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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

MOTION OF THE PUBLIC ADVOCATES OFFICE TO ADMIT ITS DISTRIBUTION GRID ELECTRIFICATION MODEL 2025 STUDY AND REPORT INTO THE RECORD

In accordance with Rule 11.1 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure, the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) files this motion to admit its *Distribution Grid Electrification Model 2025 Study and Report* (DGEM 2025 Study and Report)[1] into the record of Rulemaking (R.) 21-06-017, *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*.

In July 2021, the Commission opened R.21-06-017. This Rulemaking focuses on preparing the electric grid for a high penetration of distributed energy resources (DERs),[2] including EVs and related infrastructure.[3] The scope of R.21-06-017 includes consideration of the planning and forecasting strategies that are necessary to determine the timing and scope of system investments needed to facilitate the integration of DERs into the grid.[4]

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[1] Cal Advocates, *Distribution Grid Electrification Model 2025 Study and Report*, October 2025 (DGEM 2025 Study and Report). Available at: https://www.publicadvocates.cpuc.ca.gov/press-room/reports-and-analyses/distribution-grid-electrification-model-2025.

[2] A DER is an object connected to the distribution system that can serve as a resource for grid operators and planners. DERs include generators such as rooftop photovoltaics, shiftable loads such as electric heat pumps and electric vehicle (EV) chargers, home batteries, and energy efficiency.

[3] *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*, issued July 2, 2021 at 2 and 8. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M390/K664/390664433.PDF.

[4] *Assigned Commissioner's Amended Scoping Memo and Ruling*, August 11, 2023 (Amended Scoping Memo) at 3-5. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M516/K786/516786462.PDF.

Cal Advocates undertook its *Distribution Grid Electrification Model Study and Report* (DGEM 2023 Study and Report) to assess – in the context of electrification – costs to upgrade the grid, rate impacts, the key drivers of costs and cost uncertainties, the necessary pace of distribution asset upgrades, and the potential of load management to reduce costs and rate impacts. In September 2023, Cal Advocates filed a motion to admit its DGEM 2023 Study and Report into the record of R.21-06-017.[5] In October 2023, Assigned Administrative Law Judges Hymes and Lakhanpal granted Cal Advocates' motion and solicited party comments and reply comments on Cal Advocates' DGEM 2023 Study and Report.[6]

In October 2025, Cal Advocates published the DGEM 2025 Study and Report. Cal Advocates undertook this follow-up study to continue to assess the impacts of electrification on the distribution grid, and to specifically evaluate the effects of building electrification and of EV load management. Cal Advocates' DGEM 2025 Study and Report:

- Estimates the costs to upgrade the distribution grids of the three investor-owned utilities in California to meet the state's forecasted EV deployment and other load growth through 2040 to be $24.6 billion in the central scenario;
- Analyzes the relative cost impacts of nine scenarios, varying the adoption of building electrification technologies and the charging behavior of EVs, with total costs ranging in 2040 from $17 billion to $38 billion across scenarios; and
- Identifies a potential for electrification to lead to downward pressure on rates.[7]

[5] Cal Advocates, *Motion of the Public Advocates Office to Admit Its Distribution Grid Electrification Model Study and Report Into the Record*, September 8, 2023. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K423/520423681.PDF.

[6] *Administrative Law Judges's Ruling Soliciting Comments on Cal Advocates' Distribution Grid Electrification Model Study and Report*, October 17, 2023. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K563/520563683.PDF. The ruling solicited opening comments no later than October 31, 2023 and reply comments no later than November 7, 2023.

[7] Downward pressure on residential rates means that forecasted rates with electrification are lower than present rates in real terms, all other things being equal. Rates may still increase overall due to other factors such as wildfire mitigation or clean energy procurement.

Cal Advocates' DGEM 2025 Study and Report offers information to aid the ongoing discourse on electrification planning and help decision-makers understand the impacts of electrification, make sound policy choices regarding distribution planning, and determine where future research is needed.[8] The DGEM 2025 Study and Report contributes to an evolving landscape of distribution grid studies at the Commission, including the Electrification Impact Study Part 1 and the forthcoming Electrification Impact Study Part 2.[9] Studies that use the most up-to-date methods and data are integral to effectively plan for load growth, inform future grid investments, and identify grid costs and benefits for consideration in Track 1 of this proceeding.[10] In particular, the DGEM 2025 Study and Report provides insight into the comparative effects of possible future outcomes, such as differing degrees of building electrification adoption and differing EV charging behaviors.

For these reasons, Cal Advocates moves that the Commission admit the DGEM 2025 Study and Report into the record. The DGEM 2025 Study and Report is attached to this motion.

Respectfully submitted,

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[8] DGEM 2025 Study and Report at 18.

[9] DGEM 2025 Study and Report at 26-27.

[10] See Amended Scoping Memo at 4-6.

ATTACHMENT

Distribution Grid Electrification Model 2025

Study and Report

Our mission is to advocate for the lowest possible bills for customers of California's regulated utilities consistent with safety, reliability, and the state's climate goals.

October 2025

The Public Advocates Office
California Public Utilities Commission
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We acknowledge the following contributors, without whom this work would not have been possible:

- Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company for providing loading, rating, upgrade cost, and other data.
- The California Energy Commission's Advanced Electrification Analysis Branch for providing electric vehicle population, efficiency, and travel data.
- The California Department of Motor Vehicles for providing vehicle registration data.
- Many others who provided vision, data, guidance, insight, feedback, or otherwise contributed to this work.

Recommended Citation:

Public Advocates Office, Distribution Grid Electrification Model 2025 – Study and Report, 2025.

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Glossary

Acronyms and initialisms

AAEE	Additional Achievable Energy Efficiency
AAFS	Additional Achievable Fuel Substitution
AATE	Additional Achievable Transportation Electrification
AB	Assembly Bill
ACS	American Community Survey
ACC	Avoided Cost Calculator
ACF	Advanced Clean Fleets
AEC	Annual Energy Consumption
AMI	Advanced Metering Infrastructure
BCZ	Building Climate Zone
BE	Building Electrification
BEV	Battery Electric Vehicle
BTM	Behind-the-Meter
CARB	California Air Resources Board
CEC	California Energy Commission
CED	California Energy Demand (Forecast)
CPUC	California Public Utilities Commission
D.	Decision
DER	Distributed Energy Resource
DGEM	Distribution Grid Electrification Model
DIDF	Distribution Investment Deferral Framework
DMV	Department of Motor Vehicles
EIS	Electrification Impacts Study

EPA	Environmental Protection Agency
EV	Electric Vehicle
GHG	Greenhouse Gas
GVWR	Gross Vehicle Weight Rating
GWh	Gigawatt Hour
HVAC	Heating, Ventilation, and Air Conditioning
HD	Heavy Duty
ICA	Integration Capacity Analysis
IOU	Investor-Owned Utility
IEPR	Integrated Energy Policy Report
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
LD	Light Duty
MD	Medium Duty
MVA	Megavolt-ampere
MW	Megawatt
MWh	Megawatt Hour
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
PG&E	Pacific Gas and Electric Company
PHEV	Plug-in Hybrid Electric Vehicle
PV	Photovoltaics
ROB	Replace On Burnout
SB	Senate Bill
SCADA	Supervisory Control and Data Acquisition

SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SUV	Sport Utility Vehicle
TAC	Transmission Access Charge
TOU	Time-of-Use (Rate)
VMT	Vehicle Miles Traveled

Definitions

Battery Electric Vehicle (BEV): A vehicle powered only by an electric motor and battery. PHEVs are not considered BEVs in this report. BEVs are one of the two types of EVs.

Behind-the-Meter (BTM): Refers to resources located behind a service meter, such that a customer's load and generation from BTM resources are combined with the customer's total load. Typically, rooftop solar and home EV chargers are BTM. Large-scale generators are located in front of the meter (i.e., they are separately metered and not BTM).

Distribution Grid Electrification Model (DGEM): DGEM is our model of the distribution grid. In this document, DGEM refers to not just the model but the study and this report. DGEM 2023 refers to the first version of this report, published in 2023, while DGEM 2025 refers to this current version.

Feeder: A feeder is an entire distribution circuit, including all branching conductors between a distribution substation and all service transformers.

Class: Light Duty (LD), Medium Duty (MD), or Heavy Duty (HD). See Gross Vehicle Weight Rating.

Gross Vehicle Weight Rating (GVWR): Defines the safe, fully loaded weight of a vehicle (including passengers, freight, and the weight of the vehicle itself). This classification is used to categorize vehicles into LD, MD, and HD. We use the CEC's definitions:[1]

- LD: GVWR ≤ 10,000 lbs.
- MD: 10,000 lbs. < GVWR ≤ 26,000 lbs.

[1] CEC, *Medium- and Heavy-Duty Zero-Emission Vehicles in California*, n.d. Available at: https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics/medium-and-heavy. See section "Understanding Vehicle Weight Class" on the webpage.

- HD: GVWR > 26,000 lbs.

Investor-Owned Utilities (IOUs): Monopolies that provide utility services and are regulated by a government body. For this study, IOUs include Pacific Gas and Electric Company (PG&E), and Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

Managed Charging: Managed charging is the optimization of EV charging times in order to reduce energy costs, grid costs, and/or greenhouse gas (GHG) emissions. Active managed charging refers to strategies that give control of EV charging times to a third party in order to modify charging behavior on a real-time basis, often in response to prices or grid conditions.

Mitigation: In this report, mitigations refer to all strategies that can solve equipment overloads. In addition to constructing new infrastructure, strategies include increasing the capacity of physical grid assets, changes to Time-of-Use (TOU) rates to reduce load, DERs that can reduce net load, and EV charging management programs that can respond to grid needs.

Plug-In Hybrid Electric Vehicle (PHEV): Plug-in hybrid EVs are vehicles with a combustion engine and a battery plus electric motor system. Unlike traditional hybrid vehicles, PHEVs can be plugged in. PHEVs are one of the two types of EV.

Primary Distribution: Consists of feeders and distribution substations. Primary distribution systems in California typically include three symmetrical power phases and operate between 4 kV and 33 kV.[2]

Ratepayer: A customer of a utility. In this study, a ratepayer refers to the customers who pay electric bills to PG&E, SDG&E, or SCE.

Secondary Distribution: Secondary distribution assets include any equipment needed between primary distribution systems and the customer, including, but not limited to, distribution transformers, service drops, and secondary lines. Secondary distribution equipment typically operates between 120 and 480 volts.[3]

Subclass: Vehicle chassis information for LD vehicles, which are split into body types and sizes. Examples include subcompact cars, heavy vans, and compact pickups.

Substation: Substations are large electromechanical infrastructure that use transformers to raise or lower the voltage of electricity. Substations include protection equipment such as circuit breakers. For the purposes of this study, substations refer to distribution substations unless

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[2] Richard E. Brown, *Electric Power Distribution Reliability*, 2017 (Brown) at 4. Available at: https://books.google.com/books?id=CVNW8qW3ggwC.

[3] Brown at 4.

otherwise specified. Distribution substations typically lower voltage from transmission level voltages such as 115 kV or 60 kV to primary distribution voltage, which is most commonly 12 kV.

Executive Summary

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) studied the costs of upgrading the distribution grids of the three largest investor-owned electric utilities (IOUs) to meet California's electrification goals. This analysis, Distribution Grid Electrification Model 2025 (DGEM 2025), expands on our 2023 study (DGEM 2023).[4] In our 2025 study, we modeled nine scenarios varying by degree of building electrification (BE) adoption and electric vehicle (EV) charging behaviors.

We estimate the total cost of upgrading the grid by 2040 to be approximately $25 billion in our central scenario, with costs ranging from $17 billion to $38 billion.

California has adopted ambitious policies and goals to reduce its greenhouse gas (GHG) emissions over the next decade through a variety of strategies. One important strategy is electrification, the mass adoption of electric vehicles and electric appliances.[5] Electrification will significantly increase the amount of electricity consumed by California ratepayers, requiring electric utilities to plan for major distribution grid upgrades.

As the costs of providing electric service—including the costs to upgrade the distribution system—are recovered across more units of electricity sold, electrification may cause downward pressure on electric rates of approximately 3 cents per kilowatt hour (kWh), varying by year, IOU, and scenario. For electrification to achieve this downward pressure on rates, effective management of multiple factors will be required, including efficient infrastructure buildout and cost constraints.[6] However, downward pressure does not necessarily guarantee rates will fall; other drivers such as wildfire safety may still push rates higher. It is also important for utilities and decision-makers to minimize upward pressure on rates from these other drivers.

This report contributes to California's ongoing efforts to plan and implement the state's electrification goals. We view all feedback on DGEM 2025 as a crucial part of ensuring that our study and future studies help to advance the state's goals.

Background

As purchases of EVs and electric building appliances increase, electric utilities will need to upgrade their distribution grids to support the delivery of additional electricity. Decision-makers and utilities will need to develop new regulatory and planning approaches in order to facilitate

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[4] Cal Advocates, *Distribution Grid Electrification Model – Study and Report*, August 2023 (DGEM 2023), available at: https://www.publicadvocates.cpuc.ca.gov/press-room/reports-and-analyses/distribution-grid-electrification-model-findings.

[5] California Air Resources Board, *2022 Scoping Plan for Achieving Carbon Neutrality*, Final 2022 Scoping Plan, at 75. Accessed June 24, 2025, available at: https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.

[6] See the Assumptions and Limitations section below for further discussion.

these upgrades. Informed grid planning and effective regulation depend on a clear understanding of total distribution system upgrade costs, key cost drivers, and the impact of these costs on electric rates.

How electrification unfolds is highly uncertain. Different potential electrification outcomes could lead to different requirements for grid upgrades. For example, mass adoption of flexible loads such as EVs and smart thermostats may allow electric load to be shifted away from peak times, reducing strain on the grids. Utilities can respond to new loads using traditional grid upgrades or use strategies such as load shifting to reduce the need for upgrades. Quantifying costs across a variety of future outcomes helps to inform the collective understanding of the strategies available to address electrification.

Methodology

DGEM 2025 estimates the cost of upgrading California's three large electric IOUs' distribution grids under nine electrification adoption scenarios. Using statewide electric forecasts from the California Energy Commission (CEC)'s 2023 Integrated Energy Policy Report (IEPR),[7] we disaggregate IEPR-forecasted load growth onto individual distribution circuits within the three IOUs' service territories to estimate where distribution upgrades will be needed.

We modeled three BE adoption scenarios (based on the CEC's Additional Achievable Fuel Substitution framework (AAFS) and three EV charging behaviors (varying the degree of peak-time charging). In combination, these form nine modeling scenarios. Our central scenario follows the CEC's Planning Scenario, using AAFS Scenario 3 and the CEC's modeled EV charging behavior.

Results

We estimate that upgrading the distribution grids of California's three major IOUs will cost approximately $25 billion through 2040 in our central scenario, with costs ranging from $17 billion to $38 billion depending on different scenarios.

The key findings in this study are:

1. **Electrification exerts modest downward pressure on rates**. Across all nine scenarios, increased infrastructure costs due to electrification is offset by increased electricity consumption, producing a small downward pressure on rates of –0.2 to –4.5 cents per kilowatt-hour by 2040. All ratepayers could benefit, although the size of the benefit varies by scenario.

[7] CEC, *Adopted 2023 Integrated Energy Policy Report* (2023 IEPR). Available at: https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2023-integrated-energy-policy-report.

2. **EV charging behavior has a significant impact on grid upgrade costs.** While the exact value of managed charging is uncertain and depends heavily on default vehicle charging behavior, we estimate the value of mass adoption of managed charging to be between $5 billion and $18 billion in distribution grid upgrade cost savings by 2040. These savings exclude implementation costs and vary greatly by circuit, suggesting that targeted programs may yield the greatest benefits.

3. **BE adoption has a moderate impact on costs.** Varying levels of BE adoption could change total grid costs by $3.4 billion and have a minimal impact on rates (less than 0.6 cents/kWh). However, BE outcomes outside the range considered by DGEM 2025 could have a more significant and variable impact on both costs and rates.

4. **Updated data lowers estimates compared to 2023 study.** DGEM 2023 projected $26 billion in grid upgrades by 2035. DGEM 2025 estimates $14 billion for that year under the same assumptions, driven primarily by updated infrastructure costs data.

