how the forecasted adoption and load impacts would affect the distribution grid. PG&E's engineers identified overloaded equipment and applied engineering solutions, including load transfers, reconductoring, and new installations. PG&E estimated upgrade costs for both primary (substations, feeders, lines) and secondary (transformers, secondary lines) systems.

2.2. Key Findings

2.2.1. Key Finding 1: Electrification growth may provide downward pressure on distribution rates by as much as 25% by 2040

The EIS Part 2 includes an assessment of the potential impact of electrification load growth on distribution rates.[6] The annual Revenue Requirement (RRQ) from electrification infrastructure investment was compared to the offsetting revenue enabled by the increased customer energization load.

The Base (Mitigated) Scenario shows a small upwards (~1.6%) upwards distribution rate pressure in the near term, followed by downward distribution rate pressure from 2032 onwards, with downward pressure on distribution rates of as much as ~25% by 2040. The analysis indicates that the initial capital outlays to enable electrification are offset by sustained revenue growth from increased energization, indicating a long-term net present value of ~$14B from energization investments. A potential downward pressure on distribution rates is also shown for the Equity and Enhanced Demand Flexibility Scenario, indicating that the primary driver of the downward distribution rate pressure is the growth in revenue from the electrification load.

2.2.2. Key Finding 2: Electrification requires between $23 billion and $31 billion of distribution electrification investments through 2040.

PG&E estimated upgrade costs for both the primary (substations, feeders, lines) and secondary (transformers, secondary lines) systems for the three scenarios, summarized in Figure 2 and Table 2 below. Cumulative costs through 2040 range between approximately $8.5B - $13.5B for the primary system and $15B - $18B for secondary infrastructure, for a total distribution cost of approximately $23B - $31B. The rate of investment is relatively consistent across the 16-year study period and is consistent with current rates of energization investment in the distribution grid.[7]

[6] The analysis focused solely on distribution costs and offsetting revenues from electric distribution rates, excluding both revenues and costs from transmission, generation, and other rate components. The scope of the EIS Part 2 is solely distribution energization investments and does not include other infrastructure costs (e.g., safety, reliability, etc.). Therefore, the analysis in the EIS Part 2 is not a rate forecast, instead it is solely assessing the potential impact of electrification distribution investments and corresponding load growth. Furthermore, the ~25% downward rate pressure reflects the downward rate pressure solely on the distribution rate, which is only a portion of customer's overall costs for electricity service.

[7] Energization investment in the EIS Part 2 report corresponds to distribution investments for energization as California Senate Bill 410.

Figure 2. Total distribution costs (primary and secondary) by scenario and in cumulative, nominal dollars[8]

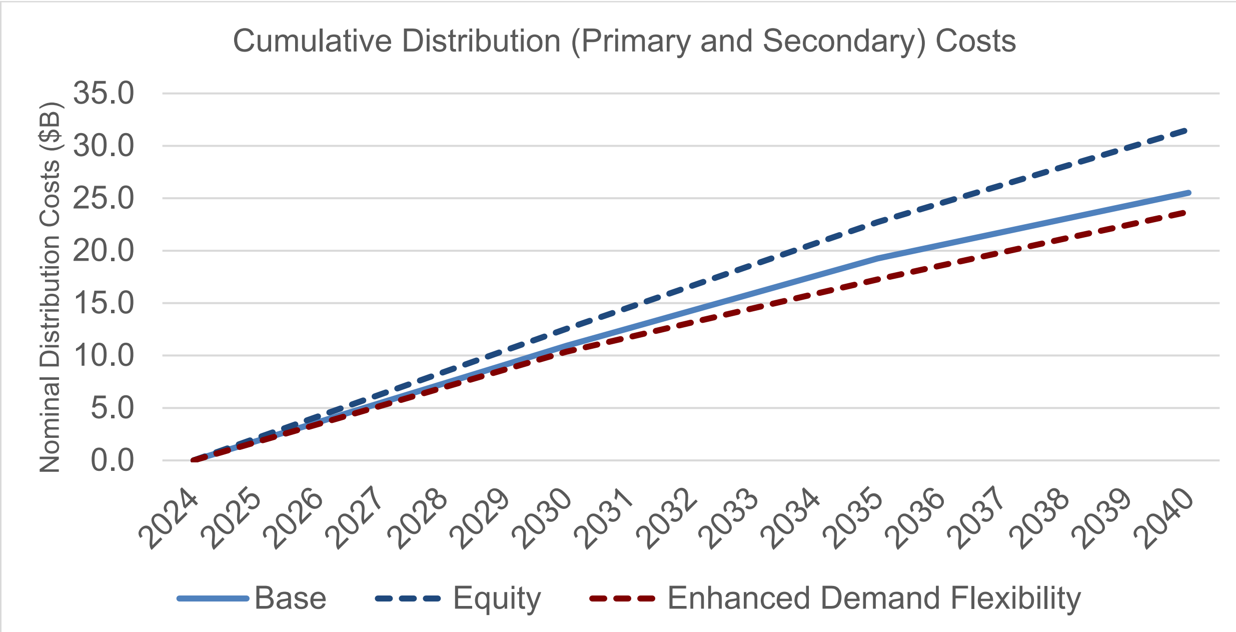


Table 2. Total primary and secondary costs for 2025-2040 by scenario (in cumulative nominal dollars)

Scenario	Primary System Cost	Secondary System Cost	*Total Upgrade Costs*
Base	$9.6 billion	$15.9 billion	***$25.5 billion***
Equity	$13.4 billion	$18.1 billion	***$31.6 billion***
Enhanced Demand Flexibility	$8.5 billion	$15.2 billion	***$23.7 billion***
EV Capacity Demand Sensitivity	*N/A***	$17.6 billion	*N/A***

**Numbers may not add exactly due to rounding*

***The EV Capacity Demand Sensitivity was designed to explore the impact on secondary costs of modeling higher EV charger needs that reflect observed demand.*

2.2.3. Key Finding 3: The EIS Part 2 is a pioneering assessment of the scope of secondary electrification investments needed for serving load energizations.

The expanded scope of secondary costs in the EIS Part 2 is consistent with the scope of distribution energization investment.[9] While the EIS Part 1 study focused solely on examining capacity overloads, the EIS Part 2 study expanded the scope to consider the secondary costs to serve customer energizations. The EIS Part 2 represents a unique, location-specific evaluation of secondary investments needed to energize customers, establishing a foundational framework to optimize secondary system planning.

[8] Linear interpolation of costs used between study years.
[9] D.24-07-008

The expanded scope of the EIS Part 2 study includes the secondary costs of new business energization, not just service transformer overloads. Therefore, while the scope of the primary cost assessment is comparable to prior studies,[10] the EIS Part 2 study is unique in its scope of secondary costs assessed. Overloaded service transformers, or transformers above 100% of their calculated capacity, correspond to $3.4B (~21%) of the secondary costs in the EIS Part 2 Base Case, with the remaining $12.5B (~79%) of secondary costs corresponding to the new service connections (see section 2.2.4). New service connections refer to new transformers built in this study to meet customer load. Therefore, most of the secondary costs identified in the EIS Part 2 were not included in the scope of the EIS Part 1.

2.2.4. Key Finding 4: Engineering best practices and incorporation of demand response in the Base Scenario resulted in $3.4B in primary savings in comparison to EIS Part 1

PG&E's EIS Part 2 demonstrates cost savings for customers by applying engineering best practices and incorporating load flexibility. Unlike the EIS Part 1's unmitigated scenario, all scenarios in Part 2 were "mitigated," meaning engineers proactively identified low-cost solutions such as load transfers[11] and load profiles incorporated existing and future customer behaviors. As a result, the Base Scenario shows significantly lower primary system costs of $3.4B by 2040, compared to the EIS Part 1. Similarly, the secondary costs for overloaded transformers in the Base (Mitigated) Scenario were $1.45B less in the EIS Part 2 than in the unmitigated EIS Part 1.[12] The scope and approach to modeling of the secondary was fundamentally different between the EIS Part 1 and EIS Part 2, and so this comparison of the secondary costs should be considered an approximation.

2.2.5. Key Finding 5: Enhanced orchestrated demand flexibility can reduce distribution infrastructure costs by an additional $1.8B through 2040.

PG&E's Enhanced Demand Flexibility Scenario reduced distribution infrastructure (primary and secondary) costs by approximately $1.8 billion through 2040, if orchestrated. Furthermore, the Enhanced Demand Flexibility Scenario reduced the summer system peak load by ~2.8 GW in 2040. The scope of the EIS does not include any potential reductions in generation, transmission, or customer (e.g., service panel) costs, which would be in addition to the cost reductions identified in the EIS. Furthermore, the Base (Mitigated) Scenario already includes some load management consistent with current distribution planning processes, so the cost reductions identified

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[10] Namely, the EIS Part 1 and Public Advocates Office (PAO)'s Distribution Grid Electrification Model (DGEM) studies.

[11] For example, PG&E identified more than 1,000 load transfers resulting in the reallocation of more than 300 MW of load across substation and distribution systems, allowing for optimized utilization of existing infrastructure and minimizing the need for new capital investments.

[12] Section 6.2.4 describes how only a component of the costs from the EIS Part 2 were used to compare to the EIS Part 1, given the differences in scope and methodologies between the two studies for the secondary system.

in the Enhanced Demand Flexibility Scenario are incremental reductions enabled by orchestrated shifting of energy demand away from peak hours and avoiding creating new peaks. "Orchestration" in the context of the EIS study refers to the ability to manage the electric load in response to local grid constraints, in a manner that can be relied upon for planning purposes using firm, dispatchable load management. Orchestration therefore does not signify the use of markets or real-time control. The costs associated with implementing and orchestrating load management are not included in the EIS, nor is the cost effectiveness of the enhanced orchestrated demand flexibility or its impact on affordability.

The Enhanced Demand Flexibility scenario assumes load management down to the secondary level consistent with the CEC's D-Flex (SB100) assessment of flexibility potential. Orchestration of load flexibility down to the premise level was not studied nor were reductions in customer infrastructure (e.g., panel upgrades) costs included.[13] The study builds on current understandings of the future of load flexibility, leveraging learnings from multiple pilots (e.g., SAVE VPP, EV Charge Manager & Hourly Flex Pricing pilots) to understand customer behavior and technology potential. The study assumes that flexible loads such as EV charging, HVAC systems, and battery storage can be orchestrated in ways that reduce peak demand (down to the secondary system) without inadvertently creating new peaks or stressing equipment in other parts of the system.

PG&E performed a non-orchestrated sensitivity case in which the enhanced demand flexibility lowered the overall system peak but did not account for local (e.g., secondary) constraints. The non-orchestrated sensitivity case triggered new overloads and distribution upgrades, resulting in a smaller cost reduction ($150 million) than the orchestrated case ($1.8 billion) through 2040. Therefore, the majority of the cost reductions identified in the Enhanced Demand Flexibility scenario required orchestration down to the secondary level to avoid triggering new upgrades.

This savings level reflects a future in which orchestrated flexibility is deployed at scale. The Enhanced Demand Flexibility estimate was developed to align with the CEC's D-Flex Tool, calibrated to a scenario that is more ambitious than today's programs but still plausible given the potential for significantly higher electrification growth, but requires structural policy changes to achieve. The modeled savings represent incremental flexibility to the base case, achievable through orchestrated shifting of load away from peak hours while avoiding the creation of new peaks.

[13] The EIS did not model the potential impact of Advanced Meter Infrastructure (AMI) 2.0, for example.

2.2.6. Key Finding 6: An additional $6B of distribution investment by 2040 in the Equity Scenario is consistent with the increased electrification load

PG&E's Equity Scenario scaled up electrification and DER adoption in disadvantaged, low-income, and Tribal communities to equal the adoption for all customers. This resulted in the addition of 6.9 GW of electrification and DERs by 2040.[14] The Equity Scenario only scaled up electrification and DER adoption and did not adjust downward the adoption of non-disadvantaged customers. Therefore, the Equity Scenario has an overall higher level of electrification and DER adoption than the Base (Mitigated) Scenario.

The increased electrification and DER load in the Equity Scenario resulted in the identification of an additional $3.8B of primary and $2.2B of secondary costs, for a total incremental distribution cost of $6B. This $6B increase in distribution infrastructure costs is consistent with the corresponding increase in electrification load (6.9 GW). The Equity Scenario also shows a downward pressure on distribution rates, indicating that the increased distribution costs are offset by the increased revenue for the additional assumed electrification growth. Furthermore, the benefits of the increased electrification and DER adoption in disadvantaged, low-income, and Tribal communities are not quantified in the study.

2.2.7. Key Finding 7: The average load factor is ~69% in 2040, including ~500 feeders with a load factor greater than 80%

Load factor, defined as the ratio of average load to peak load over a given time period (typically a peak day time period), is a key metric in calculating thermal capacity. Load factor influences the capacity rating and operational flexibility of grid equipment. PG&E currently assumes a default 75% load factor for its primary distribution system. Higher load factors mean equipment operates closer to its maximum capacity for longer durations, which increases thermal stress. This requires a lower rating of transformers and conductors to essentially maintain asset health and reliability.[15] A high load factor also indicates a reduced margin for outages and less flexibility for maintenance or emergency operations, which can impact reliability and safety.

The EIS found that the average load factor for feeders remains relatively consistent over the study period and is ~70% in 2025 and ~69% by 2040, with nearly 460 feeders exceeding an 80% load factor. This indicates that the electric distribution primary investment offsets the increasing electrification load with respect to load factor. The Enhanced Demand Flex Scenario showed a further increase in Load Factors, with ~600 feeders exceeding an 80% load factor. The increase in Load Factors is consistent with increased asset utilization enabled by load management. The EIS did not examine the

[14] This additional electrification and DER growth increases the summer system peak by 1.8 GW in 2040.
[15] For example, a load factor change from 50% to 75% results in a 2MW lower capacity or 16% lower rating on 12 kV circuit.

impact of high Load Factors on distribution investment needs, nor did it include costs associated with changes in the associated ratings or loss of operational flexibility.

The potential for high Load Factors for feeders indicates a need to incorporate the consideration of load factors into distribution planning and the orchestration of load flexibility to ensure the affordability benefits of increased asset utilization are realized.

3. Study Overview

In response to feedback received on the EIS Part 1, the California Public Utilities Commission (CPUC), authorized the Investor-Owned Utilities (IOUs) to lead the development of the **Electrification Impacts Study (EIS) Part 2** for their respective service territories within the High DER Proceeding.[16] The CPUC determined the IOUs were best positioned to incorporate insights from their operations and experience into the EIS Part 2, which will allow for a more streamlined incorporation of outcomes into their distribution planning and execution process (DPEP). CPUC Energy Division Staff issued the IOUs a final set of minimum requirements for EIS Part 2 in November 2024 and have provided guidance throughout development of this study.

The primary objective of the EIS Part 2 is to estimate the potential costs required to support California's energy goals by assessing the primary and secondary distribution needs to meet electrification under multiple scenarios and provide a range of cost impacts based on different assumptions. It builds upon the foundational EIS Part 1 study, commissioned by the California Public Utilities Commission (CPUC) and performed by Kevala Inc., which focused on high-level statewide modeling. In contrast, the EIS Part 2 was executed by the state's Investor-Owned Utilities (IOUs), including PG&E, to deliver an updated approach more grounded in the IOUs' planning processes.

The outcomes of the EIS Part 2 study are expected to have direct translation into potential improvements in each utility's DPEP. However, while the study will inform future distribution planning and estimates the distribution costs required for electrification, it is not equivalent to PG&E's annual Distribution Plan nor is it intended to identify specific distribution investments.[17]

The study is intended to inform long-term policy decisions related to transportation electrification (TE), building electrification (BE), load management (LM), and disadvantaged communities (DACs).

3.1. Scenario Descriptions

The CPUC ruling requires that the EIS Part 2 include at least three scenarios, each grounded in the 2023 Integrated Energy Policy Report (IEPR) from the California Energy Commission (CEC). PG&E modeled the three scenarios designated by the CPUC and developed a fourth exploratory scenario. These scenarios are:

1. **Base (Mitigated) Scenario**: The Base (Mitigated) Scenario uses the CEC 2023 IEPR Local Reliability forecast to provide total PG&E system-wide adoption for electrification and DER technologies. In this scenario, PG&E modeled electrification and DER adoption geospatially, following historical trends as used

[16] CPUC High DER Decision on Implementation of Distribution Planning Improvements (D.) 24-10-030, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M544/K154/544154869.PDF
[17] PG&E's annual Distribution Planning (DPEP), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M576/K519/576519221.PDF

in the annual Distribution Planning Process (DPP). Distribution engineers mitigated costs by developing low-cost solutions where feasible (e.g., load transfers) and load profiles incorporated existing and future customer behaviors. The Base (Mitigated) Scenario serves as the reference scenario for comparing incremental impacts. The EIS Part 2 did *not* model an unmitigated, high cost, bookend scenario, instead focusing on scenarios more consistent with PG&E's planning processes.

2. **Equity Scenario**: The Equity Scenario models increased electrification and DER adoption in priority populations, defined as disadvantaged, low income, and Tribal communities. The CPUC's requirements established an equity ratio to guide this scenario. The equity ratio requires that DER and electrification adoption in priority populations must be proportional to the ratio of this population to the overall customer base. As such, the Equity Scenario does not redistribute adoption patterns, but instead *increases* total adoption beyond the current IEPR forecast. This scenario reflects state policies aimed at ensuring equitable access to clean energy technologies.

3. **Enhanced Demand Flexibility Scenario**: The Enhanced Demand Flexibility Scenario models the impacts of additional load management and load flexibility. This scenario applies load flexibility modifiers to various DER and electrification technologies. The load flexibility in the scenario was benchmarked to flexibility potential modeled in the CEC's D-Flex tool. The Enhanced Demand Flexibility Scenario quantifies the reduction in infrastructure upgrades achievable through coordinated flexible loads.

4. **EV Capacity Demand Sensitivity:** PG&E modeled an additional sensitivity to explore and inform future distribution planning for transportation electrification. This EV Capacity Demand Sensitivity is a local charging demand forecast that combines system-level IEPR assumptions with EV charging demand derived from the Second CEC Electric Vehicle Charging Infrastructure Assessment (2024)[18] and observed site data.

3.2. Study Forecast and Scope

PG&E's EIS Part 2 study estimates distribution costs for the forecast years **2030, 2035, and 2040**. All results are modeled from a base year of 2024, meaning load growth is relative to 2024. Therefore, the study period includes 16 years of costs (2025-2040, inclusive). All costs are shown in nominal dollars and represent either annual or cumulative costs. Where annual results are provided, the analysis was linearly interpolated between the study forecast years.

[18] Electric Vehicle Charging Infrastructure Assessment - AB 2127, https://www.energy.ca.gov/data-reports/reports/electric-vehicle-charging-infrastructure-assessment-ab-2127

PG&E studied distribution upgrades on both the primary distribution system and the secondary distribution system. PG&E's analysis of the primary system included substation banks, feeders, and lines. PG&E's analysis of the secondary system included transformers and secondary lines. PG&E's EIS Part 2 study does **not** include transmission upgrades (which are evaluated in the Transmission Planning Process (TPP)), customer costs (such as panel upgrades or line extensions), and non-energization related costs.

In order to evaluate distribution costs from electrification, PG&E modeled a variety of technologies in this study. PG&E studied transportation electrification across both light-duty vehicle (LDV) and medium- and heavy-duty vehicle (MHDV) segments, including EV chargers at residential and non-residential locations. PG&E also modeled building electrification technologies for heating, cooling, and other electrification in both residential and non-residential segments. In addition to these electrification end uses, PG&E also modeled energy efficiency (EE), customer solar, and customer battery storage.

3.3. Scope of EIS Part 2 compared to EIS Part 1

Kevala's EIS Part 1 provides preliminary estimates of the scope and scale of potential electric distribution grid impacts from widespread transportation electrification and solar PV penetration from 2022 through 2035 (a 13-year study period). PG&E's EIS Part 2 study period was updated and expanded to a 16-year study period from 2025 to 2040.[19] The EIS Part 1 forecast was based on the 2021 IEPR, whereas the EIS Part 2 forecast was based on the 2023 IEPR. A significant change in the IEPR forecast between the 2021 and 2023 vintage was the inclusion of more building electrification, especially in the later years of the forecast.[20]

The EIS Part 1 analysis was conducted under **unmitigated** planning scenarios, assuming only traditional utility distribution infrastructure investments and existing TOU rates and BTM tariffs throughout the study timeframe.[21] The EIS Part 2 only includes **mitigated** scenarios, where distribution engineers mitigated costs by developing low-cost solutions where feasible (e.g., load transfers) and load profiles incorporated existing and future customer behaviors.

The scope of the secondary cost assessment is also expanded in EIS Part 2. The EIS Part 1 estimated grid upgrades at the service transformer level,[22] based on examining service transformer capacity overloads.[23] The EIS Part 2 modeled service transformer

[19] The study period is inclusive, meaning 2025-2040 is 16 years of forecasted electrification growth relative to 2024.
[20] Unlike more recent IEPR vintages, the 2023 IEPR does not include a separate adjustment for Data Center loads. Regardless, the EIS Part 2 study is focused on distribution connected electrification loads, so would not include transmission connected Data Center Loads.
[21] EIS Part 1, ES-6.
[22] EIS Part 1, ES-10.
[23] EIS Part 1, p 110.

overloads, but coupled geospatial forecasting using LoadSEER[24] and CYME[25] to the service connection process to include energization costs, consistent with service planning costs incurred for energizing load. In other words, the EIS Part 2 expanded upon the EIS Part 1 to model the secondary costs of energization, including the capacity overloads included in the EIS Part 1 scope. Energization costs are expenses associated with connecting new load to the electrical distribution grid, upgrading existing facilities, and building necessary infrastructure to accommodate future load. The EIS Part 2 linked hourly load growth to transformer inventory and sizing replacements based on actual headroom and planning criteria, including spatial location. The expanded scope of secondary costs in the EIS Part 2 is consistent with the scope of distribution energization investment.[26]

The EIS Part 2 study also expanded on the inclusion of building electrification and medium- and heavy-duty EVs, leveraged the latest IEPR forecasts and PG&E's geospatial adoption modeling, introduced an Equity Scenario, and included an Enhanced Demand Flexibility Scenario to quantify the impact of managed charging and flexible loads.

Table 3. Key differences between the EIS Part 1 and EIS Part 2 scopes

	EIS Part 1	EIS Part 2
Study Year	2022 - 2035	2025 - 2040
Study Period	13 years	16 years
IEPR Vintage	2021 IEPR	2023 IEPR
Mitigated or Unmitigated	Unmitigated	Mitigated
Secondary Scope	Overloaded Service Transformers	Customer Energization (new transformers *and* overloaded transformers)

A comparison of the results between the EIS Part 1 and the EIS Part 2 is included in Section 6.1.

3.4. Structure of this Report

This report provides detailed discussion of PG&E's EIS Part 2 Study, including the methodology, results, and findings. Section 4 provides an overview of the three main

[24] LoadSEER is a leading distribution planning and load forecasting software tool implemented at over 15 large utilities in North America, including PG&E: https://integralanalytics.com/products/loadseer/
[25] CYME is a power engineering modeling software used to evaluate system conditions, such as loading, voltage and protection: http://www.electrical.eaton.com/us/en-us/digital/brightlayer/brightlayer-utilities-suite/cyme-power-engineering-software-solutions.html
[26] CPUC Rulemaking 24-01-018 Decision Resolving Pacific Gas and Electric Company's Motion to Revise Its 2025 and 2026 Energization Cost Caps https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M577/K821/577821257.PDF

modeling methodology steps. Sections 5 and 6 summarize results of the EIS Part 2 Study. Sections 7 through 10 describe PG&E's key findings, implications, and conclusion on the study. Lastly, Section 11 provides detailed discussion of the inputs and methodology for each modeling step. Since the draft report was filed, PG&E incorporated responses to stakeholder feedback as summarized in Appendix F.

4. Methodology Overview

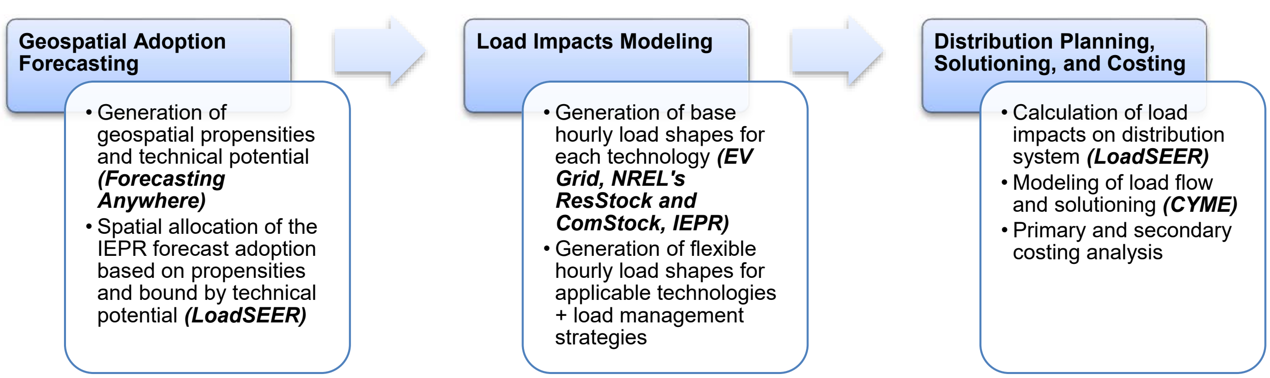
This EIS Part 2 report estimates the distribution energization costs that will be required to support California's electrification goals in different scenarios through 2040. Energization costs refer to the utility expenses associated with connecting new load to the grid through equipment upgrades or new equipment. PG&E developed a robust modeling methodology that emphasizes transparency, scenario flexibility, and alignment with real-world planning practices. As part of this study, PG&E coordinated regularly with the CPUC's Energy Division and stakeholders.

To produce this report, PG&E investigated key questions:

- Where are electrification technologies and DERs expected to be adopted in PG&E's service area?
- What are the expected impacts of that adoption on the distribution system?
- How much will distribution energization investments cost to support that adoption?

PG&E collaborated with Energy and Environmental Economics (E3) and Integral Analytics (IA) to develop a modeling methodology to answer these questions. The team structured the modeling process into three main steps, as shown in Figure 3.

Figure 3. Summary of EIS Part 2 methodology



Step 1. Geospatial Adoption Forecasting

First, PG&E analyzed where customers are likely to adopt electrification and DER technologies across its service territory on a granular geospatial level. E3 developed technical potential and propensity datasets using the Forecasting Anywhere (FA) geospatial forecasting tool, developed in partnership with IA. PG&E and IA applied these datasets to model expected adoption of each technology at a granular level in LoadSEER.

Step 2. Load Impacts Modeling

Second, PG&E and E3 developed technology-specific hourly load shapes using E3's EV Grid model, NREL's ResStock and ComStock models, PG&E meter data, and the IEPR. PG&E and E3 also created flexible load shapes for different load management techniques for the Enhanced Demand Flexibility Scenario. PG&E and IA layered the base and flexible load shapes on the geospatial adoption scenarios in LoadSEER to consider the time of day and year that each technology may be consuming or generating electricity, relative to other load on the distribution system.

Step 3. Distribution Planning, Solutioning, and Costing

In the final modeling step, PG&E modeled distribution impacts of the geospatial adoption scenarios and load shapes in LoadSEER to determine where and when overloads would occur. PG&E then conducted solutioning in CYME. Solutioning for all scenarios involved transfers, reconductoring, new feeder, new bank, and/or new step-up or step-down transformers. PG&E considered solutioning when equipment went above 100% loading. Finally, PG&E and IA calculated the resulting investment costs for the primary and secondary distribution systems. The 2030 solution set includes primary investments previously identified in PG&E's distribution planning process to ensure the EIS Part 2 study has a consistent basis with PG&E's distribution plan.

This process is followed for each EIS Part 2 scenario, with scenario-specific differences outlined in Table 4.

Table 4. High level overview of modeling differences between scenarios

DER & Electrification Inputs	Base (Mitigated) Scenario	Equity Scenario	Enhanced Demand Flexibility Scenario	EV Capacity Demand Sensitivity
Adoption Forecasts	IEPR 2023	IEPR 2023 + *incremental adoption to reach equity target*	IEPR 2023	IEPR 2023 + *modified EV/charger ratios and known loads reconciliation method*
Technical Potential	Base	Base + *revised technical potentials for incremental adoption, to reach equity target*	Base	Base
Propensities	Base	Base	Base + *percent adoption of load flexibility*	Base
Load Shapes	Base	Base	Base + *Enhanced flexible load*	Base + *diversified peak based on observed site data*

Appendix A: EIS Methodology discusses the methodology and inputs for each of these key steps. Each subsection ends with a detailed comparison of scenario-specific differences.

5. Adoption and Load Impact Results

5.1. Base (Mitigated) Scenario

The Base (Mitigated) Scenario uses adoption patterns based on historical trends and total adoption forecasted by the IEPR. The following section shows the dispersion patterns and load impacts. The following subsections compare the other scenarios to the Base Scenario.

Figure 4. Base Scenario residential EV charger adoption over time by feeder

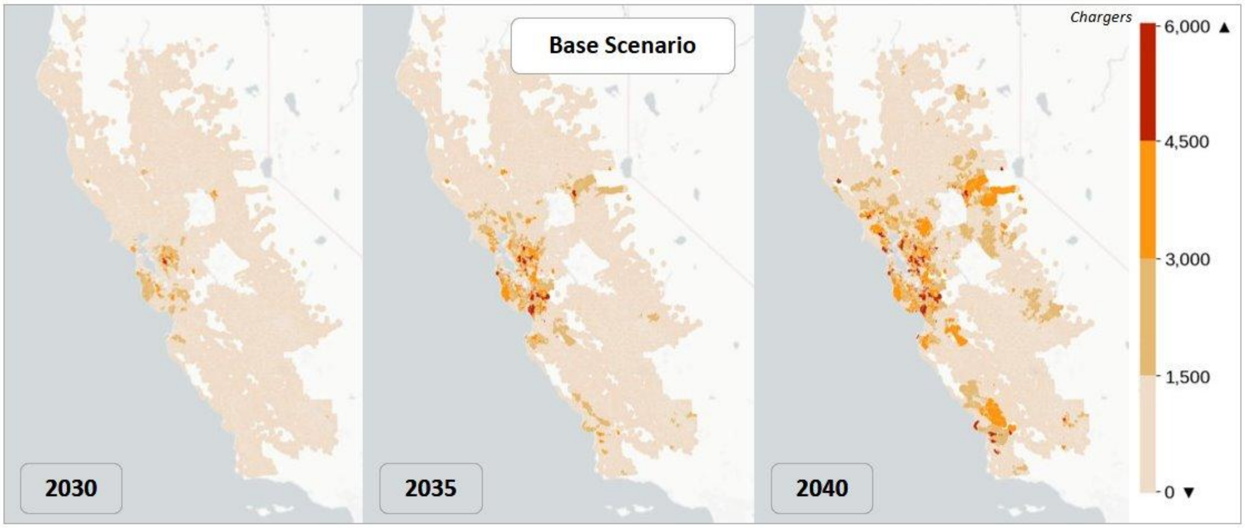


Figure 4 shows spatial adoption of residential EV chargers (home L1 and L2 chargers) over time. Feeders with higher adoption are dark red (4,500-6,000 chargers adopted). Each snapshot is on the same scale. In 2030 (far left), there are not many dark red feeders. Most feeders are light tan, meaning there are 0-1,500 chargers adopted on the feeder. In 2035 (middle), the Bay Area and surrounding areas have the highest adoption, reflecting the high population there. Areas with higher income also adopt earlier in the model. By 2040 (far right), adoption is more spread out throughout the service territory, including in the southwest and central regions of PG&E's territory.

Figure 5. Base Scenario residential AAFS adoption by feeder

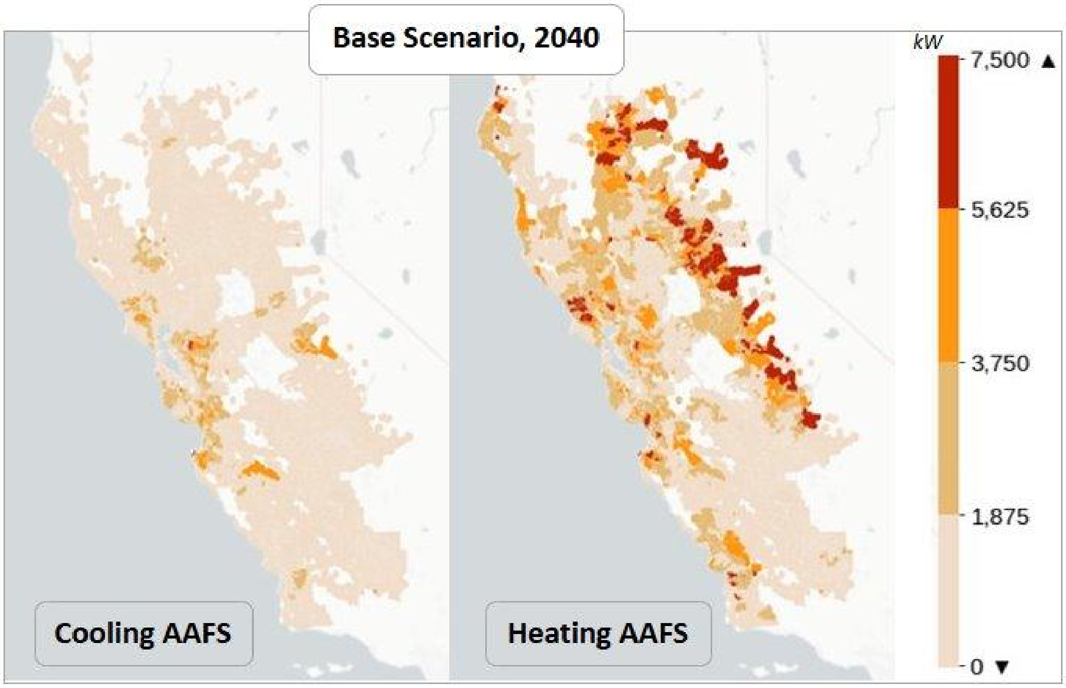


Figure 5 shows adoption of residential AAFS cooling (left) and AAFS heating (right) in the Base Scenario in 2040. Winter-peaking heating end use cases make a large portion of the IEPR AAFS load forecast. This adoption occurs mostly along the eastern and western sections of PG&E's territory, with less adoption in the central areas. Cooling AAFS load has limited impacts due to high penetration of existing electric cooling load. Cooling AAFS adoption is only modeled in areas with lower penetration of existing electric cooling devices.

PG&E thoroughly validated the LoadSEER results for each scenario. This process included validating the resulting adoption aligned with the IEPR forecast for each technology and year, comparing feeder-level adopted load metrics to the technical potential and propensity datasets, visual assessment of heat maps, and correlation analysis.[27]

5.2. Equity Scenario

In the Equity Scenario, PG&E modeled additional adoption of technologies in priority populations, incremental to adoption from the Base Scenario. This scenario, designed by the CPUC, represents business-as-usual adoption plus equity focused adoption that could be achieved through programs and incentives.

The additional adoption is calculated based on the CPUC's adoption ratio defined for the Equity Scenario. All incremental adoption in this scenario occurs in census tracts

[27] For each technology modeled, we compared the propensities to geospatial variables that impact likeliness to adopt. For example, for residential charging, we plotted residential charging propensities and income and studied their relationship.

designated as priority populations, defined by the CPUC, or by CARE or FERA customers. The CPUC defined priority populations as low income, disadvantaged and Tribal communities and recommended utilizing the priority populations designation dataset from the CEC,[28] illustrated in Figure 21 in the appendix. The team utilized this census-tract level data and layered in premise-level data on enrollment in California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) programs. Table 5 summarizes the adoption that would need to occur in priority populations to achieve balanced adoption between priority populations and non-priority populations.

