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) DRAFT ELECTRIFICATION IMPACT STUDY PART 2

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Dated: October 31, 2025

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Pursuant to Ordering Paragraph (OP) 19 of Decision (D.) 24-10-030, issued October 23, 2024, Pacific Gas and Electric Company (PG&E) respectfully submits its draft Electrification Impact Study Part 2 (Draft Study). On September 24, 2025, the California Public Utilities Commission's (Commission) Energy Division Executive Director issued a Rule 16.6 letter granting extension of time to comply with OP 19 of D.24-10-030 to October 31, 2025. The Draft Report is attached as Attachment A.

Respectfully submitted,

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ATTACHMENT A

Pacific Gas and
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ELECTRIFICATION IMPACTS STUDY PART 2 (DRAFT)

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

1. Acronyms and Definitions 8
2. Executive Summary 10
  2.1. Methodology Overview 11
  2.2. Key Findings 13
    2.2.1. Key Finding 1: Electrification growth may provide downward pressure on distribution rates by as much as 25% by 2040 13
    2.2.2. Key Finding 2: Electrification requires between $23 billion and $31 billion of distribution electrification investments through 2040. 13
    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. 14
    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 15
    2.2.5. Key Finding 5: Enhanced orchestrated demand flexibility can reduce distribution infrastructure costs by an additional $1.8B (7%) through 2040 15
    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 16
    2.2.7. Key Finding 7: The average load factor is ~69% in 2040, including ~500 feeders with a load factor greater than 80% 17
  2.3. Next Steps 17
3. Study Overview 19
  3.1. Scenario Descriptions 19
  3.2. Study Forecast and Scope 20
  3.3. Scope of EIS Part 2 compared to EIS Part 1 21
  3.4. Structure of this Report 22
4. Methodology Overview 23
5. Adoption and Load Impact Results 25
  5.1. Base (Mitigated) Scenario 25
  5.2. Equity Scenario 26
  5.3. Enhanced Demand Flexibility Scenario 30

5.3.1. Aggregated Demand Flexibility 30
5.3.2. Enabling Demand Flexibility 34
6. Distribution Planning, Solutioning, and Costing Results 34
6.1. Cost Results by Scenario 34
6.1.1. Base (Mitigated) Scenario 34
6.1.2. Equity Scenario 35
6.1.3. Enhanced Demand Flexibility Scenario 36
6.1.4. Cost Comparisons by Scenario 37
6.2. Comparison to other Electrification Studies 38
6.2.1. EIS Part 1 Study 39
6.2.2. Public Advocates Office (PAO) Distribution Grid Electrification Model (DGEM) 40
6.2.3. GridLab and Kevala's California Load Management Standard Avoided Distribution Grid Upgrade Study 40
6.2.4. Comparison of Study Results 40
6.2.1. Sensitivity of Secondary Costs 43
7. Budgeting and Implications of Resources 44
7.1. Cost Comparisons to Historical Costs 44
7.2. Equipment Results by Scenario 46
7.3. Economic, Material and Resource Considerations 49
8. Downward Pressure on Distribution Rates 49
8.1. Downward Rate Pressure Calculation Methodology 50
8.2. Downward Rate Pressure Calculation Results (Preliminary) 51
9. Key Takeaways and Insights into Distribution Planning 52
9.1. Equity in Distribution Planning 52
9.2. Load Factor and Impact on Capacity 53
9.3. Average Bank Headroom Decrease over time 55
9.4. Incorporation of EIS Findings into Planning 56
10. Conclusion 58
11. Appendix A: EIS Methodology 59
11.1. Step 1: Geospatial Adoption Forecasting 59
11.1.1. Adoption Forecast 59

- 11.1.2. Technical Potential 61
- 11.1.3. Propensities 63
- 11.1.4. Geospatial Adoption Modeling: Equity Scenario 64

11.2. Step 2: Load Impacts Modeling 66
- 11.2.1. Building Electrification 66
- 11.2.2. Electric Vehicle Chargers 67
- 11.2.3. Load Shapes: Enhanced Demand Flexibility Scenario 69
- 11.2.4. Sensitivity: Un-orchestrated Enhanced Demand Flexibility Scenario 79

11.3. Step 3: Distribution Planning, Solutioning, and Costing 80
- 11.3.1. Identifying Overloads 81
- 11.3.2. Solutioning Approach 81
- 11.3.3. Secondary Analysis 82
- 11.3.4. Unit Costs 84

11.4. Appendix B. Forecasting Anywhere Technologies Modeled 85

11.5. Appendix C. Unit Costs 86

11.6. Appendix D. Impact of Demand Flexibility on System Load 88

Figures

Figure 1. Overview of methodology 12
Figure 2. Total distribution costs (primary and secondary) by scenario and in cumulative, nominal dollars 14
Figure 3. Summary of EIS Part 2 methodology 23
Figure 4. Base Scenario residential EV charger adoption over time by feeder 25
Figure 5. Base Scenario residential AAFS adoption by feeder 26
Figure 6. Residential EV charger adoption by feeder in the Equity versus the Base Scenario 29
Figure 7. Residential AAFS adoption by scenario and by feeder 29
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 31
Figure 9. Coincident peak load reduction from Enhanced Demand Flexibility Scenario (top) and technical potential estimated by D-Flex for 2040 (bottom) 32
Figure 10. Hourly demand flexibility by category for a peak summer day (top) and peak winter day (bottom) 33
Figure 11. Cumulative primary and secondary costs for each scenario for 2030, 2035, and 2040 38
Figure 12. Secondary costs in 2040 by scenario, split into two components: overloaded service transformers and new transformers (including new service connections) 41
Figure 13. Comparison of annual costs for the EIS Part 2 and EIS Part 1 (Base Cases). The scope of the secondary costs for the EIS Part 2 includes only the overloaded transformers component to make results more comparable. 42
Figure 14. 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. 42
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. 43
Figure 16. Illustration of downward rate pressure calculation methodology 50
Figure 17. PG&E community engagement tools for the DPP 53
Figure 18. Distribution of load factors for Feeders (in 2040) for the Base Case and Enhanced Demand Flexibility Scenarios 55
Figure 19. Step 1: Geospatial adoption forecasting 59
Figure 20. Example of H3 level 11 resolution – a neighborhood (left) and a football stadium (right) 62
Figure 21. Priority populations from CEC designations 65
Figure 22. Step 2: Load impacts modeling 66
Figure 23. Residential heating (left) and cooling (right) 67
Figure 24. EV management types 69
Figure 25. Flexible loads modeled in the Enhanced Demand Flexibility Scenario 70

Figure 26. Home L2 charging profile (left) shifting from evening to mid-day and a response to dynamic pricing (right)x 72
Figure 27. Shift in Home L2 charging profile due to the combined charge management approaches (dynamic rates and active management) 73
Figure 28. Normalized V2G shapes for the Enhanced Demand Flexibility Scenario 75
Figure 29. Increased utilization of residential storage load shapes for Enhanced Demand Flexibility Scenario 76
Figure 30. 2040 LBNL supply curve for PG&E technical potential shed and shift.......... 77
Figure 31. The three identified clusters with different peak times during summer (left) and winter (right) with average load shape (black line). 78
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. 79
Figure 33. Step 3: Distribution planning, solutioning, and costing 80
Figure 34. MHDV Base Scenario profile compared to Enhanced Demand Flexibility 88
Figure 35. AAFS Base Scenario profile compared to Enhanced Demand Flexibility 88
Figure 36. Behind the meter storage Base Scenario profile compared to Enhanced Demand Flexibility 89
Figure 37. Home L2 Base Scenario profile compared to Enhanced Demand Flexibility 89

Tables

Table 1. Acronyms and definitions..8
Table 2. Total primary and secondary costs for 2025-2040 by scenario (in cumulative nominal dollars) 14
Table 3. Key differences between the EIS Part 1 and EIS Part 2 scopes......................22
Table 4. High level overview of modeling differences between scenarios 24
Table 5. Increased adoption in priority populations in the Equity Scenario....................27
Table 6. Enhanced Demand Flexibility Scenario coincident load flexibility in kW..........32
Table 7. Enhanced Demand Flexibility Scenario noncoincident load flexibility in kW....33
Table 8. Base Scenario cost breakdown in $ billion* 35
Table 9. Equity Scenario cost breakdown in $ billion* 36
Table 10. Enhanced Demand Flexibility Scenario cost breakdown in $ billion 37
Table 11. Distribution line average costs over time compared to historical costs ($M)..45
Table 12. Bank and feeder annual costs over time compared to historical costs ($M) ..46
Table 13. Annual number of new feeders compared to historical rates of installation ...47
Table 14. Annual number of new banks compared to historical rates of installation......47
Table 15. Annual number of replaced banks compared to historical rates of installation 47
Table 16. Annual miles of new conductor compared to historical rates of installation ...48
Table 17. Annual number of projects compared to historical rates of project completion 49
Table 18. Preliminary results: downward rate pressure for Base (Mitigated) Scenario..52
Table 19. Example of impact of load factor on equipment ratings 54
Table 20. Average load factor for feeders for the Base and Enhanced Demand Flexibility Scenario in 2030, 2035, and 2040 54
Table 21. Bank average headroom (MW) - summer / winter 56
Table 22. DER and electrification technologies modeled...60
Table 23. Technical potential methodology 63
Table 24. Propensity methodology 64
Table 25. Updated load shape sources 66
Table 26. EV management assumptions (Base Scenario) 69
Table 27. Customer responsiveness to dynamic pricing (Enhanced Demand Flexibility Scenario) 71
Table 28. Customer responsiveness to actively managed charging signals 73
Table 29. V2G modeling assumptions for Enhanced Demand Flexibility Scenario 74
Table 30. Effectiveness of demand flexibility depend on locally informed load management...80

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 (7%) through 2040.

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 scenarios to reflect a base case of adoption, equity-driven electrification, and enhanced demand flexibility.

- 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.

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

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[1] D.24-10-030 OP20

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)[2] and load profiles incorporated existing and future customer behaviors, like evolving time-of-use (TOU) rates. 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[3] 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.[4] 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.

This report, including all findings and numerical results, is a draft report. PG&E will incorporate stakeholder feedback, continue to validate its findings, and refine inputs prior to publication of its Final Report in January 2026.[5] Therefore, all results and findings in this draft report are to be considered preliminary.

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.

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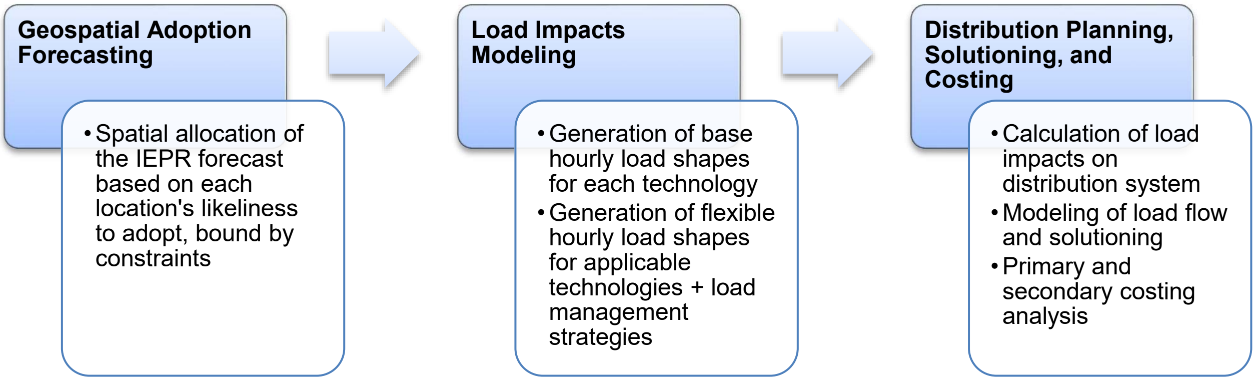
[2] For example, PG&E identified more than 1,000 load transfers resulting in the reallocation of more than 300 MW of load across substation and distribution systems, allowing for optimized utilization of existing infrastructure and minimizing the need for new capital investments.

[3] 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).

[4] 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.

[5] For example, PG&E is currently re-evaluating its modeling of energy efficiency that is expected to have a small (<10%) impact on the primary cost results but will not affect the conclusions of the report.

Figure 1. Overview of methodology


Geospatial Adoption Forecasting
• Spatial allocation of the IEPR forecast based on each location's likeliness to adopt, bound by constraints
Load Impacts Modeling
• Generation of base hourly load shapes for each technology
• Generation of flexible hourly load shapes for applicable technologies + load management strategies
Distribution Planning, Solutioning, and Costing
• Calculation of load impacts on distribution system
• Modeling of load flow and solutioning
• Primary and secondary costing analysis

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 a preliminary 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.

Preliminary results for the Base (Mitigated) Scenario show a small upwards (~1.6%) upwards 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 preliminary 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.

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]

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[6] The preliminary 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 preliminary 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.

[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]

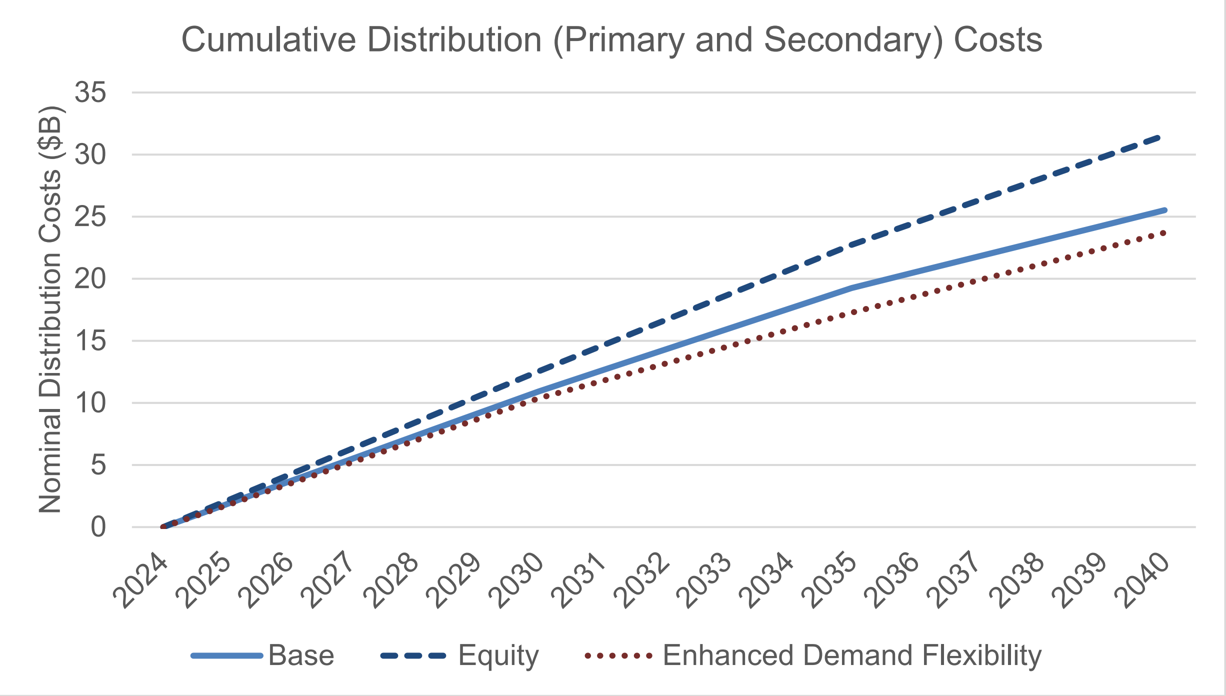

Table 2. Total primary and secondary costs for 2025-2040 by scenario (in cumulative nominal dollars)

Scenario	Primary System Cost	Secondary System Cost	*Total Upgrade Costs*
Base Scenario	$9.6 billion	$15.9 billion	***$25.5 billion***
Equity Scenario	$13.4 billion	$18.1 billion	***$31.6 billion***
Enhanced Demand Flexibility Scenario	$8.5 billion	$15.2 billion	***$23.7 billion***

**Numbers may not add exactly due to rounding*

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.