Assumptions and limitations

Our results are contingent on a large set of modeling assumptions and therefore reflect a high degree of uncertainty. Our cost estimates should be understood as comparative indications of the impacts of different adoption outcomes and policy decisions, rather than as accurate forecasts. Downward pressure on rates is contingent on:

1. Expected load growth materializing.
2. Utilities avoiding overbuilding or building infrastructure in the wrong places.
3. Grid strain not exceeding our modeling scenarios.
4. Overload mitigations not being more costly than estimated.
5. Ratepayers not funding additional electrification programs.
6. Rate designs distributing savings broadly across customers.

Even if electrification leads to downward pressure on rates, we cannot conclude that electric rates will fall. Other drivers, such as wildfire mitigation and other wildfire-related costs, could outweigh these benefits, especially as California already faces some of the highest rates in the country.[8] The key limitation is that the magnitude of downward pressure matters: greater downward pressure on rates due to electrification could offset rising costs elsewhere. Utilities should therefore focus on accurate forecasting, flexible planning, and avoiding overbuilding to preserve ratepayer benefits. Utilities must also consider the timing and magnitude of infrastructure buildout, which could create a short-term upward pressure on existing high rates if infrastructure is built now for demand arriving farther in the future. This concern applies to all potential infrastructure expansion, including investments to serve increased electrification and EV loads. While utilities should be proactive to some degree in the way they plan their distribution grids, and should consider what infrastructure will be needed in the long term, their planning must also factor in affordability considerations for ratepayers who are already struggling with historically high bills.

Further work

We welcome broad input and will engage with a wide range of stakeholders on the results of our study. We do not treat our cost projections as definitive, but rather intend our study to contribute to the continuous discourse on the future of the distribution grid and the most effective strategies for achieving California's climate goals.

Future studies could focus on:

- Improving estimates of EV charging locations and charging behaviors
- Unifying gas system data with electric data to improve estimates of BE adoption locations
- Effectively modeling the costs associated with upgrading secondary distribution infrastructure such as service transformers
- More precisely modeling the broad range of mitigations likely to be undertaken by the utilities in response to overloads.

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[8] See Cal Advocates, Q1 2025 Electric Rates Report, May 20, 2025. Available at: https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/242005-public-advocates-office-q1-2025-rates-report.pdf.

California has the second-highest utility rates in the country as of May 2025. See U.S. Energy Information Agency, Electric Power Monthly (July 2025), at 137. Available at https://www.eia.gov/electricity/monthly/current_month/july2025.pdf.

1 Introduction

In August 2023, Cal Advocates published the results of the Distribution Grid Electrification Model (DGEM 2023).[9] DGEM 2023 estimated the costs to upgrade the distribution grids of California's three major electric investor-owned utilities (IOUs) – Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric – to meet the state's forecasted electric vehicle (EV) deployment and other load growth through 2035. This study offers a new DGEM analysis by adding more detailed modeling for building electrification (BE), updating the data used, expanding the methodology, and adding new scenarios.

Through this study, we aim to continue the discourses on distribution planning, the future of the distribution grid, and electrification. We focus our work on the most accurate available data and a sound and transparent methodology. We aim to help decision-makers understand the impacts of electrification, make sound policy choices, and determine where future research is needed. We also intend to highlight the limitations and uncertainty in this and other studies, so that decision-makers can continue to develop improved planning and forecasting methods appropriate for an unpredictable future.

This introduction summarizes the purpose and drivers of electrification load growth and places this study in context. Section 1.1 examines electrification as a decarbonization strategy, with subsections on transportation (1.1.1) and buildings (1.1.2). Section 1.2 reviews other drivers of load growth, such as population growth and climate-driven increases in cooling demand. Section 1.3 considers recent grid impact studies, including our prior study *Distribution Grid Electrification Model* (DGEM 2023), to illustrate how different assumptions can shape cost estimates. Section 1.4 sets out the scope and objectives of this updated study, DGEM 2025, and Section 1.5 explains how its results should be interpreted. Together, these subsections provide the foundation for why an updated DGEM 2025 analysis is needed.

1.1 Decarbonization through electrification

California faces a myriad of challenges due to climate change, including increased wildfire risk, more intense droughts and floods, and more extreme weather events such as prolonged heat waves. These challenges have only intensified in the past few years, as demonstrated by the

[9] DGEM 2023 was originally published as *Distribution Grid Electrification Model, Study and Report*, and referred to internally as DGEM. For clarity, we now refer to that previous study as DGEM 2023 and this study as DGEM 2025.

recent Los Angeles fires.[10] California remains a national leader in efforts to combat climate change, with comprehensive and ambitious policies aimed at reducing the state's greenhouse gas (GHG) emissions.[11]

These efforts focus on the high-polluting sectors of the economy and rely heavily on electrification—mass adoption of electric vehicles (EVs) and electric building appliances—as a large-scale strategy for reducing emissions within several of those sectors. Advancements in technology also contribute to this electrification: as new EVs and electric appliances perform better and become cheaper, many consumers will electrify because of the new technologies' competitiveness over conventional options.

The mass adoption of EVs will significantly increase electricity consumption, as will the adoption of electric appliances in buildings.[12] EV adoption will add new, flexible, and potentially high-demand loads. BE adoption will increase electricity consumption in homes and businesses that currently rely on natural gas. Together, these changes will create substantial new requirements for the state's distribution grids and necessitate upgrades to California's electrical infrastructure.

Key questions facing electric utilities and decision-makers, such as the California Public Utilities Commission (CPUC) and California Energy Commission (CEC), include *where* new electrification load from EVs and other sources will appear on the grid, *when* the load will appear, *how much* load to expect, and *how costly* the resulting infrastructure upgrades will be. Electric utilities and decision-makers must also understand how different policy decisions, programs, and public behaviors will affect these outcomes. Table 1-1 provides an overview of the scale of California's projected electrification.

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[10] The January 2025 Palisades Fire was among the most expensive wildfires in history and the most destructive in the region's history. Although it is difficult to attribute anthropogenic climate change to individual events, Barnes, et al., found that our 1.3 degrees Celsius (°C) warming over pre-industrial temperatures made the fire 35% more likely. Similar weather conditions as those which preceded the fires are estimated to occur, on average, once every 17 years. The likelihood of wildfire and the frequency of precursive weather conditions are expected to increase as warming increases. See: Barnes, et al., *Climate change increased the likelihood of wildfire disaster in highly exposed Los Angeles area*, World Weather Attribution, January 28, 2025, accessed June 25, 2025, available at: https://www.worldweatherattribution.org/wp-content/uploads/WWA-scientific-report-LA-wildfires-1.pdf.

[11] One such policy is Assembly Bill (AB) 32, passed in 2006. AB 32 mandated that California reduce its GHG emissions to 1990 levels by 2020, through a Cap-and-Trade program. Senate Bill (SB) 32, passed in 2016, further required California to reduce its GHG emissions 40 percent below 1990 emissions levels by 2030. AB and SB 32 identified the California Air Resources Board (CARB) as the state agency responsible for producing GHG reduction implementation strategies and a roadmap. CARB set forth plans to reduce emissions to at least 40 percent below 1990 emissions levels by 2030 and achieve carbon neutrality by 2045. Another such policy is SB 100, passed in 2018, setting a 100% clean electricity goal for the state by 2045. Various state agencies have outlined regulations within their jurisdictions to achieve these targets.

[12] 2023 CEC IEPR hourly demand forecast, available at: https://www.energy.ca.gov/data-reports/reports/2023-integrated-energy-policy-report/2023-iepr-workshops-notices-and-2.

Table 1-1: Electrification status and goals.

Sector	Current (2023)	Forecasted
Total electricity consumed in California	281,140 GWh[13] in 2023[14]	375,869 GWh in 2040[15]
Fraction of California's electricity consumption produced by clean sources[16]	58% in 2023[17]	100% in 2045, as targeted by SB 100[18]
Electricity consumed by electrification subsectors[19]	35,754 GWh in 2023[20]	162,657 GWh forecasted in 2045[19]

1.1.1 Transportation electrification

The California State Legislature has made decarbonizing the transportation sector a priority on the basis that the sector accounts for more than 40% of the state's total GHG emissions.[21] The state has implemented regulations that require most types of fossil-fuel powered vehicles to become zero-emission vehicles within the next two decades.[22] These regulations aim to address

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13 GWh: Gigawatt-hours.

14 CEC, *2009-2023 Total System Electric Generation Spreadsheet*, 2023 Total System Electric Generation, available at: https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2023-total-system-electric-generation.

15 CEC, *CED 2024 Baseline Demand Forecast – Total State,* Form 1.2 "Total Energy to Serve Load (GWh)," Accessed June 20 2025. Available at: https://www.energy.ca.gov/data-reports/california-energy-planning-library/forecasts-and-system-planning/demand-side-2.

16 Biomass, geothermal, large hydro, nuclear, small hydro, solar, and wind.

17 CEC, *2009-2023 Total System Electric Generation Spreadsheet*, 2023 Total System Electric Generation.

18 California Legislative Information, *SB-100 California Renewables Portfolio Standard Program: emissions of greenhouse gases*, available at: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

19 Electric load in the following subsectors: commercial and residential air conditioning, cooking, space heating, water heating, residential clothes drying, LD vehicles, buses, harborcraft, HD trucking, and MD trucking.

20 CARB, *AB 32 GHG Inventory Sectors Modeling Data Spreadsheet*, "Subsector Energy Demand", 2022 Scoping Plan for Achieving Carbon Neutrality, available at: https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents.

21 California State Transportation Agency, *Climate Action Plan for Transportation Infrastructure*, July 2021 at 6. Available at: https://calsta.ca.gov/-/media/calsta-media/documents/capti-july-2021-a11y.pdf.

22 This move is required by Executive Order N-79-20. See: CARB, *California Moves to Accelerate to 100% New Zero-Emission Vehicle Sales by 2035*, Release Number 22- 30, August 25, 2022. Available at: https://ww2.arb.ca.gov/news/california-moves-accelerate-100-new-zero-emission-vehicle-sales-2035; and CARB, California Approves Groundbreaking Regulation That Accelerates the Deployment of Heavy-Duty ZEVs to Protect Public Health, Release Number 23-13, April 28, 2023. Available at: https://ww2.arb.ca.gov/news/california-approves-groundbreaking-regulation-accelerates-deployment-heavy-duty-zevs-protect.

the environmental and public health impacts of fossil-fuel powered vehicles and meet the goal of carbon neutrality in California by 2045.[23]

The California Air Resources Board (CARB) is the leading agency in promulgating many of these key regulations. For example, through the Advanced Clean Cars II regulation, CARB aims to scale down light duty (LD) passenger car, pickup truck, and Sport Utility Vehicle (SUV) emissions by requiring an increasing number of zero-emission vehicle sales starting with 35% for model year 2026 and reaching 100% in 2035.[24] In addition, through its Advanced Clean Fleets (ACF) regulation, CARB has required that all state and local government vehicle fleet purchases must be zero-emission by 2027.[25]

Figure 1-1 shows the expected on-road population of EVs, split into battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs), as projected in the CEC 2023 Integrated Energy Policy Report (IEPR).

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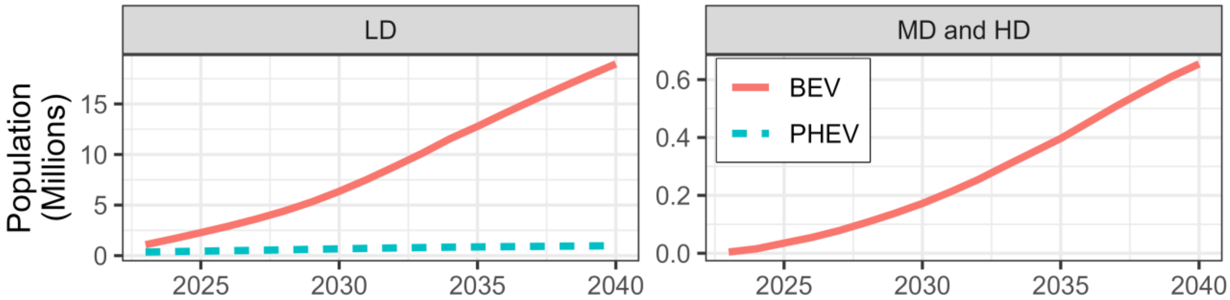
[23] California Governor's Office of Land Use and Climate Innovation, *Carbon Neutrality by 2045*, available at: https://lci.ca.gov/climate/carbon-neutrality.html.

[24] CARB, *Advanced Clean Cars II*, accessed June 24, 2025, available at: https://ww2.arb.ca.gov/our-work/programs/advanced-clean-cars-program/advanced-clean-cars-ii.

[25] The ACF regulation originally contained additional requirements on drayage, last mile delivery, and yard trucks, and on medium- and heavy-duty (MDHD)vehicle manufacturers. However, CARB has withdrawn its request for a federal waiver and authorization of for the addition of ACF to its emissions control program, a step necessary to enforce portions of the ACF such as requirements that apply to high priority and drayage fleets. While the initial comprehensive ACF regulation has been pared down, the state and local government fleets portion of the ACF regulation remains unaffected. See:

CARB, *Advanced Clean Fleets Final Approval*, see "Appendix A-1, Final Regulation Order: State and Local Government Agency Fleet Requirements" at A-1-13, "Appendix A-3, Drayage Truck Requirements" at A-3-14, "Appendix A-2: High Priority and Federal Fleets Requirements" at A-2-26, "Appendix A-4, 2036 100 Percent Medium- and Heavy-Duty Zero Emissions Vehicle Sales Requirements" at A-4-3, accessed July 10, 2025. Available at: https://ww2.arb.ca.gov/rulemaking/2022/acf2022; and CARB, *Advanced Clean Fleets*, accessed June 24, 2025, available at: https://ww2.arb.ca.gov/our-work/programs/advanced-clean-fleets; and CARB, *State and Local Government Agency Fleet Requirements*, see A.1-4, A.1-12, A.1-13. Available at: https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2022/acf22/ac/acffro11.pdf.

Figure 1-1: Vehicle deployment forecast from the 2023 IEPR.[26]



Box 1-1: IEPR Vintages

The IEPR lays out energy plans for California. It analyzes major energy trends (including electricity, natural gas, and transportation fuel), provides policy recommendations, and is produced collaboratively with stakeholders. A major focus of the report is charting a course to transition to a renewable energy future. The report includes a detailed, sectoral energy demand forecast which DGEM 2025 uses as a data input.

The CEC prepares the IEPR annually. However, each year's "vintage" takes several years to complete. While the 2024 IEPR and the 2025 IEPR have been started, neither is yet complete as of writing. Both remain in draft form, and the data sheets that DGEM 2025 requires as inputs are not yet available. Since the 2023 IEPR is the most recent complete vintage available, we have used it for this report. Any future reports will similarly use the most recent vintage available.

As EV adoption grows, charging will strain California's electric distribution infrastructure, especially if they charge at peak times in the late afternoon and early evening when the grid has limited capacity. California decision-makers have highlighted the importance of managing charging behavior as EV adoption scales.[27] For example, the CEC notes that shifting when and how EVs charge can reduce emissions, save customers money, and support reliable and economic grid operation.[28]

Such approaches are often labeled "vehicle-grid integration," "smart charging," or "managed charging." They include strategies like dynamic rate structures that directly incentivize

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[26] CEC staff email to Cal Advocates staff, June 10, 2024.