Table 5. Increased adoption in priority populations in the Equity Scenario in 2040

Load Type	Adoption in Base Scenario (MW)		Adoption in Base Scenario (kW) / Customer		Adoption Increase Needed in Priority Populations	
	All Customers	*Priority Populations*	*All Customers*	*Priority Populations*	*Load increase needed to meet equity ratio (%)*	*Load increase in Equity Scenario (MW)*
Home L1	589	267	0.120	0.090	81%	217
Home L2	6,824	2,364	1.386	0.798	185%	4,368
Res. Cooling	1,489	607	0.302	0.205	119%	725
Res. Heating	4,113	1,912	0.835	0.645	74%	1,410
Res. General	3,247	1,516	0.659	0.512	72%	1,097
School Bus	68	37	0.014	0.012	31%	11
Work L2	782	409	2.492	2.201	32%	132
Public DCFC	1,036	606	0.198	0.192	7%	42
Com. Cooling	7	6	0.023	0.033	Not needed	0
Com. Heating	2,092	1,262	6.669	6.800	Not needed	0
Com. General	220	152	0.700	0.818	Not needed	0
HDV Depot	1,813	1,094	5.780	5.892	Not needed	0
MDV Depot	659	392	2.101	2.111	Not needed	0
MHDV Highway	126	83	0.402	0.447	Not needed	0
Public L2	564	341	0.108	0.108	Not needed	0

"Res" = residential, "com" = commercial

For home L1 EV charging, the Base Scenario showed 267 MW adopted by priority customers compared to 589 MW overall. The average load per customer is lower for priority groups than non-priority groups, resulting in an 81% increase in adoption of home L1 chargers in priority groups to meet the equity target. Home L2 shows even greater disparity. While overall adoption is high at 6,824 MW, only 2,364 MW were

[28] California Open Data Portal, Low-Income or Disadvantaged Communities Designated by California, https://data.ca.gov/dataset/low-income-or-disadvantaged-communities-designated-by-california

forecasted to be adopted by priority customers in the Base Scenario. An 185% increase of home L2 adoption in priority groups was needed to reach the target. Work L2 shows a modest 32% increase (132 MW) in priority groups in the Equity Scenario, while electric school bus charger adoption shows a 31% increase (42 MW). However, there is limited data and geographic uncertainty for these categories.

Residential cooling and heating also show notable gaps in adoption. Residential cooling adoption in the Base Scenario stands at 607 MW for priority customers compared to 1,489 MW overall. This indicates a 119% increase of residential cooling in priority groups is needed to meet the target ratio. Residential heating shows a similar trend, with 1,912 MW adopted by priority customers out of 4,113 MW total in the Base Scenario. A 74% increase in adoption in priority groups is needed to meet the target.

Figure 6 illustrates the spatial adoption of the additional residential EV chargers needed to achieve the equity ratio, described in Table 5. Chargers adopted in the Equity Scenario (right) that are incremental to the Base Scenario (left) are adopted solely in priority populations. This results in a larger geospatial spread of adoption throughout PG&E's territory and more overall load throughout the territory. Feeders that have significant adoption in the Equity Scenario (dark red color) are primarily along the mid-east and mid-west areas of PG&E's territory.

Figure 6. Residential EV charger adoption by feeder in the Equity versus the Base Scenario

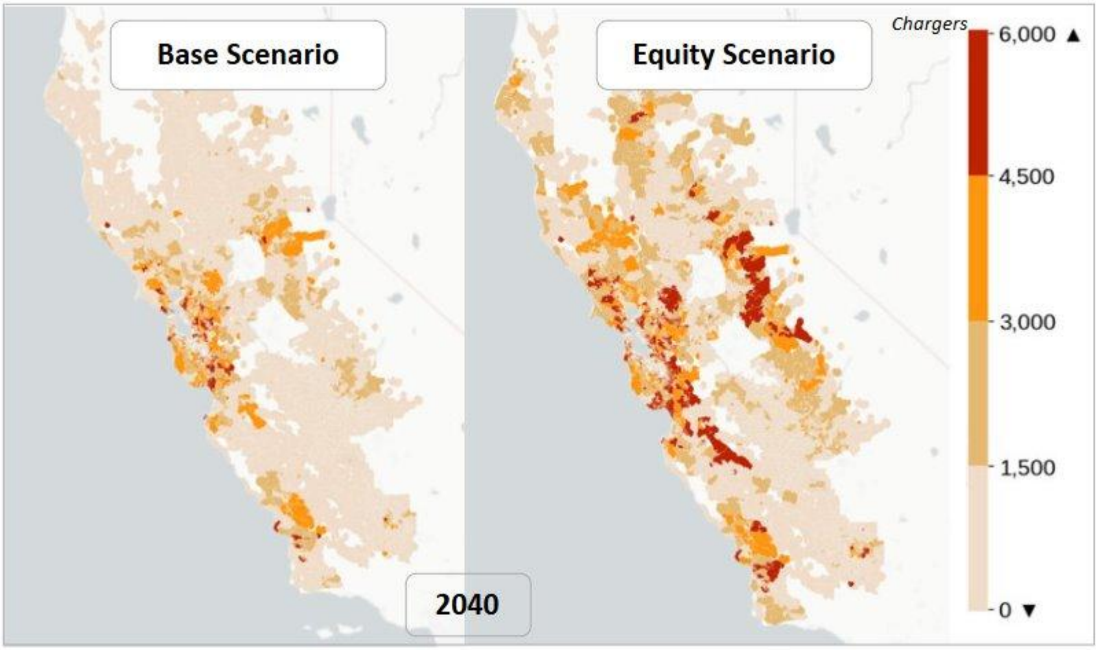
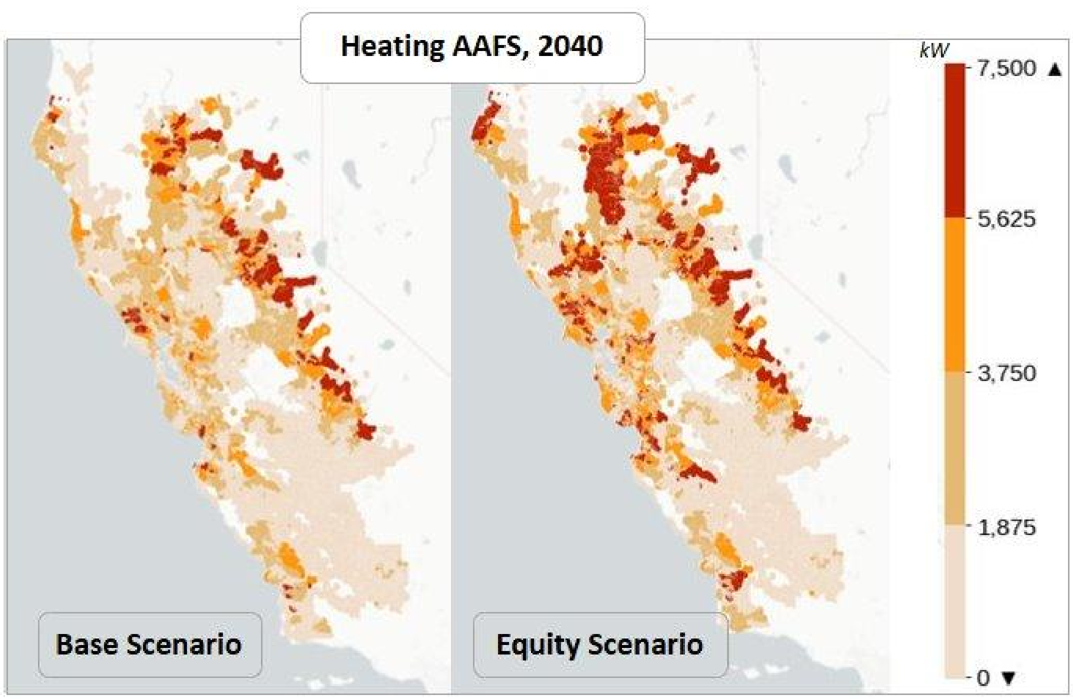


Figure 7 shows similar results for residential AAFS adoption, with incremental adoption in the equity scenario being more spread out throughout the territory, and higher adoption in areas that already had AAFS load allocated. The geospatial trend is similar to residential EV charger adoption as well, with AAFS adoption also highly impacting feeders in the northern part of the service territory.

Figure 7. Residential AAFS adoption by scenario and by feeder



The Equity Scenario assumes adoption levels in non-priority communities are held constant from the Base Scenario, while priority communities are scaled up to match the same per-customer adoption ratio based on the propensities. This approach results in overall higher adoption than the Base Scenario, rather than redistributing adoption from non-priority to priority populations.

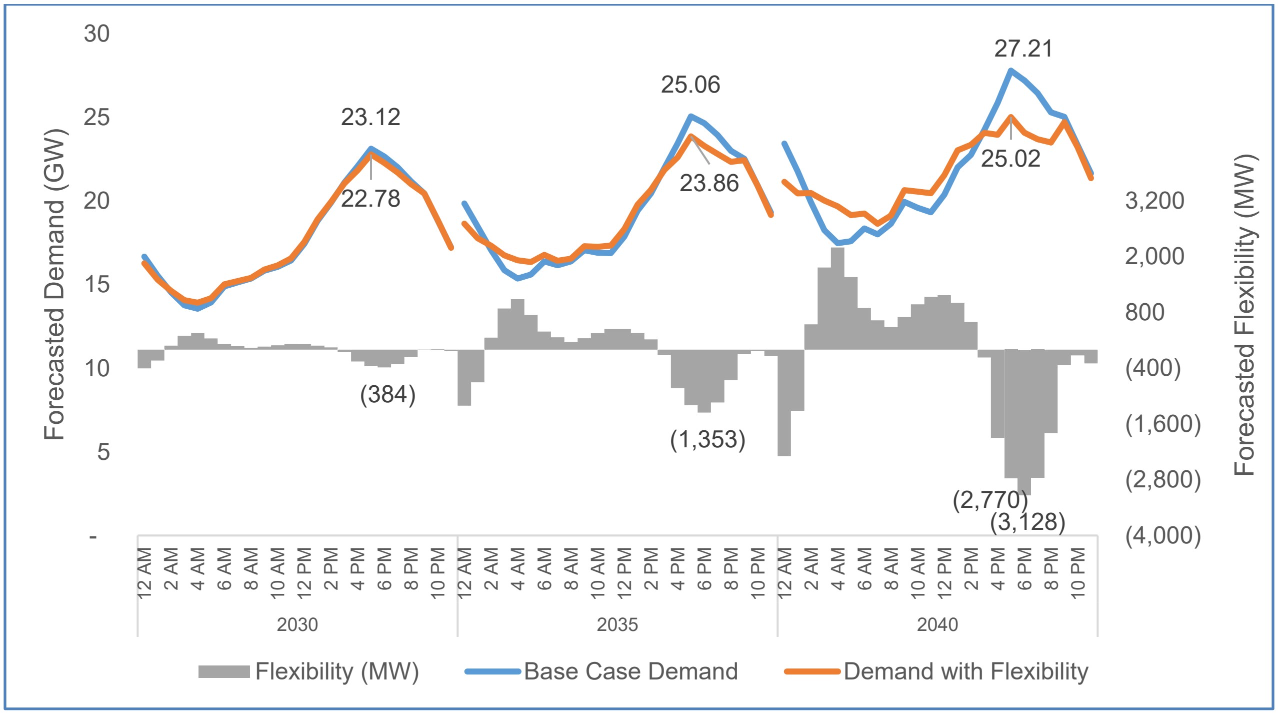
5.3. Enhanced Demand Flexibility Scenario

The Enhanced Demand Flexibility Scenario models electrification growth across the residential and commercial sectors with a growing proportion of flexible loads such as EV charging, battery, heat pumps, and smart appliances through 2040. This increase in flexible loads supports greater demand-side management opportunities, allowing consumption to be shifted away from peak periods and for more targeted management based on local feeder peaks that may differ from the system peak.

5.3.1. Aggregated Demand Flexibility

By 2040, the Enhanced Demand Flexibility Scenario includes a range of 2.2 - 3.1 GW of incremental coincident load flexibility for the bulk system peak, 6 GW of non-coincident load flexibility, and the potential to shift 16 GWh between hours of the day. Figure 8 shows the hourly demand on peak days for the PG&E territory over time in the Base Scenario and the change due to flexibility. The figure also shows the amount of flexibility on the secondary axis based on the differences between these two hourly load shapes. A substantial portion of load flexibility in the Enhanced Demand Flexibility scenario occurs in the midnight hours during the secondary peak time, outside of the traditional evening peak window. Therefore, 2.2 - 3.1 GW of effective flexibility reflects changes to the evening peak but doesn’t directly indicate the size or timing of the new peak, which varies based on load shape dynamics.

Figure 8. Peak day load in Base Scenario and Enhanced Demand Flexibility Scenario, along with amount of flexibility (secondary axis), in 2030, 2035 and 2040

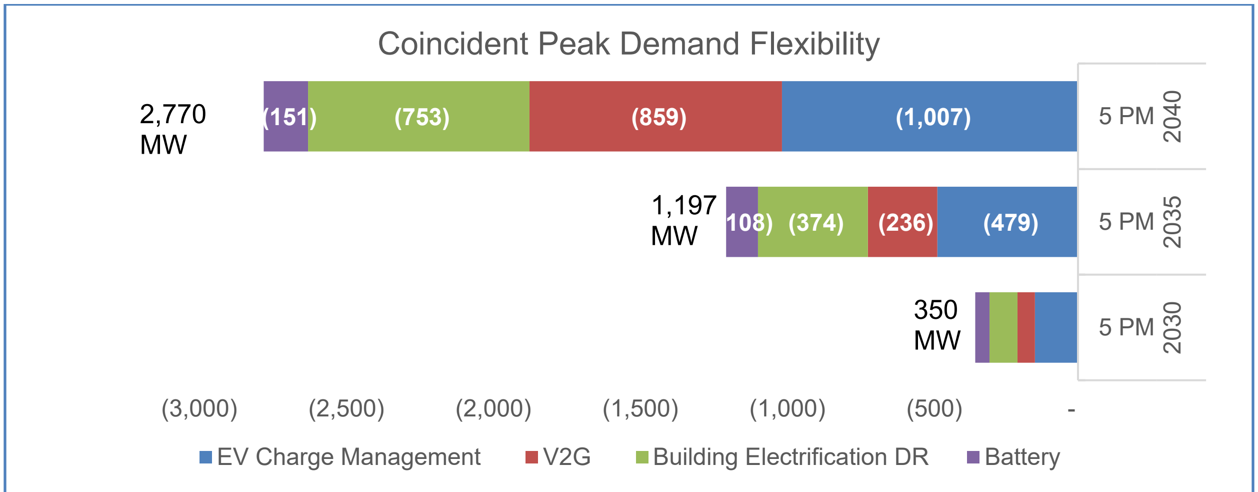


Demand flexibility from electric vehicle charging active management is a major contributor to flexibility in 2030, 2035, and 2040 in the Enhanced Demand Flexibility Scenario. Vehicle-to-grid demand flexibility is assumed to grow over time as technology matures.

As shown in Figure 9, PG&E benchmarked its estimates for demand flexibility with the resource potential estimated by the CEC using its D-Flex Tool for the SB 100 report.[29] The 2.7 GW of demand flexibility in 2040 in the Enhanced Demand Flexibility Scenario (assessed at 5 pm) exceeds the 2.2 GW of technical potential in the CEC D-Flex (assessed 4-9 pm).

[29] CEC, SB 100 Demand Scenarios Demand Flexibility Resource Potential, https://www.energy.ca.gov/sites/default/files/2025-02/DAWG_share_D-Flex_2-28-2025_ada.pdf

Figure 9. Coincident peak load reduction from Enhanced Demand Flexibility Scenario (top) and technical potential estimated by D-Flex for 2040 (bottom)



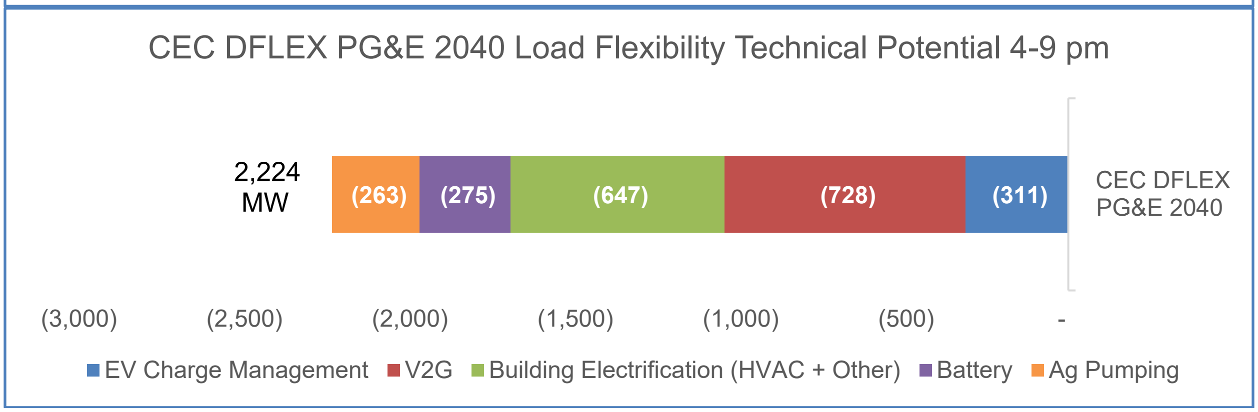


Table 6 presents the estimated reductions in coincident peak load, specifically during the PG&E system evening peak hour, for various demand flexibility components. The results show that technologies such as EV charging active management, dynamic pricing for home L2, V2G, battery storage, and building electrification DR contribute to significant peak load reductions over time in the scenario. By 2040, total coincident load flexibility reaches 2.7 GW, with V2G and building electrification DR providing the largest contributions.

Table 6. Enhanced Demand Flexibility Scenario coincident load flexibility in MW

Coincident peak (September at 5pm)	2030	2035	2040
EV charge management	(147)	(479)	(1,007)
V2G	(59)	(236)	(859)
Battery	(48)	(108)	(151)
Building electrification DR	(95)	(374)	(753)
Total	***(349)***	***(1,197)***	***(2,770)***

**Numbers may not add exactly due to rounding*

Table 7 shows the noncoincident peak load reductions for the same demand flexibility components assumed in the Enhanced Demand Flexibility Scenario. These reductions represent broader system-wide benefits beyond the single peak hour. Total noncoincident load flexibility reaches over 6 GW by 2040, with EV charging active management and building electrification DR again leading in impact. The larger magnitude of non-coincident reductions (6 GW) compared to coincident reductions (2.7 GW) suggests that orchestrated demand flexibility can play a meaningful role in shaping the local grid needs, potentially reducing the need for localized infrastructure investments.

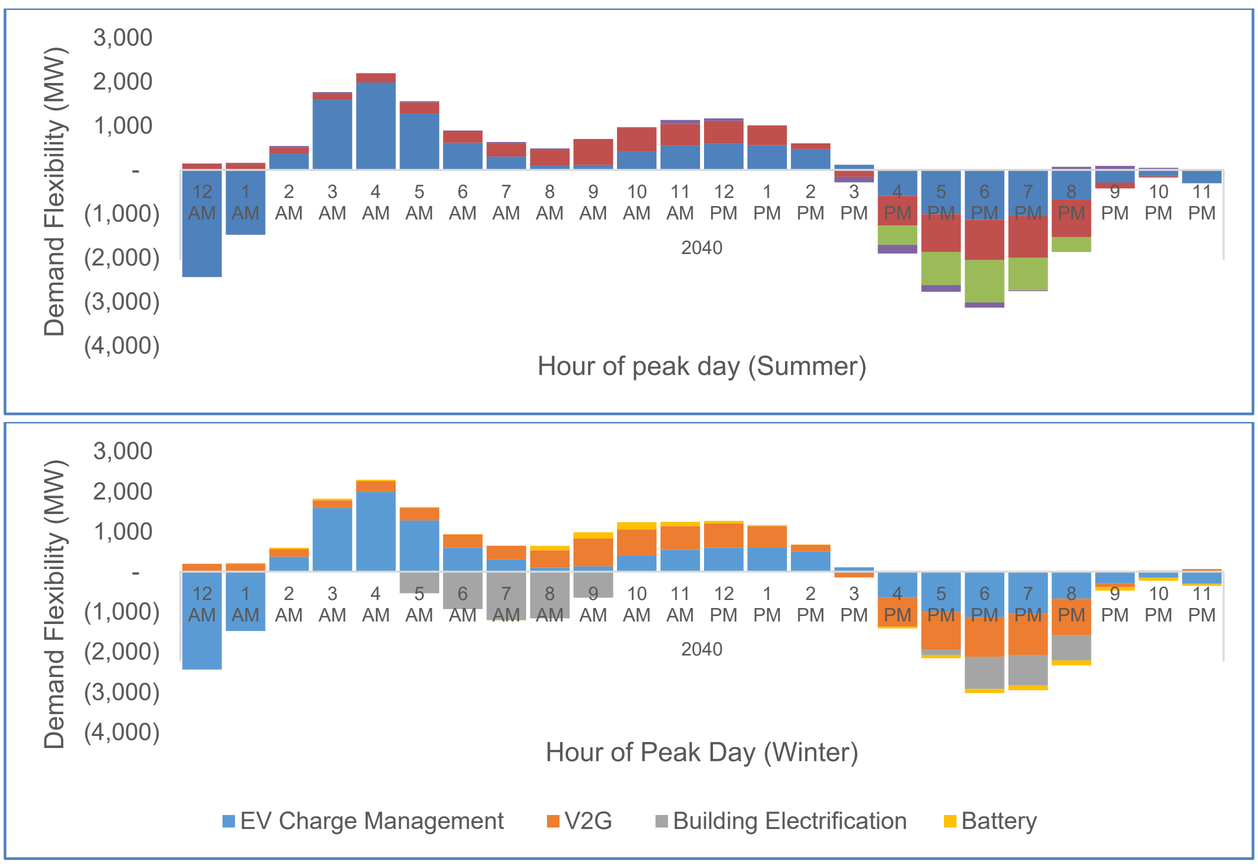
Table 7. Enhanced Demand Flexibility Scenario noncoincident load flexibility in MW

Noncoincident peak	2030	2035	2040
EV charge management	(492)	(1,521)	(3,051)
V2G	(72)	(293)	(1,059)
Battery	(94)	(214)	(307)
Building electrification DR	(196)	(820)	(1,679)
Total	***(854)***	***(2,847)***	***(6,097)***

**Numbers may not add exactly due to rounding*

Figure 10 shows the hourly flexibility for summer and winter peak days in 2040. This provides a detailed view on the contributions of each technology to reducing the midnight secondary peak and the traditional evening peak during 4-9pm.

Figure 10. Hourly demand flexibility by category for a peak summer day (top) and peak winter day (bottom)



5.3.2. Enabling Demand Flexibility

The Demand Flexibility modeled in the EIS Part 2 assumes technical investments are implemented such as Distribution Energy Resource Management Systems (DERMS) as well as policy drivers such as dynamic rates and customer programs. Over the past decade, California's demand response landscape has evolved significantly due to major policy initiatives and rapid technological advancements. The widespread adoption of DERs, transportation and building electrification, and smart appliance controls has introduced both new challenges and opportunities for load management. In response, CPUC issued the Demand Response Order Instituting Rulemaking (R.25-09-004) that seeks to evaluate and enhance the consistency, predictability, reliability, and cost-effectiveness of DR resources. The OIR also intends to re-evaluate several key Commission DR policies, including our dual participation policy, valuation methodologies and evaluation metrics. This complements the issues addressed in Track 2 of the High DER proceeding,[30] providing the regulatory structure needed for effective load management and integration of advanced technologies.

5.4. EV Capacity Demand Sensitivity

The EV Capacity Demand Sensitivity builds off the Base Scenario by modifying two components: the forecast methodology and the diversified peaks for each LDV charging segment. The aim of this sensitivity is to model distribution capacity demand at the local level and therefore focuses on the secondary costs.[31] It is an exploratory approach to forecasting transportation electrification that forecasts capacity demand based on observed site characteristics.

The EV Capacity Demand Sensitivity forecast was developed using the same general methodology as the Base Scenario: using the CEC's AB 2127 report to derive vehicle-to-port ratios that were then applied to 2023 IEPR vehicle stock growth. In the EV Capacity Demand Sensitivity, a blended vehicle-to-port ratio was used across the forecast years. PG&E applied the annual vehicle-to-port ratio in a given year to the IEPR-forecasted vehicle stock growth and summed the year-over-year port growth to develop a weighted average vehicle-to-port ratio for each vehicle segment.

The reconciliation method in the sensitivity is also different. In the EV Capacity Demand Sensitivity, capacity demand from known loads was converted into ports based on the assumed peak demand per port and subtracted from the forecasted spatial port growth. In the other scenarios, PG&E used an energy-based, IEPR-constrained reconciliation method. PG&E believes this demand-based reconciliation method may more accurately capture expected localized capacity demand and will consider integrating this approach into future DPEP cycles (see Section 9.8).

[30] Decision D.24-10-030

[31] The forecast in the EV Capacity Demand Sensitivity is also at the distribution primary system but PG&E did not perform solutioning at the primary level for this sensitivity due to timing and resource constraints.

Table 8. 2040 EV port count in the Base Scenario and the EV Capacity Demand Sensitivity

	Home L1	Home L2	Work L2	Public L2	Public DCFC
Base Scenario	1,337,956	3,220,126	311,195	458,976	42,624
EV Capacity Demand Sensitivity	1,895,783	3,355,454	327,051	416,365	33,080

Although the EV forecast is slightly different, the spatial adoption of EV charging in the EV Capacity Demand Sensitivity is generally the same as the Base Scenario since the propensities and technical potential are the same. The other main difference in the EV Capacity Sensitivity is that higher diversified peaks are applied, as shown in Table 9. Non-residential peaks were derived from active site data to more accurately capture localized capacity needs at a given site.

Table 9. Diversified peaks per port for each charging segment in the Base Scenario and EV Capacity Demand Sensitivity

	Base Scenario Diversified Peaks per Port (kW)	EV Capacity Demand Sensitivity Diversified Peaks per Port (kW)		
	2025-2040	2025-2029	2030-2034	2035-2040
Residential L1	0.44	0.44	0.44	0.44
Residential L2	2.12	2.12	2.12	2.12
Workplace	2.55	4.30	4.30	4.30
Public L2	1.31	4.30	4.30	4.30
Public DCFC	41.34	62.60	68.61	72.30

Public DCFC peaks change throughout the forecast period to account for changes in AB 2127-forecasted port power levels and varying deployment of each, as shown in Table 9. These changing peaks represent a new, more granular approach to forecasting capacity demand that required additional technical resources to run in LoadSEER. This approach was not taken in any of the other three EIS scenarios to align with PG&E's traditional forecasting approach, however, we will continue to evaluate this new approach's effectiveness in future DPEP cycles (see Section 9.8).

5.5. Load Impacts and Uncertainty

Inherent to any forecast, there are uncertainties in how customers adopt technologies, where those loads materialize on the system, and how usage patterns evolve over time. The overall levels and spatial distributions used in this study reflect reasonable and directionally consistent expectations. As a result, some areas of the system saw similar distribution impacts across the scenarios. However, differences in adoption location, technology mix, and customer behavior still led to some meaningful variations at the feeder and circuit level, which in turn produced different upgrade needs and cost outcomes.

TE adoption introduces several layers of uncertainty, such as where customers charge (home, workplace, or public), the availability of Level 2 charging, and how load shapes evolve across customer segments. Each of these inputs influences both the magnitude and the location of EV load on the system. Because distribution costs are sensitive to where and when load materializes, different assumptions about charging access, charging behavior, and customer propensity can produce different upgrade needs and cost outcomes.

PG&E's three scenarios reflect this range of uncertainty by testing different combinations of adoption levels, charging location assumptions, and flexibility potential. Taken together, the scenarios illustrate the range of infrastructure impacts that could result from different TE charging patterns and provide a broader view of how EV-related uncertainties influence both system planning and overall cost outcomes.

6. Distribution Planning, Solutioning, and Costing Results

This section discusses the distribution cost results for each scenario. Overall, PG&E expects the range of costs between the three main scenarios to be between $8.5 billion to $13.5 billion for primary distribution system through 2040. For the secondary distribution system, the estimated range is between $15 billion to $18 billion through 2040. The total distribution electrification costs (for both primary and secondary) ranges from $23 billion to $31 billion through 2040. All costs are shown as nominal totals and reflect annual inflation of 2.6%, as stated in Section 11.3.4. Cost uncertainty increases over time, with 2040 costs inherently more uncertain than nearer-term costs in 2030. Forecast trend uncertainty increases over time and substantially influences the local bank and circuit loading, which are reflected in total costs.

6.1. Cost Results by Scenario

6.1.1. Base (Mitigated) Scenario

Table 10 outlines the projected capital costs associated with the Base Scenario from 2025 through 2040. The analysis highlights substantial investment in distribution banks and feeders, which together account for approximately 54% of the total projected primary system cost of $9.6 billion. For the secondary system, the total projected cost is $15.9 billion through 2040. Combining primary and secondary results in a total of $25.5 billion through 2040.

Table 10. Base Scenario cost breakdown in $ billion*

Upgrade Types	***2025-2030 (6 years)***	***2031-2035 (5 years)***	***2036-2040 (5 years)***	***Total (16 years)***
Substation Bank and Feeder	$2.4	$1.4	$1.4	$5.2
Distribution Line	$1.9	$1.4	$1.1	$4.4
Subtotal - Primary	*$4.3*	*$2.8*	*$2.5*	*$9.6*
Transformer and Secondary	$6.7	$4.7	$4.5	$15.9
Subtotal - Secondary	*$6.7*	*$4.7*	*$4.5*	*$15.9*
Total Primary and Secondary	***$11.0***	***$7.5***	***$7.1***	***$25.5***

**Numbers may not add exactly due to rounding*

The costs shown for the mitigated Base Scenario include a forward-looking engineering approach consistent with distribution planning. Distribution engineers sized banks and feeders based on long-term system needs rather than short-term overload forecasts. This strategy aims to minimize the need for repeated substation upgrades and supports cost efficiency over time.

For the secondary system, PG&E evaluated multiple investment approaches to better understand how they met long-term infrastructure needs. The costs shown reflect the use of a “size-up” parameter when solutioning secondary investments, in which the next larger service transformer size was automatically selected during routine replacements (see section 11.3.3). This excluded the exact transformer size from consideration and emphasized proactive installation of higher-capacity units to reduce having to re-install service transformers with subsequent load growth.

The secondary system modeling establishes a cost envelope for installing new transformers and replacing existing transformers. Results indicate that the model favors new installations. In practice, PG&E would likely perform a higher share of replacements of existing transformers sized to serve all customers within the designated hexagon, ensuring adequate capacity, than the model predicts. This difference between the model and practice does not impact overall cost projections because unit costs for new installations and replacements were equivalent in the model. However, PG&E will explore opportunities to improve the algorithm in the future for consideration in use in planning.

6.1.2. Equity Scenario

Table 11 shows the total distribution infrastructure capital costs for the Equity Scenario through 2040, totaling $31.6 billion for the primary and secondary systems. The primary system costs total $13.4 billion, and the secondary system costs total $18.1 billion.

Compared to the Base Scenario, the Equity Scenario shows a $3.8 billion increase in primary distribution costs, driven by increased adoption of electrification and DERs in priority areas. Bank and feeder investments account for approximately 60% of primary system costs in the Equity Scenario. The secondary system costs are $2.2 billion higher in the Equity Scenario than the Base Scenario, again reflecting the increased electrification load in the Equity Scenario.

In total, the Equity Scenario represents an approximate $6 billion increase in capital costs across both primary and secondary systems through 2040. The Equity Scenario modeled significantly more adoption of electrification technologies, including home L1 chargers, home L2 chargers, residential cooling and heating, school bus chargers, and work L2 chargers. This increased adoption, which exceeds the IEPR forecast that was modeled in the Base Scenario, results in higher electrification loads and thus higher infrastructure costs in the Equity Scenario. In section 8.2, PG&E evaluated the offsetting revenue from this increased electrification load and how it offsets the increased costs, and thus still provides a downward rate pressure.

Table 11. Equity Scenario cost breakdown in $ billion*

Upgrade Types	***2025-2030 (6 years)***	***2031-2035 (5 years)***	***2036-2040 (5 years)***	***Total (16 years)***
Substation Bank and Feeder	$2.6	$2.4	$2.9	$7.9
Distribution Line	$1.9	$1.9	$1.9	$5.6
Subtotal - Primary	*$4.4*	*$4.2*	*$4.8*	*$13.4*
Transformer and Secondary	$8.1	$5.1	$4.8	$18.1
Subtotal - Secondary	*$8.1*	*$5.1*	*$4.8*	*$18.1*
Total Primary and Secondary	***$13.4***	***$8.6***	***$9.6***	***$31.6***

**Numbers may not add exactly due to rounding*

6.1.3. Enhanced Demand Flexibility Scenario

Table 12 shows the total distribution infrastructure capital costs for the Enhanced Demand Flexibility Scenario through 2040. The total distribution infrastructure costs for the Enhanced Demand Flexibility Scenario is $23.7 billion in 2040. The primary system upgrades cost $8.5 billion, with distribution banks and feeders accounting for 56% of primary system costs, and the secondary system upgrades cost $15.2 billion. Compared to the Base Scenario, the Enhanced Demand Flexibility Scenario reflects a cost reduction of approximately $1.8 billion, primarily driven by deferred upgrades in areas where flexible load management can alleviate peak demand. However, the scenario still requires substantial investment in both primary and secondary systems to enable the electrification load growth.

Table 12. Enhanced Demand Flexibility Scenario cost breakdown in $ billion

Upgrade Types	*2025-2030 (6 years)*	*2031-2035 (5 years)*	*2036-2040 (5 years)*	*Total (16 years)*
Substation Bank and Feeder	$1.9	$0.8	$2.1	$4.8
Distribution Line	$1.8	$0.8	$1.1	$3.7
Subtotal - Primary	*$3.8*	*$1.6*	*$3.1*	*$8.5*
Transformer and Secondary	$6.6	$4.5	$4.1	$15.2
Subtotal - Secondary	*$6.6*	*$4.5*	*$4.1*	*$15.2*
Total Primary and Secondary	***$11.2***	***$5.3***	***$7.2***	***$23.7***

**Numbers may not add exactly due to rounding*

As described in Section 11.2.4, PG&E performed a sensitivity to demonstrate the impact of not orchestrating load flexibility strategies. In this sensitivity, the load flexibility was not orchestrated to local circuit patterns and continued to shed and shift load, even if these shifts were contradictory to local conditions. PG&E found that shifting flexible loads like EV charging and HVAC without accounting for local grid capacity caused some local overloads and equipment strain. Under the non-orchestrated sensitivity, new overloads and distribution upgrades were triggered, resulting in a smaller cost reduction ($0.2 billion) than the orchestrated case ($1.8 billion) through 2040. Therefore, most of the cost reductions identified in the Enhanced Demand Flexibility scenario required orchestration down to the secondary level to avoid triggering new upgrades. The Enhanced Demand Flexibility Scenario and its sensitivity show that substantial infrastructure upgrade costs can be avoided or deferred if load management strategies are thoughtfully orchestrated and tailored to local loading profiles. However, without such orchestration around local needs, uncontrolled load shifting can lead to localized overloads, reducing expected savings and necessitating additional upgrades.

6.1.4. EV Capacity Demand Sensitivity

Table 13 shows the total secondary distribution infrastructure capital costs for the EV Capacity Demand Sensitivity through 2040. The focus of this sensitivity was on the secondary distribution system impacts from electric LDV charging without IEPR constraints. The result was $17.6 billion in secondary costs by 2040, an increase of $1.7 billion compared to the Base Scenario. These additional costs[32] reflect what PG&E believes may be a more accurate forecast of localized capacity demand from EV charging than when the forecast is constrained by the IEPR energy cap, as distribution capacity upgrades are triggered to serve the local capacity demand at an individual site.

[32] PG&E did not complete a cost estimate for primary upgrades for the EV Capacity Demand Sensitivity, but anticipates the increase in secondary costs are indicative of what would be expected for primary costs.

Table 13. EV Capacity Demand Sensitivity cost breakdown in $ billion

Upgrade Types	*2025-2030 (6 years)*	*2031-2035 (5 years)*	*2036-2040 (5 years)*	*Total (16 years)*
Transformer and Secondary	$7.3	$5.2	$5.0	$17.6

**Numbers may not add exactly due to rounding.*

6.1.5. Cost Comparisons by Scenario

Figure 11 shows cumulative primary and secondary costs for each scenario for 2030, 2035, and 2040. The Base (Mitigated) Scenario modeled growth in electrification and DER adoption consistent with existing planning approaches and provides a benchmark for distribution electrification infrastructure costs. The Base Scenario in the EIS Part 2 Study is “mitigated”, meaning that distribution engineers developed low-cost solutions where feasible (e.g., load transfers) and load profiles incorporated existing and future customer behaviors.