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[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 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). 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 (e.g., evolving TOU rates). 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 (7%) through 2040.

PG&E's Enhanced Demand Flexibility Scenario reduced distribution infrastructure costs by approximately $1.8 billion or 7% 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 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.

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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.

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.

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). Furthermore, the benefits of the increased electrification and DER adoption in disadvantaged, low-income, and Tribal communities are not quantified in the study.

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

[14] This additional electrification and DER growth increases the summer system peak by 1.8 GW in 2040.

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 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.

2.3. Next Steps

Following the filing of this draft report on October 31st, 2025, PG&E will participate in a CPUC workshop in mid-November to share the preliminary results and gather stakeholder feedback. PG&E's Final EIS Part 2 Report will incorporate stakeholder feedback and will be filed by January 28th, 2026.

Furthermore, PG&E plans to further assess how electrification enabled by energization investments may provide a downward pressure on distribution rates. PG&E also plans to complete a fourth Scenario (an "EV Capacity Scenario"), which will explore new methods of forecasting EV capacity demand unconstrained by the IEPR energy cap. This work will be included in the Final Report.

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[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.

Lastly, PG&E plans to incorporate learnings from the EIS Part 2 study into its planning processes. Learnings regarding Scenario Planning, orchestration and modeling of demand flexibility, and increasing Load Factors can be directly incorporated into PG&E's distribution planning process. Furthermore, the EIS provides a foundational framework for long-term consideration of how to optimize secondary investments to improve service planning outcomes in serving customer energizations.

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 position 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). 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 in the annual Distribution Planning Process (DPP). Distribution engineers

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[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

mitigated costs by developing low-cost solutions where feasible (e.g., load transfers) and load profiles incorporated existing and future customer behaviors (e.g., evolving TOU rates). 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.

PG&E is modeling an additional scenario for potential inclusion in the Final Report that may inform future distribution planning for transportation electrification. This **EV Capacity Scenario** is a local charging demand forecast which combines the system-level IEPR assumptions with PG&E's charger demand estimates, designed to better capture the distribution and secondary infrastructure needs of a comprehensive EV charging network. Methodology, assumptions, and results (not available yet) are not included in this draft report but will be made available in the final report.

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.

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.[18] 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.[19]

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.[20] 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 (e.g., evolving TOU rates).

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,[21] based on examining service transformer capacity overloads.[22] . The EIS Part 2 modeled service transformer overloads, but coupled geospatial forecasting using LoadSEER[23] and CYME[24] 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. 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.[25]

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[18] The study period is inclusive, meaning 2025-2040 is 16 years of forecasted electrification growth relative to 2024.

[19] 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.

[20] EIS Part 1, ES-6.

[21] EIS Part 1, ES-10.

[22] EIS Part 1, p 110.

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 (including overloads)

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 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 next steps based on the study. Lastly, Section 11 provides detailed discussion of the inputs and methodology for each modeling step.

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[23] 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/

[24] 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

[25] 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

4. Methodology Overview

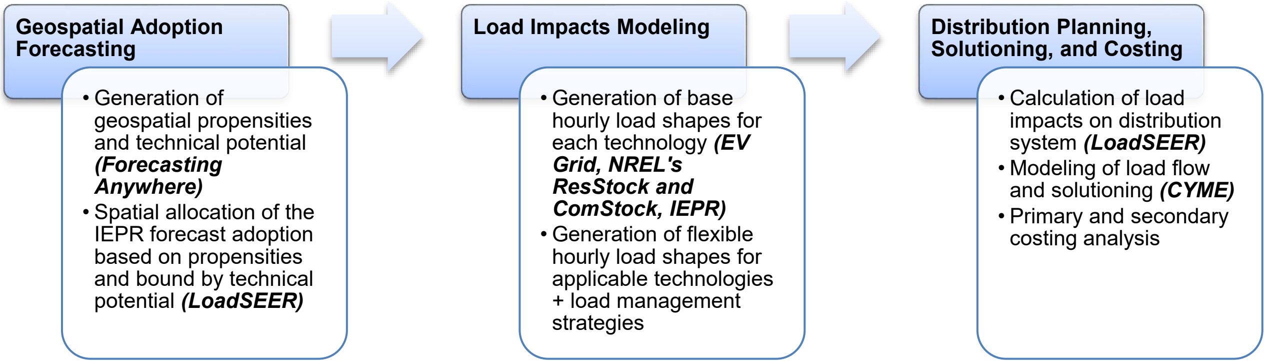
This EIS Part 2 report estimates the distribution energization costs that will be required to support California's electrification goals in different scenarios through 2040. PG&E developed a robust modeling methodology that emphasizes transparency, scenario flexibility, and alignment with real-world 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



Geospatial Adoption Forecasting

- Generation of geospatial propensities and technical potential ***(Forecasting Anywhere)***
- Spatial allocation of the IEPR forecast adoption based on propensities and bound by technical potential ***(LoadSEER)***

Load Impacts Modeling

- Generation of base hourly load shapes for each technology ***(EV Grid, NREL's ResStock and ComStock, IEPR)***
- Generation of flexible hourly load shapes for applicable technologies + load management strategies

Distribution Planning, Solutioning, and Costing

- Calculation of load impacts on distribution system ***(LoadSEER)***
- Modeling of load flow and solutioning ***(CYME)***
- Primary and secondary costing analysis

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. Solutioning was considered 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
Adoption Forecasts	IEPR 2023	IEPR 2023 + *incremental adoption to reach equity target*	IEPR 2023
Technical Potential	Base	Base + *revised technical potentials for incremental adoption, to reach equity target*	Base
Propensities	Base	Base	Base + *percent adoption of load flexibility*
Load Shapes	Base	Base	Base + *Enhanced Flexible Load*

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

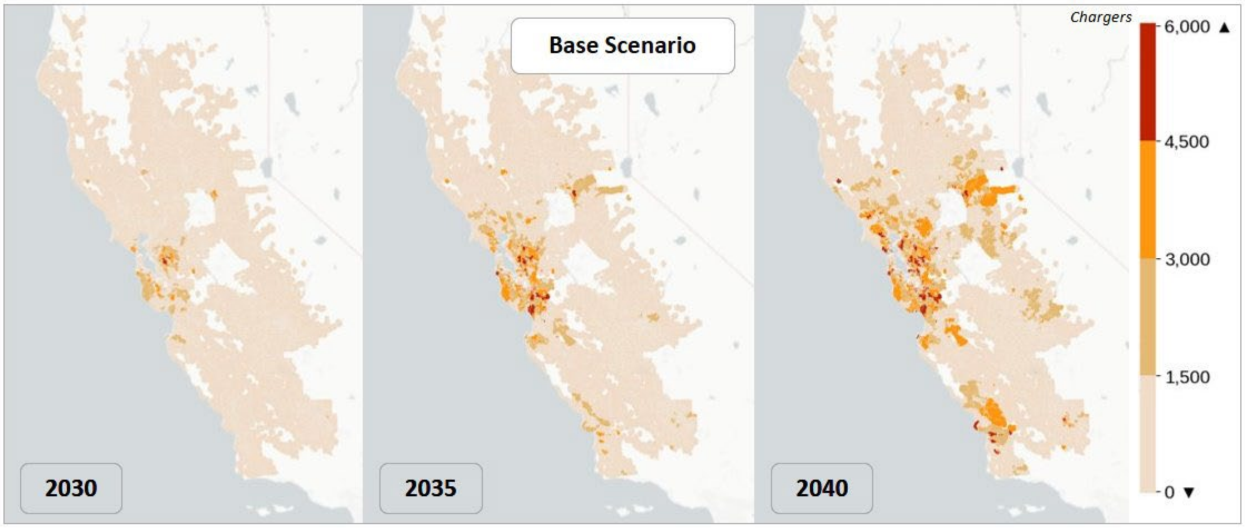


Figure 4 shows spatial adoption of residential EV chargers (home L1 and L2 chargers) over time. Feeders with higher adoption are dark red (4,500-6,000 chargers adopted). Each snapshot is on the same scale. In 2030 (far left), there are not many dark red feeders. Most feeders are light tan, meaning there 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

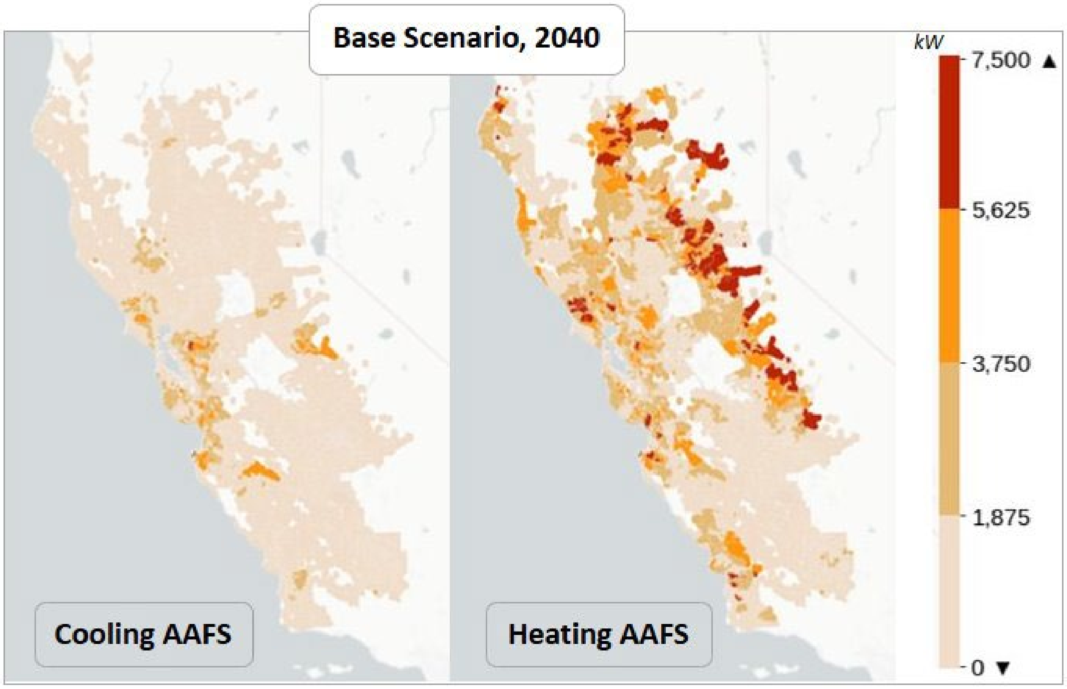


Figure 5 shows adoption of residential AAFS cooling (left) and AAFS heating (right) in the Base Scenario in 2040. Winter-peaking heating end use cases make a large portion of the IEPR AAFS load forecast This adoption occurs mostly along the eastern and western sections of PG&E’s territory, with less 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.

5.2. Equity Scenario

Table 5 summarizes the adoption that would need to occur in order to achieve balanced adoption between priority populations and non-priority populations for the Equity Scenario. The additional MW adoption is based on the CPUC’s adoption ratio defined for the Equity Scenario.

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

Load Type	All MW Adopted	MW Adopted in Priority Populations	All kW / All Customers	Priority kW / Priority Customers	% Increase Needed in Priority Adoption	Load Increase in Priority Populations (MW)
Home L1	589	267	0.120	0.090	81%	217
Home L2	6,824	2,364	1.386	0.798	185%	4,368
Residential Cooling	1,489	607	0.302	0.205	119%	725
Residential Heating	4,113	1,912	0.835	0.645	74%	1,410
School Bus	68	37	0.014	0.012	31%	11
Commercial Cooling	7	6	0.023	0.033	Not needed	0
Commercial Heating	2,092	1,262	6.669	6.800	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
Work L2	782	409	2.492	2.201	32%	132
Public DCFC	1,036	606	0.198	0.192	7%	42
Public L2	564	341	0.108	0.108	Not needed	0

For home L1, 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 L1 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 forecasted to be adopted by priority customers in the Base Scenario. A 185% increase of 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 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. 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

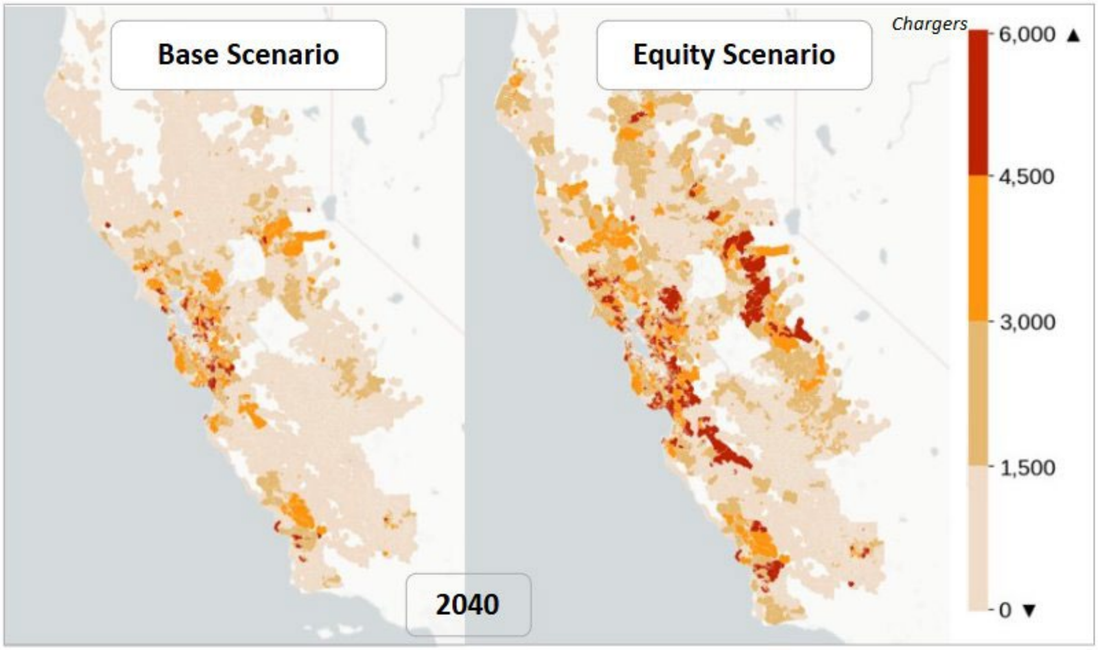
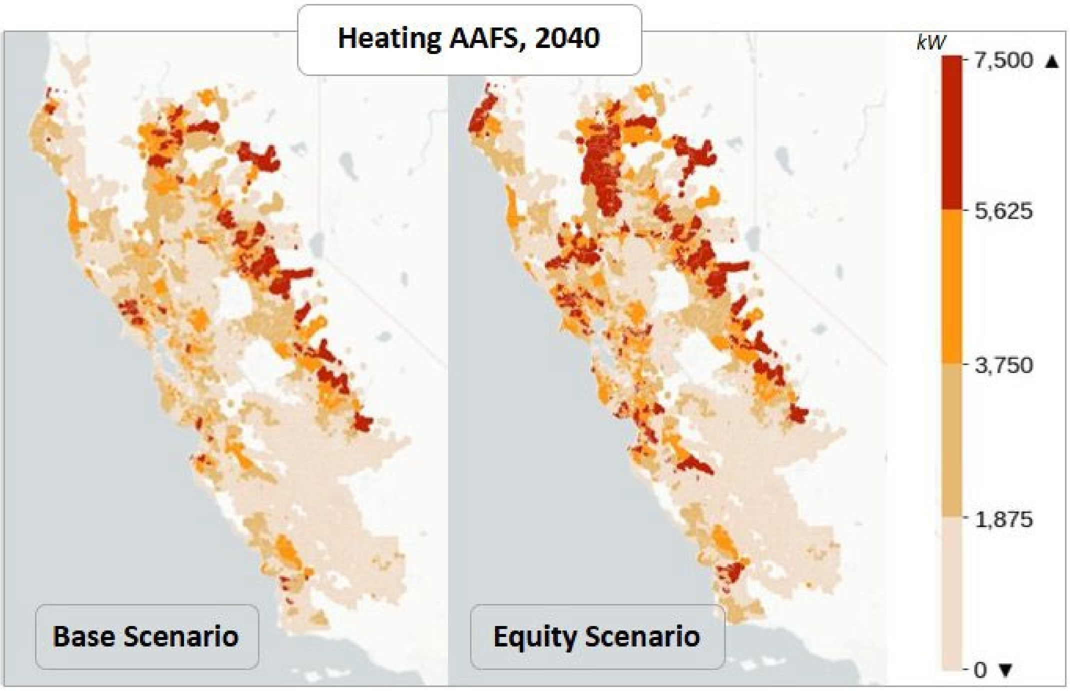

Base Scenario
Equity Scenario
Chargers
6,000 ▲
4,500
3,000
1,500
0 ▼
2040

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


Heating AAFS, 2040
kW
7,500 ▲
5,625
3,750
1,875
0 ▼
Base Scenario
Equity Scenario

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.