[27] See also Jeff St. John, *EVs will put more stress on California's grid. Smart charging can help*, Canary Media, March 4, 2024. Available at: https://www.canarymedia.com/articles/ev-charging/evs-will-put-more-stress-on-californias-grid-smart-charging-can-help

[28] CEC, *Assembly Bill 2127 Second Electric Vehicle Charging Infrastructure Assessment, Assessing Charging Needs to Support Zero-Emission Vehicles in 2030 and 2035*, February 2024 at 88. Available at: Page 88. Accessed at https://www.energy.ca.gov/publications/2024/assembly-bill-2127-second-electric-vehicle-charging-infrastructure-assessment.

consumption at specific times,[29] and enrollment programs where EV owners allow utilities or third-party operators to manage charging while the vehicle is plugged in.[30]

1.1.2 Building electrification

California has also prioritized building electrification (BE) through the replacement of gas appliances—such as those used for heating, ventilation, and air conditioning (HVAC) systems, space heating, water heating, clothes drying, and cooking—with electric appliances. Specifically, CARB has set targets recommending that all new residential buildings constructed after 2026 and all new commercial buildings constructed after 2029 contain all-electric appliances.[31] The CARB 2022 Scoping Plan also articulates a goal for electric appliances to make up 100% of appliance sales by 2035 for existing residential buildings, and by 2045 for existing commercial buildings.[32]

The CEC relays and reinforces an ambitious vision to decarbonize the state's building sector and transform California's energy landscape in its IEPR 2023 report. Accelerating building decarbonization and improving energy efficiency across both new constructions and retrofit projects is crucial to reducing GHG emissions.[33] Governor Newsom issued a clear and aggressive goal to transform 3 million existing homes into climate-ready buildings by 2030 and 7 million by 2035, marking a significant push toward converting traditional gas-dependent systems to fully electric alternatives.[34] In line with this, the adoption of approximately 6 million heat pumps by 2030 is estimated to replace conventional gas heating.[35]

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[29] For example, the CPUC directed SCE to expand its dynamic rate pilots. See D. 24-01-032, *Decision to Expand System Reliability Pilots of PG&E and Southern California Edison Company*, January 25, 2024; issued in Rulemaking 22-07-005, *Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates*. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M524/K176/524176497.PDF. SCE provides a description of it the Flexible Pricing Rate Pilot. See SCE, *SCE Expanded Flexible Pricing Rate Pilot, A New Opportunity for Southern California Edison (SCE) Customers to Shift Energy Use and Save*. Available at: https://www.sce.com/factsheet/dynamic-pricing-rate-pilot.

[30] For example, PG&E operates a charging scheduling program called EV Charge Manager. PG&E, *EV Charge Manager*. Accessed July 29, 2025. Available at: https://www.pge.com/en/clean-energy/electric-vehicles/ev-charge-manager-program.html.

[31] CARB, *2022 Scoping Plan for Achieving Carbon Neutrality*, December 2022 at 75. Available at: https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.

[32] CARB, *2022 Scoping Plan for Achieving Carbon Neutrality*, December 2022 at 75-76. Available at: https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.

[33] CEC, *Adopted 2023 Integrated Energy Policy Report*, February 2024 (2023 IEPR) at 119. Available at: https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2023-integrated-energy-policy-report.

[34] Governor Gavin Newsom, July 22, 2022. Letter from Governor Newsom to CARB Chair Liane Randolph. Available at: https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf.

[35] 2023 IEPR at 119.

Figure 1-2: Forecasted demand from three BE sectors.[36]

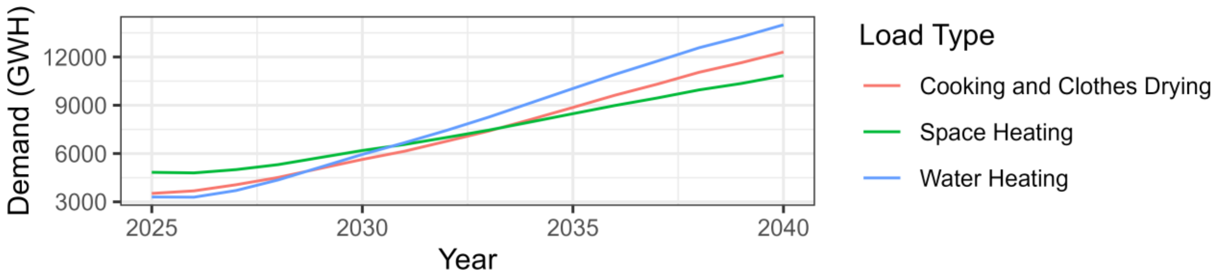

Figure 1-2 shows the CEC's projected growth in BE demand, which accelerates in the latter half of the decade, with the three graphed sectors reaching a cumulative 37,627 gigawatt-hours (GWh) in 2040.

1.2 Other forms of load growth

This report focuses on the impacts of EV charging and BE, as those are the key contributors to electrification load growth in the state. However, other changes will also impact the distribution grid, such as the electrification of other sectors, economic and demographic growth, and the increasing deployment of customer-sited solar photovoltaics (PV).[37] California building code requires most new homes to be equipped with solar PV (rooftop solar) or to be powered by a nearby solar array.[38] As of 2023, the CEC requires that several types of new commercial buildings have both solar generation and battery storage to capture excess solar production.[39] Commercial, industrial, and residential behind-the-meter (BTM) solar supplied about 9 percent of the state's total electricity generation in 2024.[40] Overall, BTM solar generation capacity is

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[36] CARB, *2022 Scoping Plan for Achieving Carbon Neutrality*, AB 32 GHG Inventory Sectors Modeling Data Spreadsheet, "Loads", accessed June 24, 2025, available at: https://ww2.arb.ca.gov/sites/default/files/2022-05/2022-draft-sp-air-quality-health-data-UCI.xlsx.

[37] California Distributed Generation Statistics, *Interconnected Projects*, accessed June 20, 2025, available at: https://www.californiadgstats.ca.gov/downloads/#_nem_cids

[38] CEC, *2019 Building Energy Efficiency Standards for Residential and Nonresidential Buildings for the 2019 Building Efficiency Standards*, December 12, 2018 at Section 110.10. Available at: https://www.energy.ca.gov/sites/default/files/2021-06/CEC-400-2018-020-CMF_0.pdf.; see also CEC, *2019 Energy Code – Solar Ready Requirements*, October 2020. Available at: https://www.energy.ca.gov/sites/default/files/2021-04/2019_Energy_Code_Solar_Ready_Requirements_ADA.pdf.

[39] California Building Standards Commission, *Section 140.10 Prescriptive Requirements for Photovoltaic and Battery Storage Systems*, January 2023. Available at: https://codes.iccsafe.org/content/CAEC2022P2/subchapter-5-nonresidential-and-hotel-motel-occupancies-performance-and-prescriptive-compliance-approaches-for-achieving-energy-efficiency#CAEC2022P2_Ch05_Sec140.10.

[40] CEC, *CEDU 2024 Baseline Electricity Forecast – Total State,* accessed June 20 2025. Available at: https://www.energy.ca.gov/data-reports/california-energy-planning-library/forecasts-and-system-planning/demand-side-2.

projected to grow from 17 gigawatts (GW) to 32 GW from 2023 to 2040.[41] Our analysis in this report includes aggregate data on solar growth, but does not examine the spatial distribution of solar uptake in detail.

Data centers are another key source of load growth. Data centers are a particularly difficult-to-forecast load, as they have high, localized, and uncertain power demand. Data center load growth will be highly dependent on specific economic, sectoral, and spatial conditions. DGEM 2025 draws its forecast from the 2023 IEPR, which estimates load growth due to data center construction projects on the basis of stakeholder outreach.[42] DGEM 2025 does not disaggregate data center load spatially to examine its impact.

1.3 Grid Impact Studies and DGEM 2023

In August 2023, Cal Advocates published the results of DGEM 2023.[43] DGEM 2023 estimated the costs to upgrade the distribution grids of California's three major electric investor-owned utilities (IOUs) – Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric – to meet the state's forecasted EV deployment and other load growth through 2035 to be $26 billion, with uncertainties in the spatial allocation of vehicles and in the cost of grid infrastructure producing a range of potential cost outcomes from $8 billion to $57 billion.

DGEM 2023 also found that load growth and infrastructure costs due to electrification could result in a net downward pressure on rates, although at the high end of the cost range, PG&E customers would experience upward pressure. Follow-up studies released in the months after the publication of DGEM 2023 further examined additional elements of the future of grid upgrades, including how the location of new loads could influence overall grid costs.[44]

DGEM 2023 used load growth forecasts published by the CEC for the 2022 IEPR. The IEPR contains an integrated assessment of major energy trends and issues facing California's electricity, natural gas, and transportation fuel sectors.[45] As part of this assessment, the CEC develops a complex model of California's energy system, including the electric grid, and

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[41] CEC, *CEDU 2024 Demand Side Modeling,* Behind the Meter Distributed Generation Forecast, Self-generation Energy and Capacity by Technology Type, Self-Gen Mid Scenario. Accessed June 20, 2025. Available at: https://www.energy.ca.gov/data-reports/california-energy-planning-library/forecasts-and-system-planning/demand-side-2.

[42] 2023 IEPR at 104

[43] DGEM 2023 was originally published as *Distribution Grid Electrification Model, Study and Report*, and referred to internally as DGEM. For clarity, we now refer to that previous study as DGEM 2023 and this study as DGEM 2025.

[44] Cal Advocates, *Distribution Grid Electrification Model Findings*, available at: https://www.publicadvocates.cpuc.ca.gov/press-room/reports-and-analyses/distribution-grid-electrification-model-findings.

[45] See Box 1-1 for why DGEM 2025 uses the 2023 IEPR.

forecasts electricity consumption at the state and IOU level. The IEPR is developed through a robust and transparent process and represents a high level of research and forecasting quality.

DGEM 2023 was published just a few months after another major study of grid impacts, the *Electrification Impacts Study Part 1: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates* (EIS Part 1), a CPUC-initiated study conducted by the data analytics company Kevala.[46] EIS Part 1 forecasted load growth for more than 12 million premises across California, including from forecasted BE, energy efficiency, and BTM photovoltaic adoption. EIS Part 1 found that up to $51 billion in distribution grid upgrades could be needed by 2035. DGEM 2023 contained many comparisons between itself and EIS Part 1, including comparisons which highlighted the importance of assumptions around EV charging behaviors. EIS Part 1 used an EV load shape with high afternoon demand and a high 9pm timer peak[47] compared to the EV load shape the CEC used in the IEPR. EIS Part 1 consequently predicted a higher degree of grid strain from EVs, leading to higher costs. This difference highlighted the importance of forecasting and managing EVs charging behavior in order to estimate and control costs.

These and other studies[48] continue to contribute to an ongoing discourse. While DGEM 2023 and EIS Part 1 have different methodological approaches and produced different estimates, their rough agreement (with cost outputs in the tens of billions of dollars) provides valuable information on the scale of the electrification costs facing California. No model can perfectly estimate the impacts of an uncertain future, but all models can contribute to our collective understanding and our ability to approach the policy challenges facing California. We also look forward to EIS Part 2, a set of three grid impact studies being undertaken by each of the three

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[46] Kevala, Inc., *Electrification Impacts Study Part 1: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates*, May 9, 2023 (EIS Part 1). Available at: https://www.kevala.com/resources/electrification-impacts-study-part-1.

[47] A "timer peak" is a term for a sharp increase in demand driven by a change in TOU rates. If EV charging timers automatically turn on when rates decrease due to a TOU change (frequently occurring at 9pm), a large number of simultaneously activating chargers could put significant strain on the grid.

[48] For example: Elmallah, et al., investigated the PG&E service area in Northern California by modeling substations and feeders using ICA loading data and DIDF cost inputs. They predicted that PG&E would spend approximately $5 billion by 2050 on infrastructure upgrades. See Salma Elmallah et al., *Can distribution grid infrastructure accommodate residential electrification and electric vehicle adoption in Northern California?*, Environmental Research: Infrastructure and Sustainability, November 9, 2022 at 1. Available at: https://doi.org/10.1088/2634-4505/ac949c.

NREL LA100 proposed potential pathways for LADWP to provide 100% renewable energy, and modeled transformer banks, feeders, and service transformers, using SCADA loading data and IOU unit costs as inputs. They predicted that LADWP would need to spend approximately $1.5 by 2045. See Cochran, Jaquelin et al., *LA100: The Los Angeles 100% Renewable Energy Study*, March 2021, National Renewable Energy Laboratory. Available at: https://maps.nrel.gov/la100/.

major electric IOUs. EIS Part 2 will be released at the end of 2025 and will continue to develop our collective understanding of the impacts of electrification.[49]

1.4 DGEM 2025 Scope and Objective

This study offers a new DGEM analysis by updating the data used, expanding the methodology, and adding new scenarios. Our research entails:

1. Using a new proportion-based model to estimate the locations of future BE loads by building climate zone (BCZ), customer class, and end use, under three different BE adoption scenarios.
2. Using propensity modeling (as used in DGEM 2023) to estimate the location and electric loads of future BE, under three different EV charging behavior scenarios.
3. Estimating the load placed on primary distribution infrastructure due to BE and EV adoption and other non-electrification load growth, for each of our nine total scenarios.
4. Estimating the costs of the feeder, substation, and secondary distribution upgrades necessary to meet the rise in electricity demand, for each scenario.
5. Estimating the electric rate impacts of increased load and grid investment, for each scenario. For this estimate only, we considered generation, transmission, and distribution grid investments.

We have three main objectives for DGEM 2025:

1. Estimate the costs of electrification and the resulting rate impacts on consumers.
2. Describe how different degrees of BE uptake and different EV charging behaviors will affect grid costs.
3. Highlight key issues, such as particularly sensitive inputs and potential mitigation strategies, for scrutiny by decision-makers and for future research.

1.5 DGEM 2025 provides directional sensitivity, not forecasts

DGEM 2025 has required a large degree of simplification, and even without such simplification, small differences between any model's inputs and assumptions versus ground truths might mean the model's outputs diverge from reality. Our results should be interpreted with a degree of

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[49] D.24-10-030, *Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps*, October 17, 2024 at 197; issued in R.21-06-017, *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resource Future*. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M544/K154/544154869.PDF.

uncertainty and are most useful to show the impacts of different adoption outcomes and policy decisions. Our results are best interpreted as directional sensitivity checks rather than as accurate, specific future forecasts.

2 Methods

This section provides an overview of the methods and key datasets used in DGEM 2025.

2.1 Study scope

DGEM 2025 disaggregates the CEC's 2023 IEPR statewide electric load forecasts onto individual distribution circuits. Table 2-1 details the nature of the relationship between parameters within the IEPR and DGEM 2025.

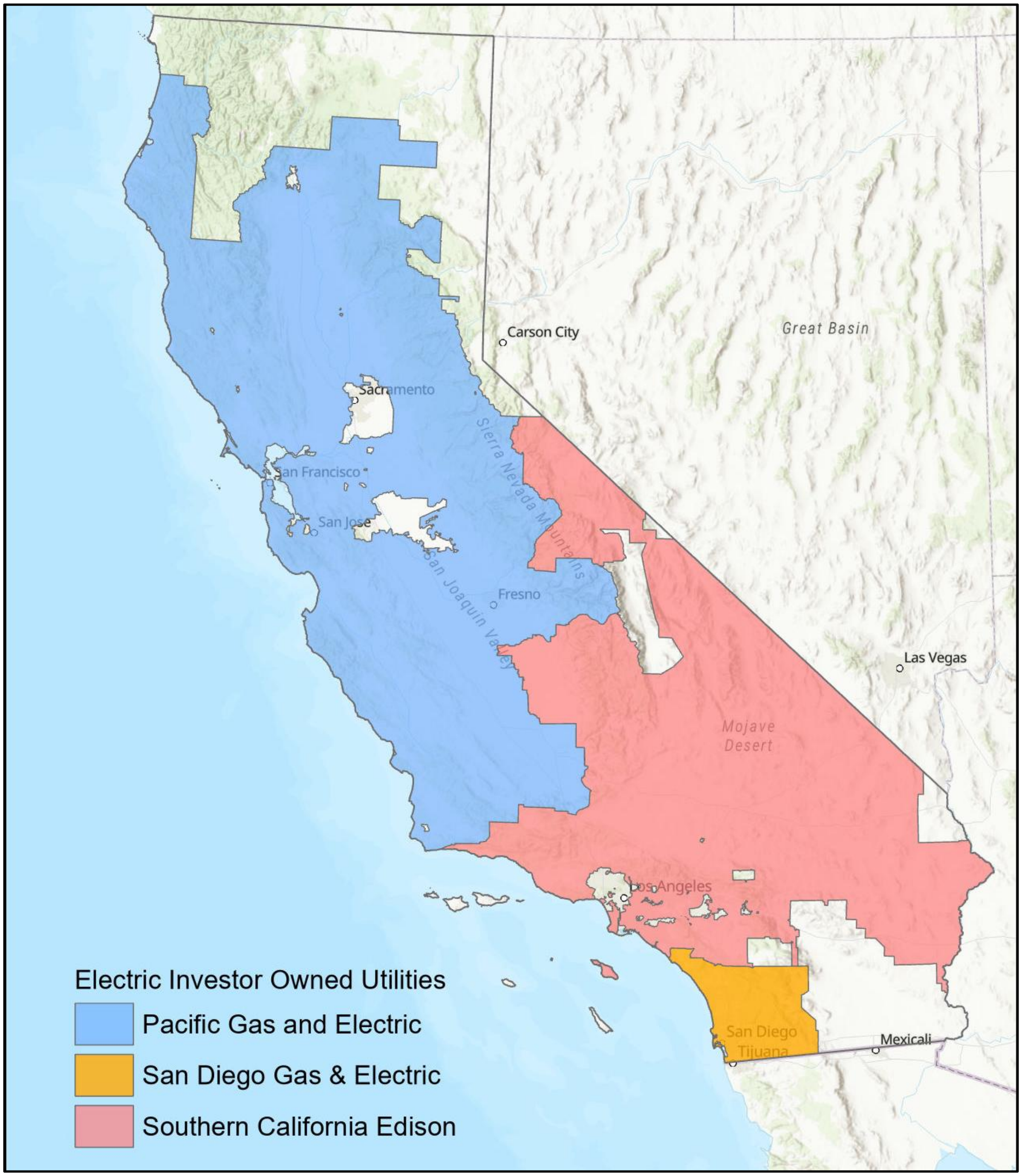
Table 2-1: Relationship between DGEM 2025 assumptions and the 2023 IEPR.