For the Base (Mitigated) Scenario, PG&E estimated cumulative costs through 2040 of $9.6B for the primary system and $15.9B for secondary infrastructure, for a total distribution cost of approximately $25.5B. The secondary costs include both capacity overloads from energization (upgrades to overloaded transformers) and new service connection costs (new transformers). In the secondary model, both types of transformers use the same sizing and material cost assumptions.

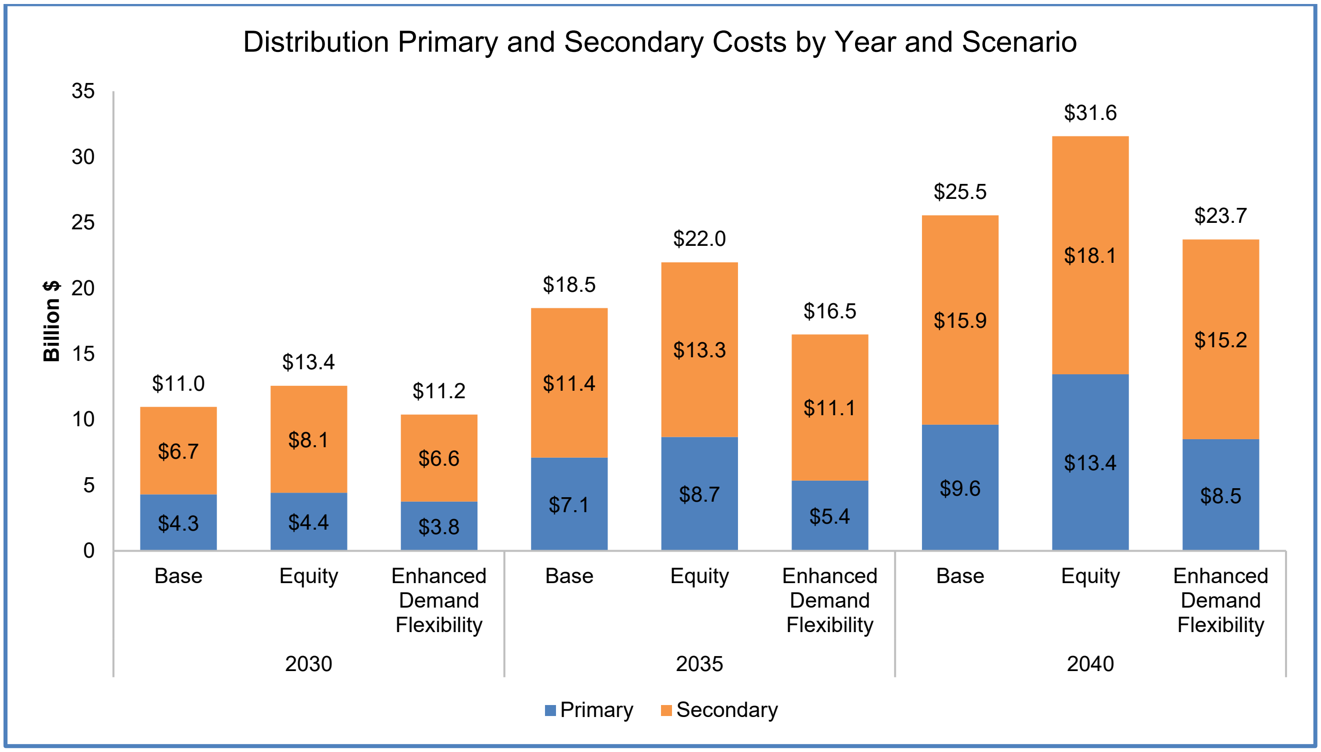
The Equity Scenario has an overall higher level of electrification and DER adoption than the Base (Mitigated) Scenario. The increased electrification and DER load in the Equity Scenario resulted in the identification of an additional $3.8B of primary and $2.2B of secondary costs, for a total incremental distribution cost of $6B. This $6B increase in distribution infrastructure costs is consistent with the corresponding increase in electrification load (~6.9 GW). Furthermore, the benefits of the increased electrification and DER adoption in disadvantaged, low-income, and Tribal communities are not quantified in the study.

PG&E’s Enhanced Demand Flexibility Scenario further reduced distribution infrastructure costs by approximately $1.8 billion, by 2040, if orchestrated.[33] The scope of the EIS does not include any reductions in generation, transmission, or customer (e.g., service panel) costs, which would be in addition to the cost reductions identified in the EIS. The cost reductions identified in the Enhanced Demand Flexibility Scenario are incremental reductions enabled by orchestrated shifting of energy demand away from peak hours and avoiding creating new peaks. The costs associated with implementing and orchestrating load management are not included in the EIS, nor is the cost effectiveness of the enhanced orchestrated demand flexibility or its impact on

[33] “Orchestration” in the context of the EIS Part 2 study refers to the ability to manage the demand flexibility in a way that is aware of the local grid constraints, in a manner that can be relied upon for planning purposes using firm, dispatchable load management. Orchestration therefore does not signify the use of markets or real time control.

affordability. The costs to implement and orchestrate the load flexibility are difficult to accurately estimate because the enhanced demand flexibility is either still in the conceptual stage or undergoing pilot testing. As a result, understanding and calculating the full range of design and operational expenses requires additional development and significant resources that was not undertaken in the EIS Part 2. Therefore, the EIS Part 2 cannot conclude whether the Enhanced Demand Flexibility scenario results in lower overall customer costs, since the costs for implementing and orchestrating the enhanced demand flexibility are not known.

Figure 11. Cumulative primary and secondary costs for each scenario for 2030, 2035, and 2040*



Since PG&E's EV Capacity Demand Sensitivity focused on secondary cost impacts, this sensitivity is not included in the figure. The sensitivity shows a $1.7 billion secondary cost increase compared to the Base Scenario. This is consistent with the modeling approach of applying higher diversified peaks to reflect the local capacity that would need to be built to support the EV charging infrastructure installations.

Table 14 reports the summer system peak load for 2030 and 2040 compared to the cumulative primary and secondary costs up to those years. Peak load and costs are lower in all years for the Enhanced Demand Flexibility scenario compared to Base Scenario, and higher for the Equity Scenario.

Table 14. Peak load and cumulative costs by scenario for 2030 and 2040

	2030 Summer System Peak (MW)	*2025-2030 Cumulative Costs ($B)*	*2040 Summer System Peak (MW)*	*2025-2040 Cumulative Costs ($B)*
Base	23.1	$11.8	27.8	$25.5
Equity	23.6	$13.4	29.6	$31.6
Enhanced Demand Flexibility	22.8	$11.2	25.6	$23.7

In each scenario, residential building electrification (general end uses and cooling) and light-duty EV charging at home L2 chargers are the greatest contributors to the peak load. In the Equity Scenario, home L2 charging requires the largest increase in adoption in priority populations, with a 185% increase (nearly 3 times the adoption in priority populations in the Base Scenario) and residential cooling also requires a 119% increase (more than doubling of adoption in priority populations in Base), so these end uses continue to contribute to peak load. In the Enhanced Demand Flexibility Scenario, these end uses provide flexibility through demand response, EV charging management, and V2G, but still contribute to the peak load.

6.2. Comparison to other Electrification Studies

Recent studies have estimated distribution costs associated with electrification in California. Each study had different scopes, methodologies, and input assumptions; therefore, it is difficult to compare each one directly to EIS Part 2 without considering the differences and how they impact the results. This section describes key studies, highlights notable differences in scope and approach, and compares the results of PG&E's EIS Part 2 study.

6.2.1. EIS Part 1 Study

The foundational EIS Part 1 study, commissioned by the CPUC and performed by Kevala Inc., focused on high-level statewide modeling. Kevala's EIS Part 1 provides preliminary estimates of the scope and scale of potential electric distribution grid impacts from widespread transportation electrification and solar PV penetration from 2022 through 2035 (a 13-year study period). The scope of the EIS Part 1 is compared to the EIS Part 2 in Section 3.3.

The EIS Part 1 analysis used unmitigated planning scenarios and assumed only traditional utility distribution infrastructure investments and existing TOU rates and BTM tariffs throughout the study timeframe.[34] EIS Part 1 is "not an absolute prediction" of investment needs; it was designed to indicate where and when needs might arise under

[34] EIS Part 1, ES-6.

scenario assumptions rather than to prescribe utility solutions or budgets.[35] In contrast, all scenarios in the EIS Part 2 are mitigated scenarios, as described in Section 3.3.

Regarding the modeling of load management, the EIS Part 1 system-level cost estimate "does not consider new real-time dynamic rates and flexible load management strategies," yielding EV profiles that concentrate load in evening hours.[36] In contrast, the EIS Part 2 Base (Mitigated) scenario includes load management consistent with current distribution planning processes, including load profiles that incorporate existing and future customer behaviors. Furthermore, the EIS Part 2 Enhanced Demand Flexibility Scenario applies additional load management, including managed charging and load shape adjustments and benchmarks expected total demand flexibility against the CEC D-Flex potential.

The scope of secondary costs included in the EIS Part 2 is significantly expanded from the EIS Part 1. The EIS Part 1 estimated grid upgrades at the service transformer level,[37] based on examining service transformer capacity overloads.[38] The EIS Part 2 modeled service transformer overloads similarly to the EIS Part 1, but also coupled geospatial forecasting using LoadSEER[39] and CYME[40] to the service connection process to include service connection costs, consistent with service planning costs incurred for energizing load. This means that the cost of transformer upgrades are included in EIS Part 1 and EIS Part 2, but the cost of new transformers are only included in EIS Part 2.

6.2.2. Public Advocates Office (PAO) Distribution Grid Electrification Model (DGEM)

The Public Advocates Office (PAO) of the CPUC produced the Distribution Grid Electrification Model (DGEM) study, evaluating the cost of upgrading California's investor-owned utility distribution grids to support widespread electrification. The DGEM 1.0 Study (August 2023) focused primarily on transportation electrification load growth, used inputs from the 2022 IEPR, and estimated costs out to 2035.[41] The study modeled primary distribution costs. The study did not model the secondary system, instead estimating secondary distribution costs as a percentage of the primary system costs.

[35] EIS Part 1, Workshop Slides
[36] CPUC cover sheet filing for Kevala Part 1
[37] EIS Part 1, ES-10.
[38] EIS Part 1, p 110.
[39] LoadSEER is a leading distribution planning and load forecasting software tool implemented at over 15 large utilities in North America, including PG&E: https://integralanalytics.com/products/loadseer/
[40] CYME is a power engineering modeling software used to evaluate system conditions, such as loading, voltage and protection: http://www.electrical.eaton.com/us/en-us/digital/brightlayer/brightlayer-utilities-suite/cyme-power-engineering-software-solutions.html
[41] Public Advocates Office, Distribution Grid Electrification Model – Study and Report, 2023, https://www.publicadvocates.cpuc.ca.gov/press-room/reports-and-analyses/distribution-grid-electrification-model-findings

The DGEM 2.0[42] study refreshed inputs using the 2023 IEPR, added new analysis on building electrification loads, and estimated costs out to 2040.

A key finding of the DGEM 2.0 study results is that optimizing EV load shapes at the feeder level, rather than system-wide, can significantly reduce infrastructure upgrade costs. Specifically, feeder-level EV load optimization can lead to a 42% reduction in projected costs compared to IEPR electric vehicle load shapes.

6.2.3. GridLab and Kevala's California Load Management Standard Avoided Distribution Grid Upgrade Study

Kevala prepared the California Load Management Standard Avoided Distribution Grid Upgrade Study for GridLab in August 2025.[43] The study found that doubling load management to achieve the 2030 goal of 7 GW, while focusing on areas with minimal overloads, could cut costs by about 50 percent. It allocated 3,500 MW of load flexibility to feeders with smaller needs before moving to those with larger requirements.

6.2.4. Comparison of Study Results

Figure 12 compares the annual costs per year for the Base Cases in the EIS Part 1 and EIS Part 2. Annual costs are used since each study had different time horizons for the analysis.

To compare secondary costs between the EIS Part 1 and EIS Part 2 studies, the secondary costs identified in the EIS Part 2 were split into two components: overloaded service transformers and new transformers (new service connections). The EIS Part 1 study modeled overloads to existing service transformers and identified either new or replacement transformers to address forecasted capacity overloads. The EIS Part 2 includes costs for both service transformer overloads and expanded the scope to include new transformers (i.e., new service connections). Overloaded service transformers correspond to $3.4B (~21%) of the secondary costs through 2040 in the EIS Part 2 Base Case, with the remaining $12.5B (~79%) of secondary costs corresponding to the new transformers added to service connections. Therefore, most of the secondary costs identified in the EIS Part 2 were not included in the scope of the EIS Part 1. To compare the EIS Part 2 and EIS Part 1, only the secondary costs corresponding to the overloaded service transformers are included in the comparisons to the EIS Part 1 results.

42 251030-public-advocates-office-distribution-grid-electrification-model-2025.pdf

43 https://gridlab.org/portfolio-item/ca-load-mgmt-standard/

Figure 12. Secondary costs in 2040 by scenario, split into two components: replaced transformers (overloaded service transformers) and new transformers (including new service connections)

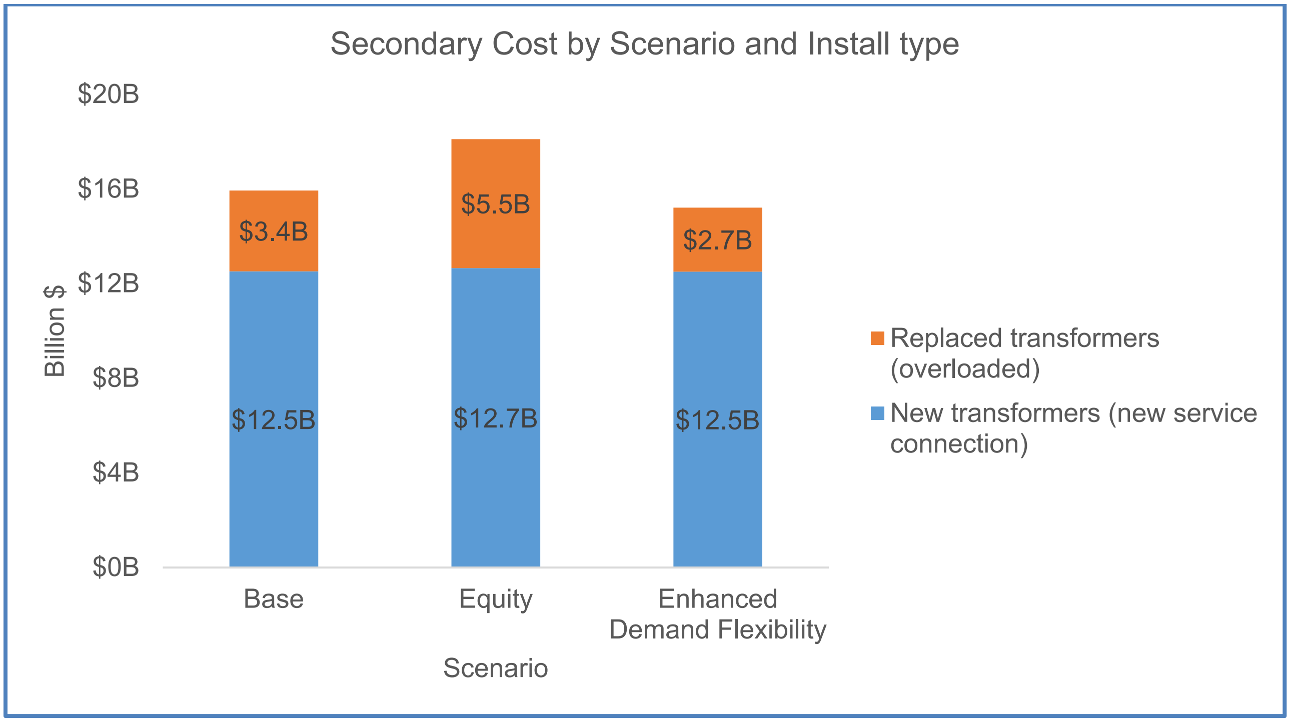


Figure 13 compares annual costs for the EIS Part 2, EIS Part 1, and PAO DGEM 2.0 studies (Base Scenarios). Annual costs are used to compare the studies because there are different study periods. The scope of the secondary costs for the EIS Part 2 includes only the overloaded transformers component to make results more comparable. The annual costs in the EIS Part 2 are similar to the DGEM 2.0 results, and both studies report lower costs than the EIS Part 1. PG&E acknowledges that this comparison is not exact, as the scope and assumptions varied between the studies as described in Section 3.3 and above.

Figure 13. Comparison of annual average costs for the EIS Part 2, EIS Part 1, and DGEM 2.0 (Base Scenarios). The scope of the secondary costs for the EIS Part 2 includes only the overloaded transformers component to make results more comparable.

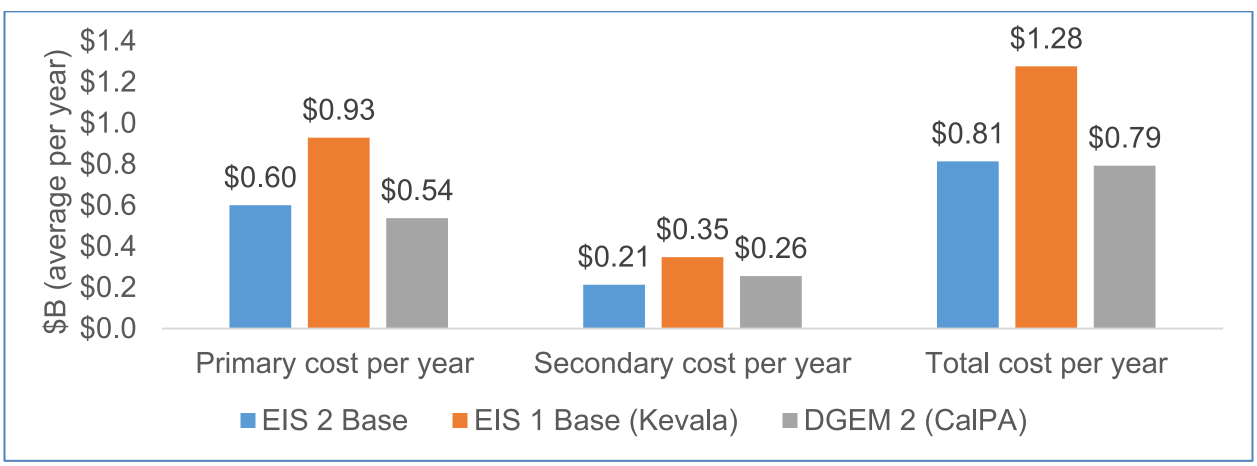
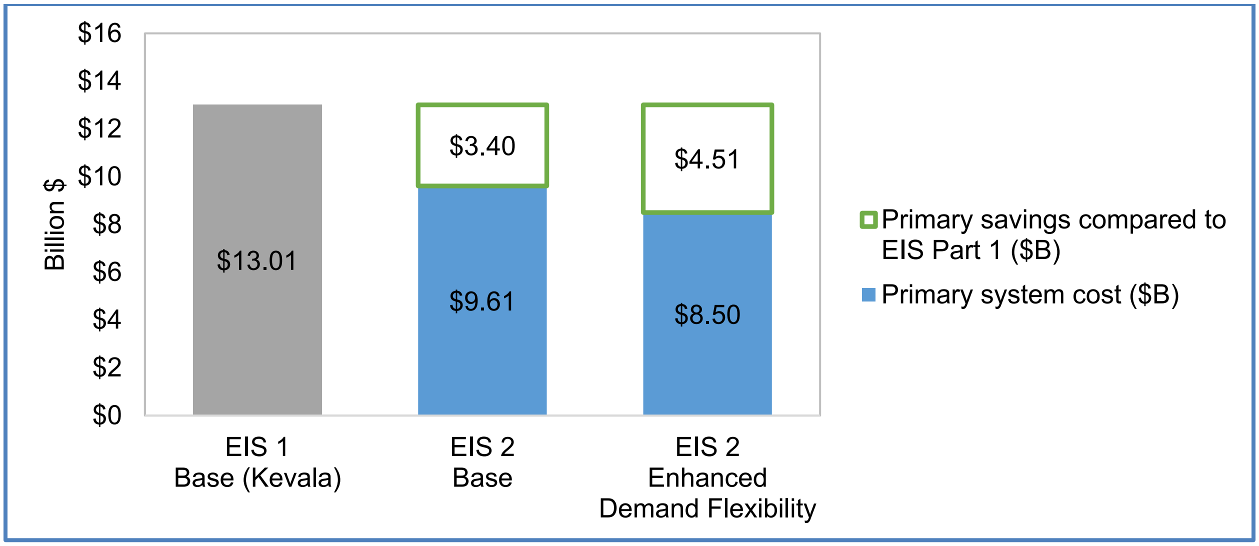


Figure 14. compares total cumulative primary costs for the EIS Part 1 Base Scenario, the EIS Part 2 Base Scenario, and the EIS Part 2 Enhanced Demand Flexibility Scenario. Even with a longer study horizon, the EIS Part 2 had lower cumulative primary costs than the EIS Part 1 (shown in green). Engineering best practices and incorporation of demand response in the Base Scenario resulted in $3.4B in primary savings in comparison to the unmitigated EIS Part 1. As described in Section 6.1.3, the Enhanced Demand Flexibility Scenario, with orchestration, achieved even further cost reductions ($4.5B less than the EIS Part 1).

Figure 14. Cumulative primary system cost comparison between EIS 1 (grey) Base Scenario and EIS 2 (blue) Base Scenario and Enhanced Demand Flexibility Scenario, with savings outlined in green.

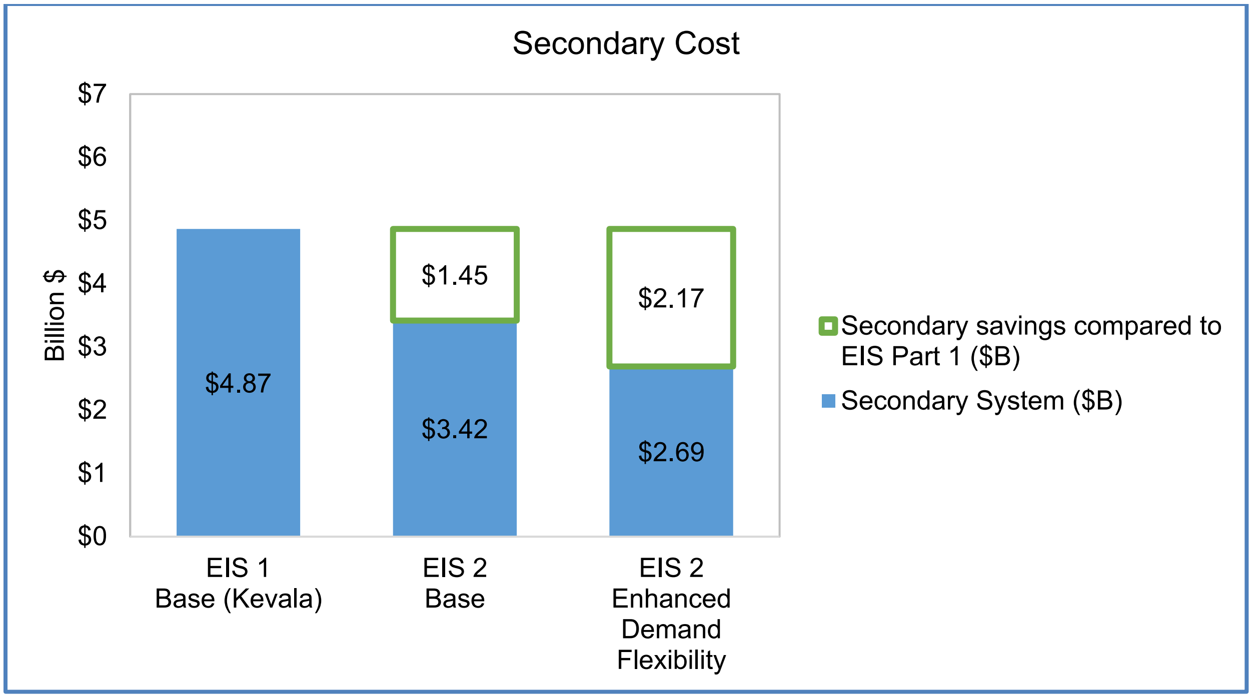


Note: EIS 2 costs are cumulative throughout the EIS 2 study period (2025-2040, 16 years inclusive), whereas EIS 1 costs are cumulative throughout the EIS 1 study period (2022-2035, 14 years inclusive)

Figure 15 compares total cumulative secondary costs for the EIS Part 1 Base Scenario, the EIS Part 2 Base Scenario, and the EIS Part 2 Enhanced Demand Flexibility Scenario. Similar to the primary results, even with a longer study horizon the EIS Part 2 had lower cumulative secondary costs than the EIS Part 1. The secondary costs for overloaded transformers in the Base (Mitigated) Scenario were $1.45B less in the EIS Part 2 than in the unmitigated EIS Part 1. As described in Section 6.1.3, the Enhanced Demand Flexibility Scenario, with orchestration, achieved even further cost reductions ($2.16B less than the EIS Part 1).

PG&E notes this is not an exact comparison as the approach to the modeling of the secondary was fundamentally different between the EIS Part 1 and EIS Part 2. Therefore, this comparison should be considered an approximation. PG&E explored the components of the secondary costs and how different modeling and investment approach might affect the results in the sensitivity analysis, described in Section 6.2.5 and in more detail in Appendix A.

Figure 15. Secondary cost comparison between EIS 1 and EIS 2. The scope of the secondary costs for the EIS Part 2 includes only the overloaded transformers component to make results more comparable.



6.2.5. Sensitivity of Secondary Costs

PG&E tested several transformer-sizing strategies to see how they affect long-term secondary system costs. Details of the secondary analysis methodology, including the sensitivities, are documented in Section 11.3.3 within Appendix A.

The sensitivities for transformer sizing strategies range from minimal sizing ("no size-up") to larger standard sizes to allow higher loading levels before replacement, including:

- **No size-up:** New and replacement transformers are sized at the minimum standard size required to meet coincident demand and loading constraints.
- **Size-up 1:** Applies a one-step size-up policy, such that all new and replacement transformers are increased by one standard size above the minimum required to serve current coincident demand.
- **Higher minimum sizes:** Enforces larger minimum transformer sizes regardless of calculated coincident demand.
- **Replacement at higher loading:** Applies a one-step size-up policy while assuming a higher maximum loading fraction (1.5). In this sensitivity, upgrades are not triggered until the loading is 1.5 times the transformer rating, effectively delaying the upgrade.

The results show $2.4B of secondary cost variation across sensitivities for the Base Scenario. Approaches that either start with larger transformers or delay upgrades until equipment is more heavily loaded generally lowered overall costs by avoiding repeated incremental replacements. For example, the “no size-up” sensitivity produces the highest costs, while the “replacement at higher loading” sensitivity produces the lowest. PG&E also validated that these costs trend with the annual count of transformers installed by sensitivity. A more detailed discussion of the methodology and results can be found in Section 11.3.3 of Appendix A.

Table 15. Secondary cost analysis sensitivities (Base Scenario)

Case Studies	Base
Case 1 - No size up	$16.3
Case 2 - Size up 1	$15.9
Case 3 - Higher minimum size	$15.9
Case 4 - Replacement at higher loading	$13.9

7. Budgeting and Implications of Resources

The EIS Part 2 estimates the distribution energization costs to meet electrification growth through 2040. However, the EIS Part 2 only includes distribution infrastructure costs. It does not include transmission and generation costs nor customer costs (e.g., panel upgrades). It also does not consider all costs necessary to achieve the mitigated Base Case or Enhanced Demand Flexibility Scenarios, such as the costs for distribution planning, service planning, orchestration tools, DERMS, nor the costs of various programs or rates to encourage electrification and load flexibility.

Furthermore, while the EIS Part 2 study will inform future distribution planning and estimates the distribution costs required for electrification, it is not equivalent to PG&E’s annual Distribution Plan nor is it intended to identify specific distribution investments.[44] Thus, the cost figures presented in the study are not immediately actionable or directly translatable into budget allocations. They represent planning-level estimates based on modeled scenarios and assumptions, and do not reflect the full scope of implementation requirements.

Regardless, the estimates from the EIS can provide directional information about the scale of the investment needed, from both a cost and resource perspective, to prepare the distribution grid to meet California’s electrification goals.

7.1. Cost Comparisons to Historical Costs

Table 16 and Table 17 provide a summary of bank, feeder, and distribution line capital costs across the scenarios compared to recent historical spending.[45] The EV Capacity Demand Sensitivity is not included in these tables because no engineering solutioning

[44] PG&E’s annual Distribution Planning (DPEP), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M576/K519/576519221.PDF
[45] PG&E GRC Ch.09 Table 9-5, 9-6

for primary was completed for the scenario (refer to 6.1.4 for details). The historical data reflects PG&E's annual electrification distribution investments from 2020-2024. Historical data is also provided for 2025 (as of October 2025), with a mix of actual and forecasted costs through the end of the year. Forecasted annual costs reflect the estimated annual costs under the three scenarios.[46]

There is a substantial increase in the forecasted costs versus historical costs, especially for bank and feeder costs. This is consistent with the recent scaling up distribution energization investment to accelerate customer energizations.[47] PG&E has scaled up its readiness and delivery work, as shown by the 2025 historical data, which is significantly increased from the 2020-2024 historical data. Distribution line section work is shorter duration than feeder and bank projects and can be scaled up quicker. As shown in Table 16, for distribution line section work, forecasted costs are similar to the 2025 historic costs (~$300M per year). This indicates that the pace of distribution line work is similar to the scaled up level of investment PG&E is currently making.

Bank and feeder projects are typically multi-year projects, so it takes longer to scale up the work on these projects.[48] PG&E has begun scaling up readiness activities associated with feeder and bank capacity work (e.g., design & estimating, permitting, etc.) to meet increasing electrification growth. For example, by the end of 2025, PG&E is forecasted to have increased readiness work by ~50% compared to 2024. This has included bulk purchasing and expanding or seeking more contracts to support work. PG&E will continue to look at these options for the future to support readiness activities.

By increasing the number of projects completing readiness activities, delivery of capacity projects in future years can continue to scale up. Table 17 shows that 2025 spend has increased to ~$190M for feeder and bank projects versus the prior years, corresponding to the increased readiness work. However, significant scaling up of investment is forecasted in the EIS (~$270M-$580M annually), consistent with the projects progressing into construction. The increase in feeder and bank forecasted costs versus historical costs indicates that the scaling up of feeder and bank readiness and construction work will need to continue to meet the needs of a high electrification future.

[46] Historical 2025 data are projected totals as of October 2025, with a mix of actuals and forecasted costs through the end of the year. The EIS includes 2025 as a study year so is included in both historical and EIS results so as to not exclude recent historical spend.
[47] Senate Bill (SB) 410 (Becker, Stats. 2023, Ch. 394) and Assembly Bill (AB) 50 (Wood, Stats. 2023, Ch. 317) required the Commission to implement directives to accelerate energization processes for customers that receive electric service from California's electric investor-owned utilities (IOUs).
[48] The majority of a project cost is often incurred during construction and thus in the latter years of a project. Therefore, even with the scaling up of readiness work for feeder and bank projects, there is a lag in that resulting in a scale up of costs until these projects are in construction.

Table 16. Distribution line average costs over time compared to historical costs ($M)

Scenario	2020-2024 Historical (Annual)	2025* Historical (Annual)	2025-2030 Forecast (Annual)	2031-2035 Forecasted (Annual)	2036-2040 Forecasted (Annual)
Historical	$158.20	$290.00	-	-	-
Base	-	-	$309.83	$284.00	$228.60
Equity	-	-	$310.17	$371.00	$373.60
Enhanced Demand Flexibility	-	-	$304.83	$162.60	$215.00

**2025 costs are projected totals as of October 2025.*

Table 17. Bank and feeder annual costs over time compared to historical costs ($M)

Scenario	2020-2024 Historical (Annual)	2025* Historical (Annual)	2025-2030 Forecasted (Annual)	2031-2035 Forecasted (Annual)	2036-2040 Forecasted (Annual)
Historical	$63.00	$189.00	-	-	-
Base	-	-	$407.17	$275.40	$273.20
Equity	-	-	$428.17	$477.80	$581.40
Enhanced Demand Flexibility	-	-	$320.67	$157.60	$414.20

**2025 costs are projected totals as of October 2025.*

7.2. Equipment Results by Scenario

Table 18 through Table 22 provides the annual number of new and replaced banks, new feeders, new and replaced conductor, and number of new projects forecasted by the EIS Part 2, compared to the historical annual rates of installation. The historical data reflects PG&E's annual count of installations from 2020-2024. Historical data is also provided for 2025 (as of October 2025), with a mix of actual and forecasted counts through the end of the year. Forecasted counts reflect the estimated counts under the three scenarios.[49]

The forecasted annual rates of installation are overall higher in the EIS Part 2 forecast than historical rates. As described in Section 7.1, PG&E has begun scaling up readiness activities associated with capacity work (e.g., design & estimating, permitting, etc.) to meet the increasing electrification growth.

The number of new feeders and new banks installed remains relatively the same throughout the 16 year period and slightly higher than the historical rate, as shown in Table 18 and Table 19.

[49] Historical 2025 data are projected totals as of October 2025, with a mix of actuals and forecasted costs through the end of the year. The EIS includes 2025 as a study year so is included in both historical and EIS results so as to not exclude recent historical spend.

Table 18. Annual number of new feeders compared to historical rates of installation

Scenario	2020-2024 Historical (Annual)	2025* Historical (Annual)	2025-2030 Forecasted (Annual)	2031-2035 Forecasted (Annual)	2036-2040 Forecasted (Annual)
Historical	13	15	-	-	-
Base	-	-	14	13	11
Equity	-	-	20	34	30
Enhanced Demand Flexibility	-	-	8	8	19

**2025 counts are projected totals as of October 2025.*

Table 19. Annual number of new banks compared to historical rates of installation

Scenario	2020-2024 Historical (Annual)	2025* Historical (Annual)	2025-2030 Forecasted (Annual)	2031-2035 Forecasted (Annual)	2036-2040 Forecasted (Annual)
Historical	2	1	-	-	-
Base	-	-	2	4	2
Equity	-	-	3	4	3
Enhanced Demand Flexibility	-	-	1	1	5

**2025 counts are projected totals as of October 2025.*

Table 20 shows the annual number of replaced banks, comparing the EIS Part 2 forecast with historical rates. While Table 19 showed a relatively stable rate of new bank installations,

Table 20 shows an increase of replacement banks to an annual rate of ~12-30 per year, versus a historical rate of ~3-4 banks per year. This is a significant scaling up of bank replacements versus the installation of new banks. This trend reflects the practical use of existing substation space and engineering judgment that prioritizes meeting future demand through bank replacements rather than new installations. Replacements typically offer a more efficient way to address the overloads while also meeting the space and construction complexities that are known within a substation.

Table 20. Annual number of replaced banks compared to historical rates of installation

Scenario	2020-2024 Historical (Annual)	2025* Historical (Annual)	2025-2030 Forecasted (Annual)	2031-2035 Forecasted (Annual)	2036-2040 Forecasted (Annual)
Historical	4	3	-	-	-
Base	-	-	15	12	13
Equity	-	-	14	26	30
Enhanced Demand Flexibility	-	-	8	8	18

**2025 counts are projected totals as of October 2025.*

It is important to note that the number of equipment upgrades does not scale based on the change in electrification or DER load. For example, the annual number of replaced banks in the Equity Scenario for 2031 onward, as shown in Table 20, is more than double the replaced banks in the Base Scenario; whereas, the Equity Scenario does not have a doubling of overall load from electrification and DERs in the Equity Scenario (as shown in Table 5). Instead, as shown in Table 5, key technologies that have substantial load impact significantly increase in the priority populations in the Equity Scenario, including nearly tripling the amount of Home L2 chargers (185% increase) and more than doubling the installations of residential cooling (119%). These technology types can have outsized impacts on peak load, leading to additional equipment upgrades even if other technologies did not increase in priority populations. Similarly, in the Enhanced Demand Flexibility Scenario, some equipment upgrade needs were cut in half, even though actual flexible load was not 50% of the total DER and electrification load.

Table 16 summarizes the annual mileage of new conductor installed in the EIS Part 2 forecast versus historical data. The forecast shows a significant increase followed by a significant decrease; however, these trends are not fully representative of actual system needs. Unlike the 2025-2030 estimates, which were derived from detailed network model solutioning in CYME, the forecast for 2035 and 2040 were developed at larger areas and do not reflect precise model-based results. Instead, mileage for these later periods was estimated using historical averages, approximately 2.7 miles of new conductor per feeder addition. Accordingly, the annual values for 2031-2035 and 2036-2040 reflect this assumption rather than detailed modeling, making comparison challenging.