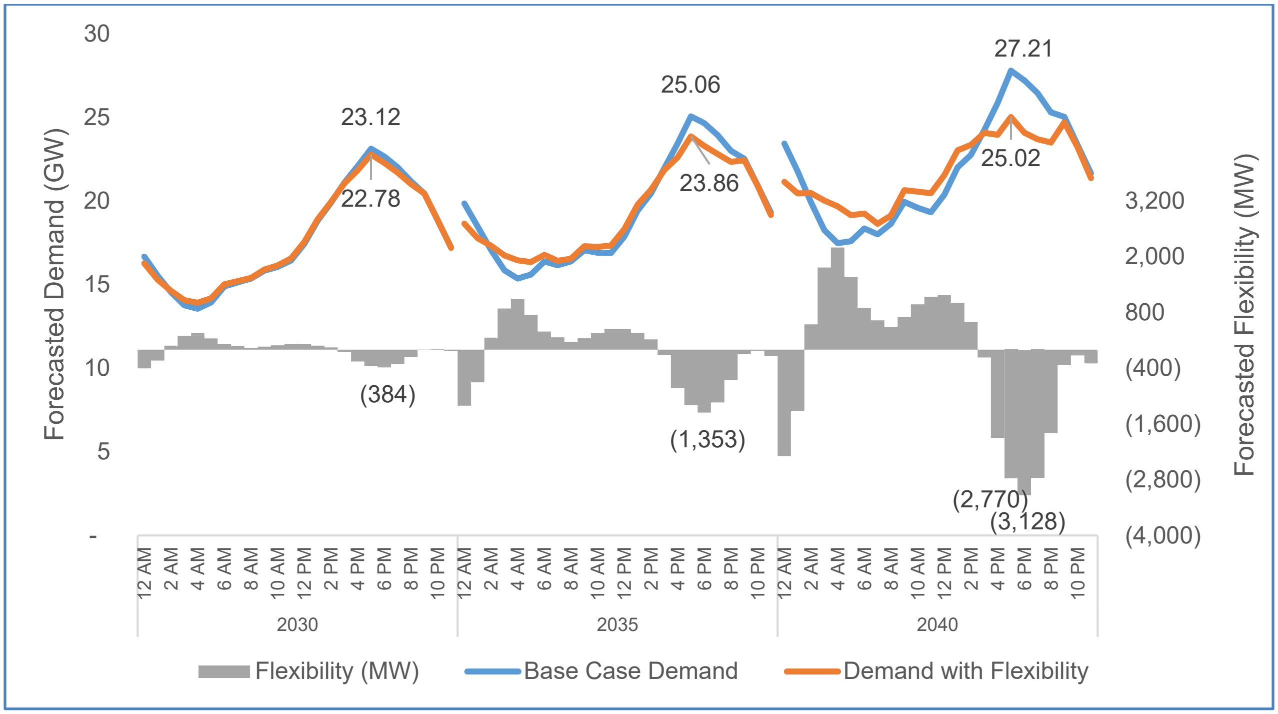
5.3. Enhanced Demand Flexibility Scenario

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.[26] 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).

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[26] 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)

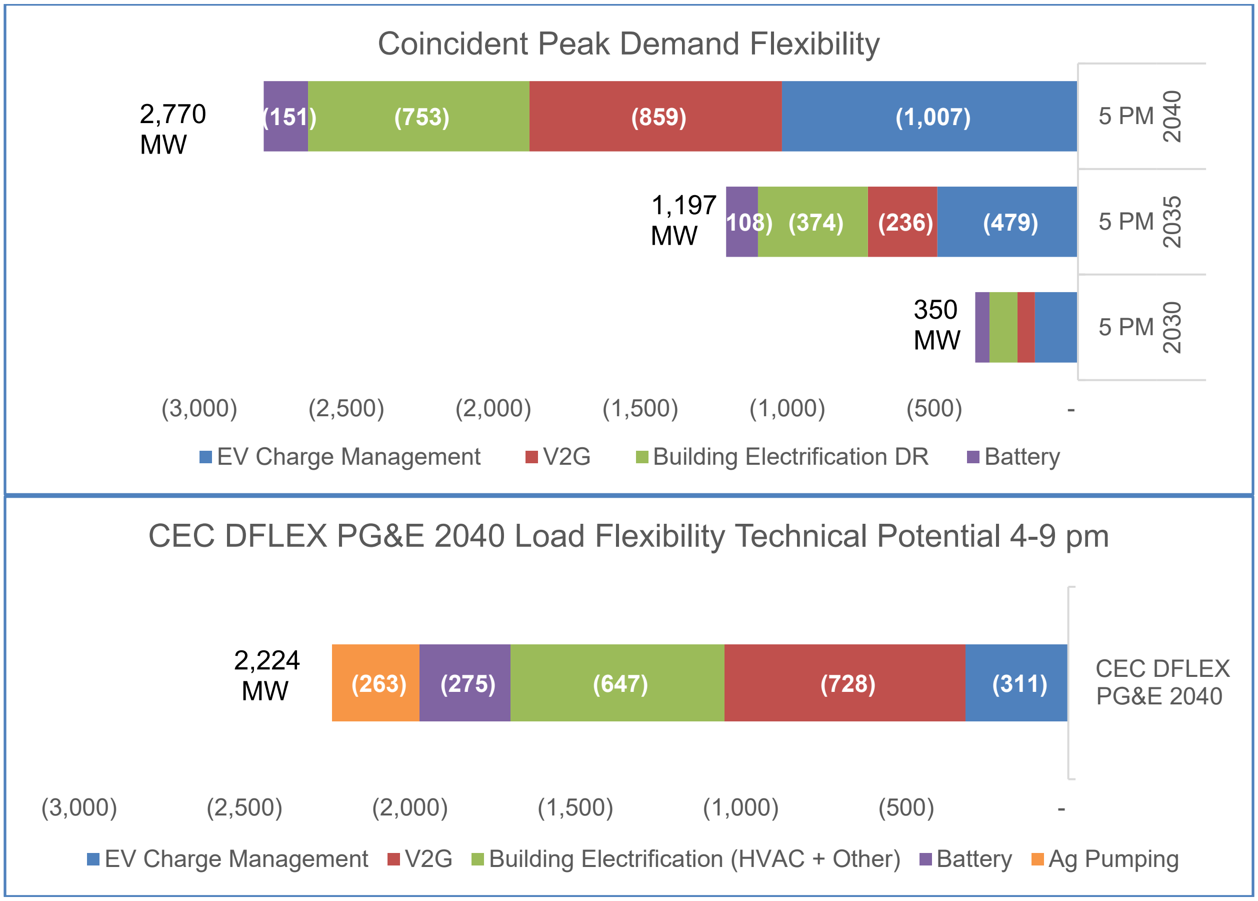


Table 6 presents the estimated reductions in coincident peak load, specifically during the PG&E system evening peak hour, for various demand flexibility components. The results show that technologies such as EV charging active management, dynamic pricing for home L2, V2G, battery storage, and building 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.

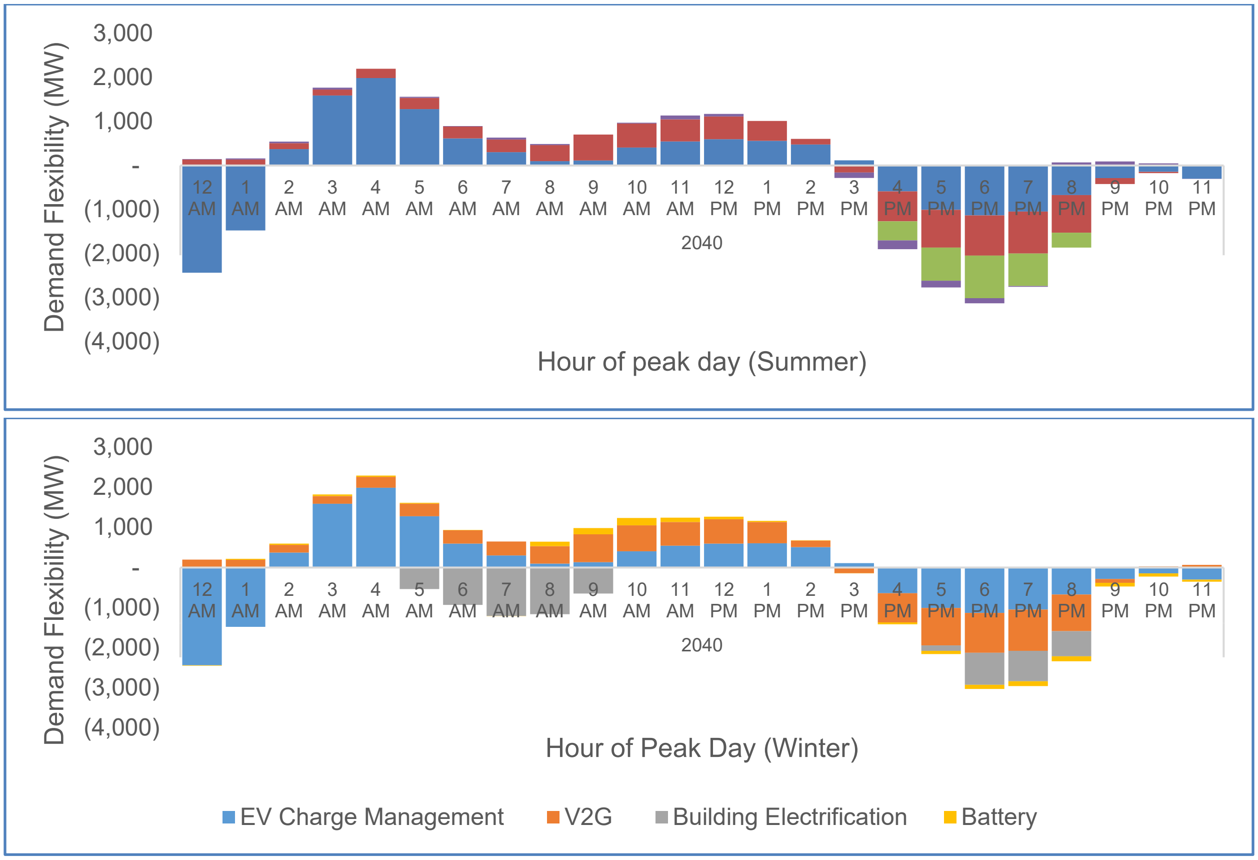
Table 7. Enhanced Demand Flexibility Scenario noncoincident load flexibility in MW

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,[27] providing the regulatory structure needed for effective load management and integration of advanced technologies.

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 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 8 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.

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[27] Decision D.24-10-030

Table 8. 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 replacements11.3.3. 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 9 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. Therefore, PG&E plans to evaluate whether the offsetting revenue from this increased electrification load may offset the increased costs, and thus provide a downward rate pressure, for the final EIS Part 2 Report.

Table 9. 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 10 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 10. 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. The non-orchestrated sensitivity case triggered new overloads and distribution upgrades, 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. 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 (e.g., evolving TOU rates).

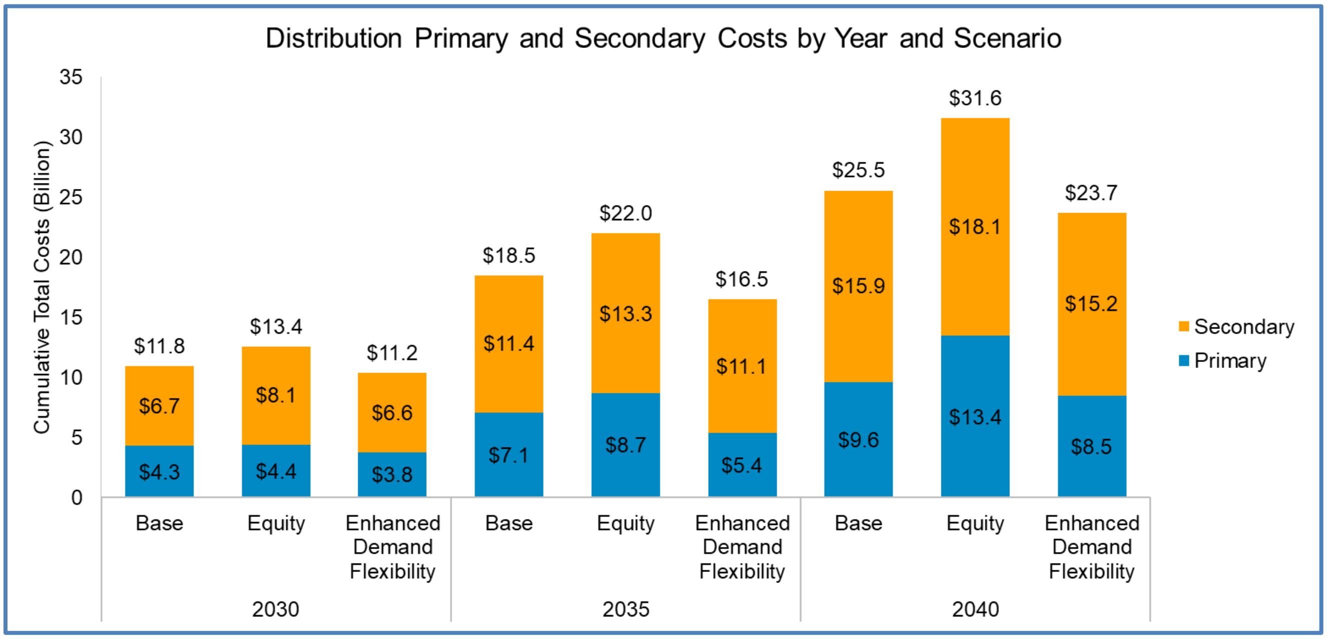
For the Base (Mitigated) Scenario, PG&E estimated cumulative costs through 2040 of $9.6B for the primary system and $15.9B for secondary infrastructure, for a total distribution cost of approximately $25.5B. The secondary costs include both capacity overloads from energization and new service connection costs.