Parameter	DGEM 2025 Relationship to 2023 IEPR
Peak load	Unconstrained but based on the IEPR
BE annual energy consumption	Constrained to the IEPR
BE peak load	Unconstrained but aligned with the IEPR
Granular BE adoption locations	Not considered in the IEPR
State EV population	Constrained to the IEPR
EV population within each IOU's service territory	Not constrained to the IEPR
Granular EV locations	Not considered in the IEPR
Annual EV charging energy	Constrained to the IEPR per vehicle
Hourly EV charging power	Constrained to the IEPR per vehicle
Growth in non-electrification demand	Proportionate to the IEPR at the IOU level

DGEM 2025 studies the combined service territories of PG&E, SCE, and SDG&E, as depicted in Figure 2-1.[50] DGEM 2025 considers only the portion of the IOU service territories for which distribution grid asset data for the three IOUs were available. The precise body of data considered in DGEM 2025 is described in Appendix B.

[50] CEC, *Electric Load Serving Entities (IOU & POU)*, December 16, 2021 (CEC 2021 Electric Load Serving Entities). Available at: https://cecgis-caenergy.opendata.arcgis.com/datasets/b662fc6de88c415fb232ed3dcf9d5d4e/explore, accessible with ArcGIS credentials. The IOUs' service territories were derived from publicly available CEC data.

Figure 2-1: IOU service territory areas considered by DGEM 2025.



2.2 Methodological phases

Our methodology consists of five primary phases:

1) **Estimate peak-day BE load (from HVAC and water heating) on each distribution circuit**, by allocating IEPR-forecasted consumption through 2040 in each BCZ onto feeders proportionally according to current consumption.

2) **Estimate peak-day EV load on each distribution circuit**, by developing propensity models to spatially allocate IEPR-forecasted EV adoption through 2040 and placing EV loads onto the nearest distribution circuit to their registration address.

3) **Estimate all other load and calculate peak demand on each circuit**, by using IOU-provided historic loads, scaled up according to IEPR-forecasted growth rates.

4) **Estimate the number of circuit and substation overloads and the associated cost of mitigations,** by comparing peak demand with IOU-provided ratings and applying estimated mitigation costs.

5) **Estimate the impact of costs on rates**, through a rate model which converts our costs into additional capital expenditures and combines those to IEPR-forecasted consumption growth.

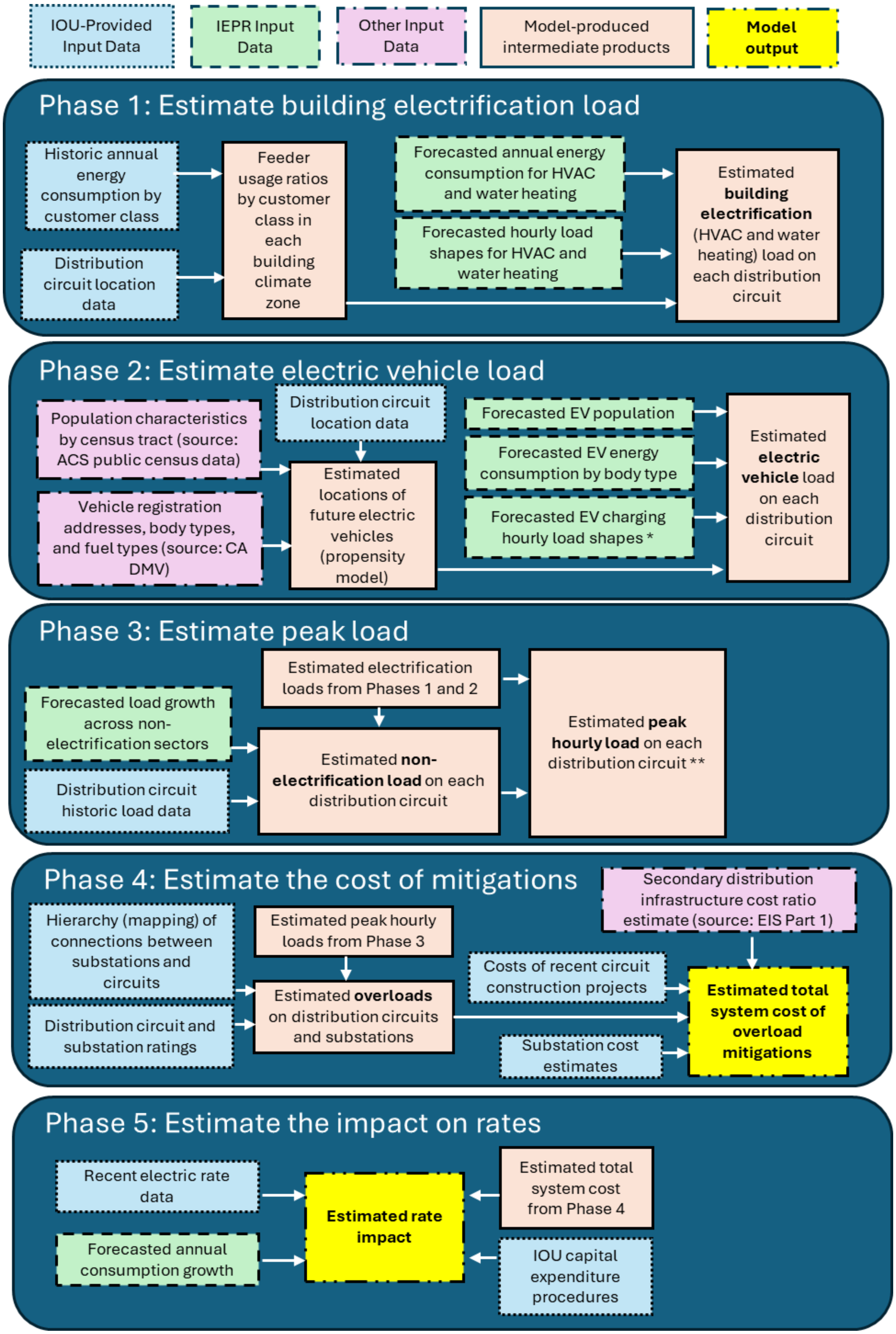
This section provides an overview of the methodology of each phase. Figure 2-2 shows the phases and their data inputs in detail.[51] Appendices C and D provide additional details.

[51] Figure 2-2 contains two footnotes, marked * and **:

Forecasted EV charging hourly load shapes *: This figure shows the model flow for our central scenario, which uses an IEPR-forecasted load shape. We also consider additional load shapes, as described in Section 2.4.

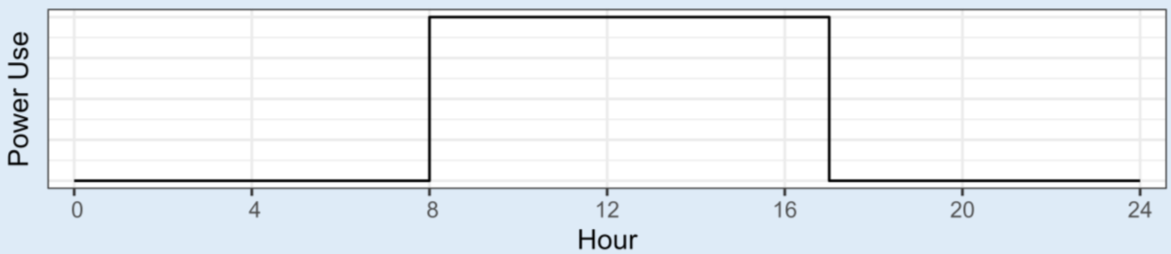
Estimated peak hourly load on each circuit **: In this step we also construct the Managed load shape, which feeds back into Phase 2.

Figure 2-2: Analytical Phases and Data Inputs.



Box 2-1: What is a Load Profile?

DGEM 2025 involves the manipulation of load profiles for different kinds of load. A load profile is a set of data which describes the expected power draw of something connected to the grid over some period of time. For example, imagine a building where lights are turned on at 8am and off at 5pm. A daily load profile for that building's electrical demand for lighting might be graphed as follows:



Load profiles can be measured in different units – for example, absolute electric power draw (usually in kW or MW), or relative electric power draw. They can cover different spans of time, such as a single day, an entire year, or even an abstract set of time like a day made of only peak hours.

Load profiles are useful for modeling because they can be easily scaled up or down, added or subtracted, and visualized, as in the above graph, or in Figure 2-3.

The majority of load profiles used in DGEM 2025 are year-long load profiles originally modeled by the CEC for use in the IEPR. DGEM 2025 converts these to 48-hour load profiles representing peak hours in summer and winter separately.

2.3 Scenarios

DGEM 2025 considers nine different policy scenarios. We consider three different levels of BE uptake. We also consider three different sets of EV charging behavior. When combined in all possible combinations, this provides nine total scenarios.

2.3.1 BE uptake scenarios

The IEPR includes a load modifier called Additional Achievable Fuel Substitution (AAFS).[52] AAFS adds additional electricity consumption to the base forecasted load to model a potential increase in electricity consumption corresponding to the electrification of buildings. Increasing

[52] 2023 IEPR at 107.

levels of AAFS represent assumptions on increasing rates of BE. DGEM 2025 considers three AAFS scenarios: AAFS 2.5, AAFS 3,[53] and AAFS 4. Table 2-2 describes these scenarios.

Table 2-2: Characteristics of the AAFS scenarios.

AAFS Scenario	Corresponding IEPR Scenario	Characteristic	Features
AAFS 2.5	Gradual Transformation	Less BE	More gradual replacement of gas space and water heaters: Replace-on-burnout (ROB) adoption reaches 100% in 2040.
AAFS 3	Planning[54]	More BE	ROB adoption reaches 100% in 2030.
AAFS 4	Local Reliability[55]	Even more BE	ROB adoption reaches 100% in 2030. Compared to Scenario 3 has greater programmatic uptake and an upward adjustment in adoption pre-2030.

The CEC models seven total AAFS scenarios: AAFS 1-6, plus AAFS 2.5. The CEC also provides recommendations for how the IOUs should use these scenarios and recommends only a subset of these scenarios (being those shown in Table 2-2) for planning. These three AAFS scenarios therefore provide a set of plausible possibilities for the degree of BE uptake and allow us to probe the impact of marginal degrees of BE on cost. These should not be seen as representing the extent of future BE, however; changes in policy or market factors could cause BE to proceed at a slower pace than predicted in AAFS 2.5, or at a faster pace than predicted in AAFS 4.

2.3.2 EV charging behavior scenarios

One of the major findings in DGEM 2023 was that EV charging behavior has a significant impact on costs. If EVs charge during periods of high demand, or if many EVs charge simultaneously on the same circuit, additional grid upgrades are required.

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53 The CEC considers AAFS 3 the "business-as-usual" scenario. See CEC 2023 IEPR at 117.

54 The IEPR Planning Scenario is a forecast used for system-level planning activities which assumes mid-level impacts (Scenario 3) from AAEE, AAFS, and AATE.

55 The IEPR Local Reliability Scenario is a forecast used for electricity planning with granular geography which assumes mid-level of transportation energy demand (AATE 3) but less energy efficiency (AAEE 2) and more fuel substitution (AAFS 4).

DGEM 2025 considers three EV load shape scenarios representing different charging behaviors, further exploring this issue by investigating the influence of charging behavior on costs:

- **High Peak:** charging pattern that places a high level of strain on the grid
- **Moderate Peak:** charging pattern with a moderate level of strain on the grid.
- **Managed:** charging pattern designed to minimize strain on the grid.

Table 2-3 provides a summary description of these load shapes, while Section 2.4 contains full descriptions.

Table 2-3: Characteristics of DGEM 2025 EV charging load shape scenarios.

Charging Behavior Scenario	EV Load Shape Source	Degree of Grid Strain	EV Load Shape Characteristics
High Peak	EIS Part 1	High	The High Peak load shape contains a high 9pm peak and a high degree of afternoon charging demand, with low morning and night charging. EIS Part 1 assumed a low degree of participation in EV-specific TOU rates, meaning many EVs would begin charging at 9pm, when standard TOU rates change.
Moderate Peak	IEPR (following the Planning Scenario)	Moderate	The Moderate Peak load shape contains moderate peaks in the morning and evening, with a low degree of afternoon charging demand. The IEPR modeling assumes a higher degree of participation in EV-specific TOU rates and a higher degree of charging during peak solar hours.
Managed	Constructed in our modeling, using the Moderate Peak load shape and estimated non-EV feeder loads	Low	We construct a new load shape unique to each feeder which concentrates load during the times that feeder is projected to have available capacity—usually during the early morning. We then apply that load shape to 50% of LD and 20% of MDHD EVs, with the remainder using the Moderate Peak load shape.

DGEM 2025 models all nine combinations of these AAFS and EV charging behavior scenarios. DGEM 2025 also models an additional three scenarios for an idealized but unachievable "optimized" charging scenario; see Appendix A for the description and results of this modeling.[56]

2.4 Methodology phase 1: BE load growth

The CEC provided Cal Advocates with the annual energy consumption (AEC) of BE loads projected from 2023 through 2040, modeled for the 2023 IEPR. This energy consumption forecast was divided according to California's 16 BCZs. The AEC estimates were further broken down by each of the following attributes:

1. IOU service territories: PG&E, SCE, and SDG&E
2. Sectors: Commercial, Residential, and Low Income
3. End Uses: HVAC, Water heating
4. Residential Building Types: Residential Single-Family and Residential Multi-Family.

The three major IOUs provided Cal Advocates with historic data representing the total AEC of customers on each feeder, divided by sector (commercial, residential, and low income).[57] The IOUs also provided location data of each of their feeders through their Wildfire Mitigation Plans (WMP).[58]

2.4.1 Mapping feeders into building climate zones (BCZs)

The CEC published the geographic boundaries of each BCZ.[59] We geospatially join the map of the locations of each IOU feeder with the BCZ map, associating each with the BCZ it is in. Any feeder which overlaps multiple BCZs is assigned to the BCZ which contains the majority of its length. We exclude some feeders which cannot be mapped, such as those which cross bodies of water, and those in locations which are not included in any BCZ, such as Catalina Island.

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[56] As these additional scenarios are unrealistic, they are discussed in Appendix B only.

[57] SCE does not distinguish between residential and low-income customers and did not provide low-income customer data.

[58] Wildfire Mitigation Plan Quarterly Data Report - Primary Distribution Line from respective IOU's 2023 Q4 submissions. Received via data requests submitted by Cal Advocates to PG&E, SCE, and SDG&E.