Table 21. Annual miles of new conductor compared to historical rates of installation

Scenario	2020-2024 Historical (Annual)	2025* Historical (Annual)	2025-2030 Forecasted (Annual)	2031-2035 Forecasted (Annual)	2036-2040 Forecasted (Annual)
Historical	26.5	118	-	-	-
Base	-	-	162	60.5	35.6
Equity	-	-	167	91.8	81.5
Enhanced Demand Flexibility	-	-	157	20.5	50.2

**2025 counts are projected totals as of October 2025. The EIS Part 2 study did not model the miles of line section upgrades in the same way for 2031-2040, making the numbers difficult to compare.*

Table 22 provides the annual number of projects forecasted versus historical projects by scenario; however, these counts should not be interpreted as precise indicators of future work and are challenging to compare. In the EIS Part 2, multiple overload conditions are often aggregated and represented as a single project. In practice, resolving these overloads may require several distinct projects, including additional line work and substation upgrades. For 2026-2030, many listed projects already have active PG&E project order numbers, reflecting realistic near-term activity. However, for 2031-2035 and 2036-2040, the counts are based only on the number of banks and feeders, which understates the complexity (and thus the count of projects) of actual implementation because typically, these projects are broken out into many different phases and components. Therefore, this difference may be attributable simply to a difference in how projects are counted.

Table 22. Annual number of projects compared to historical rates of project completion

Scenario	2020-2024 Historical (Annual)	2025* Historical (Annual)	2025-2030 Forecasted (Annual)	2031-2035 Forecasted (Annual)	2036-2040 Forecasted (Annual)
Historical	81	103	-	-	-
Base	-	-	117	30	26
Equity	-	-	121	63	63
Enhanced Demand Flexibility	-	-	111	17	41

**2025 counts are projected totals as of October 2025. The counting of projects in the EIS for 2031-2040 is not the same as historical, making the numbers difficult to compare.*

Table 23 provides the annual number of transformers forecasted versus historical by scenario. For the secondary system, the rate of transformers installed in EIS 2 relatively increases from historical installations due to the electrification modeled in the IEPR. The historical counts from the GRC include transformers in the SB410 categories of new business, WRO, and capacity and is not inclusive of all the programs of which transformers may be used or installed for[50].

Table 23. Annual number of transformers installed*

Scenario	2020-2024 Historical (Annual)	2025* Historical (Annual)	2025-2030 Forecasted (Annual)	2031-2035 Forecasted (Annual)	2036-2040 Forecasted (Annual)
Historical	10,841	14,609	-	-	-
Base	-	-	19,966	17,713	18,055
Equity	-	-	25,914	19,581	19,184
Enhanced Demand Flexibility	-	-	19,865	17,167	17,310

* The Base, Equity, and Enhanced Demand Flexibility annual transformer counts exclude the approximately 60,000 overloaded transformers that were identified for replacement prior to 2025 and this study. Although these replacements are included in the total cost estimates, they are removed from this table to present a more accurate comparison of typical annual installation volumes across the scenarios for year-to-year comparison.

Table 24 shows the cumulative breakdown of overloaded transformers (capacity upgrades) compared to the new transformers built to support load growth where rerouting load to nearby existing transformers wasn't possible. The new transformers dominate the mix for each scenario, ranging from 70% to 80% of total installs by 2040.

Table 24. Overloaded versus new transformers installed by scenario, cumulative by 2040*

Scenario	Overloaded transformers	New transformers
Base	74,500	287,000
Equity	116,000	295,000
Enhanced Demand Flexibility	67,500	287,000

**Rounded to the nearest 500*

7.3. Economic, Material and Resource Considerations

PG&E recognizes that a range of economic factors may influence costs and material and resource constraints rates over the study period. Historical experience during the COVID-19 pandemic demonstrated how global competition and supply chain disruptions can significantly impact material costs and availability. For example, PG&E faced extended lead times and procurement challenges for critical assets such as transmission transformers and circuit breakers.

To mitigate similar risks in future planning cycles, PG&E is leveraging lessons learned from the pandemic by implementing a proactive bulk procurement strategy. This involves securing long-lead materials in advance of engineering milestones. This approach also aligns with PG&E's broader asset management strategy, which

[50] GRC 2027-2030 Exh04 Ch10 – Workpaper Table 10-34 and Workpaper Table 10-36

integrates Capacity, Electric Generation Interconnection (EGI), Large Load, and Asset Health programs.

8. Downward Pressure on Distribution Rates

The EIS Part 2 includes an assessment of the potential impact of electrification load growth on the distribution component of electric rates. The annual Revenue Requirement (RRQ) from electrification infrastructure investment was compared to the offsetting revenue enabled by the increased customer energization load.

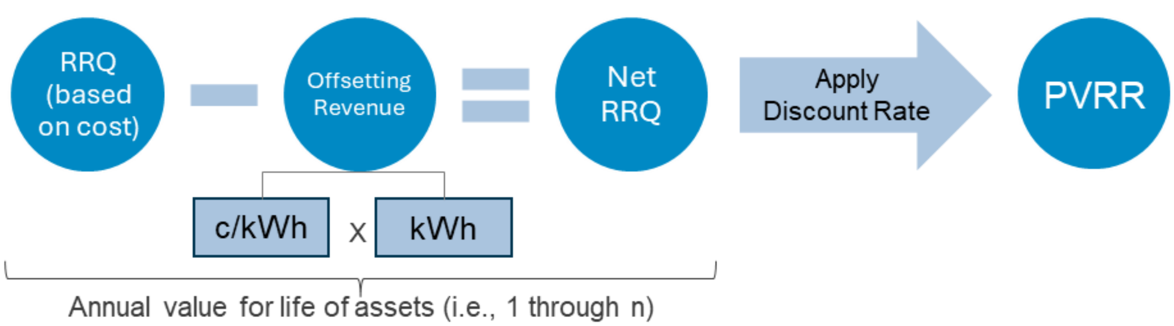
The analysis indicates that electrification may provide a near-term rate increase due to capital outlays that are then offset by sustained revenue growth from increased energization, indicating long-term value from energization investments. Results for the Base (Mitigated) Scenario show a small upward pressure on the distribution component of rates (~1.6%) in the near term followed by downward pressure from 2032 onwards, with a downward pressure on distribution rates of as much as ~25% by 2040.[51] This analysis only considers the distribution component of electric rates and therefore any generation, transmission, or wildfire safety costs or uncertainties are not included nor assessed.

8.1. Downward Rate Pressure Calculation Methodology

Figure 16 illustrates the methodology of the assessment of the potential impact of electrification load growth on distribution rates. The annual RRQ from electrification infrastructure investment was compared to the offsetting revenue enabled by the increased customer energization load.

The scope of the EIS Part 2 is solely distribution energization investments and does not include other infrastructure costs (e.g., safety, reliability, etc.). Therefore, the analysis in the EIS Part 2 is not a rate forecast, instead it is solely assessing the potential impact of electrification distribution investments and corresponding load growth.

Figure 16. Illustration of downward rate pressure calculation methodology



The RRQ was calculated based on the capital expenditures for the primary and secondary infrastructure costs described in Section 6.1.1, leveraging PG&E's Mini-RO

[51] The ~25% downward rate pressure reflects the downward rate pressure solely on the distribution rate, which is only a portion of customer's overall costs for electricity service.

model.[52] The RRQ also incorporated increased Operations and Maintenance (O&M) expense costs associated with the infrastructure investment.[53]

The analysis focused solely on incremental distribution costs and offsetting revenues from electric distribution rates, excluding both revenues and costs from transmission, generation, and other rate components. As the study excludes both offsetting revenues and costs for transmission, generation, and customers (e.g., panel upgrades and fuel substitution), the study does not include the full impact of electrification on customer affordability, nor does it provide a rate forecast. Furthermore, the scope of EIS Part 2 solely includes incremental distribution energization investments and does not include other incremental infrastructure costs (e.g., safety, reliability, etc.) that may be associated with the incremental load growth. Lastly, the analysis only includes incremental costs and revenues, it does not examine existing infrastructure nor the cost to maintain and operate the current load on the grid, or its corresponding revenues. PG&E does anticipate that electrification would result in additional transmission costs as well as additional transmission revenue[54] but cannot attest to the impact on the transmission component of electric rates; however, interested parties could complete a similar analysis to understand the impact. PG&E also acknowledges that additional generation would be required to serve the increased electrification growth. The impact on generation rates would be dependent on the marginal cost of generation, which is not examined in EIS Part 2, but rather in the Integrated Resource Plan proceeding.

Offsetting revenue was calculated based on the incremental net load growth enabled by the distribution electrification investments, based on the 2023 CEC IEPR Local Reliability Scenario Managed Sales Forecast for the PG&E Service Area (Managed Sales Forecast). The net load growth has removed line losses. The incremental net load growth is modeled from 2025-2040, corresponding to the study period. The rate pressure analysis extends through 2055 to reflect the fact that the RRQ and Offsetting Revenue continue beyond 2040. The analysis assumes no further distribution electrification investment nor any load growth beyond 2040, excluding any future load growth that may be enabled by the electrification investments (i.e., excluding growth enabled by additional capacity). The analysis calculated offsetting revenue by customer

[52] The assessment assumes assets are depreciated based on the adopted book depreciation rate of 3.78% from the 2023 GRC Final Decision and that the service life of new assets extends throughout the study period.
[53] The assessment used the O&M Loader Factors from PG&E's Prepared Testimony in its active 2023 GRC Phase II application (A.24-09-014, Exhibit (PG&E-2), Chapter 9). Although a share of modeled investments is the replacement of existing assets and thus unlikely to increase O&M costs, PG&E conservatively assumes that all capital investments carry incremental O&M costs to avoid undercounting ongoing expenses.
[54] The Transmission Planning Process (TPP) analyzes Transmission load growth and required infrastructure costs. The TPP is aligned with the DPP in regard to the IEPR Vintage and Scenario used for studies, thus making it reasonable to assume that additional costs and associated revenue as seen in the analysis done for EIS 2 would be seen in any similar Transmission analysis.

class[55] by multiplying the energy usage from the incremental net load growth (in kWh) times the corresponding customer class distribution rate. The average distribution rates per customer class were assumed to remain flat over the entire study period.

For the analysis on the Equity Scenario, the incremental net load growth from the Managed Sales Forecast was scaled by customer class proportionate to the change in the load forecast that reflected the increase in technology adoptions in priority communities.[56] Additionally, in the Equity Scenario, all incremental residential load was separated from the base residential load and a discounted distribution rate, modeled after CARE rates, was used in the offsetting revenue calculation.[57]

8.2. Downward Rate Pressure Calculation Results

Results for the Base (Mitigated) Scenario indicate electrification growth may provide downward pressure on distribution rates by as much as 25% by 2040. Results for the Base (Mitigated) show little impact on distribution rates in 2030, with an increasing downward pressure on distribution rates as electrification growth increases through 2040. Table 25 shows the results of impact on electrification on distribution rates for the Base (Mitigated) Scenario. The RRQ for 2030, 2035, and 2040 is calculated based on the distribution energization investments identified in Table 10 using the methodology described above. The annual offsetting revenue is based on the incremental net load growth and offsets the incremental RRQ to give the Net Annual RRQ for 2030, 2035, 2040. The Rate Pressure is a simplified approximation of the percentage impact on the average distribution component of electric rates calculated by dividing the Revised Average Distribution Rate by the Current Average Distribution Rate.[58] A Net Present Value Revenue Requirement (PVRR) in 2025 dollars is calculated by applying a Discount Factor of 7% to the Net RRQ.[59]

The analysis indicates long-term value from electrification, with near term capital outlays offset by sustained revenue growth from increased energization. By examining the distribution costs to connect this load and associated revenues in isolation, this analysis indicates that distribution revenues billed to these customers would exceed the incremental revenue requirement over the long term, placing downward pressure on distribution rates. Results for the Base (Mitigated) Scenario indicate electrification

[55] Customer classes included Agricultural, Commercial, Commercial EV (BEV), Industrial, Residential and Streetlight. The sectors “Mining” and “Transportation, communications, & utilities” (TCU) from the IEPR Managed Sales Forecast were incorporated into the Industrial and Commercial customer classes, respectively.
[56] This was done to ensure consistency in the basis of the offsetting revenue calculation across scenarios.
[57] A discount of 35% was applied to the average distribution component of residential electric rate as a simplified approach. In reality, the CARE rate calculation is more complex and considers many factors. For more information on CARE, please see https://www.cpuc.ca.gov/consumer-support/financial-assistance-savings-and-discounts/california-alternate-rates-for-energy.
[58] As of September 1, 2025, the system average distribution rate is about 14 cents per kilowatt-hour as implemented via Advice Letter 7684-E.
[59] D.24-10-008 Phase 2 Cost of Capital Proceeding.

growth may provide downward pressure on distribution rates by as much as 25% by 2040. The 25% downward pressure on distribution rates by 2040 in the Base Case corresponds to a decrease of ~3.3 cents per kilowatt hour (kWh) in distribution rates. Furthermore, the electrification investments show a Net Present Value (NPV) through 2055 of ~$14.2B, with near-term capital outlays offset by sustained revenue growth from increased energization, indicating long-term value of energization investments.

Table 25. Results: Downward distribution rate pressure for Base (Mitigated) Scenario

Year	2030	2035	2040
Annual Revenue Requirement (RRQ) [$B]	$1.5	$2.7	$3.4
Annual Offsetting Revenue [$B]	$1.3	$3.7	$6.1
Net Annual RRQ [$B]	$0.2	($1.1)	($2.6)
Rate Pressure (%)	1.6%	(10%)	(25%)
Net Present Value (NPV) through 2055 [$B]	**$14.2**		

Table 26 shows downward distribution rate pressure results for the three scenarios examined (Base, Equity and Enhanced Demand Flexibility).[60] The overall finding is the same across all scenarios; there is a potential downward pressure on the distribution component of electric rates by 2040. Due to the substantial increase in the forecasted electrification load in the Equity Scenario,[61] the offsetting revenue covers incremental RRQ starting in the first year of the analysis thus there is no near-term increase in the distribution rates, as seen in the other two scenarios.

Results for the Enhanced Demand Flexibility Scenario are similar to the Base (Mitigated) Scenario over the long term, but there is slightly less upward pressure on distribution rates in the short term. In 2030, the Enhanced Demand Flexibility scenario reduces distribution rate the near-term upward distribution rate pressure by 0.5% (from 1.6% to 1.1%) by 2030 and by 3% by 2035 compared to the Base (Mitigated) Scenario. The same Managed Sales Forecast is used to calculate the offsetting revenue in this scenario, making the decrease in capital expenditures[62] the only changed variable. As the Enhanced Demand Flexibility Scenario did not include the costs associated with implementing and orchestrating load management, the EIS Part 2 does not evaluate the cost effectiveness of the enhanced orchestrated demand flexibility nor its total impact on distribution rates.

[60] PG&E did not perform an analysis of the EV Capacity Demand Sensitivity because the study focused on the secondary costs only, as explained in Section 5.4

[61] The Equity Scenario forecast assumes significant policy changes and the formula to calculate the increase in adoption does not represent current policy. PG&E does not claim that the Equity Scenario is likely to occur under current conditions, and it is unclear how the scale of increased adoption shown in the scenario would be achieved.

[62] See Figure 14 for primary system cost savings in Enhanced Demand Flexibility Scenario

Comparing results across all scenarios indicates that the incremental electrification load and its offsetting revenue is the primary factor in the downward distribution rate pressure, not the distribution infrastructure costs and corresponding RRQ.

Table 26. Results: Downward distribution rate pressure by scenario

		2030	2035	2040
Net RRQ [$B]	Base (Mitigated)	$0.2	($1.1)	($2.6)
	Equity	($1.2)	($2.5)	($3.6)
	Enhanced Demand Flexibility	$0.1	($1.4)	($2.8)
Rate Pressure (%)	Base (Mitigated)	1.6%	(10%)	(25%)
	Equity	(11%)	(23%)	(34%)
	Enhanced Demand Flexibility	1.1%	(13%)	(26%)
Net Present Value (NPV) through 2055 [$B]	Base (Mitigated)	**$14.2**		
	Equity	**$29.1**		
	Enhanced Demand Flexibility	**$16.1**		

The finding that electrification load growth may provide a downward rate pressure on distribution rates is consistent with PAO's analysis in the August 2023 DGEM Study and Report.[63] The 2023 DGEM study highlighted that varying project costs, specifically for PG&E, could result in a slight upward pressure on rates.[64] Furthermore, PG&E's downward rate pressure calculation for the Base Case in 2040 (~3.3 cents per kWh) is similar to PAO's 2025 DGEM study which found that "…electrification may cause downward pressure on electric rates of approximately 3 cents per kilowatt hour (kWh) varying by year, IOU, and scenario."[65] However, the EIS Part 2 analysis found that project costs were not the main driver in impact on rates. Additionally, the DGEM rate impact analysis was limited to residential rates as well as included generation and transmission costs and rates. Despite those differences, the key takeaway remains aligned with these results.

9. Key Takeaways and Insights into Distribution Planning

The EIS Part 2 serves as a strategic reference for long-term planning. While the results provide valuable insights into infrastructure costs under various scenarios, the EIS is not generally intended to prescribe specific projects. New projects and modifications to existing projects identified in this study, especially those beyond 2030, will require more detailed engineering analysis before they can be considered for implementation or investment. Engineering solutioning for the 2031-2040 period was intentionally kept broad due to the timing of the study and assumption that forecast models are less

[63] CalPA 2023 DGEM Study, ES-1 230824-public-advocates-distribution-grid-electrification-model-study-and-report.pdf
[64] CalPA 2023 DGEM Study, page 36. Table 3-5 Rate impacts across cost scenarios.
[65] CalPA 2025 DGEM Study, page 14, 251030-public-advocates-office-distribution-grid-electrification-model-2025.pdf

accurate farther in the future, instead relying on the expertise of PG&E engineers to develop the best high-level estimates. However, a number of learnings from the EIS Part 2 can be incorporated into PG&E's Planning processes.

9.1. Equity in Distribution Planning

The EIS Part 2 Equity Scenario provides lessons learned for PG&E's DPEP, including informing equity metrics and PG&E's community engagement plans and tools.

Equity metrics for distribution planning are currently being developed jointly with Energy Division and other IOUs as part of the High DER proceeding, formally established under CPUC Rulemaking R.21-06-017. The intention of this proposal (Equity Metrics) is an annual evaluation of equity in distribution planning and does not involve modifying the planning process based on equity considerations.[66] Subject to the outcome of that Advice Letter submittal, PG&E will publish the adopted Equity Metrics and data annually starting with the 2026-2027 Distribution Planning and Execution Process cycle.

The EIS Part 2 Equity Scenario will inform the equity metrics by providing context that it is the amount of electrification and DER adoption that is the primary driver of the identification of distribution investment needs. The EIS Part 2 Equity Scenario scaled up electrification and DER adoption in disadvantaged, low-income, and Tribal communities and thus has an overall higher level of electrification and DER adoption than the Base (Mitigated) Scenario, and the increase in distribution infrastructure costs is consistent with the corresponding increase in electrification load. This would indicate the amount of electrification and DER adoption, influenced by state policy and customer adoptions, is the primary driver of the amount of distribution investments identified. Furthermore, changes to state policy and customer adoption patterns would result in changes to PG&E's DPEP forecast, and by extension change the investments identified. Therefore, the amount of distribution infrastructure is expected to be consistent with the corresponding amounts of electrification load forecasted, as reflected in the Equity Metrics.

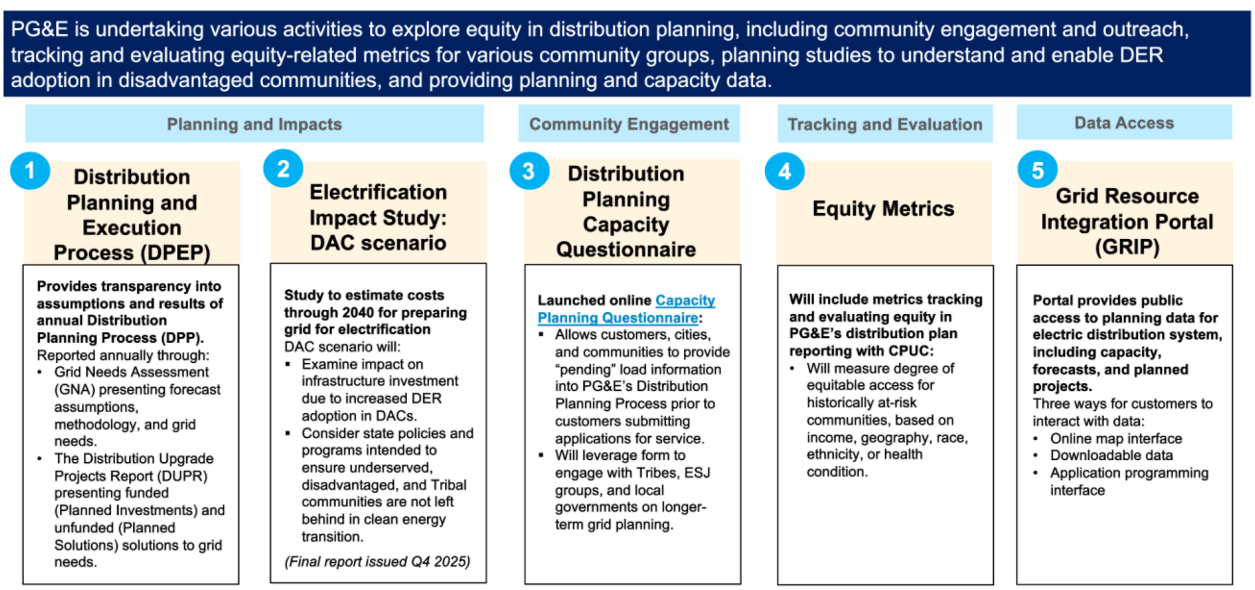
In addition to the Equity Metrics in development, PG&E submitted an annual Community Engagement Plan on May 1st, 2025, to address equity and incorporate feedback into the Distribution Planning and Execution Process (DPEP). PG&E's 2025 Community Engagement Plan aims to provide transparency and outlines how PG&E plans to conduct engagement to incorporate relevant community feedback that can inform PG&E's annual DPEP. This feedback will be gathered through various engagement efforts from internal PG&E groups, including, but not limited to PG&E's Business Energy Solutions (BES) team, Local Government Affairs (LGA) team and Tribal Community Engagement team.

[66] Decision 24-10-030, page 123.

The EIS Part 2 Equity Scenario will also inform the Community Engagement Plan. The Community Engagement Plan leverages the Capacity Planning Questionnaire to allow customers, cities, and communities to provide Pending Load information, which in turn impacts the identification and implementation of distribution investments. The findings from EIS Part 2 show the amount of electrification and DER adoption, influenced by state policy and customer adoptions, are the primary driver for the amount of distribution investments. This is consistent with the intended use of the Capacity Planning Questionnaire, which is designed to capture Pending Load information so that customer, city, and community electrification and DER adoption can be accurately reflected in PG&E's DPEP forecast. Furthermore, the finding that the Equity Scenario still provides a downward rate pressure on distribution rates indicates to the extent policy and customer behavior results in increased electrification, that there is potential for long-term affordability benefits from energization investments.

Figure 17 summarizes the tools and processes used to support communication with various customer groups.

Figure 17. PG&E community engagement tools for the DPP



9.2. Load Factor and Impact on Capacity

Load factor, defined as the ratio of average load to peak load over a given time period (typically a peak day time period), is a key metric in calculating thermal capacity. For the purposes of the EIS Part 2 Study, load factor is defined as:

Daily load factor = Average kW for the peak day / Peak kW for the peak day

PG&E currently assumes a default 75% load factor for its primary distribution system, with facilities generally sized using a 75% load factor assumption. However, the impact of load factor is equipment specific, and there is no simple rule for determining an "ideal" load factor.

Load factor influences the capacity rating and operational flexibility of grid equipment.[67] Higher load factors mean equipment operates closer to its maximum capacity for longer durations, which increases thermal stress. This requires a lower rating of transformers and conductors to essentially maintain asset health and reliability. A high load factor also indicates a reduced margin for outages and less flexibility for maintenance or emergency operations, which can impact reliability and safety.

As an example, Table 27 shows the impact of load factor on cable ratings for three different aluminum cable with 2 circuits in the same trench.[68] This example shows the decrease in rating with increasing load factor, indicating that an upgrade could be triggered at a reduced loading at higher load factors. Therefore, higher load factors reduce the rate of equipment cooling throughout the day and will affect how PG&E evaluates and rates its equipment. In particular, service transformers and underground distribution lines will be directly impacted as the ratings are based on load factor assumptions.

Table 27. Example of impact of load factor on equipment ratings

Aluminum Cable Sizes (AWG or kcmil)	Daily Load Factor & Rating in Amps		
	50%	75%	100%
1/0	195A	175A	157A
600	524A	458A	401A
1100	715A	615A	534A

As summarized in Table 28, the EIS found that the average load factor for feeders remains relatively consistent over the study period at ~69%. This indicates that the investment in electric distribution primary feeders offsets the increasing electrification load with respect to load factor.

Table 28. Average load factor for feeders for the Base and Enhanced Demand Flexibility Scenario in 2030, 2035, and 2040

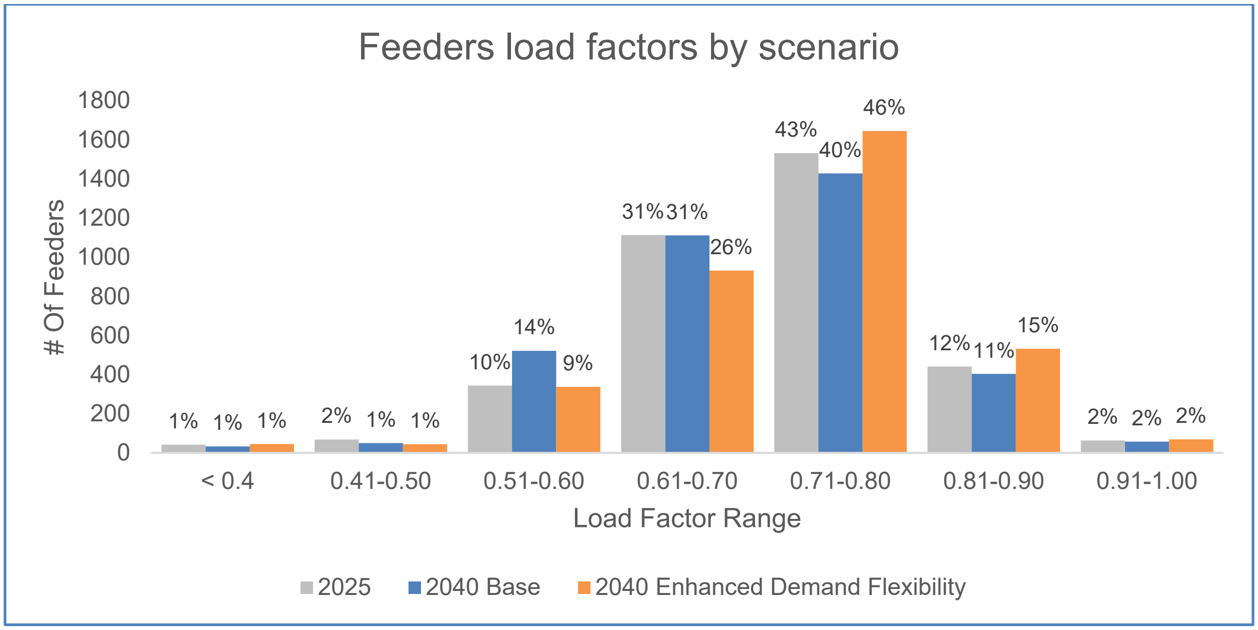
Scenario	2030	2035	2040
Base	68.9%	68.2%	68.8%
Enhanced Demand Flexibility	69.7%	70.1%	70.8%

Figure 18 shows the distribution of load factors for feeders for the Base Scenario and Enhanced Demand Flexibility Scenarios in 2040. For the Base Scenario, there are nearly 500 feeders exceeding an 80% load factor. The Enhanced Demand Flexibility

[67] Like an incandescent light bulb, equipment heats up when current passes through it. In order for equipment to cool, the rate of temperature decrease must be lower than the rate of temperature increase. This happens naturally in the distribution system as loads fluctuate throughout the day. PG&E uses the maximum daily load factor over the year to establish ratings for equipment like underground distribution lines commonly referred to as cable and service transformers.
[68] Two circuits in one trench is the most common arrangement in the PG&E system.

Scenario showed a further increase in load factors, with ~600 feeders exceeding an 80% load factor. The increase in load factors is consistent with increased asset utilization and lowered peak demand enabled by load management.

Figure 18. Distribution of load factors for feeders (in 2040) for the Base Scenario and Enhanced Demand Flexibility Scenario



While the Enhanced Demand Flexibility Scenario showed that the use of load flexibility can reduce the peak loading of equipment via the shifting of load between hours of a day, it can also increase the load factor which may require a rating reduction. For example, if the use of load flexibility shifted load and increased the load factor from 75% to 95%, a cable previously rated for 615A would experience a ratings reduction of 65A. The change would impact the net feeder rating level, where distribution cable is a common limit to feeder capacity ratings. In this example, the distribution feeder has a typical limit of 600A. A change in cable rating (due to the 95% load factor) down to 550A would thus limit the feeder rating to 550A. The net feeder rating limit would thus decrease from 600A to 550A, a reduction in capacity by ~8.3%. As a result, the use of demand flexibility may require the reassessing of equipment sizing standards and planning assumptions under evolving load profiles.

The EIS did not examine the impact of high load factors on distribution investment needs, nor did it include costs associated with changes in the associated ratings or loss of operational flexibility. The potential for high load factors indicates a need to incorporate this consideration into distribution planning and the orchestration of load flexibility to ensure the affordability benefits of increased asset utilization are realized.

9.3. Average Bank Headroom Decreases Over Time

Table 29 provides the average bank headroom for 2030, 2035, and 2040 for all scenarios. Headroom is the available capacity, calculated by subtracting the load on the equipment from the rated thermal capacity. The average bank headroom decreases over time in all scenarios. A decreasing headroom indicates a reduced margin for outages and less flexibility for maintenance or emergency operations, which can impact reliability and safety. The decrease in average headroom is consistent with increased asset utilization enabled by electrification growth. The EIS did not examine the potential impacts of this decrease in average headroom on grid operations and may be an area of future study.

Table 29. Bank average headroom (MW) - summer / winter

Scenario	2030	2035	2040
Summer			
Base	9.2	7.9	5.5
Equity	11.1	8.4	5.0
Enhanced Demand Flexibility	11.3	10.0	7.7
Winter			
Base	19.2	16.7	12.9
Equity	19.6	14.5	9.1
Enhanced Demand Flexibility	20.1	17.2	13.0

9.4. Incorporation of EIS Part 2 Learnings into Distribution Planning Tools

Furthermore, PG&E intentionally approached the EIS Part 2 to allow for direct application of learnings into its tools. By working with E3 and Integral Analytics, PG&E was able to both execute the EIS study and create forecast inputs that are compatible with our current forecast modelling approach in the distribution planning process. Key inputs like spatial adoption potential and propensities were created with the intent to use in the 2025-2026 distribution forecast. These inputs will support improved forecasting of electric vehicles, fuel substitution, energy efficiency, photovoltaic, and battery storage growth models. Additionally, expansions to the profile shape library have already been applied to the distribution models for planning for known loads. Electric vehicle charging shapes used in the EIS were made available for selection to distribution engineers in October of 2025. Full integration of the new shapes in the spatial forecast will be completed by December of 2025. The light duty electric vehicle shape improvements include replacement of the residential level 1, residential level 2, public level 2, workplace level 2, public DCFC, rural corridor DCFC. The medium/heavy duty shape improvements include the additions for medium duty depot DCFC, heavy duty depot DCFC, medium/heavy duty highway DCFC, and school bus DCFC. The fuel substitution shape set was rebuilt to isolate growth subcategories residential cooling, residential heating, residential general (everything besides heating and cooling), commercial cooling, commercial heating, commercial general (everything besides heating and cooling).

The EIS Part 2 had an extended planning horizon (16 years) beyond the current distribution planning process, which was 5 years for feeders and banks in the 2024-2025 DPP cycle. In order to complete cost estimates out to 2040 for the EIS Part 2, new processes and tools were created to estimate costs further out in time. The developments and experience will help PG&E extend the planning horizon to 10 years in the 2025-2026 DPP cycle. Furthermore, the engineering plans developed in the EIS will remain available for distribution engineers to review as they begin the next DPP cycle.

9.5. Incorporation of Learnings from Enhanced Demand Flex Scenario into Distribution Planning

The EIS Part 2 Enhanced Demand Flexibility Scenario also provided key learnings for future planning. The EIS Part 2 served as a testing ground for how to model increasing load flexibility. The Enhanced Demand Flexibility Scenario highlighted the role of orchestration in lowering infrastructure costs and clarified how those impacts should shape both planning approaches and the future expectations for load flexibility, informing PG&E's DPEP, community engagement, and project prioritization. The EIS Part 2 study demonstrated the importance of considering the specific amount of load shifted, the timing of being shifted, and the corresponding orchestration needs at the secondary, primary, and system levels.

The EIS Part 2 will directly inform PG&E's EPIC 4.08 project[69], which is developing methods of modeling load flexibility for use in distribution planning. The EPIC 4.08 project will create load flexibility load shapes and classes that will facilitate the building of load flexibility directly into the forecast. These new load shapes and classes will then be directly incorporated into the distribution forecast and planning tools, to be implemented starting with the 2027-2028 DPEP cycle, highly dependent on the outcome of the CEC's work to introduce load flexibility modifiers into the IEPR. The CEC's work to introduce load flexibility modifiers will similarly unfold over multiple iterations, with extensive back-and-forth, refinement, and adjustment. Developing accurate and actionable load flexibility inputs is an evolutionary process, and it will take time for these methods to stabilize and fully integrate into planning practices. As load flexibility evolves with changing state policies, customer adoptions, and utility management and operations (e.g., DERMS), the shapes and classes, and use of the shapes and classes in the forecast, will be updated as part of the annual DPEP process. Therefore, although PG&E is preparing for implementation beginning with the 2027–2028 DPEP cycle, the actual starting point may be affected by the timing and outcomes of the CEC's iterative development of load flexibility modifiers.

[69] EPIC 4 Public Workshop - January 16, 2024

Table 30. Demand Flex Proposed Schedule

D-Flex Schedule	
Model flexibility of loads within existing shapes	Current State
EIS Part 2 Final Report	January 2026
EPIC 4.08: Load Flexibility Track	Q4 2026
Incorporate new load flexibility shapes and classes into planning tools	Q4 2027
Incorporate new load flexibility shapes and classes into the DPEP forecast (depending on CEC IEPR updates)	2027-2028 DPEP Cycle
Update forecasting of load flexibility to reflect current state policy	Annual DPEP Cycle

9.6. Incorporation of Learnings from Secondary Planning

The EIS Part 2 represents a first of its kind, data-driven evaluation of secondary service planning and costing, establishing a foundational framework to optimize secondary investments to serve load energizations. It also demonstrated the significant investment in the secondary system and indicates that the planning is highly dependent on the geographical and electrical mapping of the secondary system. Accordingly, PG&E sees a critical need to further advance secondary system mapping, modeling, and planning efforts so that future planning can more accurately represent secondary-level conditions and guide investment decisions. The EIS Part 2 can serve as a foundation for PG&E to explore how it can improve and optimize planning of the secondary system to meet a high electrification future.

9.7. Incorporation of Scenario Planning into DPEP

As part of CPUC Rulemaking R.21-06-017, scenario planning can benefit planning for a variety of assumptions around electrification, DER adoption, and demand flexibility. The EIS Part 2 helped PG&E test this concept by considering a range of scenarios and how each scenario might inform the solutioning to meet customer needs.

Although the EIS Part 2 methodology treated each scenario as a distinct case to evaluate cost differences, the scenario-based process revealed that many solutions are applicable across multiple scenarios, with the primary differences being the scale or timing rather than the type of upgrade. For example, several substations and circuits required similar mitigation approaches across scenarios, such as sizing a larger bank or adding additional feeders in areas with high electrification or concentrated equity needs. In these cases, the core engineering solution remained the same; only the magnitude of the investment changed depending on the scenario’s adoption assumptions.