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 or 7%, through 2040, if orchestrated.[28] 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 affordability.

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



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.

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[28] "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.

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.[29] EIS Part 1 is "not an absolute prediction" of investment needs; it was designed to indicate where and when needs might arise under scenario assumptions rather than to prescribe utility solutions or budgets.[30] 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.[31] 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 (e.g., evolving TOU rates). 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,[32] based on examining service transformer capacity overloads.[33] The EIS Part 2 modeled service transformer overloads similarly to the EIS Part 1, but also coupled geospatial forecasting using LoadSEER[34] and CYME[35] to the service connection process to include service connection costs, consistent with service planning costs incurred for energizing load.

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[29] EIS Part 1, ES-6.

[30] EIS Part 1, Workshop Slides

[31] CPUC cover sheet filing for Kevala Part 1

[32] EIS Part 1, ES-10.

[33] EIS Part 1, p 110.

[34] 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/

[35] 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

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.[36] 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. The DGEM 2.0[37] study (preliminary results from October 2024) 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 preliminary 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.[38]

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.[39] 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.

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[36] 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

[37] https://www.publicadvocates.cpuc.ca.gov/press-room/reports-and-analyses/distribution-grid-electrification-model-2024

[38] CalPA DGEM Study 2.0 - Preliminary Results https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/241024-public-advocates-office-dgem-20-preliminary-results.pdf

[39] https://gridlab.org/portfolio-item/ca-load-mgmt-standard/

This can be attributed to improvements in secondary cost estimation in this study, compared to the EIS Part 1 and DGEM study.

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

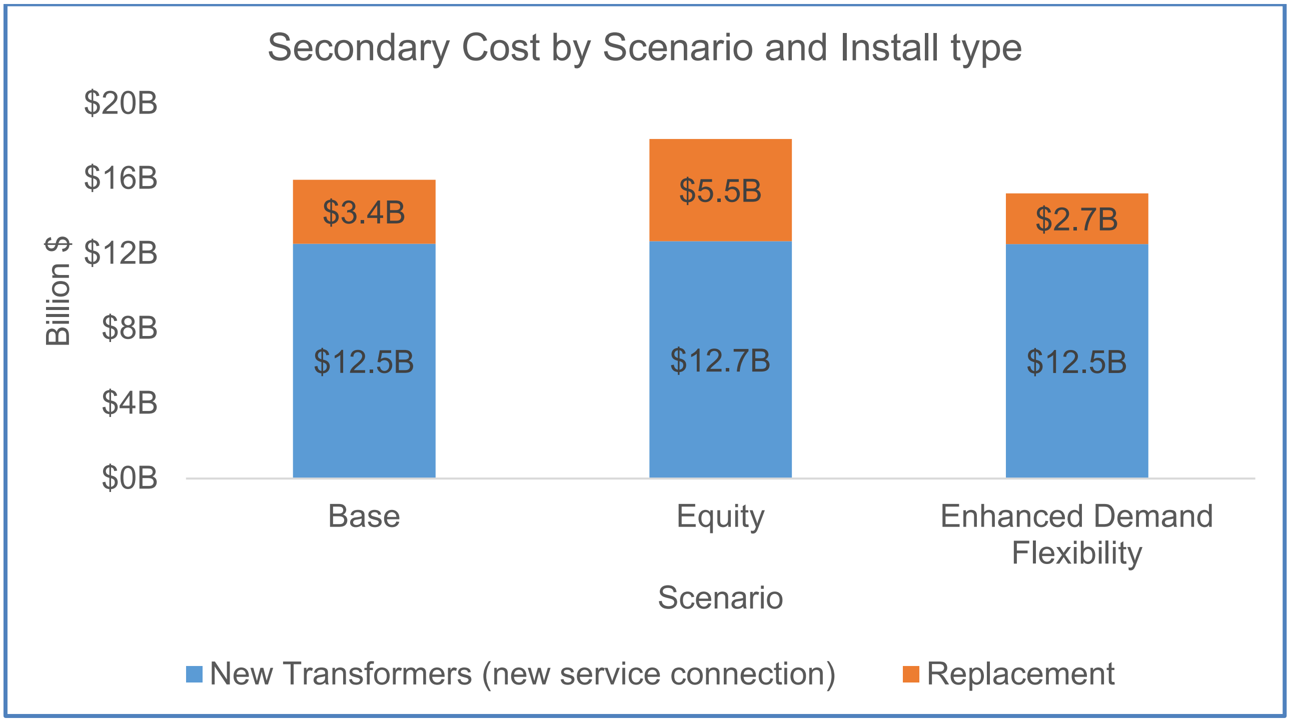


Figure 13 compares annual costs for the EIS Part 2, EIS Part 1, and PAO DGEM studies (Base Scenarios). Annual costs are used to compare the studies because there are different study periods. The scope of the secondary costs for the EIS Part 2 includes only the overloaded transformers component to make results more comparable. The annual costs in the EIS Part 1 are lower than the EIS Part 2 and the DGEM study for both the primary and secondary costs. 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 costs for the EIS Part 2 and EIS Part 1 (Base Cases). The scope of the secondary costs for the EIS Part 2 includes only the overloaded transformers component to make results more comparable.

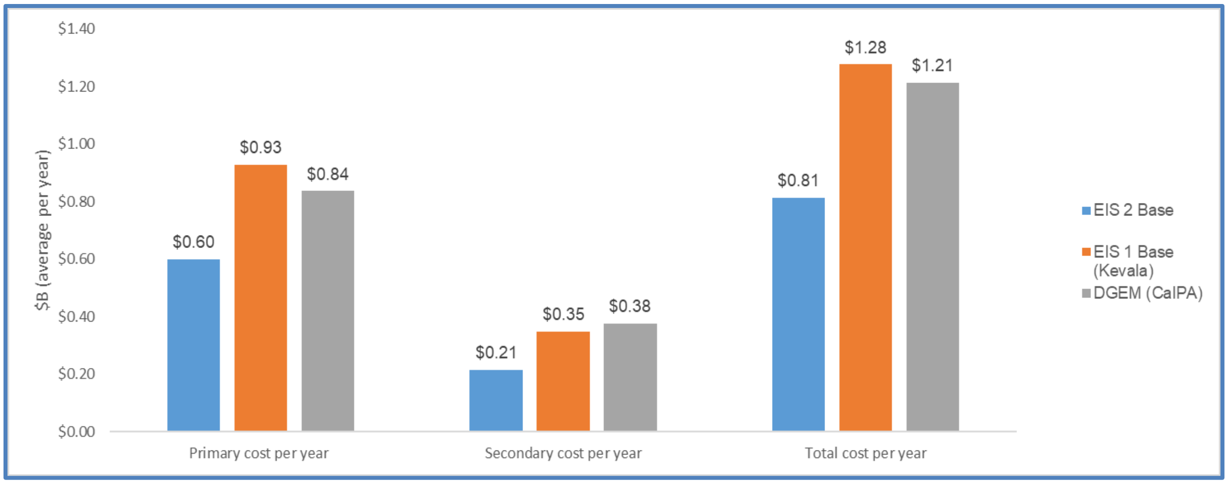


Figure 14 compares total cumulative primary costs for the EIS Part 1 Base Scenario, the EIS Part 2 Base Scenario, and the EIS Part 2 Enhanced Demand Flexibility Scenario. Even with a longer study horizon, the EIS Part 2 had lower cumulative primary costs than the EIS Part 1 (shown in green). Engineering 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. 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.

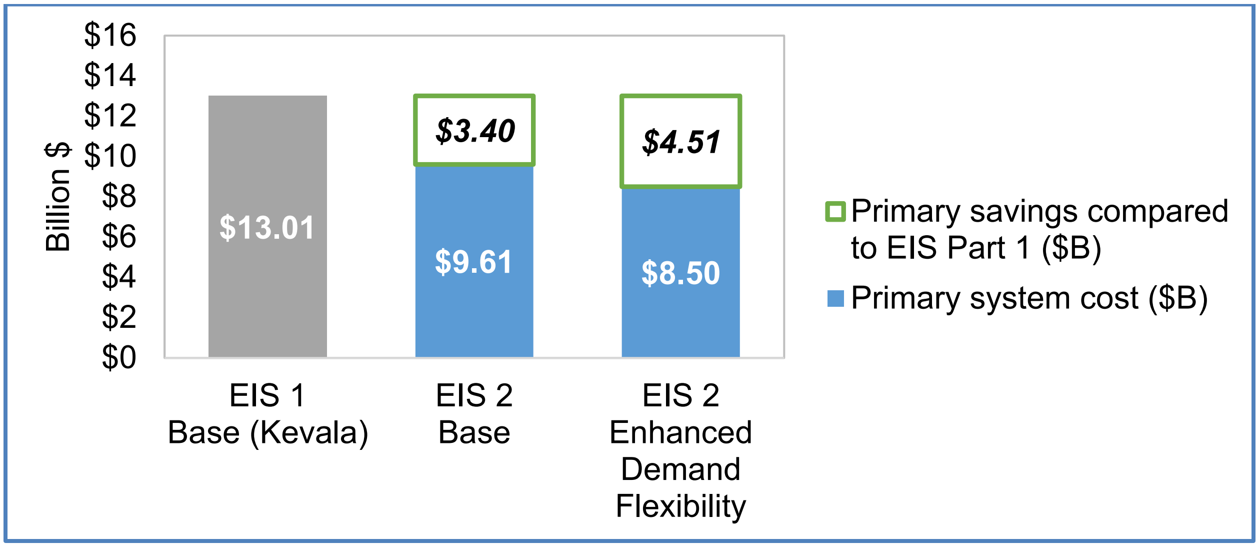
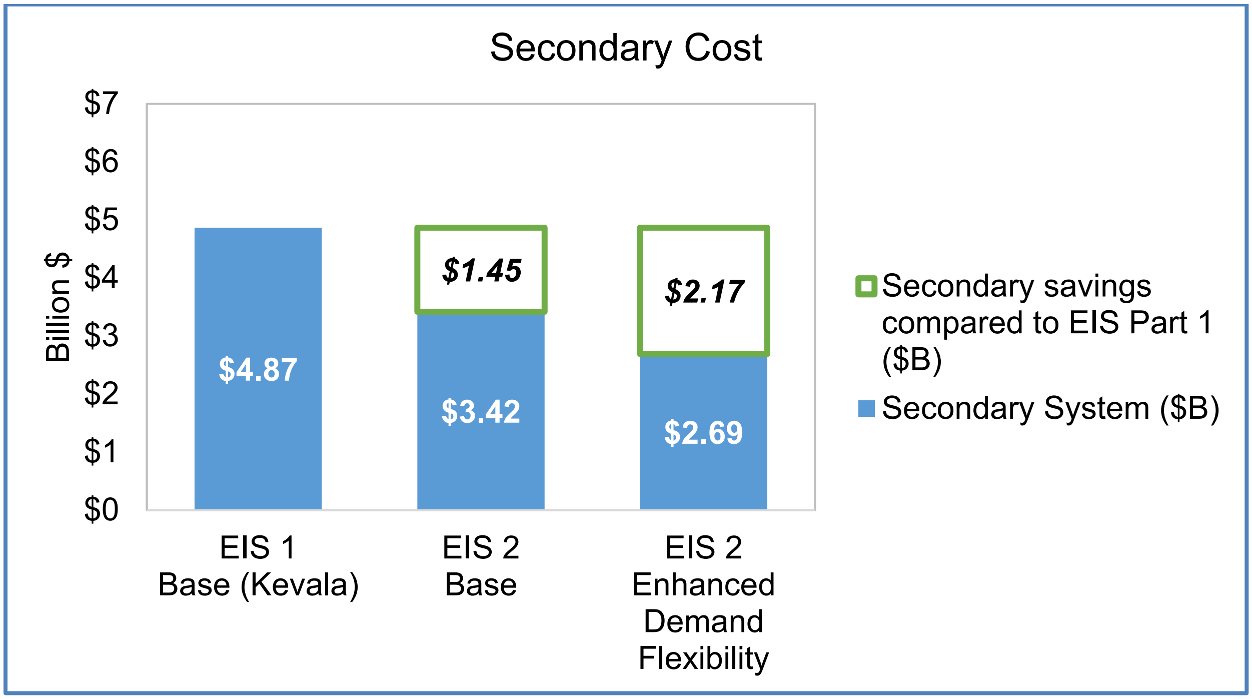


Figure 15 compares total cumulative secondary costs for the EIS Part 1 Base Scenario, the EIS Part 2 Base Scenario, and the EIS Part 2 Enhanced Demand Flexibility Scenario. Similar to the primary results, even with a longer study horizon the EIS Part 2 had lower cumulative secondary costs than the EIS 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 plans to continue exploring the components of the secondary costs and how different modeling and investment approach might affect the results for the Final Report and as described in Section 6.2.1.

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.



6.2.1. Sensitivity of Secondary Costs

The EIS Part 2 scope consists of both overloaded service transformers and new transformers for service connections. The service planning component is dependent upon the geospatial modeling assumptions used in the EIS study. As described in Appendix A, hexagons were used to model the secondary loading. The EIS Part 2 study set the hexagon size with consideration of typical service length. However, expanding the size of the hexagons allows for greater use of existing service transformers (although potentially requires longer service drops). A preliminary sensitivity run using larger hexagons resulted in a ~$2B decrease in the total $15.9B secondary costs (service planning component) through 2040. PG&E has not yet determined what increase in secondary line costs might occur under this approach. PG&E will explore the sensitivity further for the Final Report and to inform planning strategies for the secondary system.

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.[40] 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 11 and Table 12 provide a summary of bank, feeder, and distribution line capital costs across the scenarios compared to recent historical spending.[41] 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.[42]

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.[43] 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 11, 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.

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[40] PG&E's annual Distribution Planning (DPEP), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M576/K519/576519221.PDF

[41] PG&E GRC Ch.09 Table 9-5, 9-6

[42] 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.

Bank and feeder projects are typically multi-year projects, so it takes longer to scale up the work on these projects.[44] 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. By increasing the number of projects completing readiness activities, delivery of capacity projects in future years can continue to scale up. Table 12 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 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 indicates that the scaling up feeder and bank readiness and construction work will need to continue to meet the needs of a high electrification future.

Table 11. 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.*

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[43] 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).

[44] 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 12. 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

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 Tables 13 and 14.

Table 13 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.[45]

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 Tables 13 and 14.

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[45] 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 13. 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 14. 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 15 shows the annual number of replaced banks, comparing the EIS Part 2 forecast with historical rates. While Table 14 showed a relatively stable rate of new bank installations, Table 15 shows an increase of replacement banks to an annual rate of ~12-30 per year, versus a historical rate of ~2-3 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 15. 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.*

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 16. 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 17 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. Therefore, this difference may be attributable simply to a difference in how projects are counted.