[59] CEC, *EZ Building Climate Zone Finder*, accessed June 24 2025. Available at: https://caenergy.maps.arcgis.com/apps/webappviewer/index.html?id=5cfefd9798214bea91cc4fddaa7e643f.

Figure 2-3: California Building Climate Zones

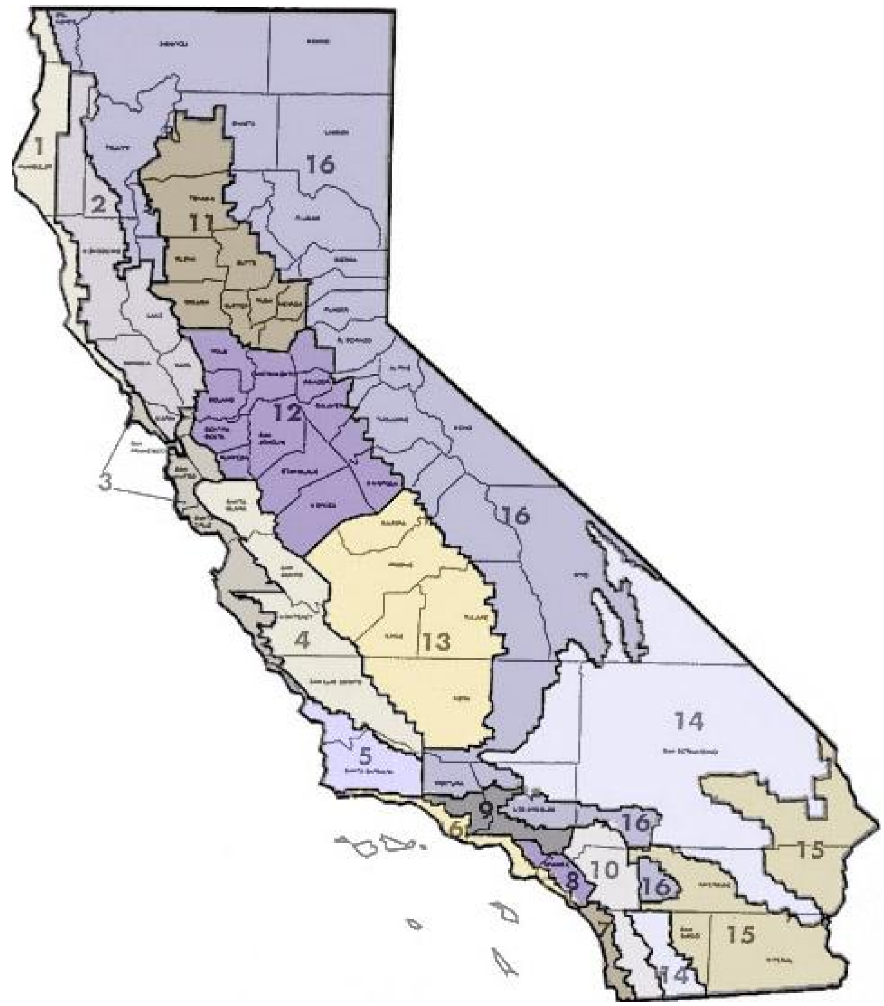


Table 2-4: Number of feeders mapped to each BCZ

BCZ	PG&E	SCE	SDG&E	Total Feeders
1	51	-	-	51
2	188	-	-	188
3	710	-	-	710
4	349	-	-	349
5	61	2	-	63
6	-	647	42	689
7	-		439	439
8	-	940	24	964
9	-	779		779
10	-	825	225	1050
11	288	-	-	288
12	608	-	-	608
13	616	230	-	846
14	-	330	18	348
15	-	168	3	171
16	52	160	-	212
All BCZs	2923	4081	751	7755

2.4.2 Disaggregating annual energy consumption of BE loads onto each feeder

We next allocate the CEC's projected HVAC consumption and water heating consumption in each BCZ to specific feeders in that BCZ, for each future year of the study. We assume that future BE loads will occur in proportion to the existing electric loads on each feeder, according to the customer classes (residential, commercial, or low-income) present on that feeder.[60] For example, if a feeder in BCZ 5 has historically delivered 30% of the total electricity consumed by

[60] "Existing electric loads" here refers to the annual electricity consumption or AEC.

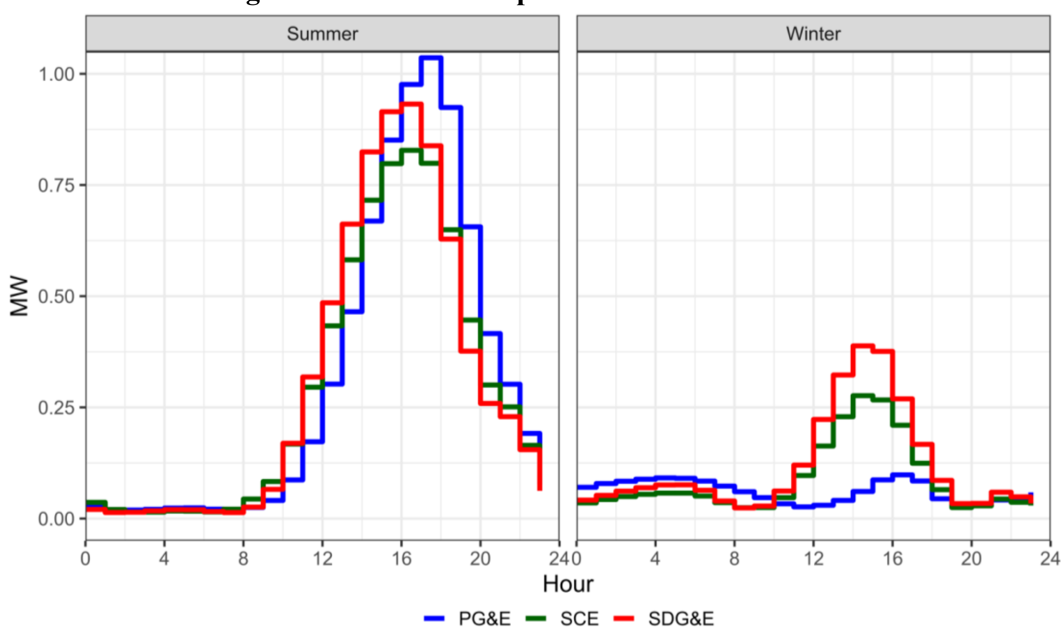
commercial customers in BCZ 5, then we apportion 30% of projected commercial HVAC consumption and 30% of projected commercial water heating consumption in BCZ 5 to that feeder.

In this fashion, following historic AEC ratios, we divide the allocated BE consumption onto each feeder. This produces annual load forecasts for each feeder for each combination of customer class and end use.[61]

2.4.3 Estimating hourly BE loads on each feeder

The CEC provided Cal Advocates with hourly load shapes for BE loads, classified by IOU service territory, end-use, and customer class. These load shapes contained 8760 data points, one for each hour of the year. We converted these annual load shapes into 48-hour peak-day load shapes by selecting the 85th percentile load for each hour of summer and each hour of winter. (For more on this conversion, see Box 2-2: Converting Year-Long Load Profiles into 48-Hour Peak Profiles.). Figure 2-4 shows the load shapes for residential HVAC as an example.

Figure 2-4: BE load shapes for residential HVAC.



[61] We do not distinguish between heating and cooling HVAC loads. However, we do produce distinct summer and winter load shapes. The summer load shapes are dominated by cooling load and the winter load shapes contain both cooling and heating load.

We then apply these load shapes to the estimated AEC on each feeder, providing a 48-hour peak load profile for each customer class and end use on each feeder. Finally, we sum these hourly loads to provide an estimated total peak BE loads on each feeder.

2.5 Methodology phase 2: transportation electrification load growth

2.5.1 Predicting locations of EVs through 2040

Our process for predicting the locations of future EVs consists of three steps:

1. We associate each existing vehicle registration address with the nearest distribution feeder.
2. We score gas-fueled vehicles using propensity models to estimate their likelihood of being replaced with an equivalent EV in the future. We use two propensity models: one for personal vehicles and one for fleet vehicles.
3. We assign non-EVs to become EVs according to their propensity scores until the population of EVs for each year according to the 2023 IEPR is reached.

These steps are described in more detail in the following paragraphs.

Step 1: The California Department of Motor Vehicles (DMV) provided Cal Advocates and the CEC with a dataset containing all registered motor vehicles in California (excluding motorcycles), current to the end of 2022. The data included registration addresses, vehicle makes and models, and fuel types (e.g., electric, diesel, gasoline). The CEC processed the data, adding vehicle class from the make and model of the registered vehicles. We geocoded[62] the dataset using the registration address to derive the latitude and longitude for each vehicle registration. We then eliminated records that we were unable to geocode or that fell outside of the combined IOUs' service areas[63] and spatially joined each record to the nearest IOU feeder.[64]

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[62] Geocoding is the process of transforming a description of a location, such as an address, to geographic coordinates that can be mapped to a location on the Earth's surface. See Environmental Systems Research Institute, *What Is Geocoding?,* n.d. Available at: https://desktop.arcgis.com/en/arcmap/latest/manage-data/geocoding/what-is-geocoding.htm.

[63] See CEC 2021 Electric Load Serving Entities.

[64] The primary distribution feeder data is derived from the confidential versions of the Wildfire Mitigation Plans of PG&E, SCE, and SDG&E. We only included feeders for which we also had load and rating data. See the IOUs' public Wildfire Mitigation Plans: PG&E, *2022 Quarterly Reports*, available at: https://www.pge.com/en_US/safety/emergency-preparedness/natural-disaster/wildfires/wildfire-mitigation-plan.page; SCE, *Wildfire Mitigation Plan Update & Related Documents*, available at: https://www.sce.com/safety/wild-fire-mitigation; and SDG&E, *2022 Wildfire Mitigation Plan*, February 11, 2022, available at: https://www.sdge.com/2022-wildfire-mitigation-plan.

Finally, we eliminated records associated with feeders with incomplete data, resulting in a subset of the IOUs' respective service territories that we call the Study Area.

Step 2: Next, we scored conventional-fueled vehicles (i.e., neither BEV nor PHEV) using propensity models to estimate their likelihood of being replaced with an equivalent EV in the future. We used one model for personal LD vehicles (herein referred to as personal vehicles) and another model for all MDHD vehicles as well as non-personal (e.g., government, commercial) LD vehicles (herein collectively referred to as fleet vehicles).[65]

For personal vehicles, each vehicle's score was calculated from a logistic regression on the 2022 DMV dataset. We used income, education, building information, commute length, and family size as independent variables and whether a vehicle was an EV as the dependent variable. All these factors are supported by the literature and were significant, with varying effect sizes; higher education had the largest effect size. See Appendix D for additional detail.

For fleet vehicles,[66] each vehicle receives a score equal to the ratio of number of EVs (PHEV + BEV) to total vehicles on its feeder in its class (LD/MD/HD). All vehicles with a score of zero receive a random score between zero and negative one (so that they are randomly selected after vehicles on feeders with some EV adoption in their class). This produces an output which is unlikely to match actual MDHD vehicle charging, as MDHD EVs are likely to be adopted in uneven and unpredictable patterns across the state, and are unlikely to charge at their registration addresses. However, we expect MDHD vehicles to cluster sharply as fleets convert, and this scoring method has the effect of clustering MDHD EV adoption onto feeders which have some EV adoption already, mimicking the anticipated grid pressure of clustered MDHD EV adoption.

Step 3: Finally, we rank vehicles based upon their propensity score and assign non-EVs to become EVs in each year until the population established by the IEPR Planning Scenario[67] is reached.[68] The IEPR Planning Scenario includes the impacts of policy, including the Advanced Clean Cars II regulation and the now withdrawn Advanced Clean Fleets (ACF) regulation established by CARB.[69] To assign vehicles, we first reduce the populations in the IEPR to

[65] We elected not to consider personal MD and HD vehicles within the personal model for the following reasons: 1) it is likely that many of these vehicles are personally owned but used for commercial purposes, and 2) the share of these vehicles registered as non-personal, and the relative impact of MD and HD compared to LD are both small.

[66] MD, HD, and non-personal LD vehicles.

[67] Data provided by CEC on April 20, 2023. These are internal model data that are not published. DGEM 2025 takes only the IEPR's Planning Scenario as an input for EV modeling.

[68] We assume that vehicle owners want to maintain their current vehicle type and, when it is their turn, they swap their current conventional vehicle to an equivalent EV. We broke down the IEPR data provided by the CEC into forecasts by sub-category (e.g., car-subcompact), but we did not enforce that our overall population changes matched the IEPR population changes at the sub-category level.

[69] CEC, *2022 Integrated Energy Policy Report Update*, May 10, 2023 (CEC, 2022 IEPR) at 46 and 49. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=250084.

correspond to the DGEM Study Area, by vehicle class, and split the LD forecast into personal and non-personal vehicles, based upon the share in the 2022 DMV vehicle registration dataset.[70] For each class, we first convert the highest-ranked conventional vehicles to EVs, and then convert the next highest-ranked set to PHEV.[71]

These methods generate a table of projected future EVs associated with their year of adoption, subclass, drivetrain, and associated feeder, and including all current EVs we can associate with feeders.

2.5.2 Calculating EV contributions to peak demand on each circuit

For each vehicle subclass, we calculate AEC by multiplying the expected miles of travel per year by the vehicle efficiency (kWh of charging energy needed to drive one mile).[72] The CEC provided the vehicle efficiency and expected vehicle miles traveled (VMT) that it calculated for the models used in the 2023 IEPR.[73] The vehicle efficiency varies across time (i.e., EVs generally drive farther and become more efficient in the future).

We then apply the annual consumption to each EV and tally up the results across each feeder, keeping LD separate from MDHD because these classes have different charging load shapes. This gives the AEC on each feeder by each vehicle class (LD or MDHD).

We now apply a load shape to convert AEC into hourly loads. 2023 IEPR EV modeling indicates that variation in EV charging across hours of the day is significant, and that load shapes are projected to evolve over time. However, the day-to-day variations are not significant.[74] The lack of day-to-day variation allows us to use two median daily load shapes for each vehicle class; one shape for summer and another for winter.

We use three different charging load shapes, keeping our results separate for three different scenarios. These load shapes are intended to model different potential charging behavior:

- **Moderate Peak:** This load shape is used in our central scenario, using load shapes derived from the 2023 IEPR.

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[70] 92.8 percent of LDs in our data are personally registered.

[71] For example, in the LD-personal model, if the IEPR populations indicate that 200,000 more EVs and 50,000 PHEVs should be deployed, the 200,000 highest-scored conventional vehicles would be converted to EVs, and the following 50,000 highest-ranked conventional vehicles would be converted to PHEVs.

[72] According to our April 21, 2023 email correspondence with the CEC's Advanced Electrification Analysis Branch, efficiency includes drivetrain efficiency, battery and charging losses. See Department of Energy Office of Energy Efficiency & Renewable Energy, *Where the Energy Goes: Electric Cars*, n.d. Available at: https://www.fueleconomy.gov/feg/atv-ev.shtml.

[73] Data provided by CEC on April 20, 2023. See Appendix C for additional details.

[74] Except that weekday charging is significantly greater than weekend charging in many hours. For that reason, we used weekday charging load shapes.

- **High Peak:** This load shape assumes lower customer participation in EV TOU rates and high EV charging responsiveness to non-EV TOU rates, with a sharp uptick in demand at 9 pm. This load shape was originally modeled by Kevala and was used in EIS Part 1. We apply this load shape to both personal and fleet vehicles; fleet vehicles are unlikely to adhere to a load shape like this one, but it serves as an effective proxy for other unmitigated load shapes which lead to high charging demand peaks.
- **Managed:** We construct a load shape which probes the impact of mass adoption of managed charging. This load shape shifts 50% of the LD and 20% of the MDHD vehicle load from the Moderate Peak load shape to our constructed load shape.