This learning can inform how scenario-based planning can most efficiently be performed under R.21-06-017. The tools, processes, and insights developed through EIS Part 2 have improved PG&E's readiness to evaluate and design solutions that work across multiple plausible scenarios. It has also informed PG&E as to where flexible or scalable solutions can be deployed and where scenario-specific approaches may still be required.

9.8. Incorporation of Learnings from EV Capacity Demand Sensitivity into DPEP

The EV Capacity Demand Sensitivity produces an additional $1.7 billion in secondary costs relative to the Base Scenario, which results from a forecast that is unconstrained by IEPR-forecasted energy demand and may more accurately model localized distribution grid capacity demand from transportation electrification. This indicates that the system level IEPR-forecasted energy demand may not be fully capturing the local port-level capacity demand from TE on the secondary distribution grid. Demand-based forecasting of TE may be more appropriate in distribution planning than energy based forecasting and allows for better comparison to actual TE adoption.

The EV Capacity Demand Sensitivity uses an effective vehicle-to-port ratio across the forecast years by applying the annual vehicle-to-port ratio in a given year to the IEPR-forecasted vehicle stock growth and summing the year-over-year port growth. PG&E believes this approach may help balance the risk of over forecasting charging infrastructure needs in the near term (by assuming fewer vehicles per port) with the risk of under forecasting charging infrastructure needs in the long term (by assuming more vehicles per port). PG&E will consider ways to integrate this approach in future DPEP cycles.

As deployment of higher-powered public DCFC charging sites is expected to increase, along with variations in the rate of deployment of different charger power levels, there may be a need in future DPEP cycles to vary the load shapes for those charging segments. This was tested in the EV Capacity Demand Sensitivity and PG&E will continue to monitor the public charging market. As new trends emerge in product development and deployment, PG&E will consider the merits of applying different EV load shapes for different years in the forecast, balanced against timing and resource needs.

The EV Capacity Demand Sensitivity will inform PG&E's use of Pending Loads by illustrating how transportation electrification can create localized load patterns that may not be reflected in the IEPR system level forecast. Because TE adoption can cluster in specific neighborhoods, corridors, or commercial centers, the resulting load growth may exceed what a system-level forecast assigns to those areas. In these cases, EV-driven growth may align more closely with Pending Loads based on customer-initiated or community-initiated developments that require proactive planning. By evaluating where these TE loads may emerge, the EV Capacity Demand Sensitivity informs PG&E's approach to evaluating and incorporating Pending Load into the DPEP, ensuring that distribution investments align with real-world electrification demand.

The reconciliation methodology tested in the EV Capacity Demand Sensitivity may also have applications in future DPEP cycles. In the EV Capacity Demand Sensitivity, capacity demand from known loads was converted into ports based on the assumed kW peak per port and subtracted from the forecasted spatial port growth, as opposed to the energy-based, IEPR-constrained reconciliation method used in developing the Base forecast. PG&E believes this demand-based reconciliation method may more accurately capture expected localized capacity demand.

The EV Capacity Demand Sensitivity is based on the Base (Mitigated) Scenario and does not include Enhanced Demand Flexibility. As learnings from the Enhanced Demand Flexibility Scenario are incorporated into the DPEP as described in Section 9.5, they will similarly be incorporated into modeling of TE. As part of the exploration of how to improve modeling of TE, the incorporation of TE specific demand flexibility will need to be included, and potentially scaled, accordingly. Therefore, the increased distribution costs associated with the sensitivity have the potential to be mitigated via orchestrated TE demand flexibility.

10. Conclusion

PG&E's EIS Part 2 demonstrates that widespread electrification, when paired with strategic planning, has the potential to improve long-term affordability for customers while supporting California's decarbonization goals. The study estimates that between $23 billion and $31 billion in distribution infrastructure investments will be required through 2040 to enable electrification across PG&E's service area. Importantly, electrification is projected to place a downward pressure on distribution rates of approximately 25% by 2040, as growing customer load and improved asset utilization offset the initial capital outlays.

The findings highlight that engineering best practices, mitigated planning assumptions, and orchestrated demand management can substantially reduce system costs. The Base (Mitigated) Scenario produced $3.4 billion in savings compared to unmitigated approaches in the EIS Part 1. The Enhanced Demand Flexibility Scenario achieved an additional $1.8 billion in cost reductions compared to the Base (Mitigated) Scenario through orchestrated management of flexible loads such as EV charging, HVAC, and storage. The Equity Scenario found roughly $6 billion in incremental investment compared to the Base (Mitigated) Scenario, which is consistent with the corresponding increase in load growth modeled in this scenario. Lastly, the EV Capacity Demand Sensitivity focused on localized EV charging impacts on the secondary system and found a corresponding increase of $1.7 billion in secondary costs compared to the Base (Mitigated) Scenario.

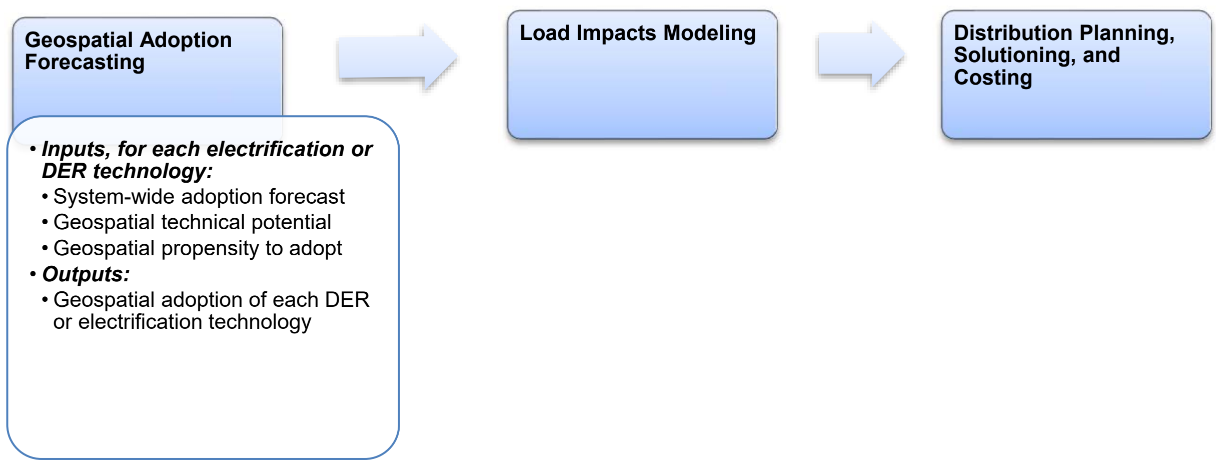
Both the methodology and the results of this study will inform future planning, including learnings from expanding the analytical scope to include secondary service costs and local grid impacts. The study establishes a robust, data-driven framework for planning future distribution investments, integrating flexibility, and incorporating equity into long-term decision-making. As PG&E refines these findings in consultation with stakeholders and incorporates them into its Distribution Planning and Execution Process, the EIS Part 2 provides a foundational roadmap for achieving California's clean energy transition in a way that is cost-effective, equitable, and affordable for all customers.

11. Appendix A: EIS Methodology

11.1. Step 1: Geospatial Adoption Forecasting

Step 1 of the EIS Part 2 study modeled where customers will adopt each electrification or DER technology across its service territory in 2030, 2035, and 2040 under each scenario.

Figure 19. Step 1: Geospatial adoption forecasting



To forecast DER and electrification adoption geospatially across PG&E territory, PG&E leveraged three main inputs:

- **Adoption forecast:** The total amount of DER/electrification adoption across PG&E's territory, geospatially distributed based on the locational technical potential and propensity inputs.
- **Technical potential:** The upper limit on the amount of DER/electrification adoption that can occur in a location.
- **Propensity:** The likeliness that there will be DER/electrification adopted in a location.

PG&E based the adoption forecast on the CEC's IEPR. PG&E allocated this forecast to locations with sufficient technical potential based on propensity. Each of these inputs is described in more detail below.

11.1.1. Adoption Forecast

PG&E used the CEC 2023 IEPR Local Reliability scenario to derive the adoption forecast for LoadSEER. PG&E leveraged its existing modeling used in prior distribution planning efforts to determine the energy efficiency, solar photovoltaic, and energy storage. The team conducted detailed updates of the inputs for EV and fuel substitution (FS) technologies modeled in the EIS Part 2.

Table 31 shows the DER and electrification technologies that PG&E modeled in the EIS Part 2 study. Table 32 shows the key input assumptions leveraged from the 2023 IEPR as the starting points for creating the adoption forecast inputs.

Table 31. DER and electrification technologies modeled

DER and Electrification Category	Individual Technologies Modeled
Light-Duty EVs	Home L1 chargers Home L2 chargers Work L2 chargers Public L2 chargers Public DCFCs
Medium- and Heavy-Duty EVs	Depot DCFCs Highway DCFCs School bus chargers
Additional Achievable Fuel Substitution (AAFS)	Heating Cooling General
Additional Achievable Energy Efficiency (AAEE)	Heating Cooling General
DERs	BTM Battery Storage BTM Solar PV

Table 32. Key input assumptions from the CEC's 2023 IEPR Local Reliability Scenario

Adoption Input from CEC 2023 IEPR Local Reliability Scenario for PG&E Territory				
DER and Electrification Category	**IEPR Input Units**	**2030**	**2035**	**2040**
Light-Duty EVs	# vehicles[70]	2,829,013	5,514,083	8,067,772
Medium- and Heavy-Duty EVs		64,690	147,913	243,243
Additional Achievable Fuel Substitution (AAFS) + Fuel Substitution Scenario Analysis Tool (FSSAT)	Annual total MWh (load increase)[71]	4,946,863	10,766,090	16,445,430
Additional Achievable Energy Efficiency (AAEE)	Annual total MWh (load decrease)[72]	2,497,895	3,227,513	3,276,408
BTM Battery Storage - Residential	Annual peak MW (discharge)[73]	373	516	506
BTM Battery Storage – Non-residential		89	135	157
BTM Solar PV		11,187	13,502	14,103

For all categories except EVs, the team calculated the annual peak load for each technology, subtracted existing applications for service, and determined the remaining incremental growth. For EVs, the team converted the CEC's EV forecast[74] into a charger forecast using charger/EV ratios derived from the CEC AB 2127[75] report. PG&E

[70] AATE Scenario 3 Stock Forecast from "CA_Planning_Library_2023_IEPR_Plug-in_Electric_Vehicle_Stock_Forecast_ada.xlsx", available at https://www.energy.ca.gov/media/9573.
[71] AAFS Scenario 4 and FFSAT from "AAEE and AAFS Hourly Load Modifier Results for the 2023 IEPR Forecast - June 2024 - PGE Planning Area", available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=257334&DocumentContentId=93176
[72] AAEE Scenario 2 from "AAEE and AAFS Hourly Load Modifier Results for the 2023 IEPR Forecast - June 2024 - PGE Planning Area", available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=257334&DocumentContentId=93176. PG&E's forecast for the EIS Part 2 did not exactly match the AAEE due to a modeling inconsistency, but it was determined to not be a significant impact on the results.
[73] California Energy Demand Forecast, 2023-2040, "TN257301_20240621T155514_CED 2023 Hourly Forecast - PGE - Local Reliability - Corrected" workbook, available at https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-03
[74] California Energy Commission (CEC), IEPR EV Stock Forecast, 2023, https://www.energy.ca.gov/media/9573
[75] California Energy Commission (CEC), AB 2127, https://www.energy.ca.gov/data-reports/reports/electric-vehicle-charging-infrastructure-assessment-ab-2127

then translated EV applications for service into equivalent adoption values, subtracted those from the forecast, and calculated the remaining adoption.

Building Electrification

The CEC forecasts building electrification load in the IEPR as a category called Additional Achievable Fuel Substitution (AAFS). The AAFS category includes end uses such as space heating and water heating. The CEC granted PG&E permission to use the more granular IEPR forecast data which disaggregates the public adoption forecasts by end use. This granularity allows PG&E to separately forecast heating loads, cooling loads, other general building loads. These distinctions enhance the accuracy of the modeling. PG&E based its adoption forecast on the annual maximum load (kW) for each technology, using the disaggregated IEPR end-use data.

Electric Vehicle Chargers

PG&E converted the CEC's EV forecast into a charger forecast based on the ratio of chargers per EV from the CEC AB 2127 report.[75] The EV forecast includes LDVs and MHDVs. PG&E first disaggregated the MHDV forecast into three categories: medium-duty vehicles (MDVs), heavy-duty vehicles (HDVs), and school buses. The team began by estimating the school bus forecast based on the size of the existing fleet and electrification targets outlined in AB 579.[76] After subtracting the school bus forecast from the total MHDV forecast, the remaining vehicles were split into MDVs and HDVs using California-specific data from the Census VIUS.[77]

Next, the team applied the charger-to-EV ratios to the LDV, MDV, HDV, and school bus forecasts to calculate charger forecasts for each vehicle type. PG&E then subtracted existing applications for service from the corresponding EV charging categories. For example, PG&E only subtracted workplace L2 applications from the total estimated workplace L2 charger growth. Because PG&E did not categorize fleet applications for service into the four new fleet charging types created in EIS Part 2 (MD depot, HD depot, MDHD highway, and school bus), it allocated those applications proportionally across the four categories. See Section 5.4 for discussion of the Electric Vehicle forecast development in the EV Capacity Sensitivity.

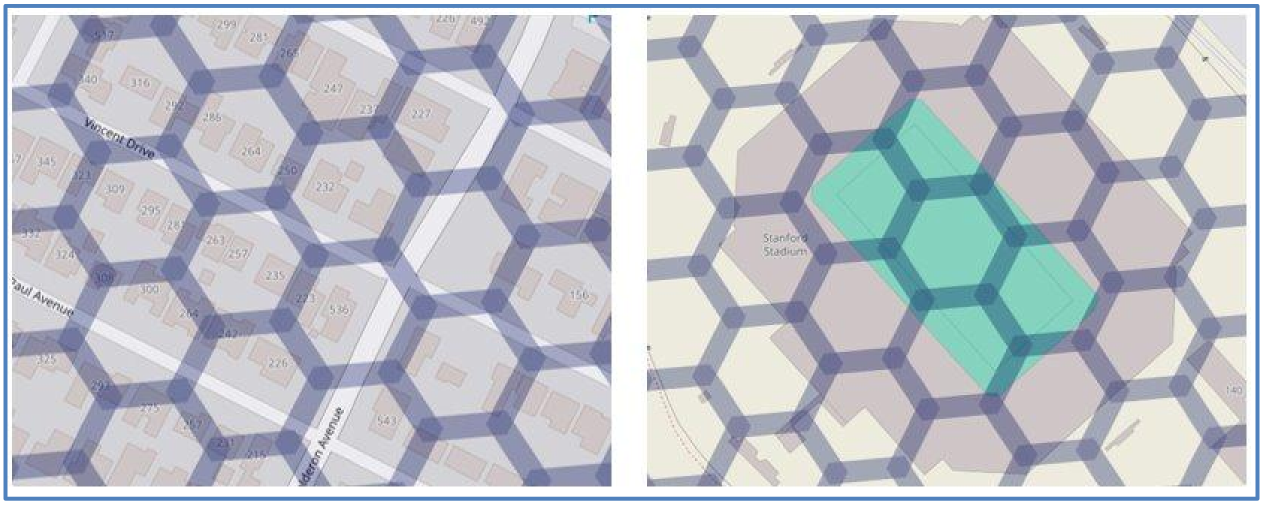
11.1.2. Technical Potential

PG&E defined technical potential and propensity geospatially using the H3 system, a hexagonal grid spatial index.[78] The Forecasting Anywhere (FA) tool mapped all datasets to H3 cells, enabling integration of multiple data sources. PG&E defined technical

[76] Assembly Bill No. 579, Ting. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202320240AB579
[77] Census VIUS, 2021, https://data.census.gov/table/VIUSA2021.VIUS211A?q=vius211a&g=010XX00US,$0400000&nkd=PRICHAR~03
[78] H3 Geo, https://h3geo.org/

potential and propensity at Level 11 H3 cells, which are approximately 2,100 square meters (about half an acre), allowing for high spatial resolution. Figure 20 compares the size of level 11 H3 cells (purple hexagons) to a typical neighborhood (left map) and a football stadium (right map).

Figure 20. Example of H3 level 11 resolution[79] – a neighborhood (left) and a football stadium (right)



After setting the system-wide adoption forecasts, PG&E defined the geospatial technical potential for each technology. Technical potential represents the maximum level of adoption that can occur in a location, constrained by physical factors. To establish this, PG&E used several datasets, including parcel data, business locations, and parking lot availability.

For residential and commercial building electrification, PG&E defined technical potential in terms of building square footage, representing the area that could be electrified. PG&E excluded industrial and agricultural load classes from the BE model due to their limited conversion potential. For transportation electrification, PG&E calculated the maximum number of chargers that could be installed at each modeled location based on physical constraints. Table 33 presents the methodology for estimating technical potential.

[79] H3 cells, https://www.h3-index.es/browse

Table 33. Technical potential methodology

Technology Category	Technical Potential Methodology
AAFS (Additional Achievable Fuel Substitution)	E3 calculated technical potential using building square footage to estimate the maximum adoption of electrification for heating, cooling, and general end uses for the residential and commercial sectors.
Light-Duty EV Charging: Home L1 and L2	E3 estimated charger potential based on residential building square footage and capped the number of chargers per location, then split L1 and L2 chargers using income data and adoption trends.
Light-Duty EV Charging: Public L2 and DCFC	E3 used parcel-level parking data to estimate available spaces for public chargers and applied constraints to avoid oversaturation.
Light-Duty EV Charging: Work L2	E3 calculated charger potential by dividing business parcel parking areas by the space per charger.
Medium- and Heavy-Duty EV Charging: Depot DCFCs	E3 filtered industrial/commercial parcels by business type and parking availability to estimate depot charger potential for MDV and HDV fleets.
School Bus EV Charging	E3 used parking area data near schools to estimate how many buses could be accommodated based on space requirements for buses and staff vehicles.
Medium- and Heavy-Duty EV Charging: Highway DCFCs	E3 identified commercial parcels near highways and fueling stations, then calculated charger potential using vehicle-specific space requirements.

11.1.3. Propensities

E3 calculated the propensity, or likelihood, of DER adoption in every location in which there is technical potential for adoption. Every location identified with technical potential for DER adoption received a propensity score, which is a value between 0 and 1 representing the relative likelihood of adoption in that location.

E3 and IA used a combination of heuristic and machine learning (ML) propensities. ML propensities were developed by training regression models on geospatial demographic variables predicting historical adoption. To develop an ML model, a large amount of geospatial data on historical adoption is needed, and therefore, ML propensities were only developed for DER types where that data was available. Heuristic propensities are developed by considering factors that are known to influence DER adoption such as income, current electricity usage, neighbor participation, business type, business size, etc. to develop a score that represents the likelihood of adoption. The heuristic methodologies are not necessarily less robust than ML methodologies as the heuristic approach allows for consideration of how DER adoption patterns may evolve in the future rather than rely solely on historical adoption patterns. Table 34 outlines this propensity methodology.

Table 34. Propensity methodology

Technology Category	Propensity Methodology
AAFS (Additional Achievable Fuel Substitution)	E3 determined residential propensity using home size and existing heating fuel types, informed by CEC and NREL data. For commercial buildings, E3 used business sales and type to estimate likelihood of electrification.
Light-Duty EV Charging: Home L1 and L2	E3 calculated residential charger propensity using income, household size, home ownership, and square footage, assuming higher likelihood in owner-occupied, larger homes.
Light-Duty EV Charging: Public L2 and DCFC	E3 assessed public charger propensity based on proximity to shopping centers, schools, parks, and highways, with different weightings for L2 and DCFC chargers.
Light-Duty EV Charging: Work L2	E3 estimated workplace charger propensity using business sales volume and type, assuming higher likelihood for businesses with capital and relevant operations.
Medium- and Heavy-Duty EV Charging: Depot DCFCs	E3 calculated depot charger propensity using business type and sales volume, focusing on those likely to operate MDV and HDV fleets.
School Bus EV Charging	E3 assigned randomized propensity scores to schools, assuming equal likelihood of adoption due to grant eligibility and statewide mandates.
Medium- and Heavy-Duty EV Charging: Highway DCFCs	E3 developed propensity scores using proximity to highways, gas stations, and parking areas, emphasizing rural and high-traffic zones.

11.1.4. Geospatial Adoption Modeling: Equity Scenario

PG&E applied the same geospatial adoption modeling methodology for both the Base Scenario and the Enhanced Demand Flexibility Scenario, as described above. PG&E modified the inputs for the Equity Scenario to reflect the scenario-specific goal and constraints.

The goal of the Equity Scenario is to model increased electrification and DER adoption in priority populations.[80] The CPUC directed the IOU's to maintain an equity ratio, as defined below, for this scenario to ensure that electrification and DER adoption achieves an equitable distribution:

$$\frac{Priority\ Population\ Customers}{All\ Customers} \leq \frac{Adoption\ by\ Priority\ Customers}{Adoption\ in\ Total}$$

This outcome is achieved without reducing adoption in non-priority populations, therefore total adoption increases relative to the Base Scenario and exceeds adoption in the IEPR forecast. As such, the Equity Scenario uses different total adoption from the

[80] EIS Part 2 Scope and Requirements, p.8

Base Scenario, as well as different technical potentials to achieve that additional adoption in priority populations.

The CPUC defined priority populations as low income, disadvantaged and Tribal communities and recommended utilizing the priority populations designation dataset from the CEC,[81] illustrated in Figure 21. The team utilized this census-tract level data and layered in geospatial data on enrollment in California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) programs. These datasets were aggregated such that census tracts and premises are classified as priority populations, and anything not included in these datasets is not a priority population. Premises enrolled in CARE and FERA may overlap with census tracts designated as priority, but since this data is just used to identify priority populations, overlap doesn't change the result.[82]

Figure 21. Priority populations from CEC designations

Next, the team calculated the amount of additional adoption needed in priority populations to meet the CPUC's equity ratio. The team grouped the Base Scenario results into priority and non-priority populations and then used the equity ratio to determine the required incremental adoption. PG&E allocated this additional adoption exclusively to priority populations. To implement this in LoadSEER, PG&E retained the

[81] California Open Data Portal, Low-Income or Disadvantaged Communities Designated by California, https://data.ca.gov/dataset/low-income-or-disadvantaged-communities-designated-by-california

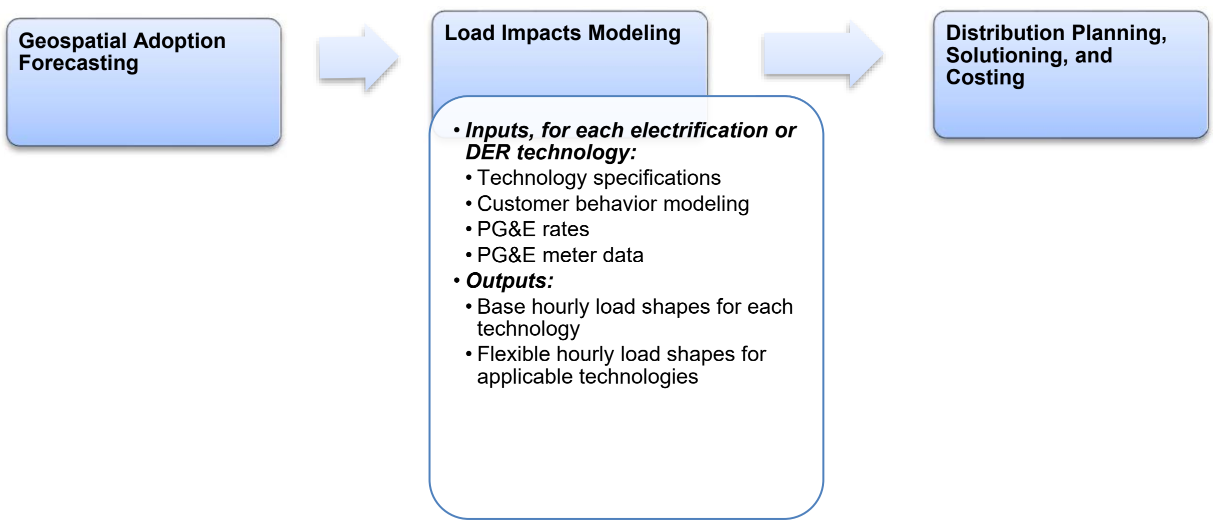
[82] The CPUC Energy Division asked PG&E how overlapping characteristics (e.g., DAC + CARE/FERA + renter status) were treated in the allocation methodology. PG&E clarifies that DAC + CARE/FERA may overlap, but these datasets are used to classify locations as priority versus non-priority. Then, LoadSEER allocates the incremental adoption needed to meet the equity ratio in the priority populations only to those priority populations according to the Base Scenario propensities. Renter status is used in some propensities, such as residential EV charging, where we assume that home owners are more likely to install a home EV charger.

same propensity scores as in the Base Scenario but set technical potential to zero in non-priority populations. In addition, PG&E revised the technical potential in priority populations to ensure that enough incremental adoption could occur to meet the equity ratio.

11.2. Step 2: Load Impacts Modeling

The team developed hourly load shapes for each DER and electrification technology to simulate their impact on the grid. Hourly load shapes are important for understanding when different technologies consume electricity from the grid or discharge electricity to the grid. Figure 22 provides an overview of this step in the modeling process.

Figure 22. Step 2: Load impacts modeling



For energy efficiency, solar PV, and battery storage, PG&E used legacy load shapes from the 2024–2025 distribution planning cycle. These shapes are from the IEPR and were not adjusted. For electric vehicles and building electrification technologies, the team developed updated load shapes using new modeling and data sources, as listed in Table 35.

Table 35. Updated load shape sources

DER Type	Load Shape Source
Building electrification	NREL's ResStock and ComStock
Transportation electrification	E3's EV Grid model and PG&E meter data

11.2.1. Building Electrification

The team used NREL's ResStock and ComStock[83] bottom-up building simulation datasets to generate load profiles for residential and commercial buildings.[84] These

[83] National Renewable Energy Laboratory (NREL), ResStock, https://resstock.nrel.gov/, and ComStock, https://comstock.nrel.gov/

profiles vary by end use (heating, cooling, general), customer type, and climate zone. These shapes vary geospatially to capture the variety of climate zones within PG&E's service territory.

Figure 23. Residential heating (left) and cooling (right)

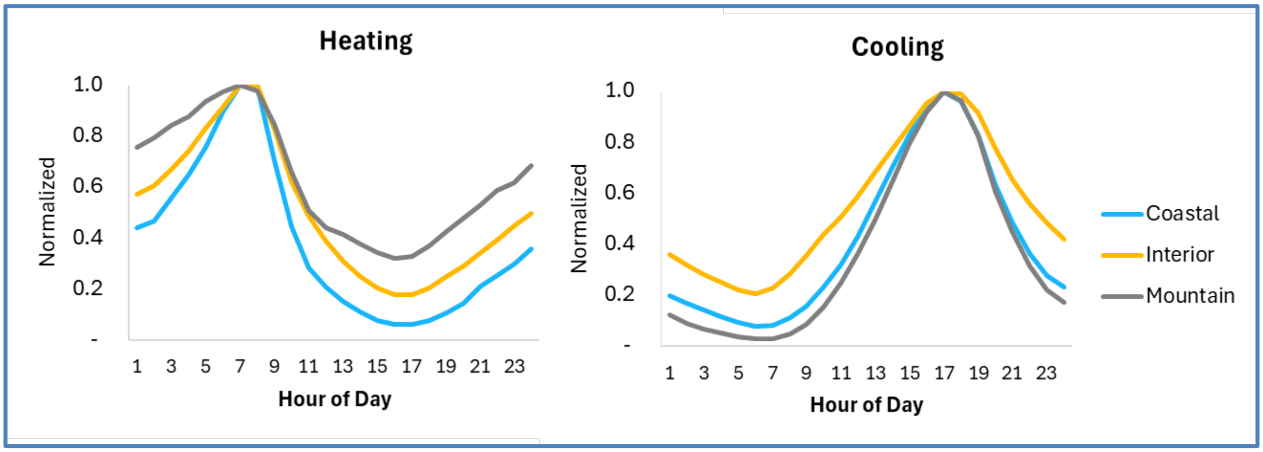


Figure 23 illustrates examples of AAFS heating and cooling load profiles. Heating demand peaks in the morning as occupants wake and raise indoor temperatures, drops midday due to solar gain and lower occupancy, and rises again in the evening. Cooling demand starts low overnight and climbs steadily to an afternoon and evening peak, driven by rising outdoor temperatures and building use. These shapes are grounded in historical behavior and are expected to remain stable as building electrification continues to scale.

The team generated end-use load shapes for each climate zone in California. To streamline the modeling process and reduce complexity without sacrificing analytical integrity, PG&E consolidated the climate zones into three broader categories that shared similar load shapes:

- **Coastal**: Moderate temperatures and marine influences.
- **Interior**: Warmer inland regions with higher cooling loads.
- **Mountain**: Cooler, elevated areas with distinct heating needs.

This grouping allowed for a more efficient and scalable approach to scenario analysis while maintaining sufficient differentiation to inform distribution planning and infrastructure cost estimation.

11.2.2. Electric Vehicle Chargers

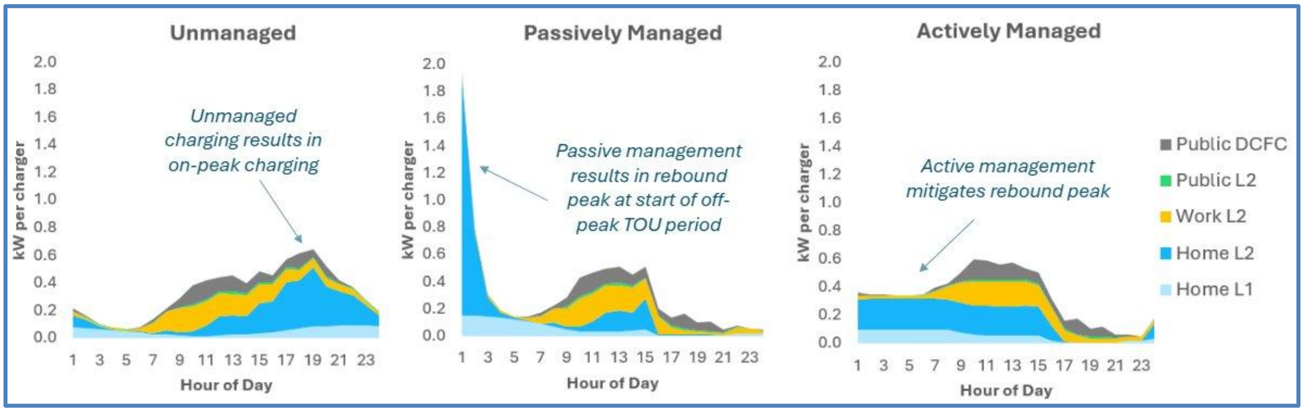
E3 used its EV Grid model to generate hourly charging profiles for PG&E. Table 31 lists the charger load shapes E3 developed. The tool generates diversified EV charging load shapes based on the driving patterns of thousands of drivers and characteristics of the driver population, including charger access, vehicle types, and cost to charge vehicles in various locations. The tool simulates how customer types make charging decisions based on their charging access and vehicle type, then weights them based on how representative each customer type is of the population of drivers. These include the vehicle and charger inputs to characterize the capabilities of chargers and vehicles on the road, costs to charge to model unmanaged and managed behavior based on PG&E rates and charging network size to simulate competition for chargers at workplace and public locations. PG&E compared EV Grid model results with available metered data for the same vehicle category. For the residential L2 charging load shape, which represents single family and multi-family residential charging, PG&E utilized AMI data. For all other charging load shapes, the EV Grid model results were used and verified qualitatively by various PG&E teams.

E3's EV Grid model creates unmanaged, passively managed, and actively managed load shapes. All charging types allow for drivers to meet their travel needs based on the constraints in the optimization, including their driving patterns and charger availability.

- **Unmanaged Charging** is based on a driver's travel patterns, convenience of and access to different charging locations, and relative price differences between charging locations. A driver will charge their vehicle as needed at different sites to meet their driving needs. A driver sees and responds to the relative prices for different charging locations but does not respond to price differences that change within a given location. For example, drivers see that charging at home is generally cheaper than public locations, and therefore prefer home charging when possible. However, they do not see that charging at home can have different prices throughout the day, such as through TOU rates.
- **Managed (Passive) Charging** includes driver response to price changes at given locations. Unlike unmanaged charging, the driver sees TOU rates when available at each location and responds accordingly. For example, drivers with home L2 charging are assumed to program their charging to start when the off-peak period begins for the residential EV TOU rate.
- **Active Managed Charging** is based on driver response to price changes and assumed smoothing within different price periods to avoid rebound peaks (such as through staggered TOU periods, charging management programs, or an aggregator). For example, drivers with home L2 charging have their charging smoothed throughout the off-peak period to avoid a rebound peak right when the off-peak time begins.

Examples of each management type are illustrated in Figure 24 for a light-duty vehicle population average load shape.

Figure 24. EV management types



These shapes for each vehicle and charger combination are weighted to create representative load shapes to be used in LoadSEER. Table 36 describes the weights used for the base load shapes for MHDV depot charging, LDV workplace L2 chargers, and all public charging. PG&E benchmarked the modeled load shapes for LDV to residential meter data from EV customers. PG&E leveraged its meter data for the final home charging shapes to ensure the shape reflects actual behavior from its customers.

Table 36. EV management assumptions (Base Scenario)

EV Type	Behavior		
	Unmanaged	Managed (Passive)	Managed (Active)
HD Depot	40%	60%	0%
MD Depot	30%	70%	0%
MDHD Highway	100%	0%	0%
School Bus	40%	60%	0%
Home Level 1	24%	76%	0%
Public DCFC	100%	0%	0%
Public Level 2	100%	0%	0%
Workplace Level 2	60%	40%	0%

*Home Level 2 assumed existing customer behavior patterns

11.2.3. Load Shapes: Enhanced Demand Flexibility Scenario

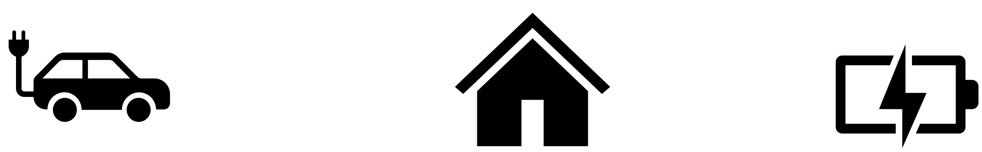
The Enhanced Demand Flexibility Scenario aims to reflect how demand flexibility of electrification technologies may evolve into the future. Since demand flexibility is an active area of research, PG&E focused on modeling what may be possible, rather than extrapolating existing assumptions. While PG&E believes this study may inform the future of flexible loads, it should not be interpreted as the only way that demand flexibility may be enhanced.

Demand flexibility depends on the pattern of electricity consumption, how much of the load is flexible (controllable or expected to change due to behavior changes) and the impact of controlling the load on the rest of the hours. For example, reducing EV fleet charging load will result in increased load at other hours to accommodate customer's need of charging their fleet.

Lawrence Berkeley National Laboratory (LBNL) describes load management using four approaches: "shift" moves electricity use from peak to off-peak periods; "shape" changes overall consumption patterns; "shed" cuts demand during peak times, often through demand response; and "shimmy" quickly adjusts loads to help balance the grid in real time.[85]

In the Enhanced Demand Flexibility Scenario, PG&E focused on shape, shift, and shed approaches for technologies that are believed to have significant contribution to the load flexibility of the future: electric vehicles, battery storage and building-related end uses. Participation levels for these technologies are difficult to accurately estimate because the expected enhanced demand flexibility is either still in the conceptual stage or undergoing pilot testing.

Figure 25. Flexible loads modeled in the Enhanced Demand Flexibility Scenario



Electric vehicles

Charge Management and Vehicle-to-grid (V2G) capabilities

Buildings

Shed and shift air heating, cooling, water heating and other end-uses

Battery storage

Increased utilization of residential and non-residential batteries

This scenario utilized the same geospatial adoption outcomes as the Base Scenario but applied flexible load shapes in this step instead of the Base Scenario load shapes. This section outlines the underlying data and key assumptions for flexible load shapes that differ in the Enhanced Demand Flexibility from the Base Scenario.