Table 17. 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.*

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

8. Downward Pressure on Distribution Rates

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

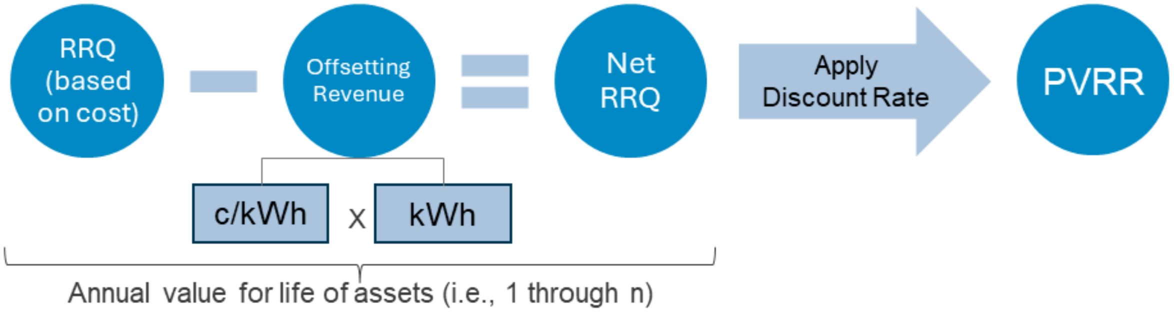
Preliminary analysis indicates that electrification may provide a near-term rate increase due to capital outlays that are then offset by sustained revenue growth from increased energization, indicating long-term value from energization investments. Preliminary results for the Base (Mitigated) Scenario show a small upward rate pressure (~1.6%) in the near term followed by downward distribution rate pressure from 2032 onwards, with a downward pressure on distribution rates of as much as ~25% by 2040.

8.1. Downward Rate Pressure Calculation Methodology

Figure 16 illustrates the methodology of the preliminary 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 preliminary 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 preliminary 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 model.[46] The RRQ also incorporated increased Operations and Maintenance (O&M) expense costs associated with the infrastructure investment.[47]

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. The net load growth has removed line losses. The incremental net load growth is modeled from 2025 -2040, corresponding to the study period. The preliminary rate pressure analysis extends through 2055 to reflect the fact that the RRQ and Offsetting Revenue continue beyond 2040. The analysis assumes no further 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).

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[46] The preliminary 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.

[47] The preliminary assessment assumed all investments were new (although a share is replacing existing assets and thus unlikely to increase O&M costs) consistent with a maximum O&M cost.

The preliminary analysis calculated offsetting revenue by customer class[48] 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.

The preliminary 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 the 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 preliminary analysis only includes incremental costs and revenues, it does not examine existing infrastructure or revenues.

8.2. Downward Rate Pressure Calculation Results (Preliminary)

Preliminary results indicate electrification growth may provide downward pressure on distribution rates by as much as 25% by 2040. Preliminary results for the Base (Mitigated) Scenario show little impact on distribution rates in 2030, with an increasing downward pressure on distribution rates as electrification growth increases through 2040.

Table 18 shows preliminary results of impact on electrification on rates for the Base (Mitigated) Scenario. The RRQ for 2030, 2035, and 2040 is calculated based on the distribution energization investments identified in Table 8 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 rates calculated by dividing the Revised Average Distribution Rate by the Current Average Distribution Rate.[49] A Net Present Value Revenue Requirement (PVRR) in 2025 dollars is calculated by applying a Discount Factor of 7% to the Net RRQ.

The preliminary 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, our 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. Preliminary results indicate electrification growth may provide downward pressure on distribution rates by as much as 25% by 2040. 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.

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[48] 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.

[49] As of September 1, 2025, the system average distribution rate is about 14 cents per kilowatt-hour as implemented via Advice Letter 7684-E.

Table 18. Preliminary results: downward 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**		

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.[50] The DGEM study highlighted that varying project costs, specifically for PG&E, could result in a slight upward pressure on rates;[51] 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 preliminary results.

9. Key Takeaways and Insights into Distribution Planning

9.1. Equity in Distribution Planning

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.[52] Subject to the outcome of that

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[50] CalPA DGEM Study, ES-1 230824-public-advocates-distribution-grid-electrification-model-study-and-report.pdf

[51] CalPA DGEM Study, page 36. Table 3-5 Rate impacts across cost scenarios.

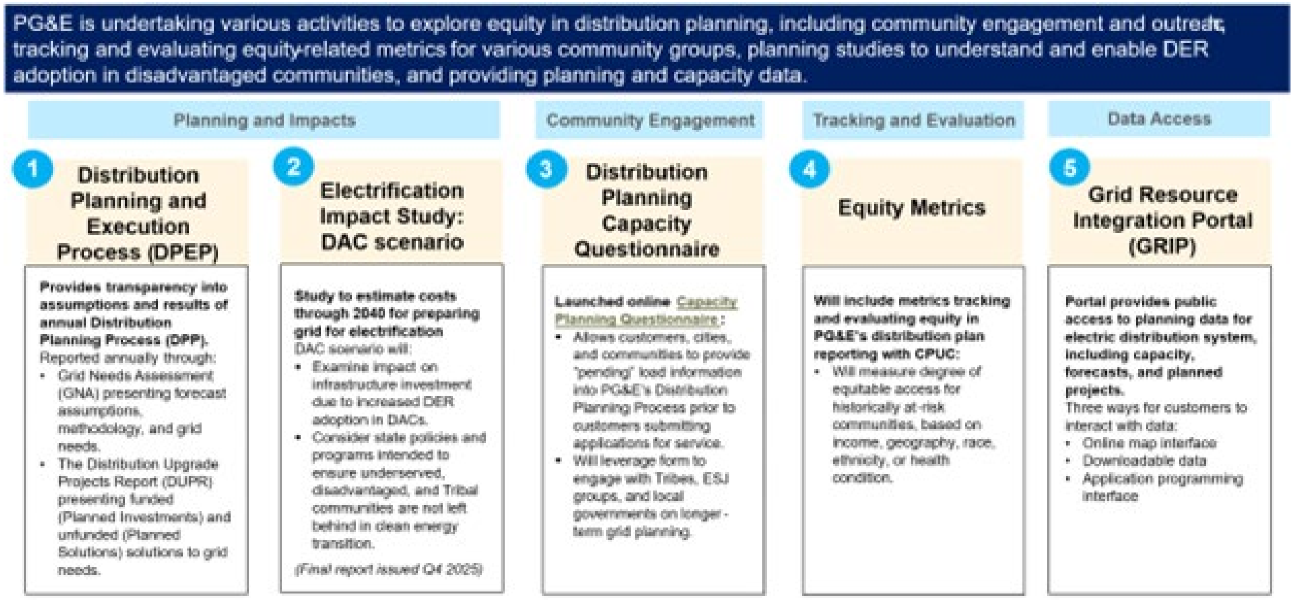
[52] Decision 24-10-030, page 123.

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.

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.

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



PG&E is undertaking various activities to explore equity in distribution planning, including community engagement and outreach, tracking and evaluating equity-related metrics for various community groups, planning studies to understand and enable DER adoption in disadvantaged communities, and providing planning and capacity data.

Planning and Impacts

1 **Distribution Planning and Execution Process (DPEP)**

Provides transparency into assumptions and results of annual Distribution Planning Process (DPP).
Reported annually through:
- Grid Needs Assessment (GNA) presenting forecast assumptions, methodology, and grid needs.
- The Distribution Upgrade Projects Report (DUPR) presenting funded (Planned Investments) and unfunded (Planned Solutions) solutions to grid needs.

2 **Electrification Impact Study: DAC scenario**

Study to estimate costs through 2040 for preparing grid for electrification
DAC scenario will:
- Examine impact on infrastructure investment due to increased DER adoption in DACs.
- Consider state policies and programs intended to ensure underserved, disadvantaged, and Tribal communities are not left behind in clean energy transition.

(Final report issued Q4 2025)

Community Engagement

3 **Distribution Planning Capacity Questionnaire**

Launched online Capacity Planning Questionnaire:
- Allows customers, cities, and communities to provide "pending" load information into PG&E's Distribution Planning Process prior to customers submitting applications for service.
- Will leverage form to engage with Tribes, ESJ groups, and local governments on longer-term grid planning.

Tracking and Evaluation

4 **Equity Metrics**

Will include metrics tracking and evaluating equity in PG&E's distribution plan reporting with CPUC:
- Will measure degree of equitable access for historically at-risk communities, based on income, geography, race, ethnicity, or health condition.

Data Access

5 **Grid Resource Integration Portal (GRIP)**

Portal provides public access to planning data for electric distribution system, including capacity, forecasts, and planned projects.
Three ways for customers to interact with data:
- Online map interface
- Downloadable data
- Application programming interface

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.[53] 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 19 shows the impact of load factor on cable ratings for aluminum cable with 2 circuits in the same trench.[54] 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 19. 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 20, 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 20. 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 Scenario showed a further increase in load factors, with ~600 feeders exceeding an

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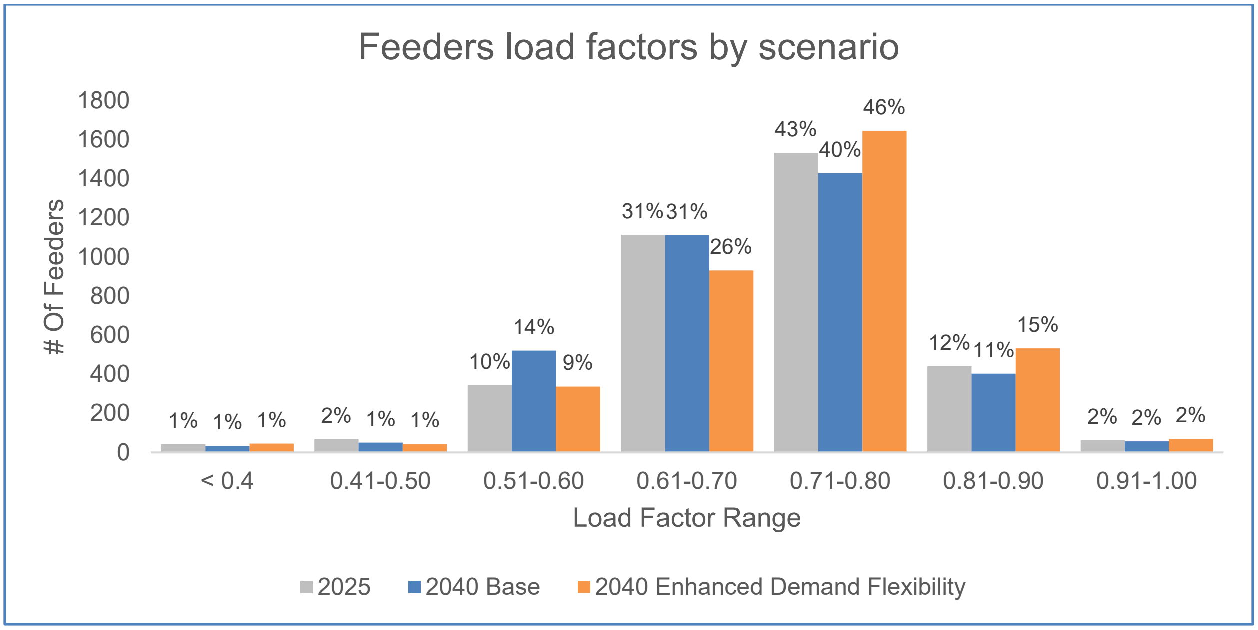
[53] Like an incandescent light bulb, equipment heats up when current passes through it. In order for equipment to cool, the rate of temperature decrease must be lower than the rate of temperature increase. This happens naturally in the distribution system as loads fluctuate throughout the day. PG&E 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.

[54] Two circuits in one trench is the most common arrangement in the PG&E system.

80% load factor. The increase in load factors is consistent with increased asset utilization enabled by load management.

Figure 18. Distribution of load factors for Feeders (in 2040) for the Base Case and Enhanced Demand Flexibility Scenarios



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 Decrease over time

Table 21 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 21. Bank average headroom (MW) - summer / winter

Scenario	2030	2035	2040
Summer			
Base	15.1	13.8	11.5
Equity	18.3	15.5	12.1
Enhanced Demand Flexibility	18.3	17.0	14.7
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 Findings into 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 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.

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 process by considering a range of scenarios and how each scenario might inform how to best meet customer needs. For example, PG&E has gained experience about the use of scenarios in informing the solutioning process. Although the scope of the EIS required multiple distinct solutions to determine an estimated cost differences between forecasts, the experience to solution across multiple scenarios has given us a head start from a process and tools perspective for scenario planning.

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 vehicle, 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 integrations 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.

The EIS Part 2 Enhanced Demand Flexibility Scenario also provided key learnings for future planning. The first is with regards to the impact of orchestration on reducing infrastructure costs, and what that means for both planning and future requirements for load flexibility. The EIS Part 2 also served as a test bed for how to model increasing load flexibility. The EIS will directly inform PG&E’s EPIC 4.08 project, which is developing methods of modeling load flexibility for use in distribution planning. As an example, the EIS Part 2 study showed the importance of considering the specific amount of load that will be shifted, when it will be shifted, and how that may need to be orchestrated to the secondary, primary, or system level.

Lastly, 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. 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.

PG&E will expand more on its plans to incorporate the EIS Findings into its Planning Processes in the Workshop and Final Report.

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 (7%) 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.

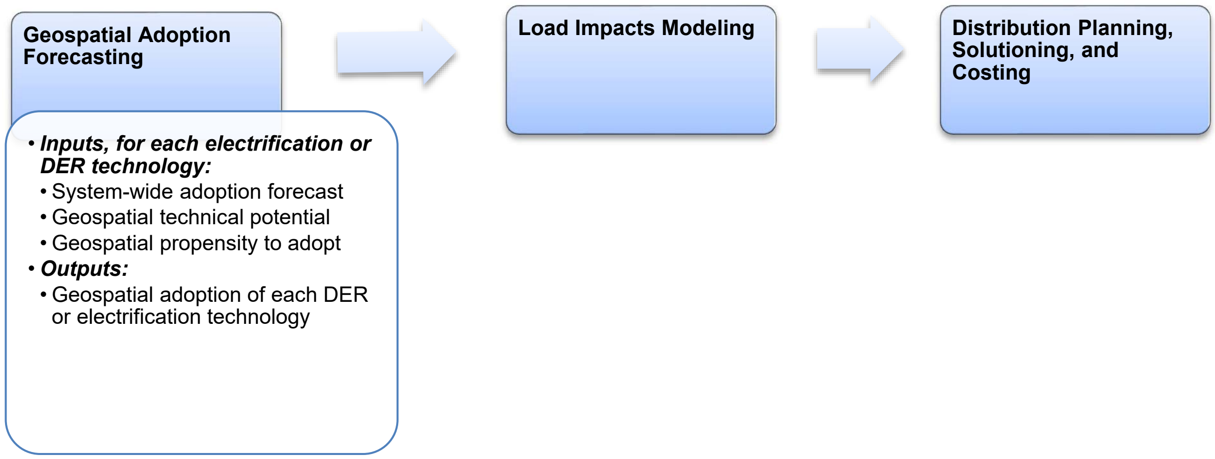
Both the methodology and the results of this study will inform future planning, including learnings from expanding the analytical scope to include secondary service costs and local grid impacts. The study establishes a robust, data-driven framework for planning future distribution investments, integrating 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


Geospatial Adoption Forecasting
Load Impacts Modeling
Distribution Planning, Solutioning, and Costing
• Inputs, for each electrification or DER technology:
• System-wide adoption forecast
• Geospatial technical potential
• Geospatial propensity to adopt
• Outputs:
• Geospatial adoption of each DER or electrification technology

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 22 shows the DER and electrification technologies that PG&E modeled in the EIS Part 2 study.

Table 22. 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

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[55] into a charger forecast using charger/EV ratios derived from the CEC AB 2127[56] report. PG&E 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.

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[55] California Energy Commission (CEC), IEPR EV Stock Forecast, 2023, https://www.energy.ca.gov/media/9573

[56] California Energy Commission (CEC), AB 2127, https://www.energy.ca.gov/data-reports/reports/electric-vehicle-charging-infrastructure-assessment-ab-2127

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.[56] 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.[57] 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.[58]

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.