For the Managed charging scenario, we construct a simple, unique managed load shape for each feeder, applying the following constraints:

- A "high charge" time block of up to 15% of daily charging in a single hour, for 5 hours. This block is placed during the time with the most available capacity on the feeder.
- A "low charge" time block, of at least 0.5% of daily charging in a single hour, for 10 hours. This block is placed during the time with the least available capacity on the feeder.
- The remaining 9 hours have a "medium charge" time block, of up to 5% of daily charging in a single hour.
- The load shape may not contribute to additional overloads during the high charge block (i.e., timer peaks). If 15% hourly charging during the "high charge" block would create a timer peak on the circuit, excess charging is instead spread evenly across the other hours.

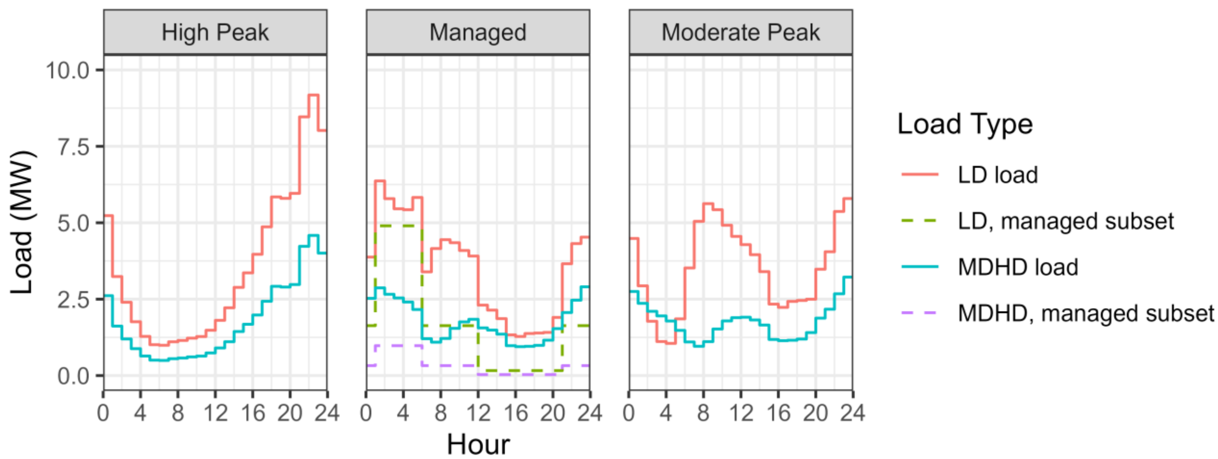
We derive these constraints from pilot data provided to Cal Advocates by WeaveGrid, a managed charging provider currently running several active managed charging pilots.[75] WeaveGrid provided Cal Advocates with 24-hour load shapes representing the average charging behavior of vehicles enrolled in each of four pilot cohorts. We examined these data, looking in particular at the cohorts where WeaveGrid provided both electricity cost optimization to the EV owners and grid optimization to utilities. WeaveGrid's data indicated that a "high charge" of 15% and a "low charge" of 0.5% are plausible outcomes for a cohort enrolled in managed charging for grid optimization. Other than providing realistic constraints on our managed charging load shape, we do not use WeaveGrid's data as a direct input to our model. The data

[75] WeaveGrid email to Cal Advocates staff, February 25, 2025.

provided by WeaveGrid is described further in Appendix B, and the construction of this load shape is described in detail in Appendix D.

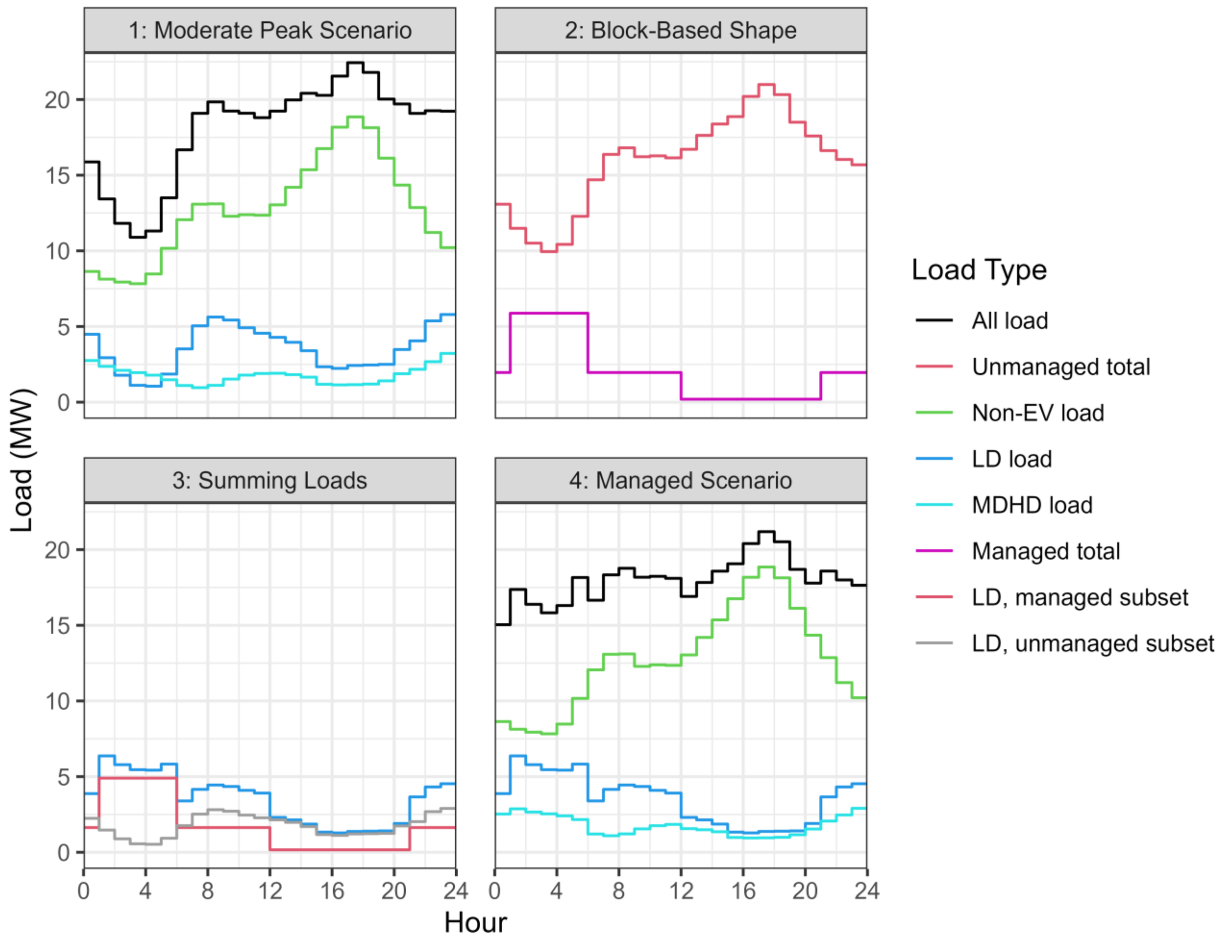
Figure 2-5 shows examples of all three of these load shapes for a particular feeder with both LD and MDHD charging. Figure 2-6 shows the construction of the managed load shape.

Figure 2-5: EV loads for a feeder in the PG&E service territory with significant LD and MDHD load in 2040, for each EV charging behavior scenario.



In the Managed EV charging behavior scenario, we assigned 50% of LD EVs and 20% of MDHD EVs to our constructed load shape; the remainder are assigned the Moderate Peak load shape. The dashed lines in the Managed scenario panel of Figure 2-5 represent the subset of vehicles which have been assigned to our constructed load shape, while the solid lines represent the total net load shape including all vehicles.

Figure 2-6: Construction of the Managed load shape for the same feeder in 2040.



In Figure 2-6:

- Panel 1 shows total load for the Moderate Peak scenario, broken into non-EV, LD, and MDHD loads.
- Panel 2 shows the unmanaged total load, which contains non-EV load plus 50% of LD and 80% of MDHD loads; as well as our constructed load shape, with the high charging time block placed during the time window with the most capacity available, and the low charging time block placed during the time window with the least capacity available.
- Panel 3 shows the constructed load shape and the Moderate Peak load shape adding together to create the Managed load shape for LD vehicles.
- Panel 4 shows the total load for the Managed scenario, with a lower peak than in the Moderate Peak scenario, due to the new load shape.

For each of our three main load shapes, DGEM 2025 multiplies the hourly consumption rate by the AEC by vehicle class to yield the hourly energy consumption on each feeder. We carry out these calculations for each year of the study.

We additionally construct an optimized load shape, probing an unrealistic scenario of 100% participation in managed charging, in order to provide an upper bound on the possible value of managed charging. As this final load shape is unrealistic, we have not included it in the primary DGEM 2025 calculations. Details and results for this load shape are described in detail in Appendix B.

2.6 Methodology phase 3: estimating peak demand on each circuit

Having estimated peak-hour BE and EV loads, we then produce peak-hour load profiles for each circuit and substation by first estimating the sum of all other sources of load, here called non-electrification load. BE and EV loads do not account for all loads on any given feeder, and non-electrification loads will also evolve over time.

We use historic demand to establish a baseline non-electrification load before forecasting further non-electrification load growth. To establish the historic demand, we use a set of feeder-level net loading data provided by the three IOUs which provide 8,760 observations per year[76] of load on each feeder (24 hours per day times 365 days per year).[77] These data span multiple years. We then collapse the historic load down to 48-hour profiles, select the peak load in each hour for each year, and then select the median load value of those peaks. We select the median peak across a multi-year sample to avoid double-counting extreme weather, as the IEPR already includes projected weather variation.

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[76] For SDG&E, some of these data contained 576 observations per year, 24 hours per day times 12 months per year times two day-types: weekend and weekday.

[77] No statistical cleaning was performed on these load data. See Section 4.11 for more detail. For more detail on what information the IOUs provided, such as how much time each IOU's loading data spans, see Appendix C.

Box 2-2: Converting Year-Long Load Profiles into 48-Hour Peak Profiles

The CEC's 2023 IEPR forecast uses IOU-wide load shapes which cover every hour of every year from 2023 to 2040. This format is often called "8760," as a non-leap year contains 8,760 hours. Due to computational limitations, DGEM 2025 is not able to process full 8760 load shapes for each feeder.

DGEM 2025 estimates the peak annual demand on each circuit, so there is only one relevant hour for DGEM 2025 each year: the single hour with the highest demand. We cannot select this hour in advance; feeders dominated by different sources of load (such as HVAC or LD EVs) might have different peak hours. Seasonal variability is also potentially significant; some northern-California counties might have winter-peaking circuits.

To capture the peak hour while accounting for variation in different sources of load, we collapse each 8760 load profile into a 48-hour format. This includes 24 hours for summer (May to October) and 24 hours for winter (November to April). Each of the 24 hours for a given season is intended to represent the highest load during that hour in that season. For example, the 10-11am hour in a summer load profile is the estimated highest-load 10-11am hour for the entirety of the season.

On a given circuit, it is unlikely that the highest seasonal EV load and the highest seasonal BE load occur in the same hour; these are similarly unlikely to occur simultaneously with the highest seasonal non-electrification load. If we were to select the 48 hours with the highest EV load, the 48 hours with the highest BE load, and the 48 hours with the highest non-electrification load, and add them together, we would overestimate the peak.

Instead, we estimate the relative contribution to the peak hour produced by each source of load by analyzing the IEPR's 8760 load profiles. EV load has low day-to-day variance, but is generally higher on weekdays than on weekends, so the worst circuit day is likely to be a weekday with median EV load. BE load has high day-to-day variance, and both circuit and system peak days frequently occur on hot days with high air-conditioning load at times when the non-electrification load is also high, such as the late afternoon and early evening when lighting load is significant as well. Analysis of the IEPR's load profiles show that system peak hours are usually roughly 85th-percentile BE days—i.e., if the system peak hour occurs on a specific day at 5pm in the summer, on average, the BE load on that day will be higher than the 5pm load on 85 percent of other summer days.

We therefore construct our peak-day profile as follows: 85th-percentile hours for BE loads, 50th-percentile weekday hours for EV loads, and 100th-percentile (maximum) hours for non-electrification loads. This construction has some limitations. It may overestimate the relative contribution of water heating compared to HVAC, and it may fail to account for spatial variety in the composition of peak hours. Generally, we expect these inaccuracies to average out across each IOU's service territory without producing major systematic biases.

On each feeder and substation, we then subtract our calculated 2023 BE and EV demand (in all scenarios using the Moderate Peak EV load shape) to estimate a base-year non-electrification demand. We turn this base-year estimate into a forecast by multiplying each observed peak by the cumulative intra-hour non-EV and non-BE growth rate[78] between the base year and the forecast year, as established in the 2023 IEPR.[79] In effect, this copies the growth rate of all non-EV loads and resources, which include rooftop solar, home battery storage, effects of population growth, cultivation, and other factors. Notably, the 2023 IEPR does not contain significant forecasts of data center growth, so we ignore data centers in this non-electrification demand. This methodology also does not account for spatial variation in non-electrification loads, which may be significant.

Finally, we sum BE, EV, and non-electrification load. This gives us a 48-hour load profile for each feeder and substation for each year from 2023 to 2040. We then select the maximum value for each year. This value represents the estimated peak load on each piece of infrastructure, in each year, for each set of BE and load shape scenarios.[80]

2.7 Methodology phase 4: estimating mitigations and mitigation cost

The next methodological step consists of estimating the number of mitigations required to handle projected overloads and estimating the associated costs of these mitigations. We directly analyze feeders and substations in the primary distribution system and estimate secondary distribution infrastructure costs as a percentage of primary distribution system costs.[81]

Each IOU provided a set of infrastructure ratings for feeders and substations.[82] We subtract the power rating of each feeder and substation from its calculated peak load. If the result is positive, that indicates the asset is overloaded and provides the size of the overload. Then, we calculate the number of units necessary to mitigate each overload. DGEM 2025 only recognizes two kinds of overload and can mitigate each in only one way. The two recognized overloads are on feeder heads (where the "trunk" of the primary feeder connects to the substation transformer bank) and

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[78] For example, if demand at 5pm were 10 MW and peak demand at 5pm grew 2 percent from 2023 to 2024 and 3 percent from 2024 to 2025, our forecasted 2025 peak demand would be: 10 MW · (1.00+0.02) · (1.00+0.03) = 10.506 MW.

[79] We used the 2021 IEPR for 2021 and 2022 data and the 2022 IEPR for data from 2023 forward. 2021 CED hourly mid-baseline scenario forecast for each IOU is available at: https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report/2021-1. See also CED 2022 Hourly Forecast Planning Scenario forecast for each IOU (i.e., PG&E, SCE, and SDG&E). Available at: https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2022-integrated-energy-policy-report-update-2.

[80] See Appendices C and D for further details, including variation in historical loading data among the IOUs.

[81] Our analysis does not account for the impacts of EVs and other load growth in BTM infrastructure; we consider feeder infrastructure and BTM infrastructure to be two distinct categories with similarly distinct costs.

[82] For further discussion on the data the IOUs provided, see Appendix C.

on the total capacity of a substation. For feeder overloads, DGEM 2025 models the construction of new feeders rated at 12 MW in the year of the overload until the new aggregate feeder capacity is greater than the overload. For substation overloads, DGEM 2025 models the installation of new 28 MW transformers similarly. Each mitigation—a new feeder or a new substation transformer bank—has a fixed capacity. We apply multiple feeders or transformer banks to mitigate overloads if a single unit is insufficient, although this is rare in DGEM 2025.

We estimate the cost of mitigations in each year by applying a single cost estimate for each additional 12 MW feeder and 28 MW substation bank constructed. For each feeder constructed, we also apply an additional cost to cover estimated substation work which may occur whenever a new feeder is constructed and connected. For each substation bank constructed, we apply an additional cost to cover the fraction of cases for which an entirely new substation will be required. Finally, we apply a multiplier to all primary distribution costs to estimate the upgrade costs of the secondary distribution system.

Table 2-5 shows the infrastructure costs used for this analysis. For a more detailed breakdown of cost estimate data, see Appendix C.

DGEM 2023 used multiple infrastructure cost scenarios—Lowest, Medium, and Highest—to probe the boundaries of cost outcomes. Our new cost estimates are closer to the DGEM 2023 Lowest Cost scenario than to the Medium Cost scenario: see Table 3-5-4 for additional details. Because of our focus on policy scenarios, we do not include multiple cost scenarios in DGEM 2025; however, our cost outputs should still be interpreted with a high degree of uncertainty.