EV Load Flexibility

The Base Scenario modeled representative charging profiles for each charger type, as described above. In the Enhanced Demand Flexibility Scenario, dynamic rates become more prevalent, charge management becomes active, and vehicle-to-grid technologies

[85] 2015_dr_potential_study_phase1_final_report.pdf (https://eta-publications.lbl.gov/sites/default/files/2015_dr_potential_study_phase1_final_report.pdf)

mature. The following section discusses the assumptions of each management approach.

Charge Management: Dynamic Rates

The Enhanced Demand Flexibility Scenario assumes the California policy framework enables widespread adoption of demand flexibility solutions by creating a dynamic pricing signal such as that outlined through the CPUC's Demand Flexibility Rulemaking (R.22-07-005) and the California Energy Commission's Load Management Standards.[86] PG&E runs a pilot called Hourly Flex Pricing (HFP) that is designed to promote cleaner energy by varying electricity prices by the hour, allowing consumers to save money by shifting their energy use to cheaper times.[87] While this is a new pilot and its performance hasn't been evaluated yet, the Scenario assumes that customers will show some elasticity in their load in response to price. The elasticity of residential customers is also expected to be higher than commercial customers. The Enhanced Demand Flexibility scenario assumes only home L2 EV charging will respond to dynamic pricing. Table 37 shows the assumption that by 2040, 40% of residential charging will shift to periods of time with low dynamic pricing.

Table 37. Customer responsiveness to dynamic pricing (Enhanced Demand Flexibility Scenario)

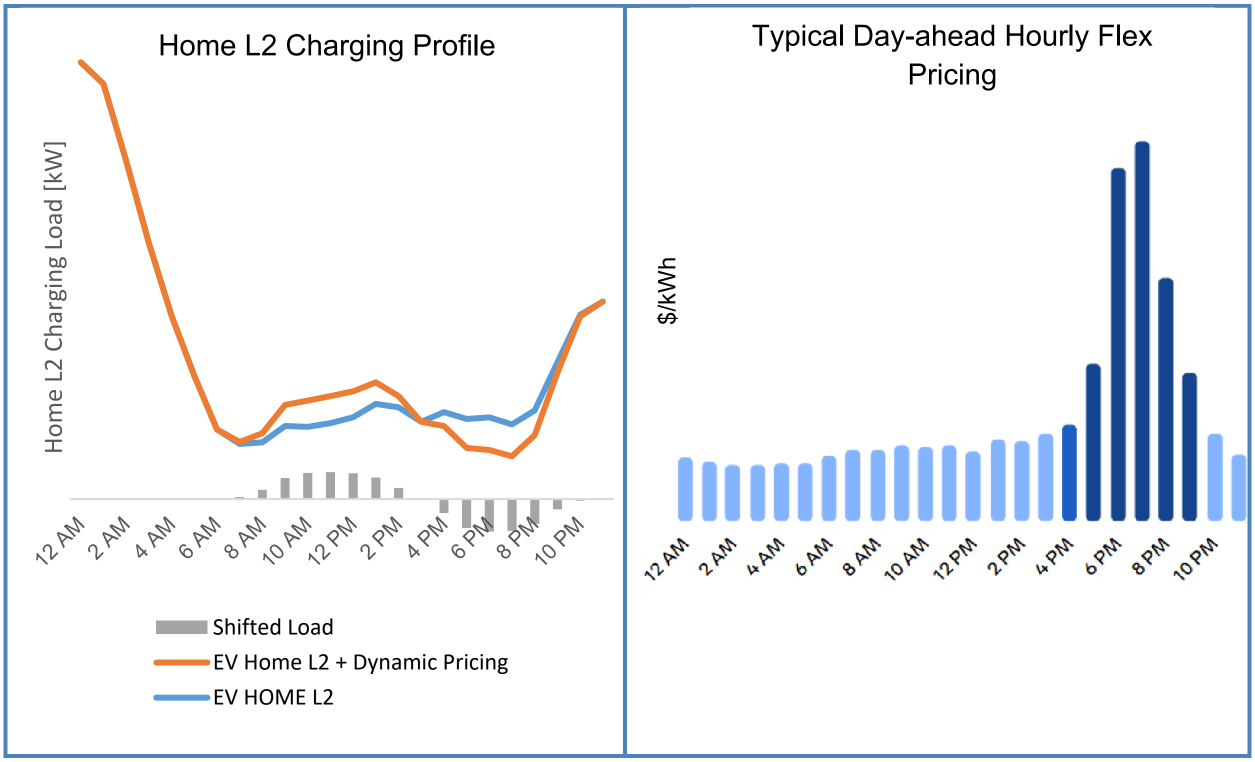
	2030	2035	2040
Elastic Home L2 Chargers	20%	30%	40%

Current charging patterns indicate that charging ramps up at the start of the TOU off-peak period, with a peak around midnight. The introduction of dynamic pricing, characterized by low overnight rates, is not assumed to result in significant changes to customer behavior regarding the timing of midnight charging. However, peak-period charging is assumed to shift towards mid-day when the rates are low.

Estimating changes in customer responsiveness requires careful consideration, as it is based on observed customer actions rather than established control methods that result in firm load management. Customer response expectations rely on current hourly flex pricing and available data and may be revised following pilot evaluations or significant pricing changes.

[86] CalFUSE (California Flexible Unified Signal for Energy) is a CPUC-led framework designed to enable real-time, dynamic pricing signals that reflect grid conditions across generation, transmission, and distribution levels.
[87] PG&E, Hourly Flex Pricing Pilot, https://www.pge.com/en/account/rate-plans/hourly-flex-pricing.html

Figure 26. Home L2 charging profile (left) shifting from evening to mid-day and a response to dynamic pricing (right)



<u>Charge Management: Active Charging Demand Management</u>

While rate-based management can influence behavioral changes over time, it may also reduce load diversity and does not fully ensure that load will remain within specified thresholds. In contrast, active management is effective in limiting charging during designated periods or distributing demand across extended intervals, all while maintaining vehicle readiness and state of charge under typical operating conditions.

Early load management, such as passive management, delays EV charging to off-peak TOU periods, but this can cause a rebound peak as many vehicles begin charging at once as soon as the off-peak period begins. Active charge management helps prevent this surge by smoothing charging across off-peak times, which can be achieved through an aggregator or varied TOU rates to stagger start times.

In the Enhanced Demand Flexibility Scenario, active management is assumed to achieve a smooth and gradual load shifting from the peak time at the system/bulk level or at the circuit-level and spread it over off-peak hours.

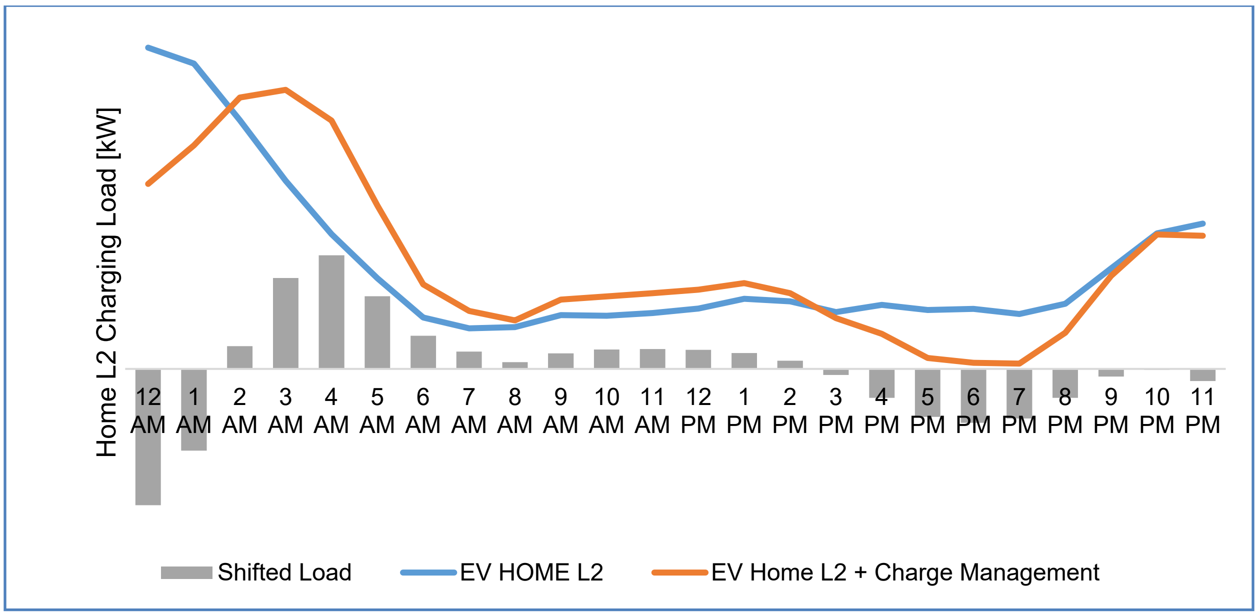
Active load management is expected to help manage the load of home L2 charging, workplace charging, medium and heavy-duty depot charging, and school bus charging. Table 38 shows the expected percentage of chargers that will shift their load due to Active Load Management.

Table 38. Customer responsiveness to actively managed charging signals

Load Types	2030	2035	2040
Home L2 chargers	30%	40%	50%
MDV & HDV depot chargers	10%	20%	35%
School bus depot chargers	10%	20%	35%
Workplace L2 chargers	11%	22%	39%

Figure 27 illustrates how home Level 2 (L2) charging profiles shift when both dynamic rates and active management strategies are applied. This shift is a direct result of combining dynamic pricing signals with active management, encouraging users to charge their vehicles in a way that benefits both the grid and consumers.

Figure 27. Shift in Home L2 charging profile due to the combined charge management approaches (dynamic rates and active management)



<u>Vehicle-to-Grid Demand Management:</u>

V2G bidirectional charging technology offers a promising opportunity for integrating electric vehicles into the PG&E grid. By allowing EVs to discharge energy back to the grid at times of peak demand, V2G can help balance electricity supply, enhance grid resilience, and provide value for both utilities and vehicle owners. The widespread deployment of V2G will require coordination between different parties, supportive regulatory frameworks, and consideration of vehicle use patterns ensuring vehicles are charged by the needed time. Home and fleet depot chargers are ideal candidates for V2G as the vehicles using these chargers have predictable downtime and are parked for extended periods. PG&E's pilot programs with the Oakland Unified School District

(OUSD)[88] and Fremont Unified School District (FUSD)[89] are testing using electric school buses as mobile energy storage, discharging to the grid during high-demand periods and charging when electricity is abundant and inexpensive. These real-world pilots are critical for understanding the operational impacts, benefits, and challenges of V2G as technology matures.

Table 39 lists the V2G modeling assumptions used in the Enhanced Demand Flexibility Scenario. The scenario assumes that the majority of V2G deployment will originate from the non-residential sector, as depending on residential customers may be less feasible due to varying vehicle usage patterns throughout the day compared to the more predictable scheduling associated with non-residential users. The higher battery utilization of fleet vehicles assumes that these vehicles will be back at their depots after hours to charge back to the original state of charge. The scenario assumes that all vehicles need to get back to the same state of charge within a day, with an assumed round-trip efficiency of 86 percent.

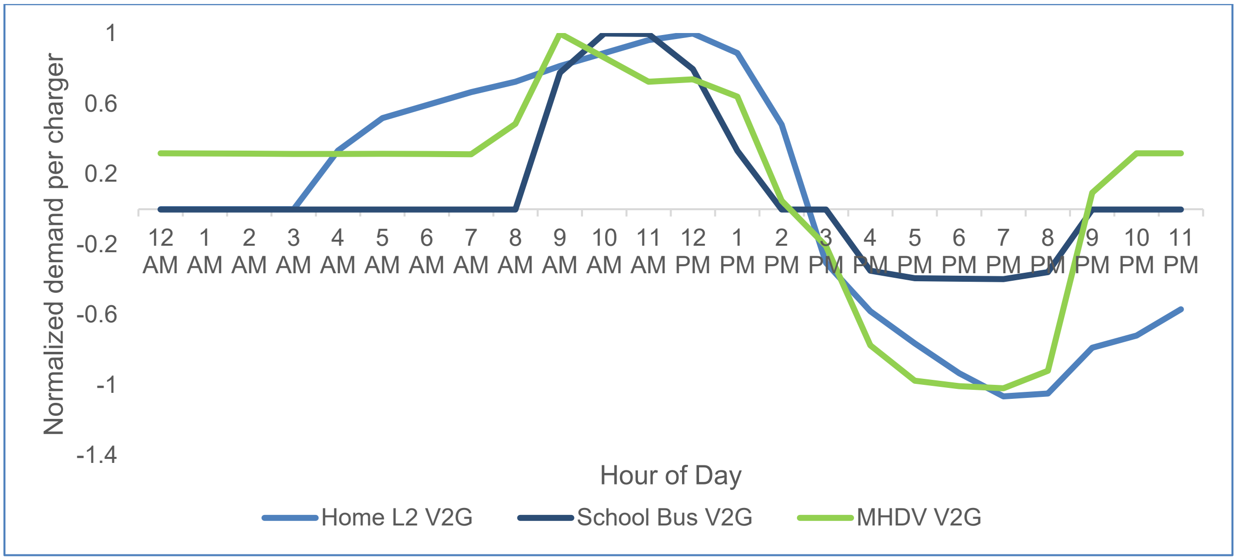
Table 39. V2G modeling assumptions for Enhanced Demand Flexibility Scenario

V2G Options	Battery Size (kWh)	Percent of Battery Utilization	Percent of Chargers with Bidirectional Capability
Home L2	82	10%	6%
MDV	152	50%	10%
HDV	474	50%	25%
School bus	183	10%	10%

Figure 28 illustrates the assumed average daily charging and discharging profiles for V2G enabled chargers. Each vehicle charges during the lowest priced period based on the TOU rate they are charging on, and discharges during the highest price period. All V2G shapes are developed in E3's EV Grid model based on each vehicle's availability to charge or discharge given driving constraints, battery specifications, participation assumptions and charger availability.

[88] https://www.pge.com/en/newsroom/currents/future-of-energy/articles-4040-pge-helps-zum-deploy-nations-100-electric-school-bus-fleet-oakland-new-school-year.html
[89] https://www.pge.com/en/newsroom/currents/future-of-energy/in-fremont--pg-e-helps-launch-another-vehicle-to-grid-electric-s.html

Figure 28. Normalized V2G shapes for the Enhanced Demand Flexibility Scenario



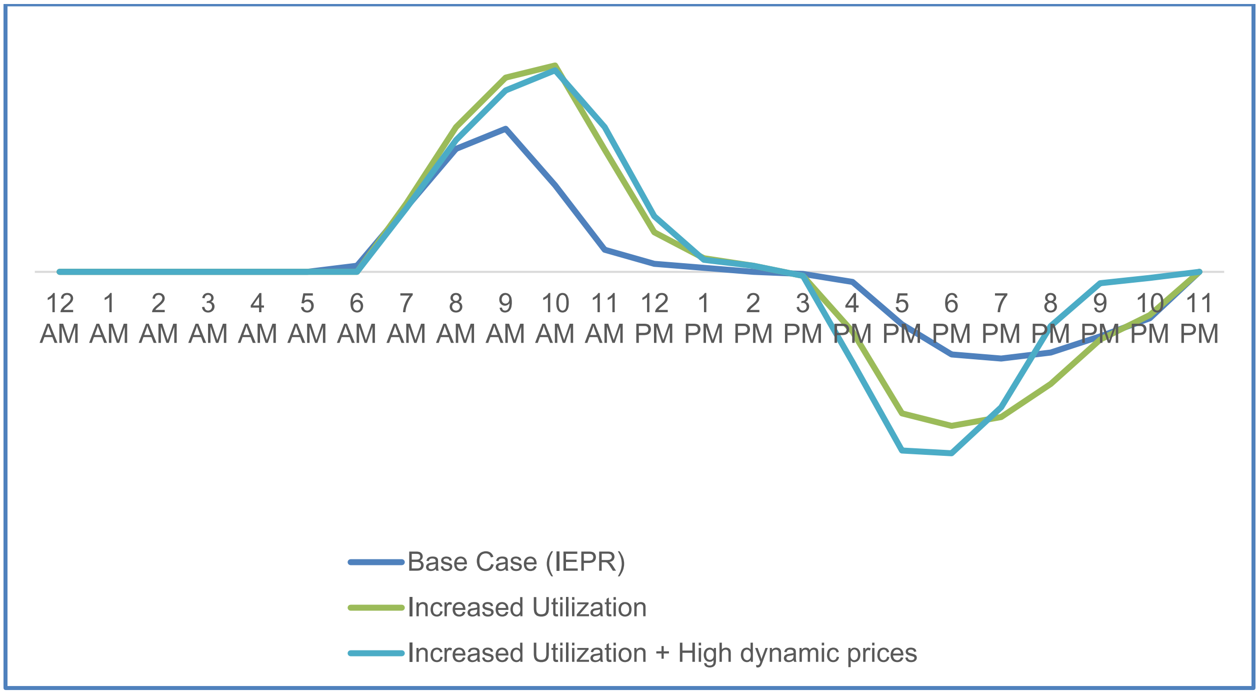
Battery Storage Flexibility

The Base Scenario modeled residential and non-residential battery behavior based on the CEC IEPR load shape. In the Enhanced Demand Flexibility scenario, PG&E assumed the following:

1. Batteries that are paired with solar may charge from solar PV or from the grid and can export to the grid at any time. With the increased adoption of dynamic prices, charging from the grid will happen at the lowest price hours.
2. Batteries will continue to respond to TOU signals; however, as dynamic prices are adopted, customers will shift to exporting during the highest price hours in addition to the specified TOU peak period.
3. Advancement in battery technology allows batteries of the future to export at a higher power.

PG&E increased daily storage dispatch from the Base Scenario load shapes to improve battery utilization in the Enhanced Demand Flexibility Scenario. The Base Scenario shapes vary across the year, with less utilization in certain months. PG&E applied the maximum monthly shape from the Base Scenario to all months in the Enhanced Demand Flexibility Scenario and assumed that this shape will shift towards higher export capacity for narrower duration during high dynamic prices. Figure 29 illustrates the storage shapes used for the Enhanced Demand Flexibility scenario.

Figure 29. Increased utilization of residential storage load shapes for Enhanced Demand Flexibility Scenario



Building Electrification Demand Flexibility

The Base Scenario considered AAFS building electrification load in three categories: heating, cooling and general. The Enhanced Demand Flexibility Scenario considered DR for AAFS building electrification technologies based on the LBNL's California Demand Response Potential Study Phase 4.[90] Shed DR is used to reduce load at peak times during discrete event periods, while shift DR is used more regularly to shift load from peak times to off-peak times. For the Enhanced Demand Flexibility Scenario, both types of load management are modeled, however shift DR is modeled as shed: load is reduced during peak hours but not reallocated to other hours. Because this is a distribution planning study that evaluates capacity requirements, load reallocated to off-peak hours is excluded for simplicity.

The LBNL DR Potential Study provides DR potential and end use load shapes by customer type and utility.[90] PG&E used the supply curves shown in Figure 30 to determine DR technical potential for the Enhanced Demand Flexibility Scenario. The scenario assumes the potential at the avoided cost represents the highest potential that can be achieved. The potentials are developed such that shed and shift events occur during the CAISO system's highest load hours and local circuit peak hours.

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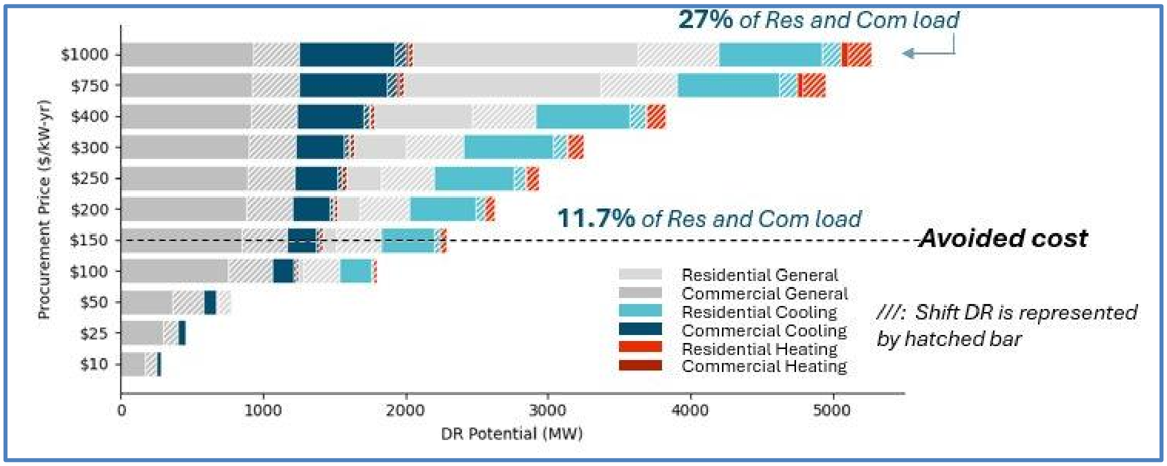
[90] Lawrence Berkeley National Laboratory, The California Demand Response Potential Study, Phase 4: Report on Shed and Shift Resources Through 2050, 2024, https://eta-publications.lbl.gov/publications/california-demand-response-0

Figure 30. 2040 LBNL supply curve for PG&E technical potential shed and shift



The LBNL DR potential includes new and existing electric loads. Because the load in IEPR AAFS shapes represents new electrification, the team capped the DR potential from the LBNL study at the max of the AAFS shape for the scenario.

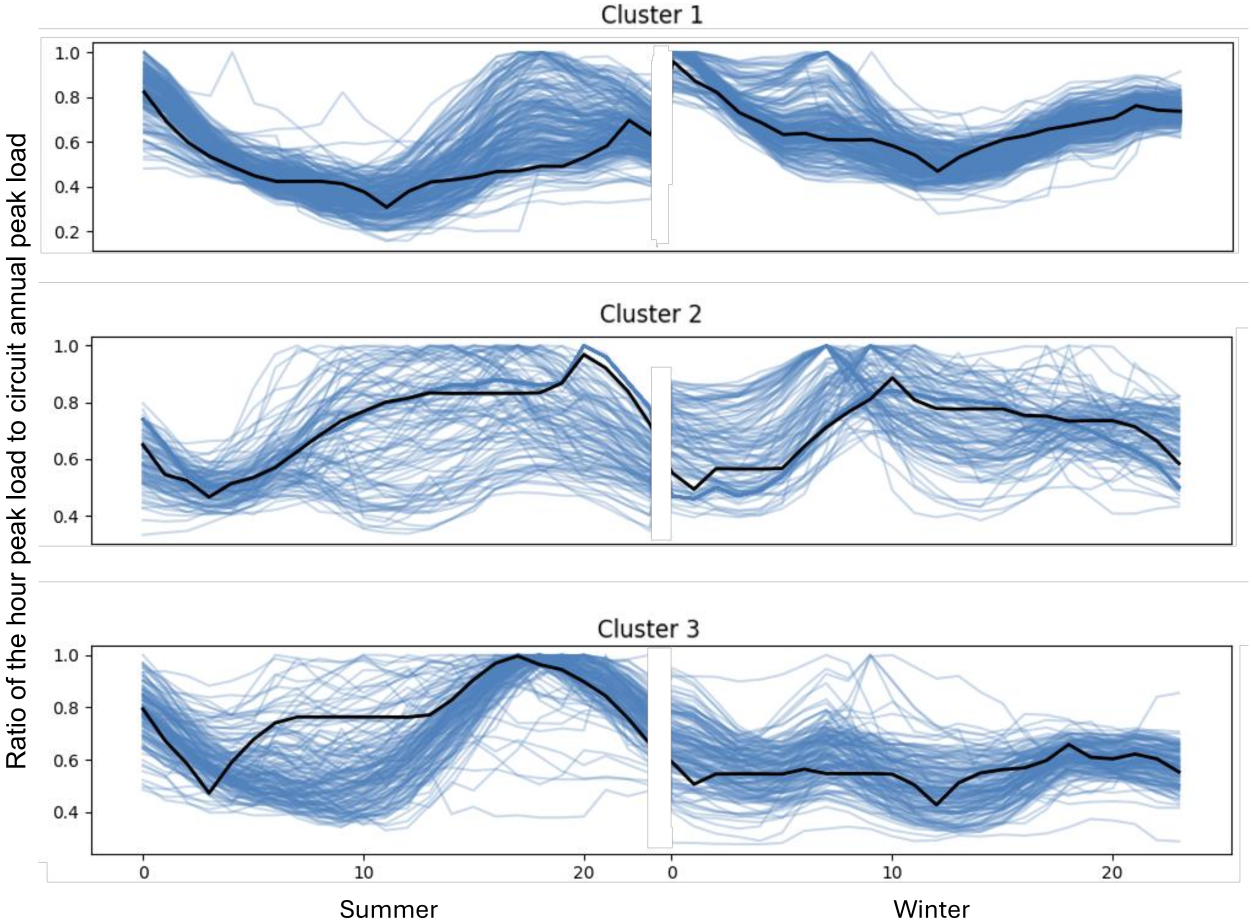
Local Management

Load management strategies are implemented to address periods of elevated demand, particularly during system peak times and emergencies. Traditionally, load management has focused on system peaks occurring between 4pm to 9pm during summer months. Recently, other energy end-uses with peaks outside the summer 4pm to 9pm peak have emerged, such as residential EV charging, which peaks at midnight due to customers responding to the current TOU rate periods. This shift introduces new challenges for distribution planning, as circuits may experience unexpected stress during what has historically been considered off-peak hours. These emerging patterns highlight a need for evolving load management approaches to address local distribution circuit peaks.

To understand how load flexibility contributes to the local distribution circuit peaks, PG&E ran a time-series clustering analysis to identify main contributors to circuit overload. Then, PG&E introduced flexibility approaches to reduce the load at this time given the participation levels listed in the sections above.

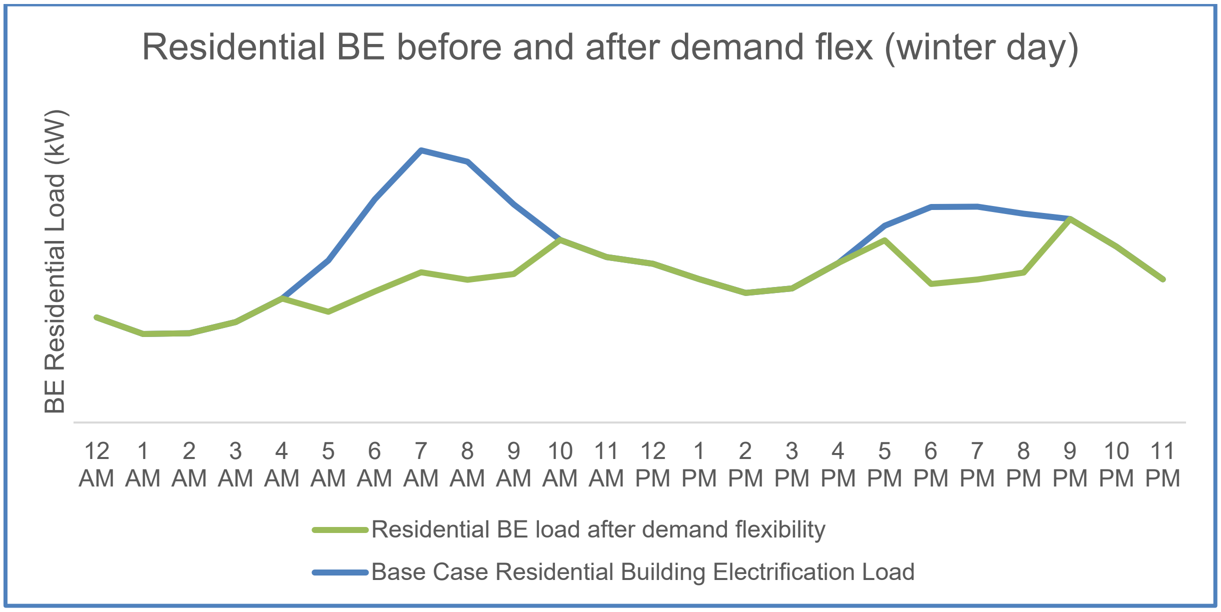
Figure 31 illustrates three peaking patterns identified by clustering circuits according to each hour's peak load relative to the circuit's annual peak load. Cluster 1 demonstrates elevated loads at midnight, likely due to residential EV charging, as well as higher summer evening and winter morning loads, possibly from building heating and commercial EV charging. Cluster 2 exhibits peaks during summer evenings and winter mornings. Cluster 3 aligns with the system peak, with its maximum load occurring in the summer evening.

Figure 31. The three identified clusters with different peak times during summer (left) and winter (right) with average load shape (black line).



Based on the findings of the different peak load clusters, PG&E introduced load management strategies to mitigate the major contributors to the peak load at the identified times above. The introduced load management strategies are home L2 charger midnight peak managed charging, building electrification winter heating, and workplace L2 morning charging (9 am - 12 pm). Figure 32 illustrates how early morning load management reduced building electrification peak demand on a typical winter day.

Figure 32. Demand flexibility of residential building electrification end-uses for a typical winter day. This strategy is applied to circuits with an aggregated load peaking in the early morning.



11.2.4. Sensitivity: Un-orchestrated Enhanced Demand Flexibility Scenario

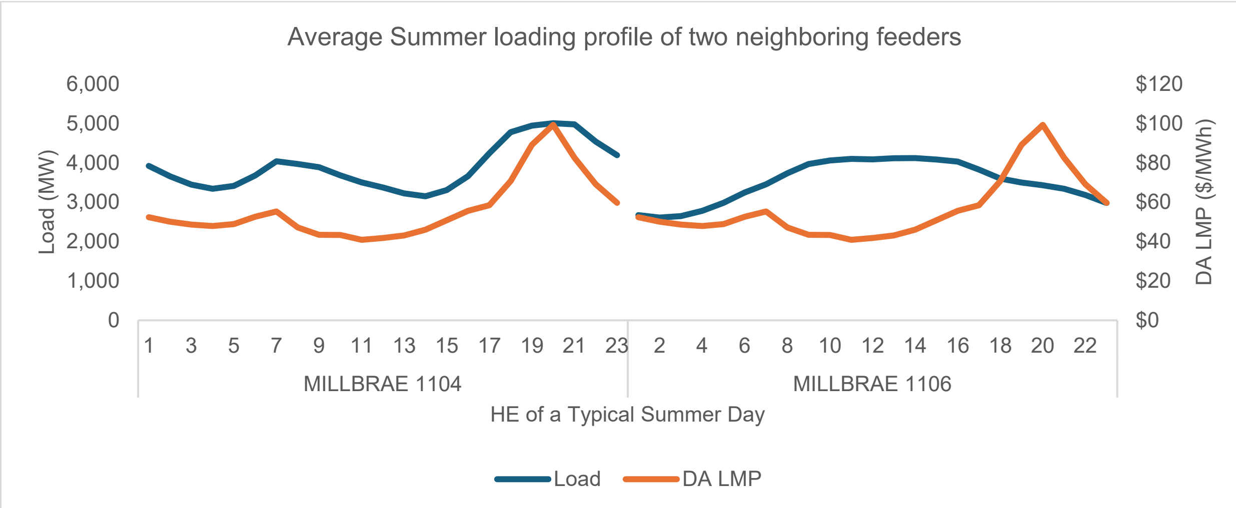
PG&E developed the Enhanced Demand Flexibility Scenario to reflect the future state of flexibility in the future and implement load flexibility strategies that help reduce local peaks. However, this Enhanced Demand Flexibility Scenario assumes Orchestration, in which the demand flexibility is managed in a way that is aware of the local grid constraints, in a manner that can be relied upon for planning purposes using firm, dispatchable load management.

To explore how well the distribution load is correlated with the system load, PG&E compared the load profile for distribution feeders to system level pricing.[91] Using five years of historical data, PG&E found that only ~45% of the feeders were strongly correlated with the system price during summer evenings, with ~12% of the feeders showing a negative correlation.

As an example, Figure 33 shows two neighboring feeders that serve different customer groups and have varying DER penetration. As a result, the load profile varies significantly (shown in blue) in comparison to a day-ahead Locational Marginal Price (LMP) (shown in orange). Therefore, load shifting based on a bulk system signal based on a day-ahead locational marginal price (LMP) would have very different impacts for the two feeders, indicating that orchestration may be needed to account for local conditions.

[91] The average Sub-LAP, Day-Ahead (DA) Locational Marginal Price (LMP) over the past 5 years was correlated with the average hourly load of the feeders in the same Sub-LAP over the same period. Strong correlation is identified as a correlation coefficient greater than 0.6.

Figure 33. Loading profile and Day-Ahead (DA) Locational Marginal Price (LMP)[92] of two neighboring feeders



To demonstrate the impact of not orchestrating load flexibility strategies, PG&E performed a Sensitivity to model a case where load flexibility was not orchestrated to local circuit patterns and continued to shed and shift load, even if these shifts were contradictory to local conditions. PG&E found that shifting flexible loads like EV charging and HVAC without accounting for local grid capacity caused local overloads and equipment strain. This un-orchestrated Sensitivity to the Enhanced Demand Flexibility Scenario shows that the effectiveness of demand flexibility (as shown Table 40) in reducing costs hinges on a strategic, locally informed approach to load management. Results of the scenario and its sensitivity will be discussed in Section 6.1.3.

Table 40. Effectiveness of demand flexibility depend on locally informed load management

Scenario	2040 Total Cost ($M)	Difference from Base	
		($M)	(%)
Base	$25,549	-	-
Enhanced Demand Flexibility (Orchestrated)	$23,713	$1,836	7.2%
Non-Orchestrated Enhanced Demand Flexibility (Sensitivity)	$25,387	$162	0.6%

92 The Day-Ahead Locational Marginal Price (DA-LMP) represents the hourly price at a specific location on the grid determined by energy bids, transmission congestion, and grid losses, as defined in the Day-Ahead market clearing process. DA-LMP was obtained for PG&E Sub-LAPs (pge.com/assets/pge/docs/save-energy-and-money/energy-savings-programs/PGE-SubLap.pdf) from CAISO Oasis (https://oasis.caiso.com).

11.2.5. Load Impacts Modeling: EV Capacity Demand Sensitivity

The EV Capacity Demand Sensitivity is an exploratory sensitivity designed to better capture localized, distribution-level capacity needs of light-duty EV charging unconstrained by the IEPR energy forecast. This sensitivity evaluates how different forecasting and peak-load assumptions for EV charging affect secondary distribution capacity requirements, particularly for local transformer and secondary system loading.

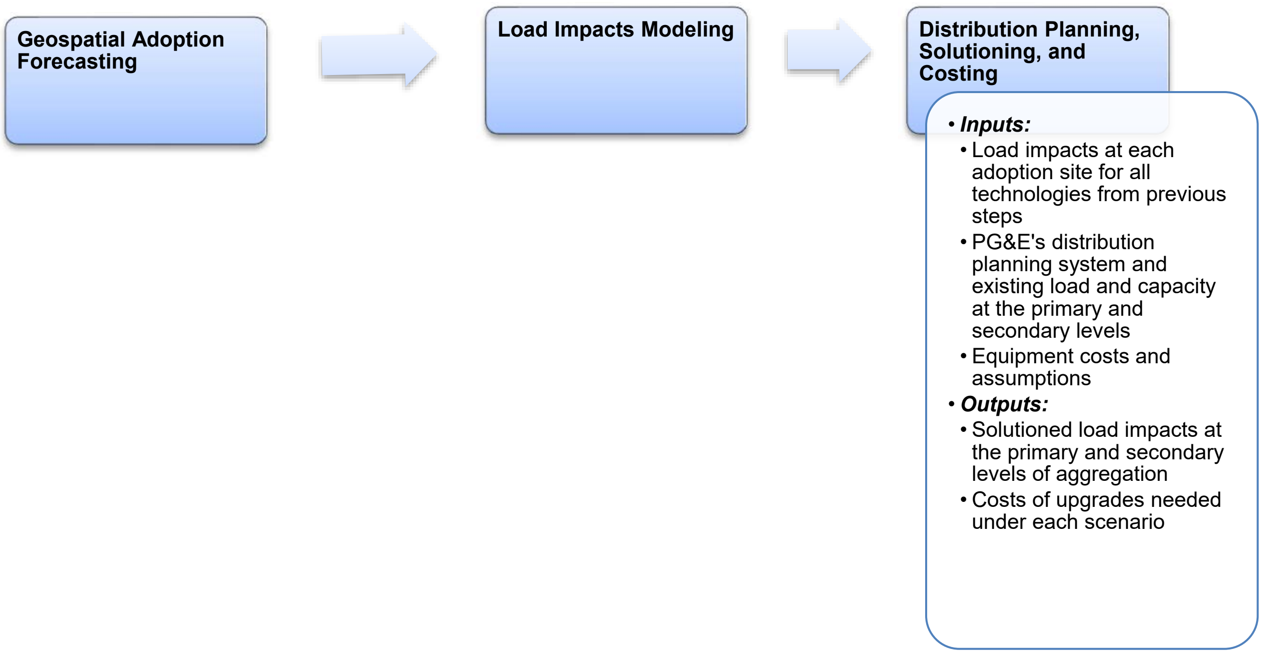
This sensitivity used a similar approach as the Base Scenario for generating the adoption forecast with slight differences explained in Section 5.4. Instead of applying the ratios year-by-year, PG&E calculates a blended (weighted average) vehicle-to-port ratio across years to smooth near-term vs. long-term dynamics. Furthermore, instead of reconciling to system-level energy caps (as in other scenarios), this sensitivity takes a demand-based approach.