PG&E's Scenario 4 (not included in the Draft Report) would explore an alternative method for modeling EV electrification load.

11.1.2. Technical Potential

PG&E defined technical potential and propensity geospatially using the H3 system, a hexagonal grid spatial index.[59] The Forecasting Anywhere (FA) tool mapped all datasets to H3 cells, enabling integration of multiple data sources. PG&E defined technical 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).

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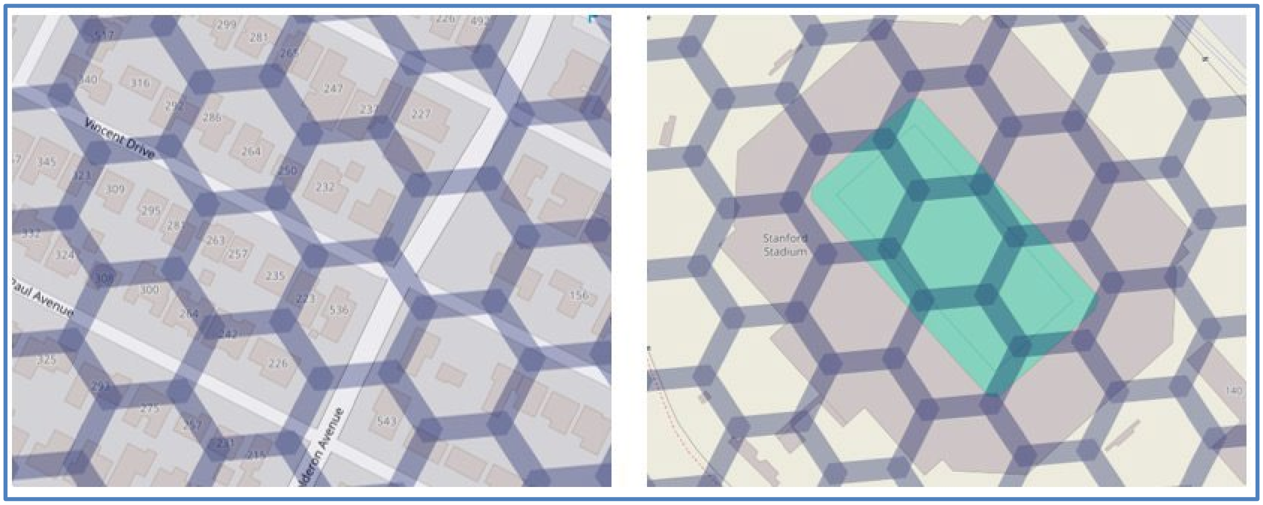
[57] Assembly Bill No. 579, Ting. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202320240AB579

[58] Census VIUS, 2021, https://data.census.gov/table/VIUSA2021.VIUS211A?q=vius211a&g=010XX00US,$0400000&nkd=PRICHAR~03

[59] H3 Geo, https://h3geo.org/

Figure 20. Example of H3 level 11 resolution[60] – 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 23 presents the methodology for estimating technical potential.

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

Table 23. 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 24 outlines this propensity methodology.

Table 24. 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.[61] 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:

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

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

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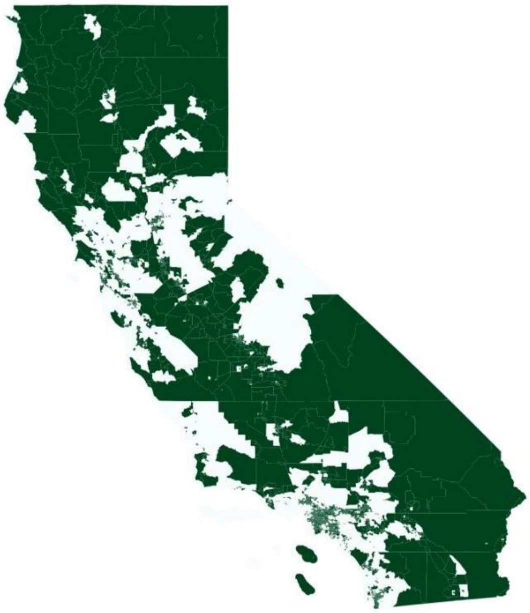
[61] EIS Part 2 Scope and Requirements, p.8

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,[62] 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.

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 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.

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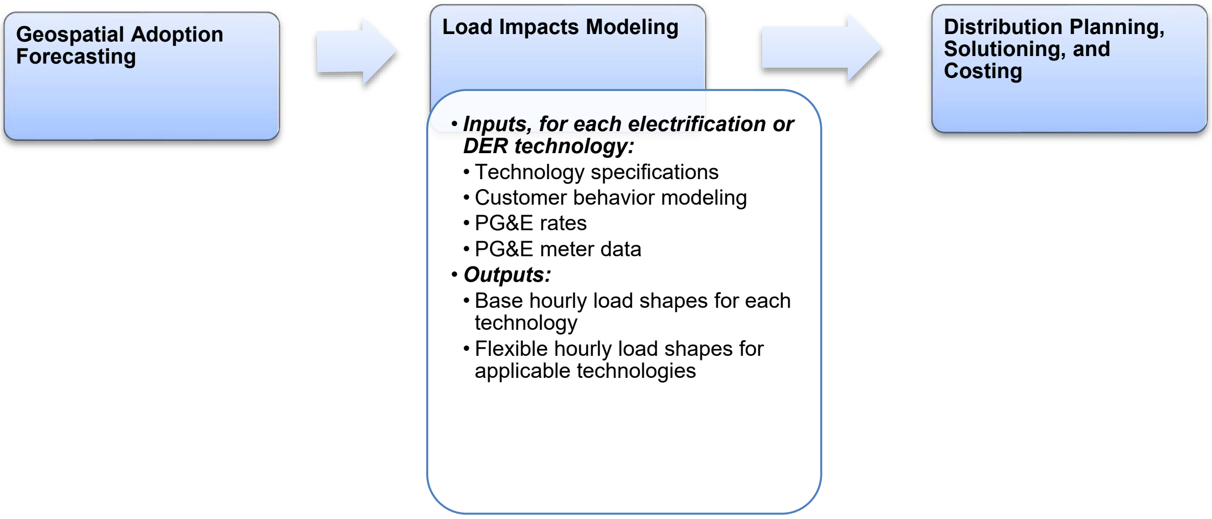
[62] California Open Data Portal, Low-Income or Disadvantaged Communities Designated by California, https://data.ca.gov/dataset/low-income-or-disadvantaged-communities-designated-by-california

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


Geospatial Adoption Forecasting
Load Impacts Modeling
Distribution Planning, Solutioning, and Costing

- ***Inputs, for each electrification or DER technology:***
  - Technology specifications
  - Customer behavior modeling
  - PG&E rates
  - PG&E meter data
- ***Outputs:***
  - Base hourly load shapes for each technology
  - Flexible hourly load shapes for applicable technologies

For energy efficiency, solar PV, and battery storage, PG&E used legacy load shapes from the 2024–2025 distribution planning cycle. For electric vehicles and building electrification technologies, the team developed updated load shapes using new modeling and data sources, as listed in Table 25.

Table 25. Updated load shape sources

DER Type	Load Shape Source
Building electrification	NREL’s ResStock and ComStock
Transportation electrification	E3’s EV Grid model

11.2.1. Building Electrification

The team used NREL’s ResStock and ComStock63 bottom-up building simulation datasets to generate load profiles for residential and commercial buildings.[63] These 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.

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

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

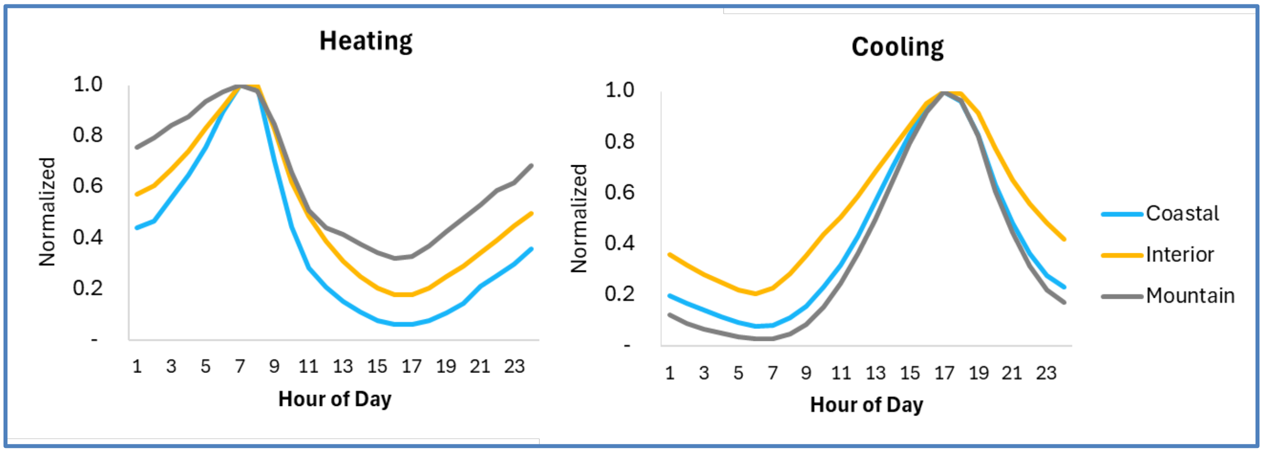


Figure 23 illustrates examples of AAFS heating and cooling load profiles. Heating demand peaks in the morning as occupants wake and raise indoor temperatures, drops midday due to solar gain and lower occupancy, and rises again in the evening. Cooling demand starts low overnight and climbs steadily to 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 22 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

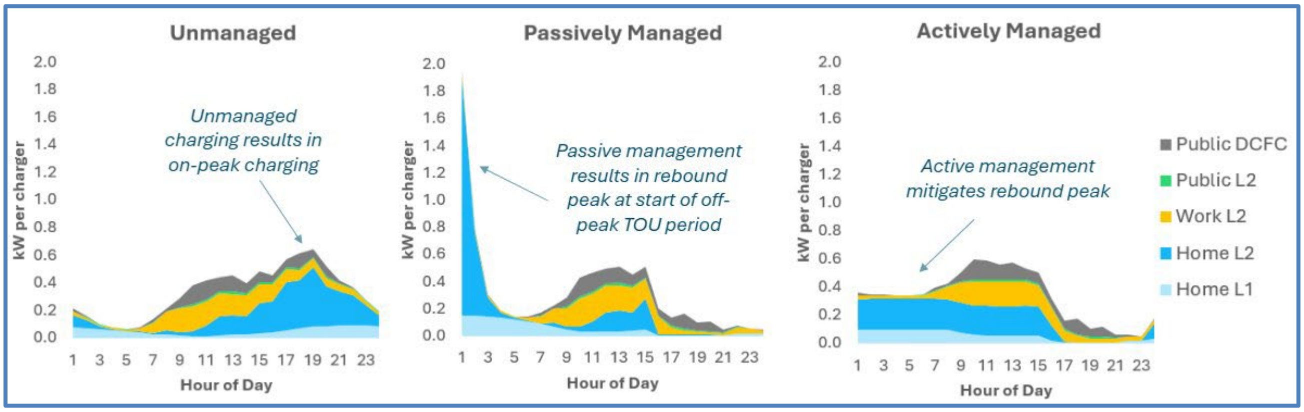
rates and charging network size to simulate competition for chargers at workplace and public locations. PG&E compared EV Grid model results with available metered data for the same vehicle category.

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 26 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 26. 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.[64]

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.

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

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[64] 2015_dr_potential_study_phase1_final_report.pdf (https://eta-publications.lbl.gov/sites/default/files/2015_dr_potential_study_phase1_final_report.pdf)

Charge Management: Dynamic Rates

The Enhanced Demand Flexibility Scenario assumes the California policy framework enables widespread adoption of demand flexibility solutions by creating a universally accessible, dynamic, and economic signal for energy through frameworks, like CalFUSE.[65] 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.[66] 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 27 shows the assumption that by 2040, 40% of residential charging will shift to periods of time with low dynamic pricing.

Table 27. 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.

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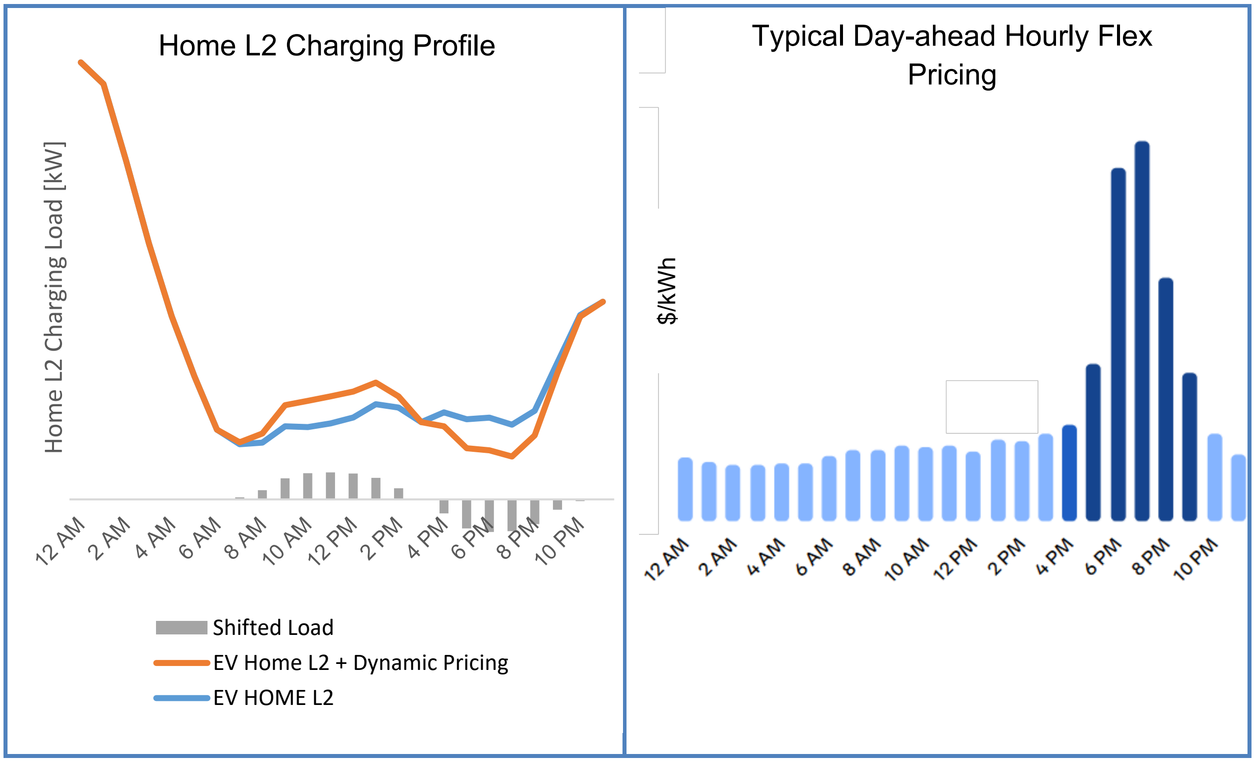
[65] CalFUSE (California Flexible Unified Signal for Energy) is a CPUC-led framework designed to enable real-time, dynamic pricing signals that reflect grid conditions across generation, transmission, and distribution levels.

[66] 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)



Charge Management: Active Charging Demand Management

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.