Summing up the cost of each mitigation in each year provides a total cost of needed distribution mitigations in each year until 2040.

Table 2-5: Cost estimates for new infrastructure.

Infrastructure	Estimated cost per new unit	Notes
12 MW feeder	$3,506,826	New estimate based on costs of recent new feeder projects.[83]
Substation work associated with new feeder installation	$4,972,110	New estimate based costs of recent new feeder projects.
28 MW transformer bank	$4,685,000	From EIS Part 1, used in DGEM 2023 median cost scenario.[84]
Substation	$27,000,000	From EIS Part 1, used in DGEM 2023 median cost scenario.
Fraction of new banks requiring new substations	20.42%	From EIS Part 1, used in DGEM 2023 median cost scenario. After being multiplied by the substation cost, this effectively adds $5,513,400 to each bank's cost.
Secondary distribution costs	47.56% of primary distribution costs	From EIS Part 1.

2.8 Methodology phase 5: rate impact

For each IOU in each year of the analysis, we calculate the average residential rates with the increased load and costs associated with electrification and compare them to 2025 average residential rates. We account for the calculated increase in revenue requirements for the IOUs associated with distribution capital and maintenance expenses, plus forecasted transmission and generation costs, and weigh them against the forecasted increase in electricity volume. Then, we compare rates with this additional electrification to rates without it to determine the potential rate impact of electrification.

We assume a marginal operations and maintenance (O&M) cost of 3.5 percent per year on the un-depreciated value of new capital. This is informed by data from the most recent general rate case applications of PG&E, SCE, and SDG&E.[85] We account for transmission costs through the

[83] Costs data were provided to Cal Advocates by PG&E, SCE, and SDG&E in response to data requests. To create our estimate, we averaged new feeder costs across all three IOUs.

[84] DGEM 2023 at 80. DGEM 2023 selected IOU unit cost guides to provide high, median, and low transformer bank costs. DGEM 2023 used SDG&E's 2023 transformer bank cost for the median bank cost. DGEM 2025 uses only SDG&E's 2023 transformer bank cost and does not consider other cost scenarios.

[85] See Appendix D for details and data sources.

transmission access charge (TAC), which the CAISO projects to rise to $19.50 per MWh in 2029 and $21.85 per MWh in 2035.[86] We derive generation costs from the 2022 avoided cost calculator (ACC),[87] including costs associated with generation energy, generation capacity, ancillary services, GHG emissions, and high global warming potential gases.

Appendix D elaborates on the methods for the rate impact study.

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[86] See Cal Advocates, C*omments on Draft Transmission Plan of the California Independent System Operator*, April 25, 2023 at Section 9, Table 1. Available at: https://stakeholdercenter.caiso.com/Comments/AllComments/3b5eb926-9bce-4c7f-806c-9ae156a4f9f3#org-b4bc96db-9bb3-478b-a339-41f5d6e8413c.

[87] See CPUC, *2022 Distributed Energy Resources Avoided Cost Calculator Documentation*, June 22, 2022. Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2022-acc-documentation-v1a.pdf.

3 Results and Discussion

We estimate the total costs to upgrade the distribution grids of the three largest electric IOUs in California to support the state's forecasted load growth to be $5 billion dollars by 2030, $14 billion dollars by 2035, and $25 billion dollars by 2040. These costs reflect our central estimate which follows the IEPR Planning Scenario (using AAFS Scenario 3 and IEPR-forecasted EV charging behavior).

3.1 Cost results by scenario

DGEM 2025 produces nine different sets of cost results, for three AAFS scenarios and three EV load shape scenarios. We report cost results for the years 2030, 2035, and 2040. Table 3-1 shows these results, provided in approximate 2025 billions of US dollars, with bold rows indicating total costs across all three IOUs.[88] Figure 3-1 and Figure 3-2 show cost results over time, and in particular highlight how these costs differ when BE versus EV scenarios are varied. See the following sections for more detailed discussion.

All DGEM 2025 results are estimates, not forecasts. All DGEM 2025 reported costs are associated with a high and unquantified degree of uncertainty, due to large uncertainties in the locations of load, the timing and coincidence of different kinds of load, and the costs of mitigations. DGEM 2023 quantified this uncertainty with cost scenarios, with an output cost ranging from $8 billion to $51 billion dollars, producing a total uncertainty spanning nearly an order of magnitude. DGEM 2025 does not quantify uncertainty. Our cost estimates should be interpreted as comparative indications of the impacts of different adoption outcomes and policy decisions, rather than as accurate forecasts of the future.

Despite this uncertainty, we expect comparative differences between our scenarios to realistically represent the comparative differences between the costs of different outcomes.

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[88] DGEM 2025 uses cost inputs drawing from data gathered across the last four years. Some of these data sets contain costs aggregated across multiple recent years without adjustment for inflation. DGEM 2025 also reports future costs without adjustment for projected inflation. For simplicity and consistency, we have not performed any additional adjustments for inflation on our input costs data. This means that we may be adding together, for example, substation costs in 2022 dollars with feeder costs in 2024 dollars.

Our most recent costs data come from early 2025, so we report our costs as being in approximate 2025 dollars, with some uncertainty due to inflation. We estimate that this uncertainty is no more than 15%, the net inflation rate between January 2022 and the present, according to the Bureau of Labor Statistics at https://www.bls.gov/data/inflation_calculator.htm. Actual grid upgrades will be specific and unique to the circumstances of each upgrade, with an extremely high variability in costs. This upgrade-based uncertainty is much larger than the inflation-based uncertainty.

Table 3-1: Estimated distribution grid upgrade costs by adoption scenario, IOU, and year.

COSTS	**2030**			**2035**			**2040**		
in 2025 $billion	AAFS 2.5	AAFS 3	AAFS 4	AAFS 2.5	AAFS 3	AAFS 4	AAFS 2.5	AAFS 3	AAFS 4
High Peak Shape	**7.9**	**8.4**	**9.4**	**20.9**	**22.6**	**23.8**	**34.8**	**36.9**	**37.5**
PG&E	4.3	4.4	4.9	10.3	10.9	11.6	16.3	17.2	17.9
SCE	3.0	3.3	3.8	8.8	9.8	10.4	15.5	16.6	16.7
SDG&E	0.6	0.7	0.7	1.8	1.9	1.8	3.0	3.1	2.9
Moderate Peak Shape	**4.6**	**4.9**	**5.6**	**11.7**	**13.6**	**14.9**	**21.9**	**24.6**	**25.3**
PG&E	2.5	2.5	2.9	6.7	7.6	8.3	11.7	12.7	13.5
SCE	1.8	2.1	2.4	4.3	5.2	5.8	8.7	10.2	10.4
SDG&E	0.3	0.3	0.3	0.7	0.8	0.8	1.5	1.7	1.4
Managed Shape	**3.1**	**3.4**	**4.0**	**8.6**	**10.4**	**11.6**	**17.0**	**19.6**	**20.4**
PG&E	1.8	1.8	2.1	5.5	6.3	7.0	10.0	11	11.8
SCE	1.2	1.5	1.8	2.9	3.8	4.3	6.2	7.6	7.8
SDG&E	0.1	0.1	0.1	0.2	0.3	0.3	0.8	1.0	0.8

Appendix A contains additional cost result tables, highlighting the cost differentials between different scenarios and exploring differences between the IOUs.

Figure 3-1: Comparing distribution upgrade costs through time between BE adoption scenarios.

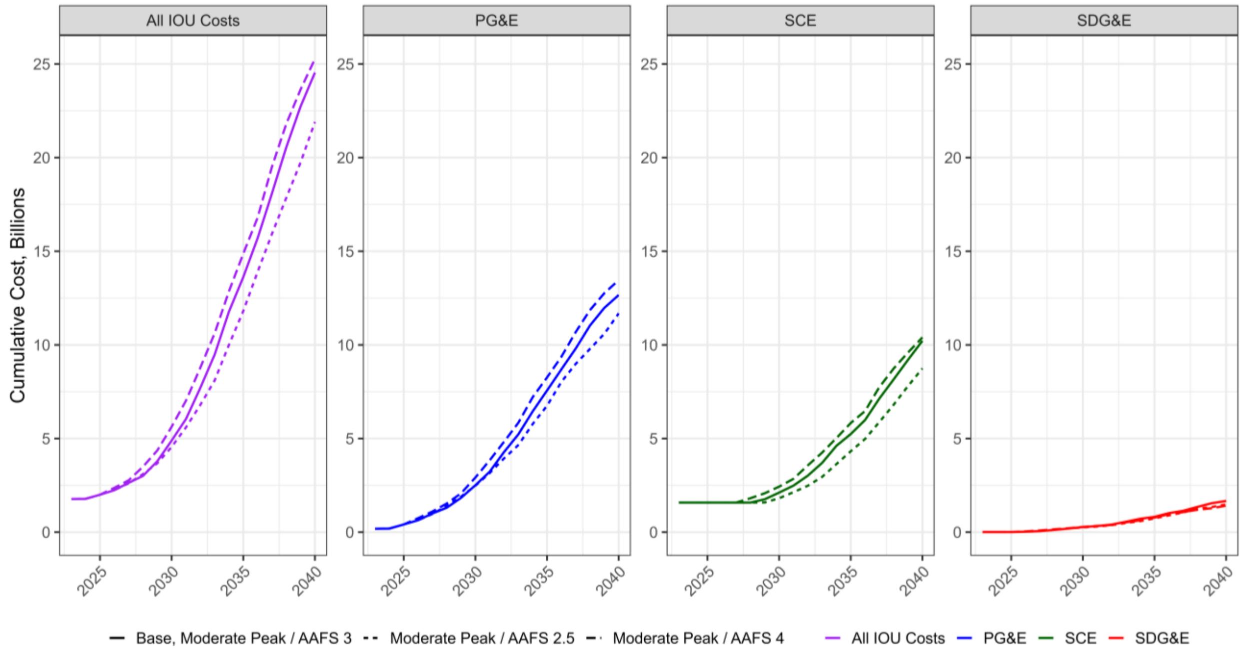
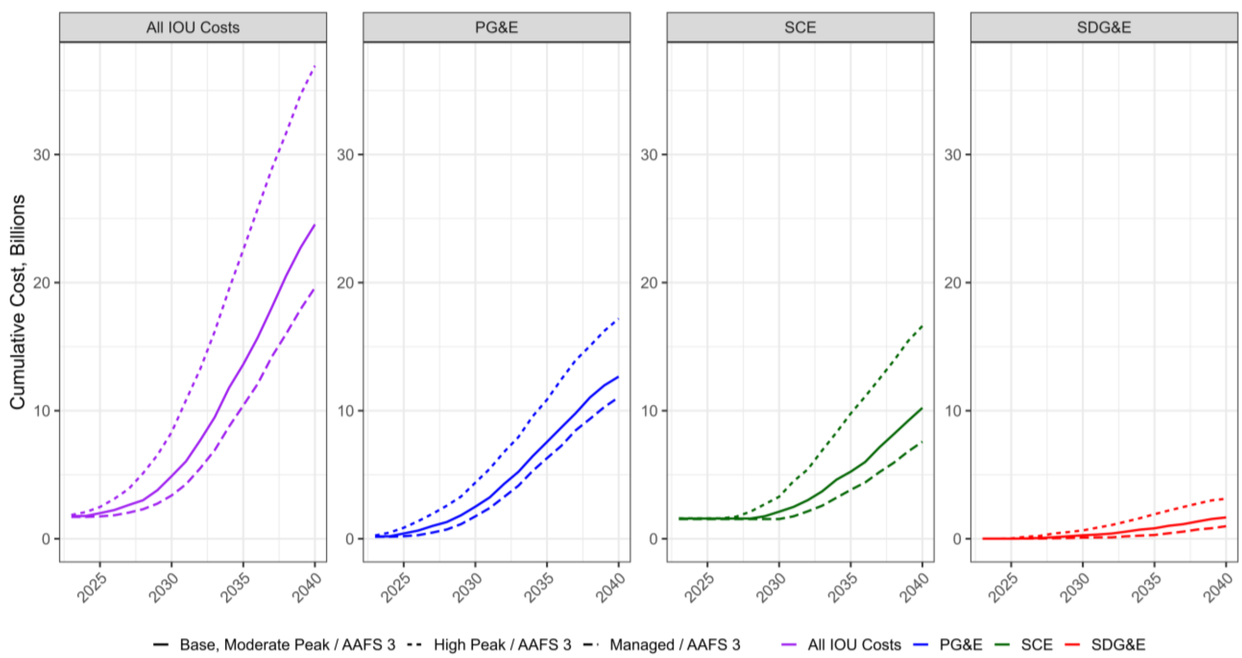


Figure 3-2: Comparing distribution upgrade costs through time between EV charging management scenarios.



3.1.1 Interpreting cost results by scenario

Our results show that variation among the AAFS scenarios has a moderate impact on costs, spanning a total cost range of up to $3.4 billion, depending on the year and EV load shape scenario. These cost differentials are significant, but comparatively small in the context of the overall cost, especially in later years when total costs reach tens of billions. All of the CEC's AAFS scenarios build on policy assumptions[89] which may overestimate the total uptake of BE. However, our cost findings and this possible overestimation should not be taken to indicate that variation in potential BE uptake will not have significant effects on costs and planning impacts. While AAFS 2.5, 3, and 4 represent plausible scenarios recommended by the CEC for various planning uses and targets set by decision-makers, these scenarios do not constitute a hard boundary on the possible outcomes.

Our results also show that variation among the EV load shape scenarios has a moderate to significant impact on costs, with differences of up to $11.8 billion between the High Peak and Moderate Peak scenarios, and of up to $5.1 billion between the Moderate Peak and Managed scenarios. Table 3-2 highlights the impact of different EV charging behaviors on costs.

Table 3-2: Total costs by AAFS scenario and EV charging load shape scenario.

2040 Total Costs in 2025 $Billion	**AAFS 2.5**	**AAFS 3**	**AAFS 4**
High Peak Shape	**34.8**	**36.9**	**37.5**
High Peak/Moderate Peak Difference	12.9	12.3	12.2
Moderate Peak Shape	**21.9**	**24.6**	**25.3**
Moderate Peak/Managed Difference	4.9	5.0	4.9
Managed Shape	**17.0**	**19.6**	**20.4**

These results indicate that EV charging behavior has a significant impact on costs, and that different charging outcomes will have radically different impacts on the grid. Both the High Peak and Moderate Peak load shapes assume EV owners respond only to existing TOU rates, and

[89] As described in Section 2.3.1, AAFS scenarios represent different sets of BE uptake assumptions. The CEC considered impacts from programs to support SB 350, compliance with California Building Standards (Title 24), potential program impacts projected by utilities (2023 IEPR at 117), impacts of programs pursuant to the CEC Equitable Electrification and Clean Energy Reliability Investment Plan, Inflation Reduction Act, High Efficiency Electric Home Rebate Act, local government ordinances, and load-serving entity decarbonization programs (2023 IEPR at 118). AAFS 3 also considers impacts from the Zero Emissions Standards detailed in CARB's 2022 State Strategy for the State Implementation Plan, which aims to control smog (2023 IEPR at 117).

do not include estimates of potential future managed charging. This means that the value of possible managed charging—as estimated by a comparison between the cost of the Managed scenario and the cost of another scenario—varies substantially depending on how much strain unmanaged charging actually places on the grid. If, in the absence of managed charging, EVs charge according to the profile modeled for EIS Part 1, aggressive managed charging could save up to $18 billion dollars in grid costs by 2040. If, in the absence of managed charging, EVs charge according to the profile described in the 2023 IEPR, aggressive managed charging might only save up to $5 billion dollars in grid costs.