The capacity assumptions were also increased to align with an exploratory view on localized demand for distribution capacity needed to serve EV charging infrastructure. In the other EIS scenarios, population average load patterns and peak values are utilized to estimate the loading on distribution equipment. In this scenario, higher peak values are applied to reflect the need for the utility to serve each charger's anticipated capacity demand, not just the diversified load. This is further explained in Section 5.4.

11.3. Step 3: Distribution Planning, Solutioning, and Costing

The final step of the EIS methodology is to determine how the geospatial adoption of electrification/DERs and their hourly impacts affect the distribution system, and how much those upgrades cost. Figure 34 shows an overview of this modeling step.

Figure 34. Step 3: Distribution planning, solutioning, and costing



The forecasting model was structured around two interlinked tools: LoadSEER and CYME. LoadSEER served as the primary forecasting engine, assigning DER and electrification growth to individual feeders and banks based on the geospatial adoption modeling described in Section 11.1 and the associated load shapes described in Section 11.2. These assignments were then transferred into CYME for detailed 2030 analysis, following PG&E's standard distribution planning process. Notably, the analysis focused solely on loading issues, intentionally excluding voltage regulation due to timeline constraints and the relatively lower cost of voltage mitigation compared to capacity upgrades (e.g., cost of installing voltage regulator versus reconductoring cable/conductor).

PG&E made the following assumptions related to project solutioning:

- All 2025-2029 projects that were created and submitted in the GRC are completed in 2029. Project costs associated with those projects are included in the results.
- 4kV cutover projects are included in the EIS results.

To support the scale and speed required by the EIS, distribution engineers leveraged automated scripts and batch processing tools to streamline the solutioning workflow. These tools enabled efficient generation of abnormal condition reports, automated solution recommendations, and consistent application of engineering logic across thousands of feeders. Transfers between circuits and substations were explored as non-cost alternatives.

11.3.1. Identifying Overloads

In the context of PG&E's current distribution planning standards, equipment is deemed overloaded when demand exceeds 100% of its calculated capacity. The capacity is determined using PG&E's engineering criteria, which account for multiple factors specific to each equipment type. These include ventilation method (e.g., forced air or forced oil and air), load factor, geographic location (coastal vs. interior), and seasonal variations (summer vs. winter). Additionally, constraints from adjacent upstream or downstream equipment may influence the effective capacity.

For the purposes of the EIS study, the identification and treatment of overloaded equipment align directly with PG&E's existing Distribution Planning Process. No modifications were made to the underlying assumptions or thresholds used to justify equipment replacement. This consistency ensures that the EIS results are grounded in established utility practices and reflect realistic upgrade needs under projected electrification scenarios.

11.3.2. Solutioning Approach

Distribution solutioning methods in the EIS were intentionally streamlined compared to traditional distribution engineering practices. Under normal circumstances, distribution engineers evaluate multiple solution alternatives for each project, weighing cost-effectiveness, technical feasibility, and long-term benefits. However, in the context of EIS, engineers were directed to prioritize simplified, experience-based solutioning. This meant relying on professional judgment to select viable solutions without conducting exhaustive alternative analyses, especially when cost differences between options were expected to be marginal. This approach was adopted to meet tight timeline constraints and ensure consistency across the large volume of forecasted upgrades.

The most commonly applied methods included transfers and reconductoring, which were favored for their simplicity and effectiveness in resolving capacity constraints. This involved installing switches or reconductoring small portions of circuits or extending a small amount of line to initiate a load transfer. Other solutions, such as procurement of incremental non-wires alternatives, were not directly considered, but rather were considered up-front as part of the forecast and scenarios, for example as reflected in the Enhanced Demand Flexibility Scenario. For the 2030 horizon, solutioning focused primarily on feeder and bank-level upgrades, addressing localized overloads identified through bottom-up modeling. These upgrades were derived from CYME simulations that flagged thermal violations.

As the study progressed to 2035, the solutioning strategy evolved to accommodate increasing forecast uncertainty. Rather than targeting individual feeders, engineers adopted an area-level solutioning approach, which allowed for more flexible planning in regions where DER growth projections were less geographically precise. This shift also enabled the incorporation of broader system constraints, such as existing transmission and substation limitations, into the solutioning logic. Engineers considered new feeders, banks, substations, and strategic transfers to mitigate projected overloads, aligning with the bottom-up modeling insights that highlighted regional stress points. By 2040, the same high-level solutioning principles were applied, with an emphasis on scalability and meeting the 2040 capacity needs.

To support the scale and speed required by the EIS, distribution engineers leveraged automated scripts and batch processing tools to streamline the solutioning workflow. These tools enabled efficient generation of abnormal condition reports, automated solution recommendations, and consistent application of engineering logic across thousands of feeders. Transfers between circuits and substations were also still explored as non-cost alternatives.

11.3.3. Secondary System Capacity and Cost Analysis

Purpose and Scope

The secondary system analysis estimates the incremental secondary distribution system investments required to serve forecasted load growth associated with electrification and DER adoption under each EIS scenario. The analysis focuses on customer-level distribution infrastructure (primarily service transformers) and evaluates where, when, and how additional secondary capacity would be required to reliably serve coincident demand over the study horizon.

The objective of this analysis is not to model the full lifecycle management of secondary assets, nor to optimize long-term replacement strategies for aging infrastructure. Instead, it quantifies incremental secondary capacity investments driven solely by forecasted load growth, consistent with how electrification impacts are evaluated in long-range planning studies.

Results are intended to support system-level cost comparisons across scenarios and spatial understanding of where secondary constraints emerge. This provides transparency into the drivers of secondary investment needs attributable to electrification and DER adoption.

Analytical Framework Overview

The analysis links forecasted, hourly, geospatially resolved load growth to PG&E’s existing secondary transformer inventory using a common spatial reference system based on a hexagonal grid (H3 grid). For each year of the study and for each grid cell, forecasted incremental load is translated into coincident secondary demand and compared against the available capacity of nearby service transformers.

When available capacity exists, incremental load is allocated to existing transformers. When coincident demand exceeds available capacity, the model triggers either the replacement of an existing transformer or installation of a new transformer. In both cases, the model uses PG&E standardized sizing and cost assumptions.

Critically, once a transformer is replaced or installed, the resulting capacity is available to serve future years' load, subject to the same seasonal loading limits. Capacity additions therefore persist over time and can absorb subsequent growth, rather than being re-counted or stranded.

Representation of Load Growth

Coincident Load Definition

Hourly forecast outputs from the geospatial adoption modeling are converted into seasonal coincident demand values for secondary planning. For each feeder, year, and adjustment type, coincidence factors are applied at the feeder peak hour, consistent with utility planning practice. Coincident demand is evaluated separately for summer and winter planning seasons. This approach captures the fact that secondary infrastructure must be capable of serving localized peak conditions rather than annual average load.

Load Aggregation

Incremental coincident load is aggregated within each spatial cell across all modeled electrification technologies and DERs. Load-reducing technologies (e.g., energy efficiency or behind-the-meter generation) reduce net coincident demand and therefore increase available headroom but do not trigger any equipment removal or cost credits.

Spatial Association Between Load and Transformers

Spatial Reference System

All load and asset data are mapped to a common hexagonal grid (H3 grid), which provides a consistent, non-overlapping spatial framework for associating forecasted demand with existing infrastructure.

Secondary Tie-In Method

In this study, incremental secondary load is associated with nearby distribution infrastructure using a spatially localized allocation approach. Each increment of new or increased demand is first assumed to be served by service transformers located within the same small geographic grid cell as the load itself. If sufficient spare capacity is not available within that immediate area, the model then considers transformers located in adjacent grid cells within a limited, predefined search radius.

This approach reflects how secondary systems are typically planned and constructed in practice: new customer load is generally connected to the closest feasible transformer rather than arbitrarily routed across longer distances. By constraining load allocation to transformers that are geographically proximate, the analysis avoids assuming unrealistic secondary routing or long service drops, while still allowing for limited sharing of available capacity among nearby assets.

Capacity Pooling and Search Radius

Transformers within the defined search radius are treated as a shared pool of available secondary capacity for that load location. This allows the analysis to reflect practical clustering of secondary assets, the ability to utilize nearby spare capacity, and avoids unrealistically forcing each load increment to map to a single transformer.

Capacity Evaluation and Upgrade Triggers

Seasonal Capacity Constraints

Each transformer has separate summer and winter usable capacity limits. Incremental load is evaluated against both seasons, and the binding condition determines whether an upgrade is required.

Triggering of an Upgrade

An upgrade is triggered when coincident seasonal demand cannot be allocated to any eligible transformer within the search area without exceeding planning thresholds. Importantly, the model does not distinguish between “energization-driven” and “overload-driven” upgrades in terms of sizing or cost. Both are treated as a seasonal capacity shortfall that must be served. Once triggered, the same engineering rules apply regardless of the underlying cause of the load increase.

Transformer Sizing and Capacity Persistence

Standard Size Selection and Size-Up Policy

When a replacement or new installation is required, transformer sizes are selected from PG&E’s standard nameplate ratings. A modest size-up policy is applied to provide additional planning margin at the time of upgrade. The size-up policy represents a one-time planning approach intended to reduce the likelihood of immediate re-replacement due to near-term growth while mitigating the risk of oversizing based on uncertain long-range forecasts.

Persistence of Installed Capacity

Once installed or replaced, transformer capacity remains in service for all subsequent years and is available to absorb future load growth. The capacity is re-evaluated annually against incremental demand. This ensures that costs are not double-counted and that early investments provide ongoing value over the study horizon.

Cost Representation

Unit Cost Assumptions

For purposes of this study, secondary system costs are represented using a single average unit cost per service transformer. This unit cost is applied uniformly to all modeled transformer replacements and new installations, regardless of nameplate size or triggering condition.

The unit cost is inclusive of labor, line extension, and related installation costs, and reflects historical average costs rather than project-specific engineering estimates. As a result, costs are not differentiated by transformer size or whether an upgrade is driven by new service connections or by capacity overloads. Labor, construction methods, and site-specific complexity are intentionally abstracted.

This approach supports consistent, scenario-comparable estimates of secondary investment needs across the service territory, while avoiding reliance on highly granular design assumptions that are not available or appropriate at the study scale.

Cost Escalation

Annual escalation factors are applied to unit costs to reflect projected changes in labor and material prices over time.

Temporal Dynamics and Planning Interpretation

Upgrades occur when and where capacity shortfalls emerge, rather than assuming perfect foresight of end-of-horizon demand. This produces a staged pattern of replacements and installations that aligns with observed planning practice and avoids unrealistic early over-investment.

The analysis does **not** represent: condition-based lifecycle modeling, failure risk or reliability-driven replacements, operations and maintenance costs, or proactive asset management programs for aging infrastructure. Results therefore reflect incremental investments required to accommodate forecasted load growth, not baseline replacement activity or long-term asset optimization.

Validation, Transparency, and QA

To ensure the robustness and internal consistency of the secondary system results, PG&E conducted a series of structured validation and quality assurance checks throughout the analysis. These checks relied on detailed intermediate outputs generated during the modeling process, which allow results to be traced from forecasted load growth through capacity allocation decisions and resulting secondary system investments.

Two internal extract datasets were used to support these validation activities: a load-level assignment extract and a transformer-level system state extract. Together, these datasets enabled systematic review of allocation logic, upgrade triggers, and capacity evolution over time.

Load Assignment Validation

An internal load assignments extract was used to validate the handling of incremental secondary demand at a localized level. This extract is organized at the level of individual demand events, with one record per year and spatial cell, and documents how seasonally coincident load is evaluated and resolved in each location.

As part of the QA process, this dataset was used to: confirm correct application of feeder-specific coincidence factors at the planning peak hour, verify that incremental load was first evaluated against nearby available transformer capacity before triggering upgrades, review the spatial allocation of load to ensure it was constrained to geographically proximate infrastructure, confirm the timing and location of transformer replacement and new installation triggers, and validate that size-up policies were applied consistently when upgrades occurred.

These checks helped ensure that incremental load growth translated into secondary investments only when and where capacity constraints emerged, and in a manner consistent with planning assumptions.

Transformer State Validation

A complementary transformer-level extract was used to validate the evolution of the secondary system over time. This dataset captures the state of all service transformers (both existing and newly added) across the study horizon, including seasonal capacities, utilization, and replacement history.

This extract supported validation activities including: verifying that installed or replaced transformer capacity persisted in subsequent years and was available to serve future load growth, confirming that seasonal capacity limits and planning loading thresholds were applied consistently, reviewing utilization levels before and after upgrades to ensure reasonable loading outcomes, checking the sequencing, frequency, and geographic distribution of replacement and new installation activity, and confirming that transformers flagged for replacement or overload were treated consistently across years.

Role of QA in Interpreting Results

Together, these validation steps provided assurance that the secondary analysis results reflect internally consistent application of the study's assumptions and planning logic. This QA process ensured that modeled investments respond directly to forecasted load growth, respect spatial and seasonal constraints, and avoid double-counting or premature upgrades.

Visualization of Methodology

The following examples illustrate how the secondary distribution costing methodology evaluates incremental demand events at the H3-cell level. This includes how available transformer capacity is identified, how new load is allocated, and under what conditions transformer upgrades are triggered.

In Figure 35, a demand event in 2025 introduces 9.5 kVA of new coincident summer load and 11.2 kVA of new coincident winter load within a single H3 cell. Three existing service transformers are identified within the configured eligibility radius (one H3 ring), providing a combined seasonal capacity of 215 kVA (summer) and 252.5 kVA (winter). Available headroom across these transformers is sufficient to fully accommodate the new demand. Accordingly, the incremental load is allocated proportionally across the eligible transformers based on their relative capacities, and no new transformer installations or replacements are required.

Figure 35. Example event 1: allocation of new load to existing secondary capacity (no upgrade required)

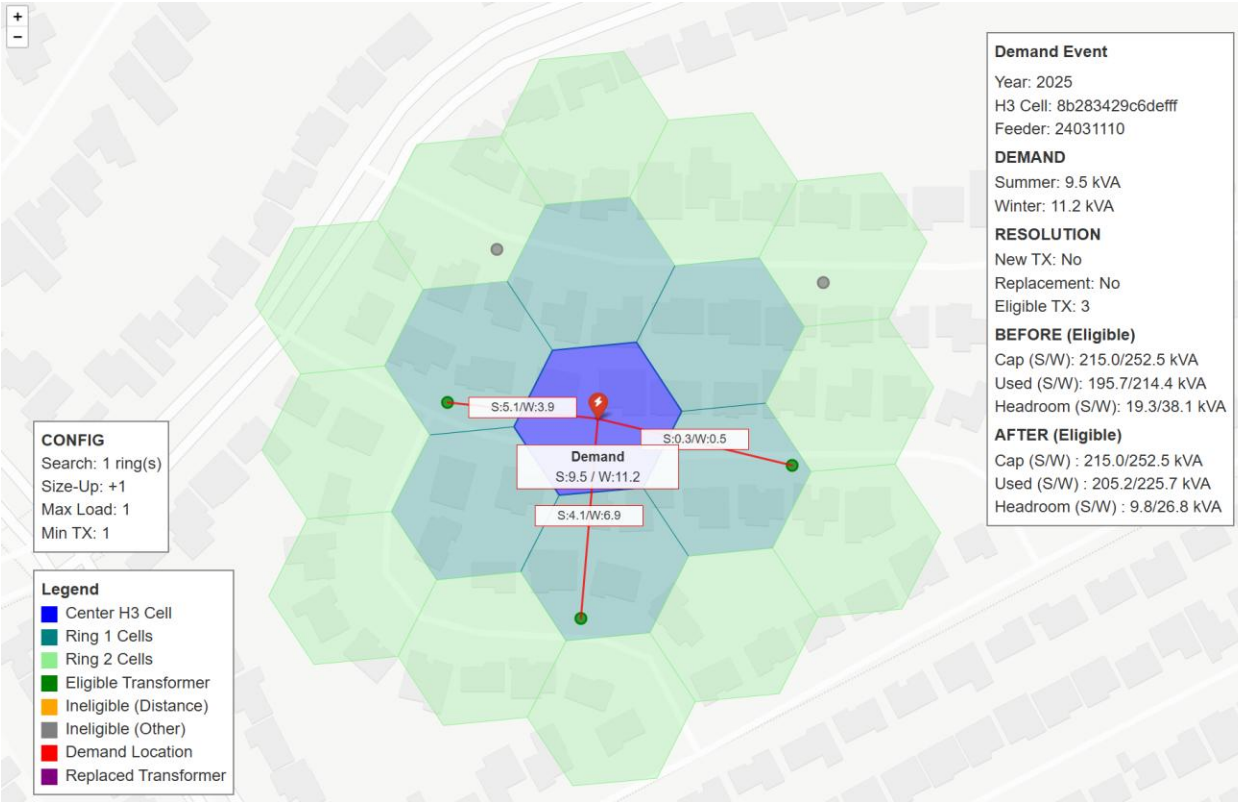
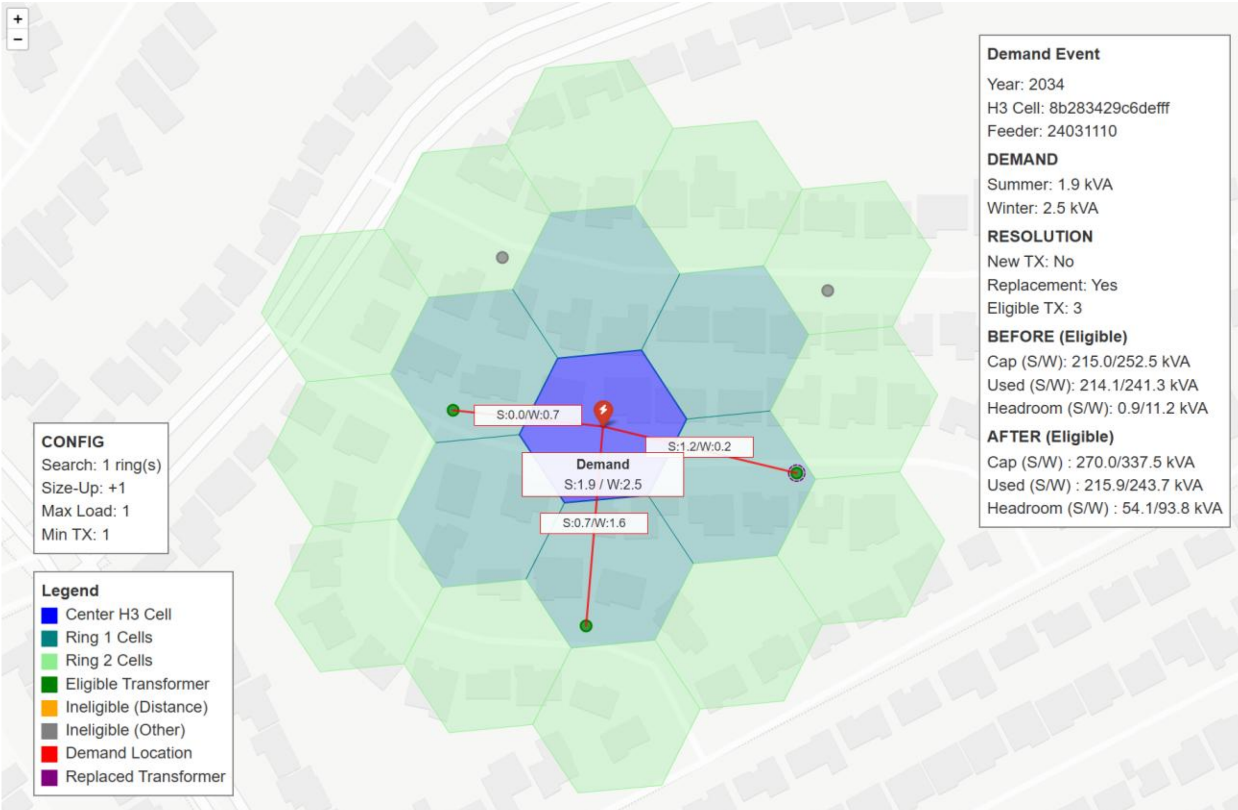


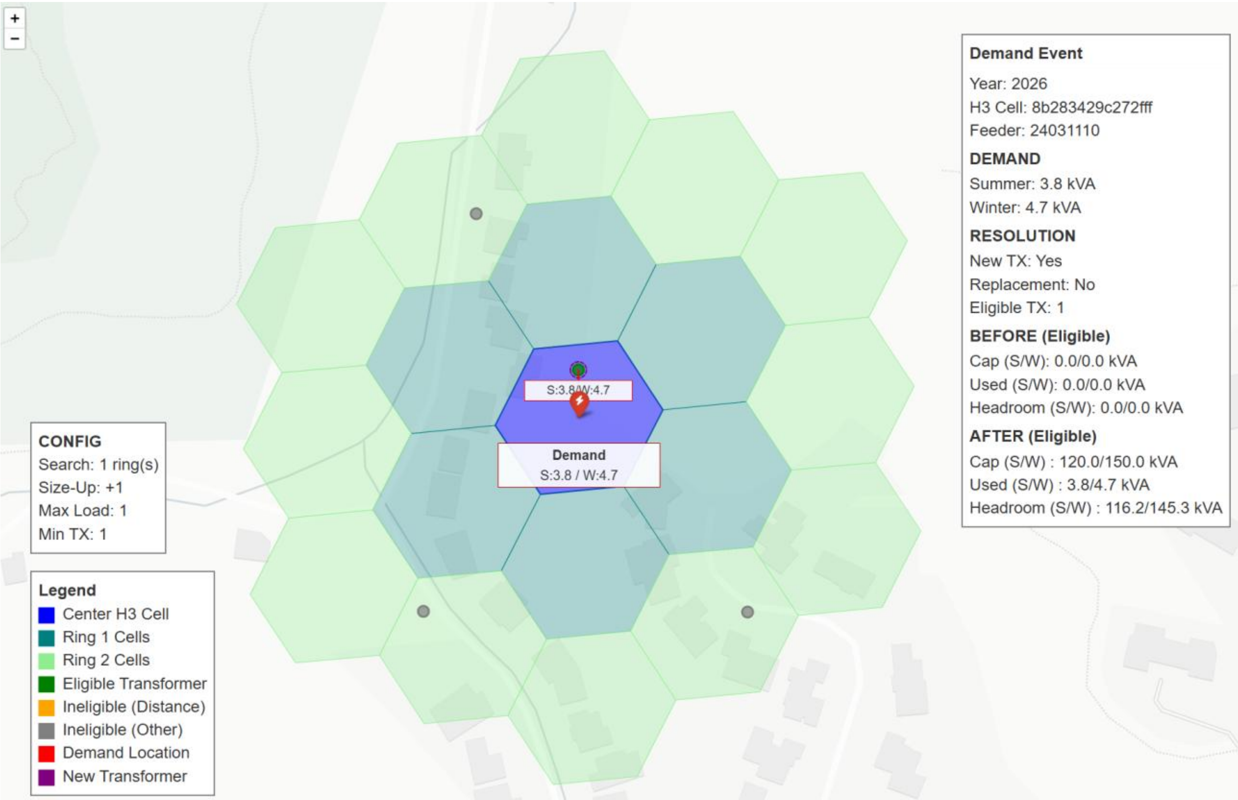
Figure 36 shows the same H3 cell in 2034 with an additional 1.9 kVA of summer and 2.5 kVA of winter coincident load. While the same three transformers remain within the eligibility radius, available capacity has been substantially reduced due to prior allocations from earlier demand events in surrounding cells. Because the remaining headroom is insufficient to fully serve the new load, the model triggers a replacement of the smallest eligible transformer. The original 65 kVA unit is replaced, and consistent with the configured one size-up policy, a 100 kVA transformer is installed, providing 120 kVA (summer) and 150 kVA (winter) of seasonal capacity. This upgrade increases total available capacity within the search radius and the expanded capacity may be leveraged by future demand events in any H3 cell that includes this transformer within its eligibility radius.

Figure 36. Example event 2: transformer replacement triggered by insufficient available capacity



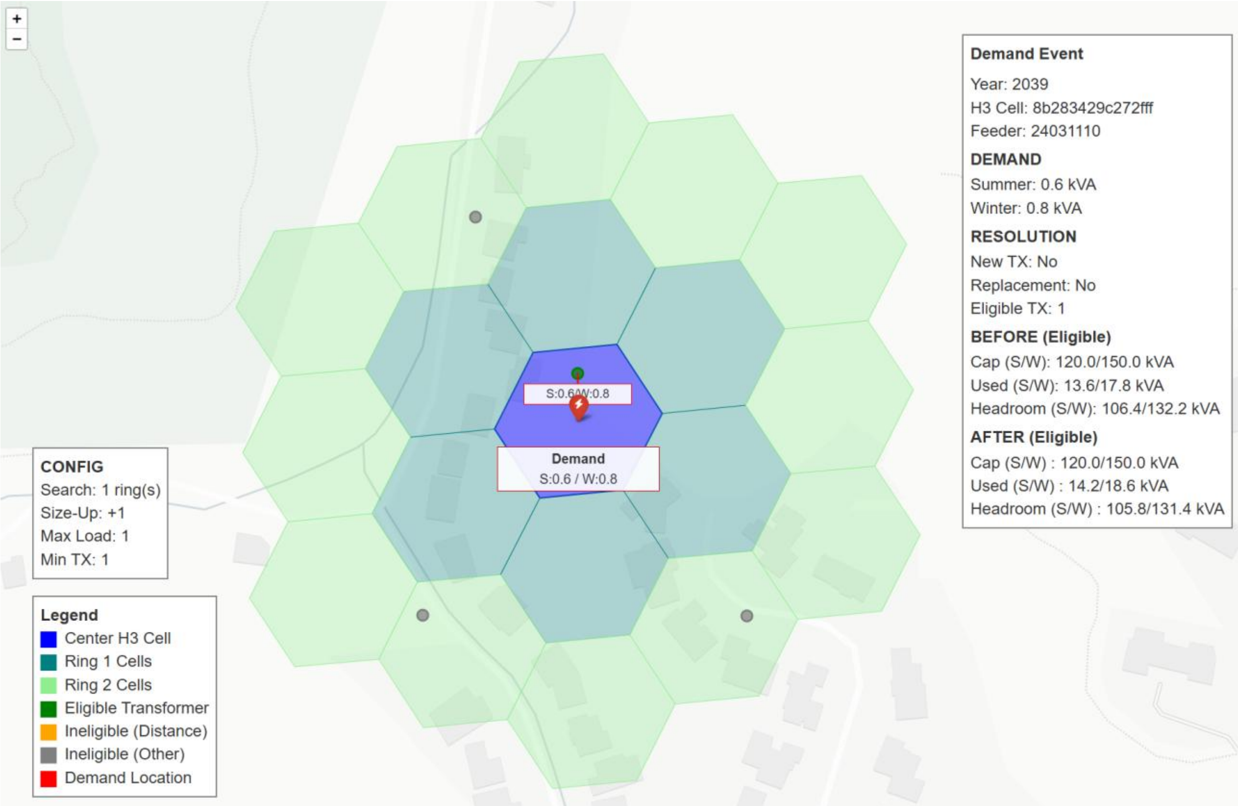
The next two figures show a new H3 cell that see load growth. In Error! Reference source not found., a demand event in 2026 introduces 3.8 kVA of new coincident summer load and 4.7 kVA of new coincident winter load within a single H3 cell. No existing service transformers are found within the configured eligibility radius (one H3 ring), resulting in zero available secondary capacity to serve the new demand. As a result, the model installs a new service transformer to meet the incremental load. Consistent with the configured size-up policy (+1), a 100 kVA transformer is installed, providing 120 kVA (summer) and 150 kVA (winter) of seasonal capacity. The new transformer serves the immediate demand and establishes available capacity that may be leveraged by future demand events in nearby H3 cells within the eligibility radius.

Figure 37. Example event 3: new transformer installation due to absence of eligible capacity



By 2039, the same H3 cell has an additional 0.6 kVA of summer and 0.8 kVA of winter coincident load. The transformer installed in this H3 cell in 2026 remains within the eligibility radius and has sufficient available headroom to accommodate the new demand. Accordingly, the incremental load is allocated to the existing transformer without triggering additional installations or replacements. Remaining transformer capacity continues to be available for future demand events in this and neighboring H3 cells.

Figure 38. Example event 4: subsequent load allocation to previously installed transformer



Secondary Sensitivities

PG&E ran sensitivities for the secondary analysis to understand how different transformer-related assumptions influence long-term cost outcomes. The scenarios tested included:

- **No size-up:** New and replacement transformers are sized at the minimum standard size required to meet coincident demand and loading constraints. No additional conservative oversizing is applied beyond base model assumptions.
- **Size-up 1:** This sensitivity applies a one-step size-up policy, such that all new and replacement transformers are increased by one standard size above the minimum required to serve current coincident demand. This functions as a look-ahead planning assumption, proactively accommodating near-term load growth rather than sizing strictly “just in time.” When forecast growth materializes, this approach can reduce the total number of transformer installations and replacements over time by avoiding repeated incremental upgrades.
- **Higher minimum sizes:** Larger minimum transformer sizes are enforced regardless of calculated coincident demand. This reflects operational or standardization practices that avoid very small installations. This sensitivity operates similarly to the "Size-Up 1" approach above in practice.
- **Replacement at higher loading:** This sensitivity applies a one-step size-up policy while assuming a higher maximum loading fraction (1.5). This means an

upgrade isn't triggered until coincident peak demand reaches 150% rated capacity. This delays the triggering of transformer upgrades.

These cases were designed to capture a realistic range of operational strategies and to quantify how each approach affects projected capital needs over the analysis horizon. The results are shown in Figure 39.

Figure 39. Secondary cost analysis sensitivities

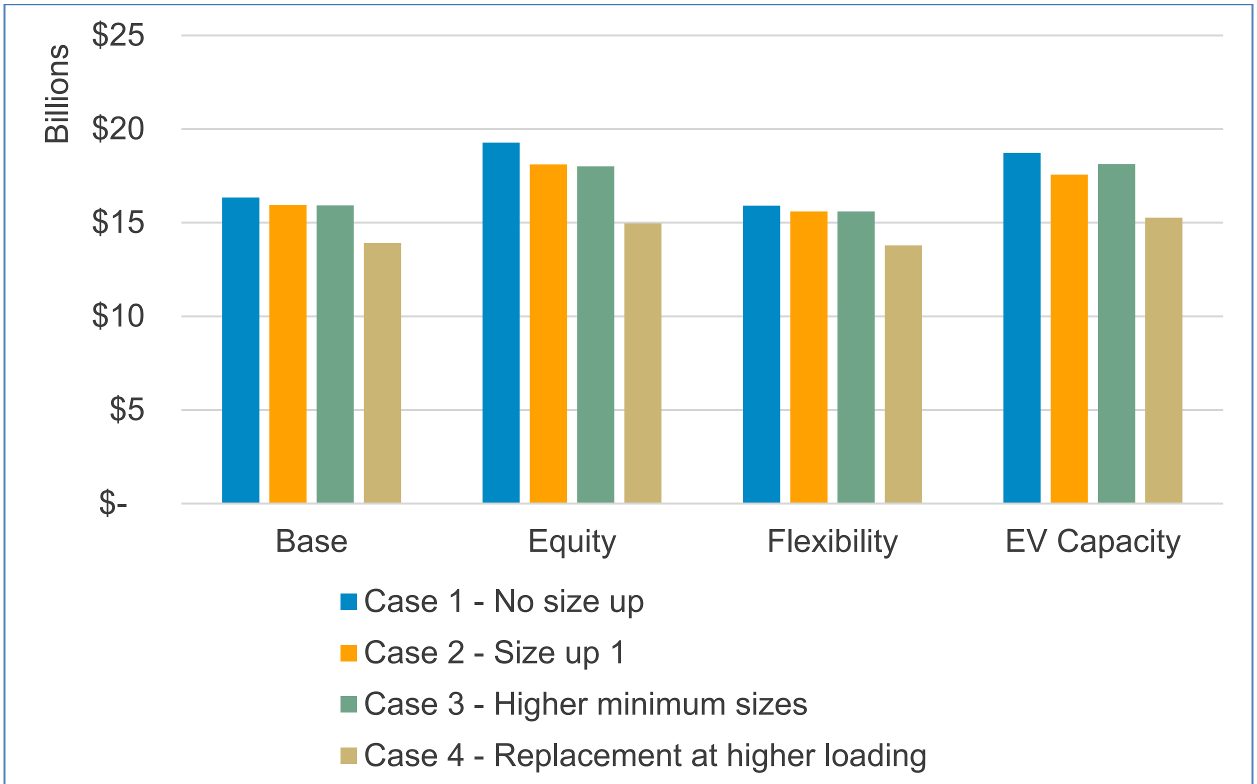


Table 41. Secondary cost sensitivities

Case Studies	Base	Equity	Enhanced Demand Flexibility	EV Capacity Demand
Case 1 - No size up	$16.3	$19.3	$15.9	$18.7
Case 2 - Size up 1	$15.9	$18.1	$15.6	$17.6
Case 3 - Higher minimum size	$15.9	$18.0	$15.6	$18.1
Case 4 - Replacement at higher loading	$13.9	$15.0	$13.8	$15.3

Transformer sizing strategies tested result in a range of $2B-$4B across the scenarios. Approaches that either begin with larger transformers or delay replacements until higher loading levels are reached have lower secondary costs over the study period. These strategies reduce the frequency of upgrades. Variations in cost due to construction type, terrain, or regional construction conditions were not incorporated into this sensitivity analysis. The findings focus solely on the impacts of transformer-related assumptions and distance parameters.

11.3.4. Unit Costs

Unit costs for all assets are consistent with unit costs used in PG&E’s 2027 GRC submission. Appendix C. Unit Costs shows a table of all asset upgrade unit costs in 2030, including costs for bank upgrades, new substation, new feeder, and reconductoring costs. PG&E used an inflation rate of 2.6% to escalate costs through 2040. Costs are not discounted in this study because the solutioning analysis was done for 5 year increments.