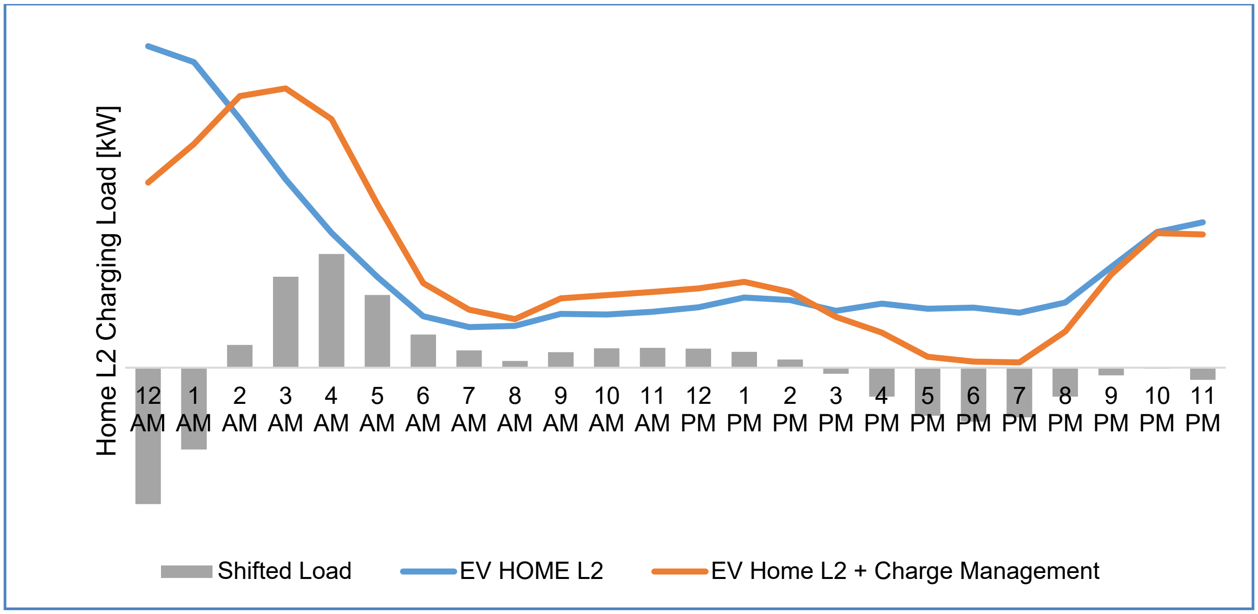
Active load management is expected to help manage the load of home L2 charging, workplace charging, medium and heavy-duty depot charging, and school bus charging. Table 28 shows the expected percentage of chargers that will shift their load due to Active Load Management.

Table 28. 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)



Vehicle-to-Grid Demand Management:

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)[67] and Fremont Unified School District (FUSD)[68] 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 29 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 29. 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.

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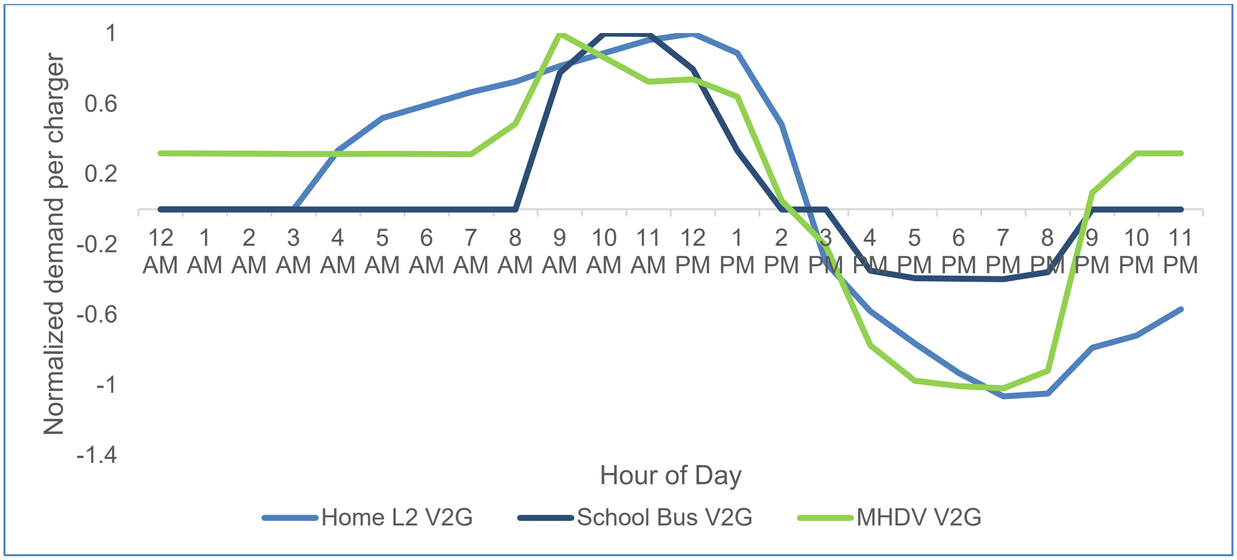
[67] https://www.pge.com/en/newsroom/currents/future-of-energy/articles-4040-pge-helps-zum-deploy-nations-100-electric-school-bus-fleet-oakland-new-school-year.html

[68] 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



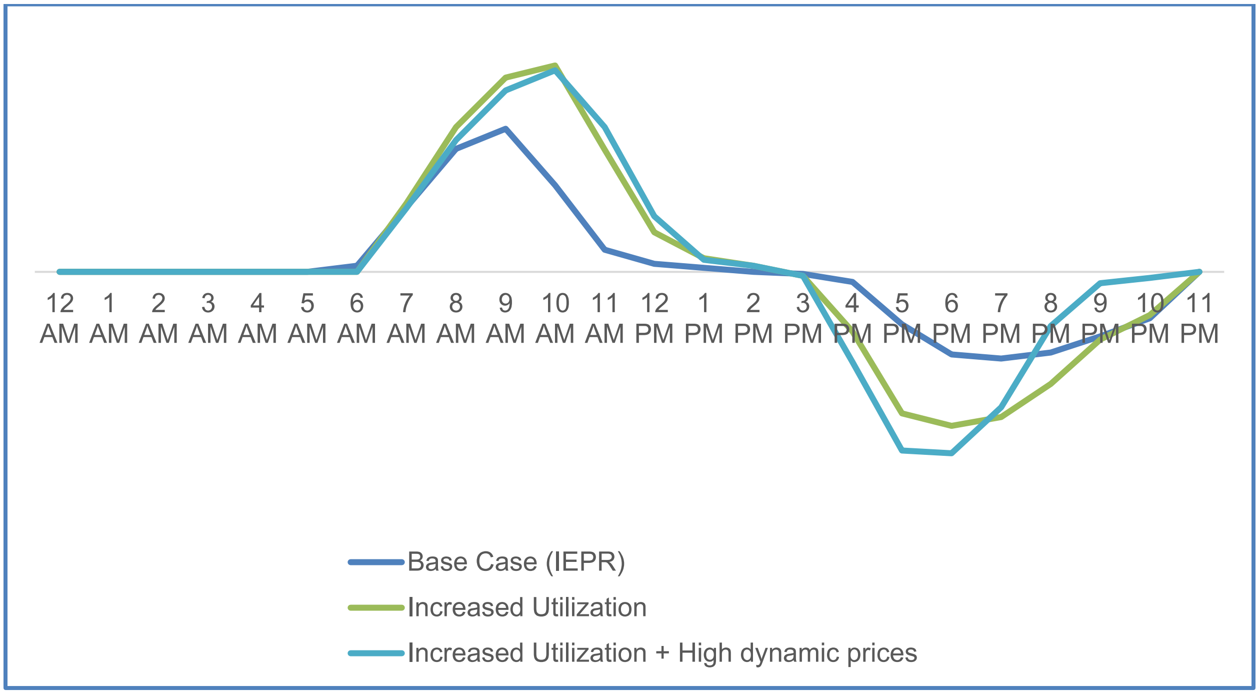
Battery Storage Flexibility

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.[69] 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.[69] 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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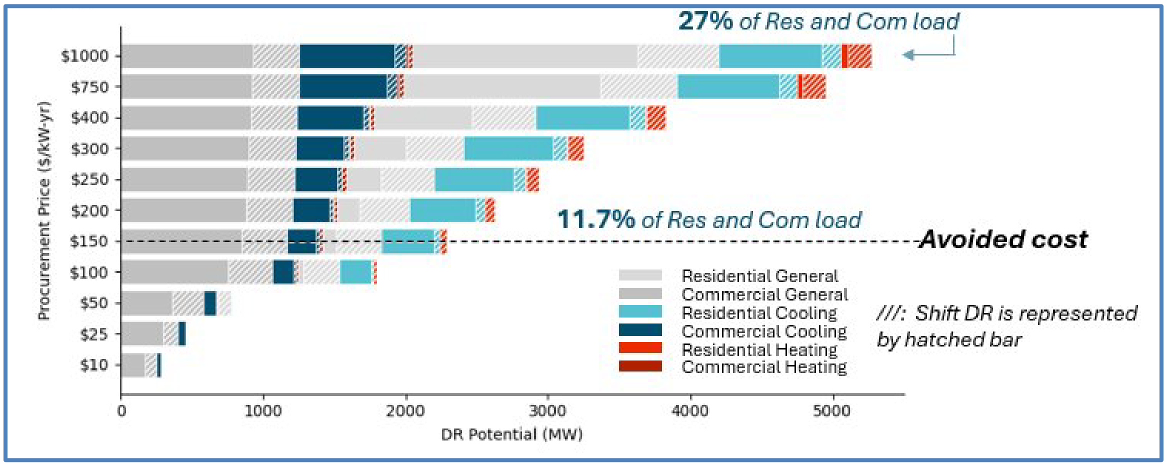
[69] Lawrence Berkeley National Laboratory, The California Demand Response Potential Study, Phase 4: Report on Shed and Shift Resources Through 2050, 2024, https://eta-publications.lbl.gov/publications/california-demand-response-0

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.

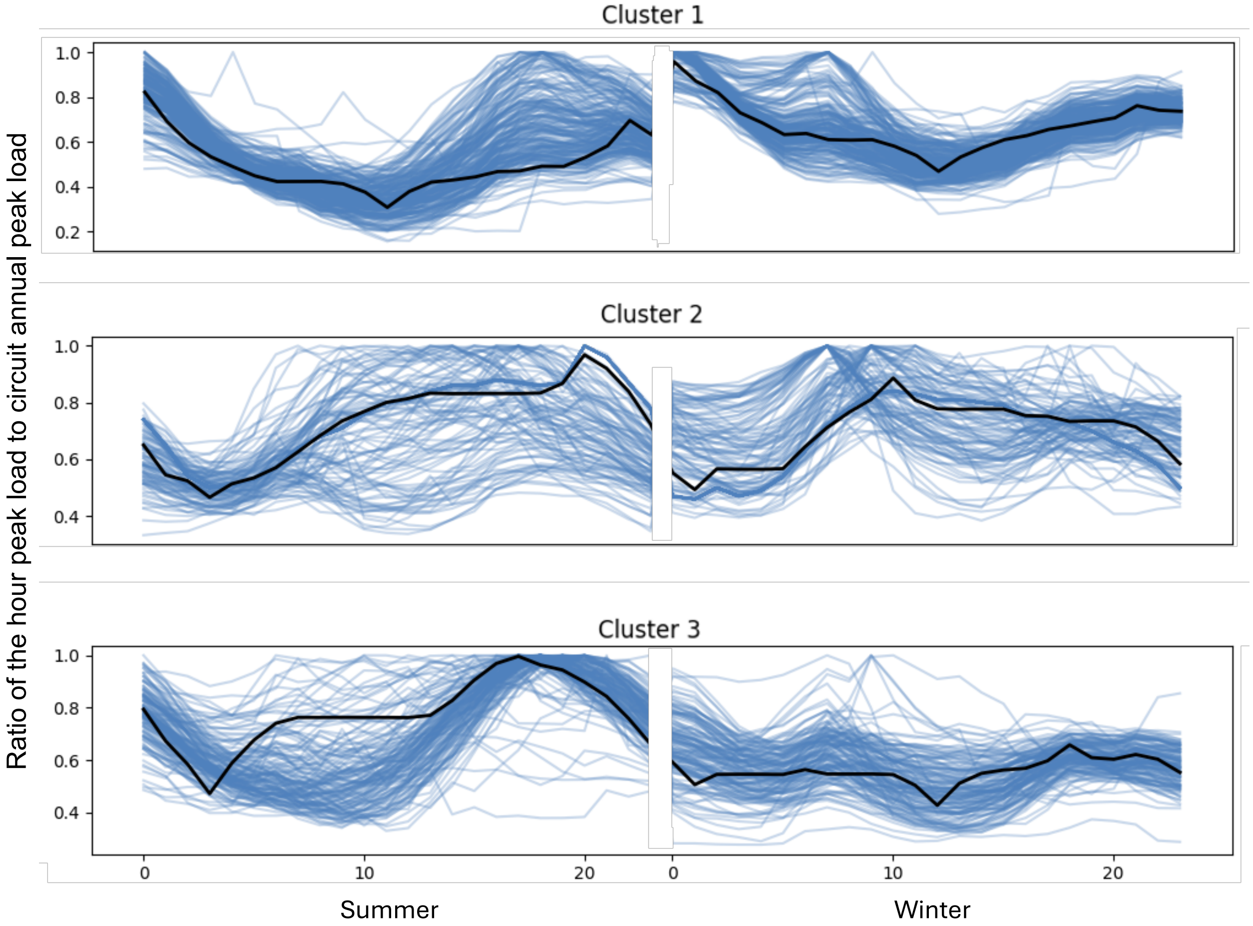
Local Management

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.

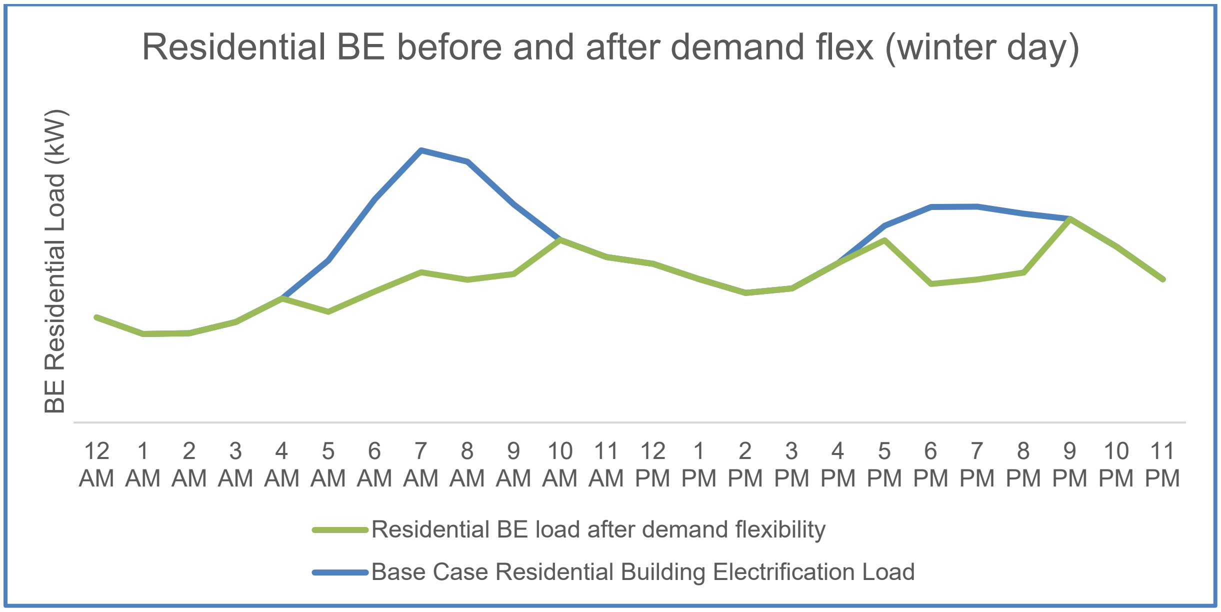
Figure 31 illustrates three peaking patterns identified by clustering circuits according to each hour's peak load relative to the circuit's annual peak load. Cluster 1 demonstrates elevated loads at midnight, likely due to residential EV charging, as well as higher summer evening and winter morning loads, 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 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 30) 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.

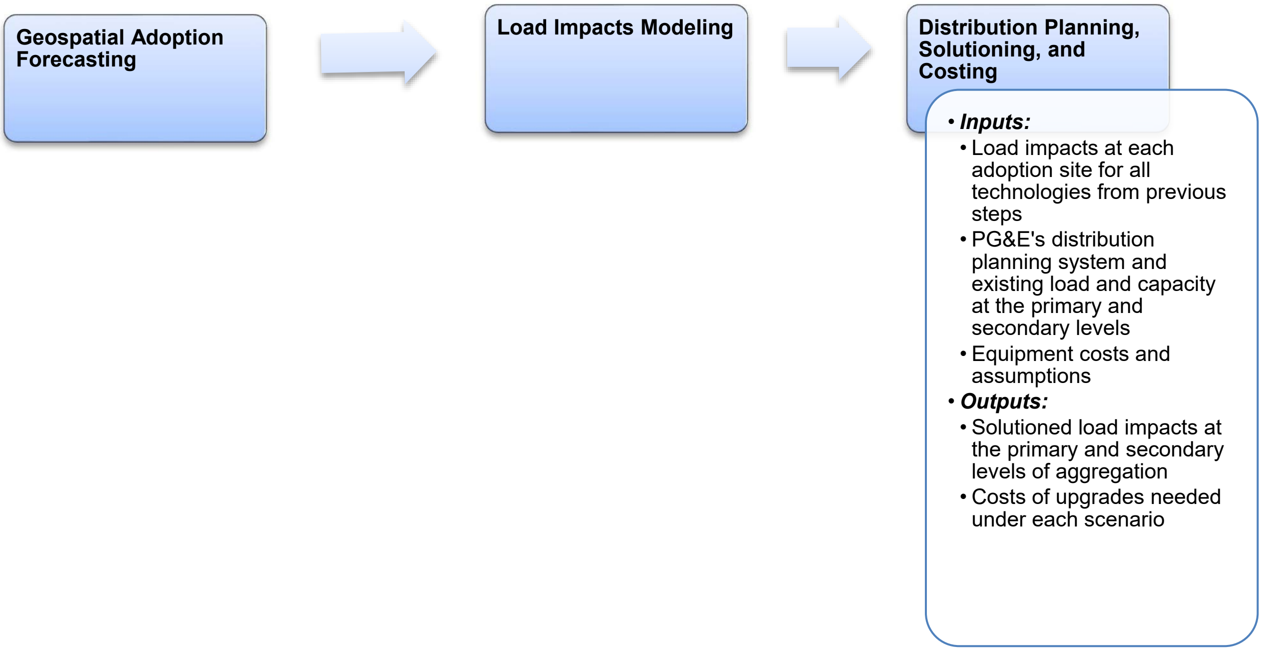
Table 30. Effectiveness of demand flexibility depend on locally informed load management

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%

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 33 shows an overview of this modeling step.

Figure 33. Step 3: Distribution planning, solutioning, and costing


Geospatial Adoption Forecasting
Load Impacts Modeling
Distribution Planning, Solutioning, and Costing

- ***Inputs:***
  - Load impacts at each adoption site for all technologies from previous steps
  - PG&E's distribution planning system and existing load and capacity at the primary and secondary levels
  - Equipment costs and assumptions
- ***Outputs:***
  - Solutioned load impacts at the primary and secondary levels of aggregation
  - Costs of upgrades needed under each scenario

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. 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 Analysis

The secondary analysis estimated capacity needs and service connection costs for customer-level distribution equipment (primarily service transformers) under each scenario of the EIS. PG&E’s objective was to evaluate how forecasted electrification and DER adoption translates into localized transformer loading, replacement, and new installation requirements across the service area.

Overview of Methodology

The analysis linked forecasted hourly load growth from the geospatial adoption modeling to PG&E’s existing inventory of secondary transformers, using a consistent spatial reference system (the H3 hexagonal grid). For each year and grid cell, the incremental coincident demand from all modeled electrification technologies was calculated separately for summer and winter planning seasons. These incremental loads were then compared to the seasonal headroom of nearby existing transformers within the hexagon and nearby hexagons, applying coincidence factors aligned with the feeder’s peak.

Transformers within a defined geographic search radius were treated as the available pool of capacity for each demand location. Where sufficient spare capacity existed, additional load was allocated to existing transformers within the hexagon(s). Where the combined seasonal loading exceeds the accepted engineering thresholds, transformers were assumed to require replacement or augmentation. Replacement events were sized to meet both summer and winter coincident peaks while adhering to standard nameplate sizes and planning multipliers used in PG&E's design standards. In areas without nearby capacity, the analysis assumed installation of new transformers of standard types.

Key Planning Assumptions

Several planning assumptions guided the secondary analysis:

- **Seasonal Capacity Ratings:** Summer and winter transformer capacities were modeled separately to capture temperature-dependent ratings and loading limits. Equipment utilization was constrained by a maximum loading fraction consistent with PG&E's planning guidance.
- **Load Aggregation:** Hourly forecast data were aggregated to annual coincident summer and winter peaks within each H3 cell. This approach reflects how planners evaluate cumulative impacts of multiple DER and electrification technologies on a localized basis.
- **Search Radius and Capacity Pooling:** Each load event was evaluated against transformers located within a limited geographic radius, representing practical service-territory clustering of secondary assets. This allowed the model to account for both immediate and nearby spare capacity when allocating incremental load.
- **Size-Up Policy:** When replacements or new installations were required, transformer sizes were selected from standard equipment ratings and modestly increased ("sized up") to provide additional operational margin. This reflects a conservative engineering practice ensuring adequate future headroom and reduces the likelihood of having to replace the transformers twice due to subsequent load growth.
- **Negative Load Effects:** Technologies that reduce net load, such as energy efficiency and behind-the-meter solar, were treated as creating additional capacity. These reduce the modeled utilization of existing equipment but do not trigger any cost or equipment addition.
- **Cost Basis:** Equipment and labor costs were derived from PG&E's historical cost data, expressed as a single average unit cost per transformer. Annual escalation factors were applied to reflect projected future labor and material price trends through 2040. The same average unit cost was applied regardless of the nameplate of the service transformer.
- **Spatial Integration:** All results are reported at the H3 cell level, allowing flexible aggregation consistent with PG&E's planning processes.

Methodology

PG&E first converted annual DER and electrification loads (kW) to apparent power (kVA) using a planning power factor and seasonal coincidence factors. For each H3 cell, coincident summer and winter kVA were compared to available transformer capacity within the defined search area. PG&E allocated surplus capacity to existing units, and remaining unmet demand triggered replacements or new installations. Replacement or new units were selected from PG&E's standard transformer sizes, with capacities adjusted by seasonal multipliers to reflect usable limits. Finally, for each replacement or new installation, PG&E applied costs on a unit cost basis, inclusive of escalation factors.

Spatial and Temporal Considerations

This analysis is spatially complete at the hex-grid level (H3), which accounts for future land-use growth (new service points) and loads that do not map to an existing premise (e.g., public EV charging) by assigning those increments to nearby transformers in a physically plausible way. Additionally, over time, upgrades are triggered when and where overloads actually emerge rather than assuming perfect foresight to the end of the forecast horizon. As a result, some locations see staged replacements or added units as adoption materializes. To reflect procurement standards and prudent cost control, replacements follow standard nameplate steps with a bounded "size-up" policy (rather than one-time, far-ahead oversizing), which maintains reliability while avoiding unrealistic assumptions about installing equipment many sizes larger solely on the basis of long-range forecasts.

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.

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 34. MHDV Base Scenario profile compared to Enhanced Demand Flexibility

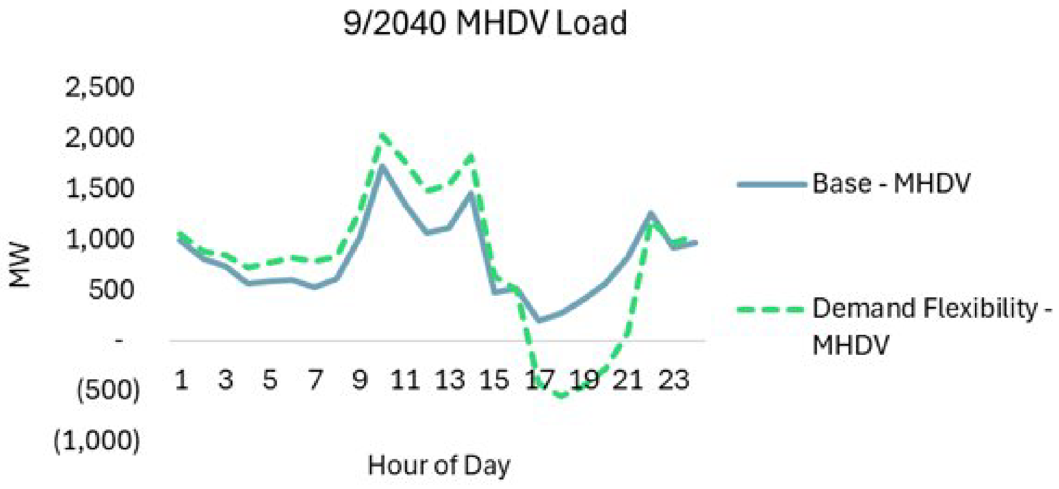


Figure 35. AAFS Base Scenario profile compared to Enhanced Demand Flexibility

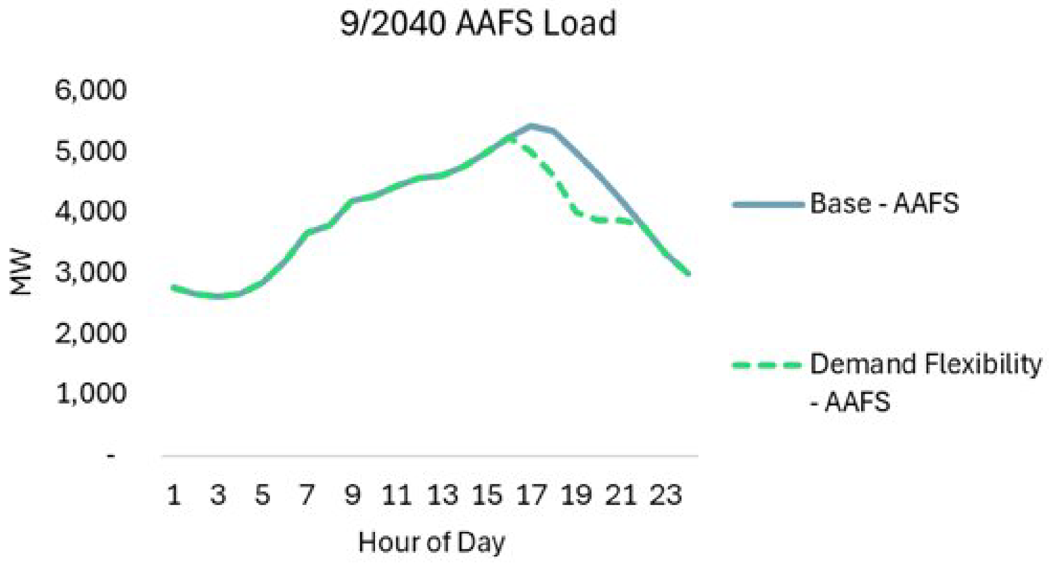
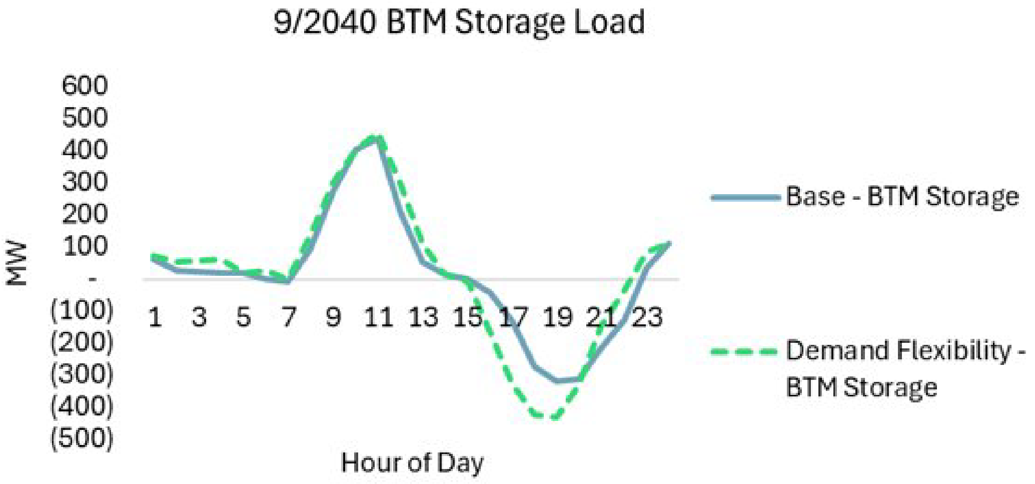
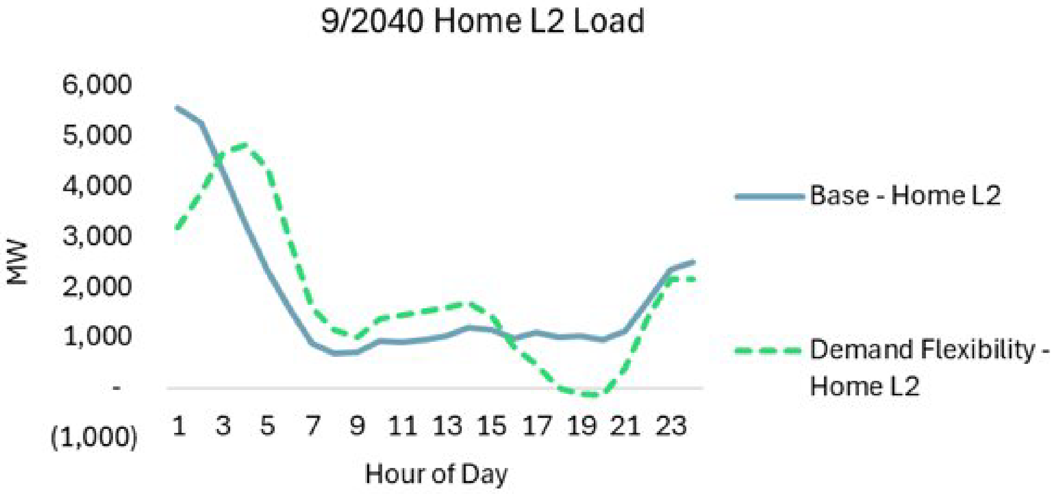


Figure 36. Behind the meter storage Base Scenario profile compared to Enhanced Demand Flexibility



Figure 37. Home L2 Base Scenario profile compared to Enhanced Demand Flexibility