11.4. Appendix B. Forecasting Anywhere Technologies Modeled

	Description	Adoption Forecast	Load shapes
TE	Home L1 LDV chargers	**Chargers** CEC EV forecast * time varying chargers/EV ratio from AB2127	E3 generated shapes
	Home L2 LDV chargers		
	Workplace L2 LDV chargers		
	Public L2 LDV chargers		
	Public DCFC LDV chargers		
	Depot DCFC MDV chargers		
	Depot DCFC HDV chargers		
	Depot DCFC school bus chargers		
	Highway DCFC MHDV chargers		
EE	Residential EE	**kW** Annual maximum load from IEPR	Hourly shape from IEPR
	Commercial EE		
DER	Solar PV kW	**kW** Annual maximum discharge from IEPR by class (class split calculated from IEPR capacity)	Hourly shape from IEPR
	Residential Battery Storage		
	Commercial Battery Storage		
BE	Residential Heating HVAC BE	**kW** Annual maximum load from IEPR	HVAC vary geospatially Water heating does not vary geospatially
	Residential Cooling HVAC BE		
	Residential General		
	Commercial Heating HVAC BE		
	Commercial Cooling HVAC BE		
	Commercial General		

11.5. Appendix C. Unit Costs

Description	2030 Unit Cost	Per
New Substation Total	$35,101,481	Substation
Construction	$22,788,962	Substation
Regulatory	$6,480,273	Substation
Land	$2,592,109	5 Acre Parcel
Transmission line remote end work	$3,240,137	Substation
Substation Transformers	$16,524,697	Transformer, = < 45 MVA with Switchgear
	$12,312,520	Transformer, = < 45 MVA Outdoor Bus, Install
	$7,668,324	Transformer, = < 45 MVA Outdoor Bus, Replace
	$1,188,050	Cost adder for transformer > 45 MVA
Circuit Switcher or Breaker	$2,862,121	High Side Circuit Switcher or Circuit Breaker
Breakers	$1,512,064	Low Side Circuit Breaker
Recable SF Circuit outlet in indoor substations	$1,188	Foot
Non-Bay		
OH New	$173	Foot
OH Reconductor	$173	Foot
OH Capacitor (Cap)	$81,003	Capacitor
OH Switch	$55,082	Switch
OH Regulator	$226,810	3 Regulator Bank - Does not Include Materials
OH Recloser	$147,966	Recloser
OH Fuse/Disconnect	$18,361	Fuse/Disconnect
Autotransformer	$1,836,077	Autotransformer
UG New w/trench	$540	Foot
UG New no trench	$486	Foot
UG Switch	$124,205	Switch
UG Interrupter	$167,407	Interrupter
Bay		
OH New	$594	Foot
OH Reconductor	$594	Foot
OH Capacitor (Cap)	$81,003	Capacitor
OH Switch	$55,082	Switch
OH Regulator	$226,810	3 Regulator Bank - Does not Include Materials
OH Recloser	$147,966	Recloser
OH Fuse/Disconnect	$18,361	Fuse/Disconnect
Autotransformer	$1,836,077	Autotransformer
UG New w/trench	$1,140	Foot
UG New no trench	$519	Foot

Description	2030 Unit Cost	Per
UG New no trench - SF Only	$864	Foot
UG Switch	$124,205	Switch
UG Interrupter	$167,407	Interrupter
Distribution OH/UG Transformer (Replace)	$41,225	Transformer
Distribution OH/UG Transformer (Install)	$41,225	Transformer

11.6. Appendix D. Impact of Demand Flexibility on System Load

Figure 40. MHDV Base Scenario profile compared to Enhanced Demand Flexibility

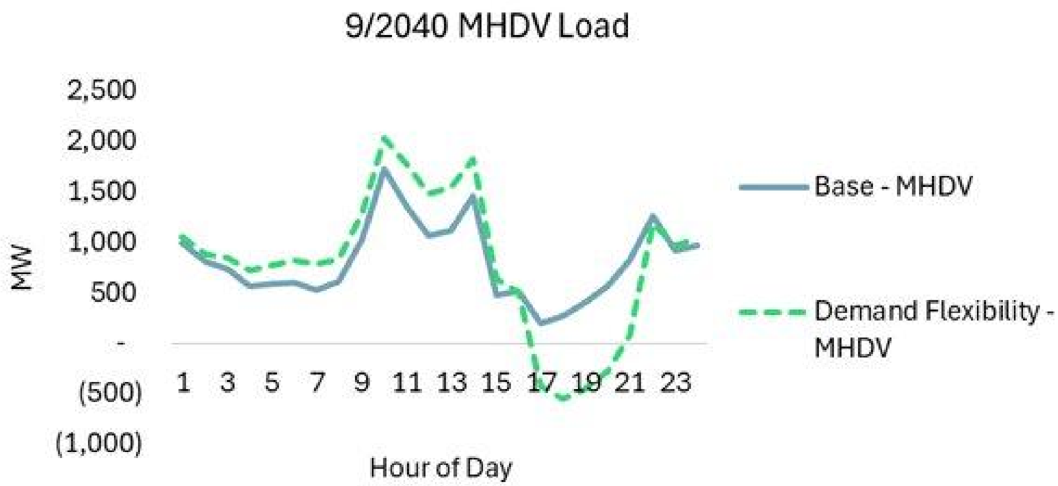


Figure 41. AAFS Base Scenario profile compared to Enhanced Demand Flexibility

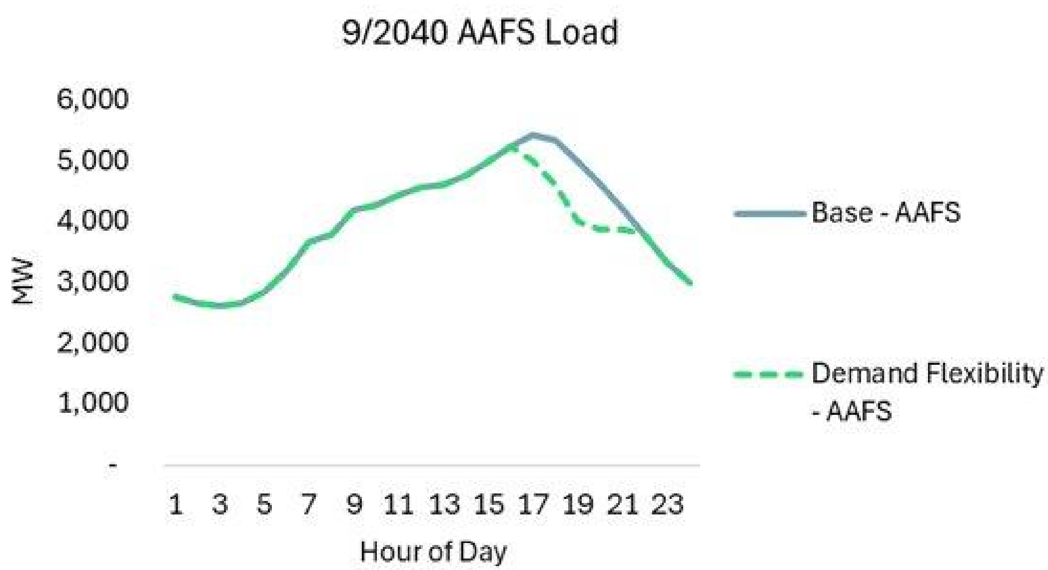


Figure 42. Behind the meter storage Base Scenario profile compared to Enhanced Demand Flexibility

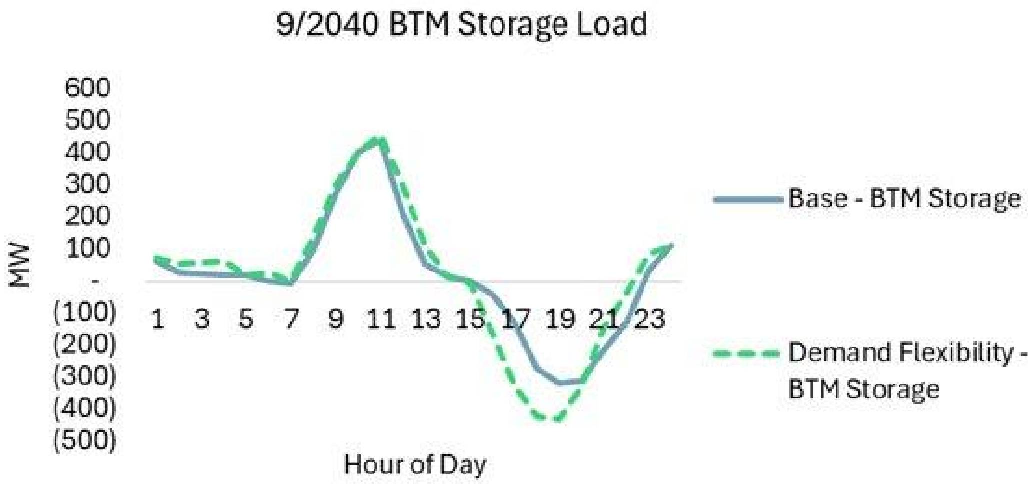
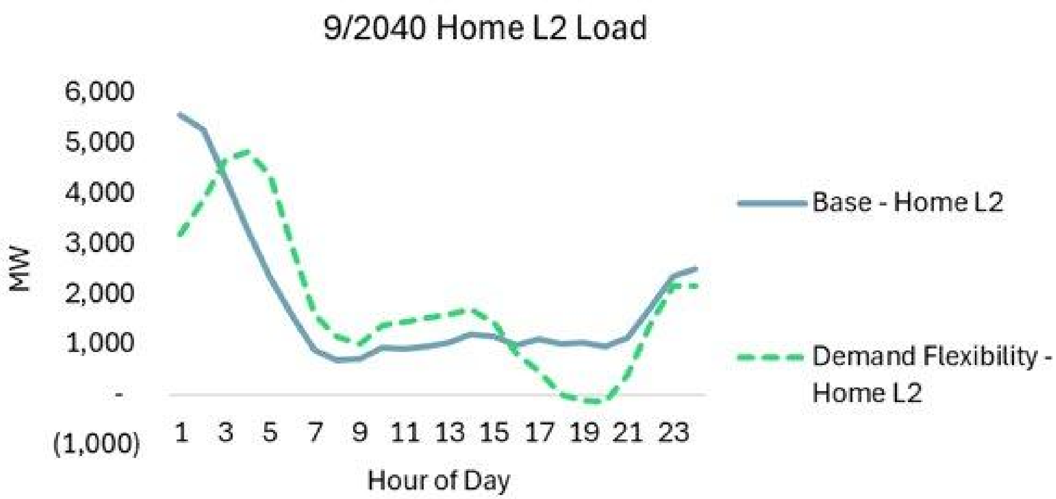


Figure 43. Home L2 Base Scenario profile compared to Enhanced Demand Flexibility



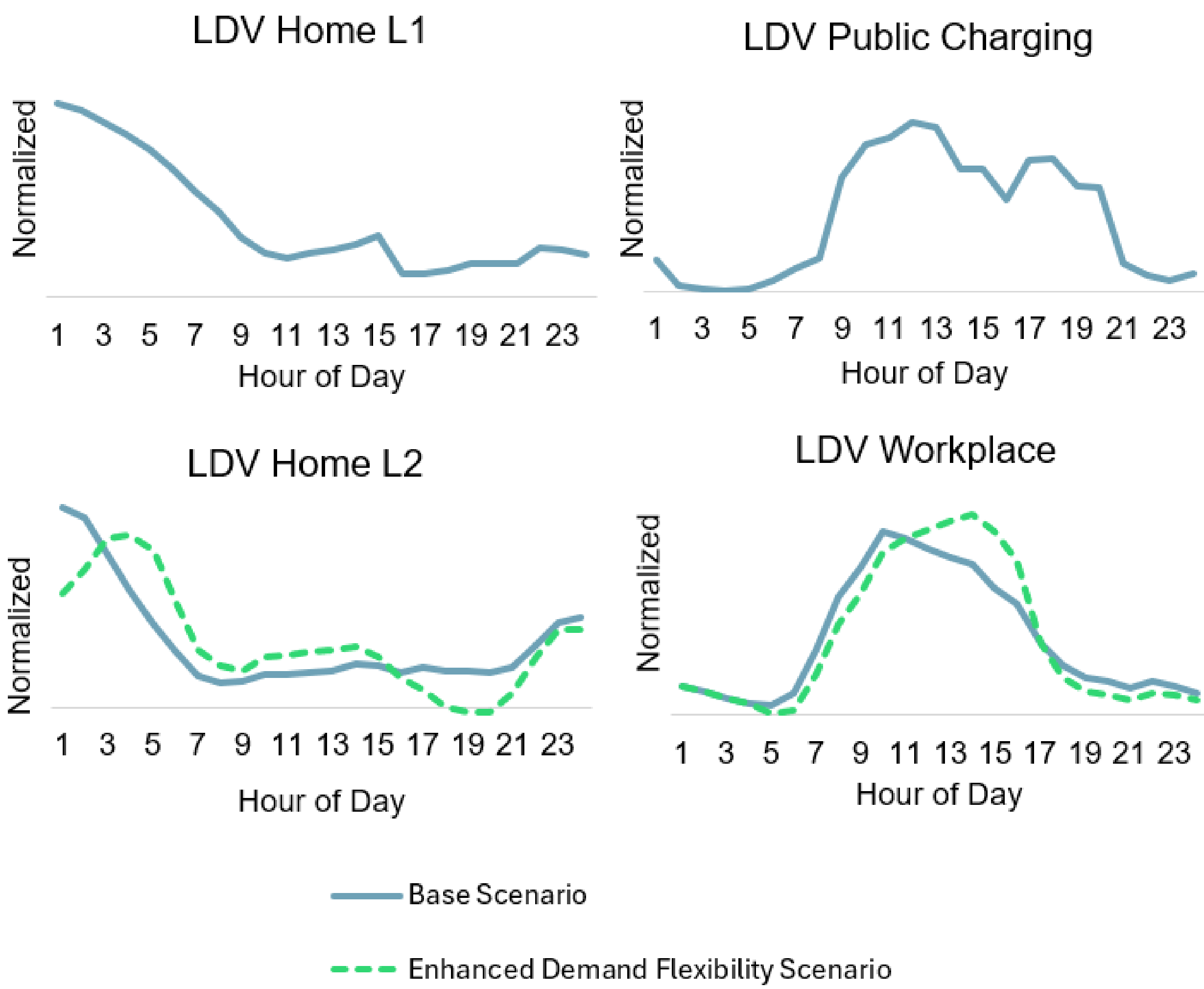
11.7. Appendix E. Load Shapes

In this section, PG&E documents the load shapes generated for the EIS and used in the modeling. If a load shape is not shown here, PG&E used the load profiles from the IEPR (such as for solar PV and energy efficiency).

Load shapes are shown for the Base Scenario and the Enhanced Demand Flexibility Scenario for an example day but note that the load shapes generated and used in the modeling are 8760. Profiles shown below are for a summer day unless otherwise noted.

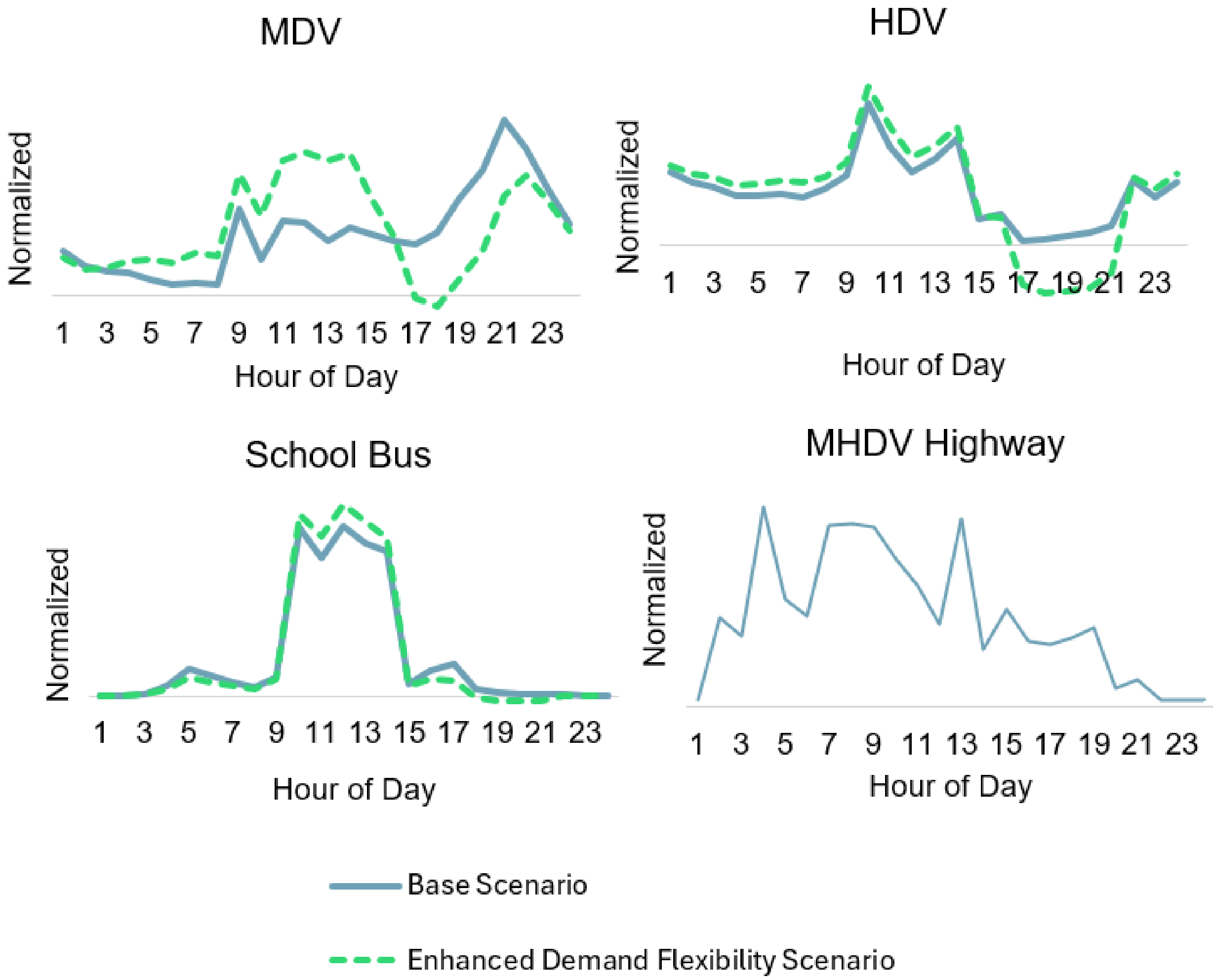
The Equity and EV Capacity Demand Sensitivity use the same normalized shape as the Base Scenario, however, the peaks might have different magnitude.

Figure 44. Example day load profiles for LDV charging



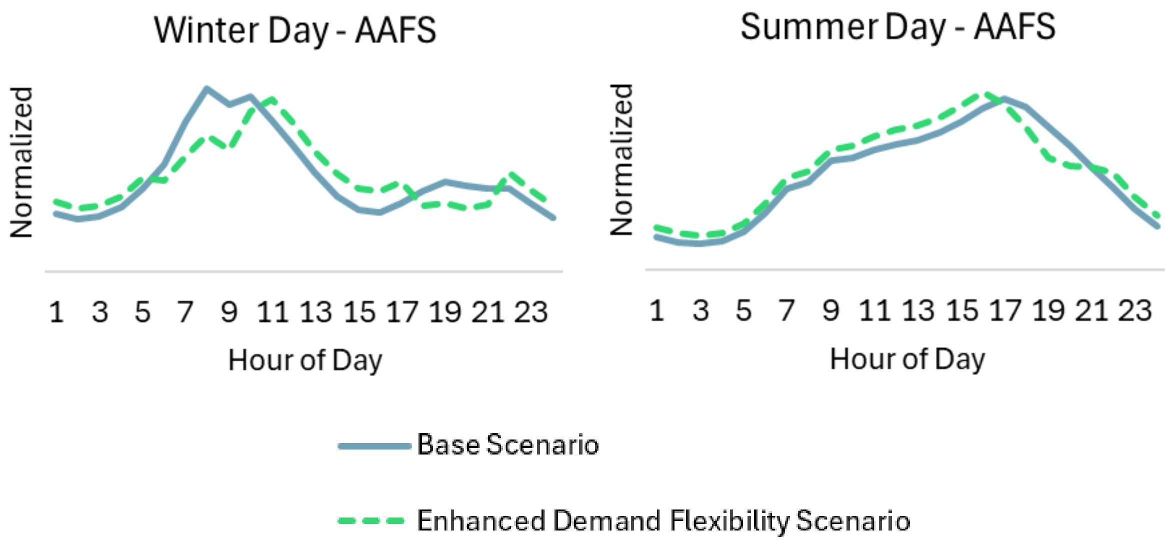
From top left to bottom right: LDV home L1, LDV public (includes L2 and DCFC), LDV home L2, LDV workplace L2. Note that home L1 and public charging do not have demand flexibility modifiers in the Enhanced Demand Flexibility Scenario.

Figure 45. Example day load profiles for MHDV charging



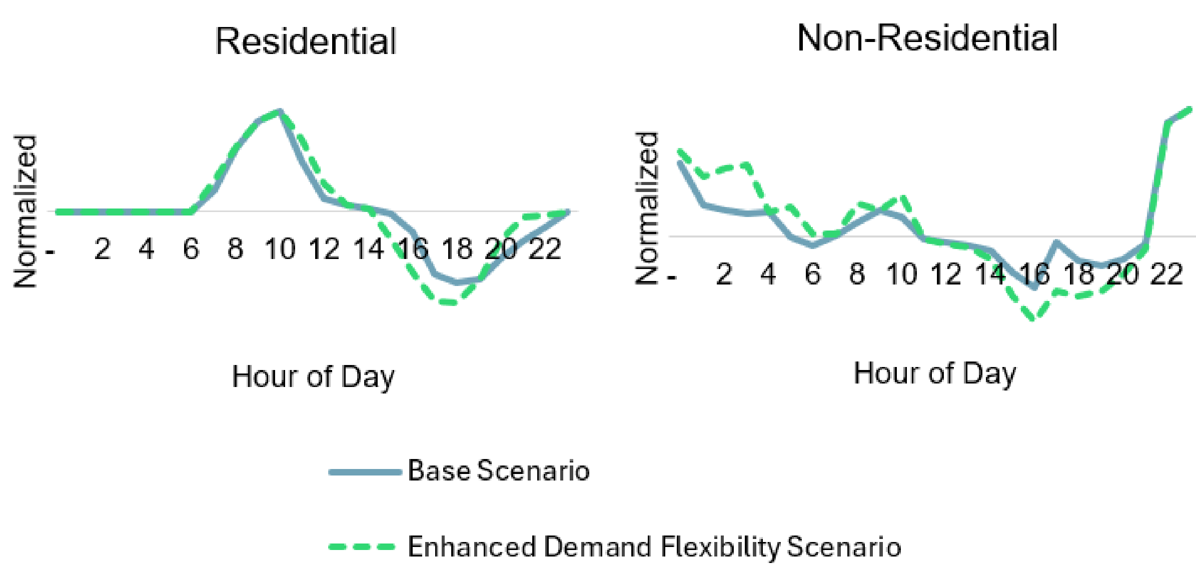
From top left to bottom right: MDV Depot DCFC, HDV Depot DCFC, School Bus Depot DCFC, MHDV Highway Public Charging. Note that public charging does not have demand flexibility modifiers in the Enhanced Demand Flexibility Scenario.

Figure 46. AAFS load profiles by season



A winter day (January) is shown on the left, while a summer day (September) is shown on the right

Figure 47. Example day load profiles for storage



Residential storage is shown on the left, while non-residential storage is shown on the right

11.8. Appendix F. Historical Participation Rates

Table 42. Historical PG&E participation for programs and rates

Year	2018	2019	2020	2021	2022	2023	2024	2025
Rates								
EV2A		42,517	59,456	75,535	98,881	118,718	135,480	159,571
E-ELEC					11	9,848	24,354	34,170
EVB	372	373	400	391	377	411	442	404
EVA	52,921	55,616	9,992	8,070	6,186	5,961	2,748	2
Sub Total	*53,293*	*98,506*	*69,848*	*83,996*	*105,455*	*134,938*	*163,024*	*194,147*
BEV - 1			69	208	217	269	339	458
BEV - 2			101	195	348	483	646	817
Sub Total	*0*	*0*	*170*	*403*	*565*	*752*	*985*	*1,275*
HFP * RES							1	253
HFP * COM							60	99
Sub Total	*0*	*0*	*0*	*0*	*0*	*0*	*61*	*352*
** HFP is a pilot rate available to customers on EV2A, E-ELEC and BEV, already accounted for in the EV rates adoption.*								
Managed Charging								
Resilient Charging					2,697	2,550	1,554	1,268
EVCM							2,761	6,240
Sub Total	*0*	*0*	*0*	*0*	*2,697*	*2,550*	*4,315*	*7,508*
V2X Pilots Residential								
Back Up	0	0	0	0	0	0	2	13
V2G	0	0	0	0	0	0	0	0
Sub Total	*0*	*0*	*0*	*0*	*0*	*0*	*2*	*13*
V2X Pilots Commercial								
Back Up	0	0	0	0	0	0	0	0
V2G	0	0	0	0	0	0	1	0
Sub Total	*0*	*0*	*0*	*0*	*0*	*0*	*1*	*0*

11.9. Appendix G. Stakeholder Comments and Feedback

Table 43. CPUC Energy Division Feedback

#	Request/Comment	Location
1	Contextualize how TE-related uncertainties (charging location, access, workplace/public charging) affect cost range	Section 5 - Adoption and Load Impact Results
2	Add side-by-side comparison table for 2030 vs. 2040 results (peak load, costs by scenario)	Table 11. Peak load and cumulative costs by scenario for 2030 and 2040
3	Clarify which end-use categories drive peak load differences across scenarios	Section 6.1
4	Add narrative on how incremental equity scenario costs inform equity metrics and DPEP implementation	Section 9.1
5	Indicate if additional equity scenario costs are concentrated in specific geographic clusters	Section 5.2 equity scenario
6	Explain how much of the $1.8B demand flexibility savings is realistically achievable under current/foreseeable programs	Section 2.2.5
7	Compare modeled participation rates to historical DR enrollment, current EV rate enrollment, and adoption of controllable tech	Section 11.2.3 and Appendix F
8	Clarify if secondary system constraints were modeled as limits on achievable load flexibility	Section 6.1.3 and Executive Summary.
9	Clarify Table 5 headings ("all MW adopted", "MW adopted in priority populations", etc.)	Table 5
10	Define terms: "overloaded" transformers, "new" transformers, "energization costs", "service connection costs"	Section 3.3 and Section 6.1.4
11	Clarify year for data in Figure 14	Figure 14
12	Explain why project counts per year drop in later years vs. historical	7.2 and Appendix E
13	Discuss readiness activities, actions, and outcomes to address workforce/supply chain risks	Section 7.1
14	Explain equity scenario's higher project counts vs. lower % MW increase; interpret implications for readiness	Section 7.2
15	Detail on project counting methodology and possible over/under-estimates	Section 7.2
16	Describe geospatial TE adoption model consistency (customer-level vs. circuit-level outcomes)	Section 5.1 (at the end)
17	Separate costs: new connections vs. overload mitigation vs. modernization vs. concentrated TE adoption	Section 6.2.4 Figure 12
18	Explain energization-driven upgrades vs. overload-driven upgrades (transformer sizing, costs, asset management)	Section 11.3.3

#	Request/Comment	Location
19	Methodological detail on orchestrated demand flexibility (local level modeling, conflicts between system and local constraints, enabling technology, and constraints)	Section 6.1.3
20	Connect equity scenario assumptions to policies, incentives, funding, demographics, technical constraints	Section 5.2
21	Explain treatment of inflation and discounting in future costs	Appendix A.11.3.4
22	Add summary table of key IEPR assumptions (EVs, building electrification, PV/ES)	Table added in Appendix 11.1.1
23	Indicate if IEPR shapes/trajectories were adjusted for climate zones, housing stock, PV penetration	Appendix A.11.2
24	Expand documentation of TE load shapes, coincidence factors, building electrification profiles.	Appendix E
25	Document differences in EV charging behavior (single-family vs. multifamily)	Appendix A 11.2.2
26	Validate EV load shapes against AMI/submetered data if performed	Appendix A 11.2.2
27	Detail geospatial data sources for equity scenario (CALENVIROSCREEN, SB 535, CARE/FERA, Tribal boundaries)	Section 5.2
28	Describe treatment of overlapping characteristics in allocation methodology	Section 11.1.4
29	Add sensitivity/qualitative discussion of how key input changes affect rate impacts	Section 8.2
30	Note on modeled downward pressure vs. wholesale procurement/transmission cost changes	Section 8
31	Clarify use of supplemental TE data sources for spatial TE adoption calibration/validation	Section 11.2.2
32	Describe integration of scenario planning into future DPP cycles	Section 9.7
33	Describe how equity/demand flexibility insights will affect project prioritization/community engagement	Section 9.1
34	Explain how EIS2 learnings inform equity metrics under D.24-10-030	Section 9.1
35	Explain how TE-driven load forecasts and DER adoption inform pending loads evaluation/prioritization	Section 9.8
36	Clarify if intermediate checkpoints/adaptive triggers will be used for TE/DR changes in planning future cycles	PG&E has not considered developing adaptive planning triggers to incorporate material changes in TE adoption or DR participation.
37	Scenario 4 - Outline how the new EV Capacity Scenario will interact with TE planning in other CPUC proceedings	Section 9.8

#	Request/Comment	Location
38	Scenario 4 - please clarify whether the EV Capacity Scenario will incorporate differentiated assumptions for unmanaged residential charging, commercial depot charging, workplace charging, and public fast charging, as these distinctions materially affect load shapes and infrastructure needs.	PG&E responded to this request through email
39	Scenario 4 - Respond to inquiry in paragraph before final report, preferably before end of 2025	PG&E responded to this request through email
40	Scenario 4 - Please describe how uncertainties in TE adoption, demand flexibility participation, enabling technology availability (e.g., AMI 2.0, controllable EVSE, DERMS), and DR program evolution will be tracked and incorporated into future DPP cycles.	TE Load and adoption, as well as other technologies, will be captured and tracked through the DPEP, including the GNA and DUPR. For example, Pending Loads may reflect Studies or other developments in technologies. Demand Flexibility and technology is being explored via the EPIC 4.08 project.
41	Scenario 4 - A concise adaptive planning framework would strengthen the practical application of EIS2 findings.	Section 9.8

Table 44. Stakeholder Feedback

Stakeholder	Request/Comment	Location/Response
CalAdvocates	PG&E fails to reasonably explain these anomalous results. PG&E states that its new methodology produces results which should not be compared to other studies; however, PG&E fails to fully explain its new methodology and does not provide any information as to how it verified its results. PG&E's Final Report should include additional detail, context, and comparisons in order to allow parties to further evaluate its modeling and results	Appendix A Section 11.3.3
CalAdvocates	PG&E does not report the total number of new and replacement service transformers projected in its Draft EIS Part 2. PG&E's Final Report needs to provide significantly more information about its methodology and its results in order for stakeholders to evaluate their credibility.	Appendix A Section 11.3.3
CalAdvocates	PG&E excludes new transformers from this comparison on the basis that EIS Part 1 only adds service transformers in locations with existing transformers. Rather than breaking down costs between "new" and "replacement," PG&E should report costs broken down between "in a location with existing transformers" and "in a location with no existing transformers."	Appendix A Section 11.3.3
CalAdvocates	A full description of any analyses it performed to verify that the model allocates load growth in a realistic manner, allocates service transformers in a realistic manner, and does not underuse existing transformers or over-estimate new transformers. PG&E should include the results of those analyses and the sources of any additional data that PG&E used for those analyses. If PG&E has not performed any analyses to verify the accuracy of the model, it should include in the Final Report a statement that the methodology is not verified.	Appendix A Section 11.3.3
CalAdvocates	A clear comparison between forecasted installations and historical installations and between forecasted costs and historical	Section 7.2.

Stakeholder	Request/Comment	Location/Response
	costs. In section 7.2 of PG&E Draft EIS Part 2, PG&E should include an additional table comparing historical service transformer installation rates to projected installation rates.	
CalAdvocates	A detailed qualitative discussion of these cost results, explaining PG&E's practical justification of the results and a description of the load growth drivers PG&E believes will place such a disproportionate burden on its existing secondary distribution system	Appendix A Section 11.3.3
CalAdvocates	Contextualize the scale of downward pressure on distribution rates	Section 8.2
CalAdvocates	Elaborate on PG&E's rate modeling	Section 8.1
CalAdvocates	Include all modeled load shapes rather than a sample	Appendix E
CalAdvocates	Elaborate on how PG&E models the evolution of time of use (TOU) rates	PG&E removed from report as this was not explicitly modeled in the EIS and thus was an incorrect statement in the draft.
CalAdvocates	Define key terms with respect to load factor calculations.	PG&E defined all key terms related to load factor in the body of the report.
EDF	Ongoing work in both the Energization Timelines proceeding and High DER proceeding demonstrates that there is significant interest from the Commission, customers, and stakeholder in the development and use of flexible service connections, and this tool cannot simply be ignored in the utilities' EIS analysis	The EIS Part 2 does not specify what solutions are being used to achieve the load management in Scenario 3. Flexible Service Connections could therefore be one type of solution leveraged in this scenario.
EDF	EDF recommends that PG&E revise its analysis to include assumptions regarding active managed charging of EVs consistent with expected application of programs PG&E currently offers (PG&E is currently operating at least two programs – its Charge Manager program and their V2X pilot program -- which by its own definition would be considered active managed charging programs)	PG&E's EIS Part 2 focuses on current BAU trends for active managed charging and does not assume any pilot programs as BAU.
UCAN	The Utility Approach: The IOUs relied on deterministic snapshots—scaling a single "worst-case" peak load profile out to 2040 and	PG&E clarifies that we used 8760 load profiles for each technology, not a single worst case day. The EIS Part 2 is a deterministic scenario based study

Stakeholder	Request/Comment	Location/Response
	applying manual or simplified decision trees to solve for thermal capacity. 3 • The Scientific Standard: The DOE's Integrated Distribution System Planning (IDSP) framework and PNNL Report 28138 establish probabilistic, multi-objective planning as the emerging standard.4 This approach accounts for the uncertainty of adoption and co-optimizes for cost, reliability, and equity, rather than solving for a single thermal constraint. • The Resulting Deviation: Because the IOUs utilized legacy tools for a modern problem, the study results likely represent an "Upper-Bound Wires Ceiling"—the cost of the grid if we refuse to innovate—rather than an optimized roadmap. The results reflect a conservative administrative preference that systematically inflates the need for capital investment.	(rather than probabilistic) that leveraged existing load forecasting and capacity planning tools so that the utilities could build upon their current planning processes. The goal of EIS Part 2 is to estimate the long-term distribution grid infrastructure costs associated with achieving California's electrification goals through 2040 under three scenarios.
UCAN	The "Missing Money": By excluding the administration and incentive costs required to achieve demand flexibility, the study prevents a true cost-benefit analysis. We are left with a false comparison between a "fully loaded" infrastructure cost and a "capital-only" flexibility savings.	Section 6.1.5
UCAN	Ignoring Commercial Technology: Perhaps most critically, PG&E and SDG&E admitted to ignoring commercially available non-wires technologies, such as smart panels and circuit splitters. DOE research confirms these technologies can mitigate secondary system upgrades at a fraction of the cost of civil work	Appendix A Section 11.3.2
UCAN	Supplemental Sensitivity Analysis: UCAN recommends the Commission direct the IOUs to provide specific "Likely Achievable" sensitivities (based on LBNL Phase 4 data) and "Total Resource Cost" estimates (including program costs) before the Final Report is accepted.	PG&E was unable to perform this sensitivity analysis in this timeline as suggested.
UCAN	Incomplete Record: The EIS Part 2 cannot be considered finalized until	PG&E believes that the EIS Part 2 provides a comprehensive and robust record that fully meets and in several

Stakeholder	Request/Comment	Location/Response
	the "Missing Money" (program costs) is accounted for.	areas exceeds the scope established for the study. While program implementation costs ("missing money") were intentionally excluded, the analytical results, methods, and findings offer a complete and transparent assessment of distribution infrastructure needs across scenarios.
UCAN	Non-Precedential Status: The Commission must explicitly rule that the cost estimates in these reports are illustrative only. They must not serve as the evidentiary basis or a rebuttable presumption of reasonableness for the 2026 Distribution Planning Process (DPP) or future General Rate Cases (GRC).	Section 3.
CALIFORNIA COMMUNITY CHOICE ASSOCIATION	Since distribution system costs are a large and growing cost component of electricity rates, the IOUs must be diligent in identifying assumptions, limitations of the study, and potential mitigation measures to offset potential rate increases.	Section 8
CALIFORNIA COMMUNITY CHOICE ASSOCIATION	PG&E should revise its assumptions for Level 1 (L1) and Level 2 (L2) Electric Vehicle (EV) charging participation in dynamic pricing programs	PG&E believes the assumptions created for L1 and L2 charging behaviors represents the most realistic outcome based on data and industry knowledge.
CALIFORNIA COMMUNITY CHOICE ASSOCIATION	PG&E should reassess its assumptions for new transformers on the secondary system	Appendix A Section 11.3.3
CALIFORNIA COMMUNITY CHOICE ASSOCIATION	PG&E should update its Enhanced Demand Flexibility scenario to not assume perfect orchestration.	PG&E reported the Enhanced Demand Flexibility costs assuming orchestration is involved. PG&E also includes a sensitivity without orchestration in Section 6.1.3.
CALIFORNIA COMMUNITY CHOICE ASSOCIATION	The IOUs should provide details about the assumptions used in their Base Cases, as they serve as the foundation for evaluating the results of the other scenarios. The IOUs should also align the assumptions for their Base Cases to the extent possible, enabling a comparison of the effectiveness of the mitigation measures across the IOUs and supporting fair and equal treatment of all customers	Appendix A Section 11.3.2