DGEM 2025 also predicts that a large number of circuits overload in all three load shape scenarios (High Peak, Moderate Peak, and Managed). On these circuits, the managed charging we model may delay but not remove the need for mitigations, so this form of managed charging has minimal value on such circuits. This suggests that any potential benefits of managed charging may be most efficiently realized if IOUs and managed charging providers can target adoption to specific regions and specific circuits which provide the most relative benefit from controlling load.[90]

Box 3-1: Questions and Answers About the DGEM 2025 Cost Results

Why does SCE's cost data start above zero in 2023? The data that SCE provided contains substations whose combined historic load exceeds their provided rating. These costs reflect the estimated cost of addressing existing, current substation overloads in the data that SCE provided. It is unclear whether these overloads are primarily data artifacts or describe substations which are allowed to overload in certain circumstances. We include these costs for the sake of consistency in handling overloads.

Why is AAFS 4 sometimes less costly for SDG&E than AAFS 3? SDG&E's territory has little building heating load, so AAFS loads are dominated by water heating. AAFS 4 assumes a higher market adoption of heat pump water heaters, which are more efficient than resistive water heaters. This means some electric resistance water heaters adopted in AAFS 3 are converted to heat pump water heaters in AAFS 4, which reduces net load, even though more electrification is adopted overall. While the same effect is present in SCE and PG&E's service territories, increases in HVAC load in those territories mean AAFS 4 remains higher load and higher cost than AAFS 3. (See 2023 IEPR at 135-136.)

[90] See section 4.9 for more.

3.1.2 Comparisons of cost impact among key cost drivers

DGEM's cost outputs are non-linear and incremental. A small increase in load on a circuit can have no effect, if it doesn't result in any overload, or an enormous effect, if it results in a substation overload. Because of this, it is difficult to assign any given dollar of cost to any specific load.

However, we can gain some insight by running the model while eliminating a specific source of load growth, such as LD EVs or HVAC load. This estimates grid costs in a hypothetical future without increases in that load type. The associated cost difference indicates how significant that particular cost driver is to the output costs.

Table 3-3: Cost changes in 2040 when removing sectoral load growth from the central scenario (AAFS 3 / Moderate Peak charging behavior).

Load Growth Removed	PG&E Cost Impact	SCE Cost Impact	SDG&E Cost Impact
HVAC + Water Heating	**-32%**	**-22%**	**-24%**
HVAC	-21%	-11%	-14%
Water Heating	-9%	-10%	-10%
All EVs	**-24%**	**-42%**	**-44%**
LD	-20%	-34%	-40%
MDHD	-4%	-6%	-5%

This analysis indicates that, in the DGEM 2025 central scenario, BE load growth is the largest cost driver for PG&E, and EV load growth is the largest cost driver for SCE and SDG&E.[91] All three IOUs receive proportionally similar amounts of EV load in our model. However, our BE model allocates HVAC load growth preferentially to PG&E's service territory, as PG&E's territory contains colder BCZs which require more heating, and warmer BCZs which will require the installation of new air conditioning as temperatures rise.

This analysis also indicates that HVAC and water heating load have roughly similar degrees of impact, and that LD vehicle load growth has 5-7 times the cost impact of MDHD vehicle load growth. However, these estimates may not accurately represent real cost drivers. Our methodology for producing peak-day BE load assumes a high degree of coincidence between HVAC and water heating load; without that assumption, HVAC could dominate over water heating. Our model also has large spatial uncertainties regarding the locations of MDHD load,

[91] In section 3.1.1, we noted that cost variations between the three BE scenarios are lower than cost variations due to EV load shape scenarios. Here we consider *only* the DGEM 2025 central scenario. Within this scenario, building electrification overall contributes significantly to the overall cost.

so the exact impact of MDHD load is imprecise. *We reiterate that these results should be interpreted as directional, rather than specific predictions of future load or total cost outcomes.*

3.1.3 Cost comparison to DGEM 2023 and DGEM 2025 Preliminary Results

Table 3-4: DGEM cost results by release.

DGEM Vintage	2023 Medium	2025 Preliminary Results[92]	2025
Cost Results	$26 billion	$22 billion	$14 billion

DGEM 2025 baseline scenario results are substantially lower than those of DGEM 2023 and of DGEM 2025 preliminary results. While many elements of DGEM have been updated or added between 2023 and 2025, four changes have the largest impact on the cost: updated infrastructure unit costs, updated historic load data, a new IEPR vintage, and our new BE methodology. The first two of these changes decrease our output costs significantly, while the second two increase costs moderately, producing a net decrease in estimated costs. We had completed only some of these changes in the modeling that produced the preliminary results released in October 2024.

The largest driver of the decrease is our updated feeder and substation unit costs. Rather than using circuit length estimates and per-foot reconductoring costs as used in DGEM 2023, we use cost estimates taken from utility data on new feeder projects in the past four years. Discussions with utilities and planning engineers suggested that utilities have access to a large array of mitigation options which allow them to avoid constructing the full length of any new feeder by repurposing existing circuits. Given the uncertainty of the circuit length upgraded for any given feeder, we believe that using cost data from recent feeder upgrades as the basis of future costs is more accurate than using short/middle/long circuit length scenarios, although it is possible that, in order to support distributed loads due to electrification, the IOUS will need to construct or upgrade larger lengths of circuit.

Our new infrastructure unit cost estimates are substantially lower, decreasing our total output costs by about 55%.[93] We also unified our substation bank costs across the three IOUs, leading to a relative increase in SCE's costs and a relative decrease in PG&E's costs. For more discussion on these costs, see Sections 2-7 and 4-7 and Appendix C.

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[92] Cal Advocates, *DGEM 2.0 Preliminary Results*, October 2024. Available at: 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.

[93] We say "about" and "roughly" in this section because these changes cannot be fully isolated in the model; each change affects the impact of each other change. For example, our new BE methodology has a much larger impact when used in combination with the costs inputs of DGEM 2023, which use higher bank and substation costs for PG&E.

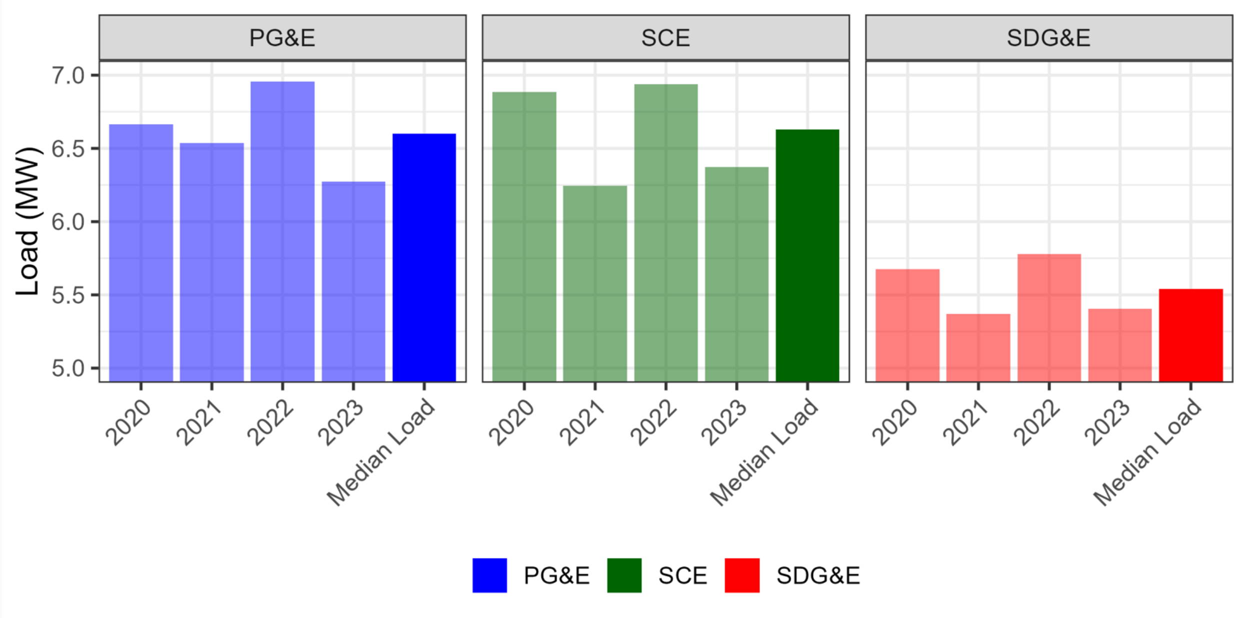
Table 3-5: Cost input comparison between DGEM 2023 and DGEM 2025 unit costs. Costs are in millions of dollars.

DGEM Cost Scenario	Feeder length (miles)	Feeder cost (millions)	Transformer bank cost (millions)	Substation marginal cost (millions)	New bank requires new substation frequency
2023 Lowest	1.35	$2.86	$2.02	$15.20	6.38%
2023 Medium	9.50	$20.01	$3.40	$36.38	20.42%
2023 Highest	10.90	$32.40	$11.80	$37.64	42.17%
2025	N/A	$5.52	$4.69	$27.00	20.42%

Updated historic load data also contributes to the decrease in estimated costs. DGEM 2025 preliminary results used updated 2023 feeder loading data provided by the IOUs; these data showed significantly lower feeder peaks than the 2021 and 2022 feeder loading data originally used in DGEM 2023.[94] The IEPR forecast includes variation due to extreme weather; accordingly, selecting feeder peaks from an outlier year would double-count the effects of extreme weather. We therefore expanded our feeder loading data to a four-year span for SCE and PG&E, from 2020 to 2023, and a seven-year span for SDG&E, from 2018 to 2024. We took each IOU's loading data, extracted the annual maximum load, and then took the average of those annual maxima. Overall, this has the net effect of decreasing costs by about 25%. Figure 3-2 shows how this annual variation affects feeder peak loads.

[94] DGEM 2023 used 2021 loading data for PG&E and 2022 loading data for SCE and SDG&E.

Figure 3-3: Average annual feeder peaks, showing recent peaks and DGEM 2025's median peak load output.



Countering these decreases is an increase in cost driven by the new IEPR vintage. Many changes in the IEPR are passed through to DGEM, but most relevantly, the 2023 IEPR forecasts higher EV and BE load growth than the 2022 IEPR. All else being equal within DGEM 2025, the updated 2023 IEPR vintage leads to an overall increase in costs by about 20% compared to using the 2022 IEPR.

Finally, our new BE methodology has complex impacts on the costs, but in general it tends to cluster BE load growth onto a smaller number of circuits, and it particularly adds load growth to PG&E's service territory, which has less available capacity on its circuits compared to SCE or SDG&E. This increases costs by about 40% compared to the non-EV methodology used in DGEM 2023.

Cumulatively, these changes lead to a roughly 45% overall decrease in the cost from DGEM 2023 to the DGEM 2025 baseline scenario.[95]

3.2 Residential rates

Electrification-related grid upgrades will have significant costs. But electrification also comes with substantial load growth, spreading all costs across more sales of electricity. This means that

[95] Note that percentages compound by multiplying, not by adding. (100% - 55%) × (100% - 25%) × (120%) × (140%) = 57%, for a 43% decrease.

there is an uncertain relationship between costs and rates. Simplistically, load growth produces a downward pressure on rates, while infrastructure costs produce an upward pressure on rates. The net effect of electrification on rates is therefore uncertain.

Box 3-2: Understanding Electrification and Downward Pressure on Rates

We use the phrases “upward pressure on rates” and “downward pressure on rates” rather than “rate increases” or “rate decreases.” This is because electrification is just one of many changes which could affect rates in the future. If electrification produces downward pressure on rates, but other factors cause rates to increase, the net effect could still be an increase in rates, but a smaller increase than would occur without the downward pressure.

The concept of downward pressure on rates from electrification hinges on how utility capital costs—such as infrastructure costs to upgrade the grid—are shared. Here is an extremely simplified example, ignoring volumetric rates and assuming equal distribution of costs:

Example A: A grid costs 12 units and serves two customers. Each customer pays 6 units worth of the grid costs.

Example B: As electrification occurs, another customer is added without expanding the grid. Each customer now pays only 4 units, reducing costs for everyone.

Example C: Now, suppose that instead of the situation in Example B, the utility builds more grid in order to connect the third customer. This will cost an additional 3 units, bringing the total cost to 15 units. While this increases the grid’s cost, each customer still benefits by paying only 5 units.

The key driver of downward pressure is increased utilization of the grid. Adding the additional customer (adding load) reduces the fraction of fixed costs that every customer must bear. While the optimal outcome is Example B—where new load is added without having to increase the size of the grid—Example C also represents a win for ratepayers compared to Example A because the benefit to all ratepayers of the additional load outweighs the costs of expanding the grid to support the new load.

Not all electrification scenarios result in downward pressure on rates. Consider:

Example D: Starting from the same grid setup as Example A, connecting a third customer requires a disproportionate 9 units of additional infrastructure, bringing the total cost to 21 units. Each customer now pays 7 units— more than in Example A.

This situation results in upward pressure on rates.

3.2.1 Predicted rate pressures by scenario

Through our rate modeling, DGEM 2025 can provide some insight into the potential impact on rates of electrification. For each policy scenario, DGEM 2025 produces a rate impact result. Note that rates for each of the three major IOUs are independent. Table 3-6 shows the rate results for each DGEM 2025 policy scenario.

Table 3-6: Predicted rate pressures for all nine scenarios.

Rate Impacts	2030			2035			2040		
in cents / kWh	AAFS 2.5	AAFS 3	AAFS 4	AAFS 2.5	AAFS 3	AAFS 4	AAFS 2.5	AAFS 3	AAFS 4
High Peak Shape									
PG&E	-1.6	-1.7	-1.6	-2.1	-2.3	-2.2	-2.6	-2.8	-2.7
SCE	-1.3	-1.4	-1.0	-1.0	-1.1	-0.5	-0.5	-0.5	-0.2
SDG&E	-1.7	-1.8	-1.4	-2.2	-2.4	-1.7	-2.6	-2.8	-2.1
Moderate Peak Shape									
PG&E	-1.9	-2.1	-2.0	-2.8	-2.9	-2.8	-3.4	-3.6	-3.5
SCE	-1.6	-1.7	-1.4	-2.2	-2.3	-1.7	-2.1	-2.3	-1.7
SDG&E	-2.1	-2.2	-1.8	-3.2	-3.4	-2.7	-3.9	-4.0	-3.4
Managed Shape									
PG&E	-2.1	-2.2	-2.2	-3.0	-3.1	-3.0	-3.7	-3.8	-3.7
SCE	-1.7	-1.9	-1.6	-2.5	-2.6	-2.1	-2.7	-2.8	-2.2
SDG&E	-2.3	-2.4	-2.0	-3.7	-3.9	-3.2	-4.4	-4.5	-3.8

DGEM 2025 finds a small downward pressure on rates across all of the considered scenarios in all years. This indicates that upward pressure on rates due to infrastructure costs is more than offset by downward pressure on rates due to the increased consumption of electricity resulting from electrification, across all considered scenarios. This suggests that customers who cannot convert from gas vehicles and appliances to EVs or appliances—because they cannot, or choose not to, or have already converted—may still benefit from electrification through comparatively lower rates.[96]

DGEM 2025 estimates rate impacts of a few cents per kWh over 15 years, which pales in comparison to recent rate increases. In the past 10 years, rates for all three major IOUs have

[96] Electrification may affect gas rates as well as electric rates. An analysis of the impact of electrification on gas rates or total household energy expenses is beyond the scope of this report.

increased by more than 10 cents per kWh.[97] While a downward pressure of a few cents over the next 15 years would be highly beneficial to ratepayers, it alone is not a solution to the rates crisis.

3.2.2 Rates may still go up

These findings do not mean that downward pressure is certain. Cost outcomes outside the bounds of those probed by DGEM 2025 could easily produce upward pressure on rates. Downward pressure on residential rates might be reduced or might not be achieved if any of the following occur:

1. Expected load growth due to electrification does not appear.
2. Utilities build more infrastructure than is needed or build infrastructure in the wrong places, unnecessarily increasing upgrade costs.
3. Overload mitigations are more expensive than DGEM 2025 estimates.
4. Electrification puts more strain on the grid than any of our policy scenarios suggest, such as through especially high HVAC usage due to extreme weather, or especially clustered EV charging, leading to additional required infrastructure.
5. Ratepayers fund additional electrification programs, such as the installation of BE appliances or EV charging equipment.
6. Rate designs pass the majority of savings to a small number of customers, such as commercial customers or high-use EV owners.

Sound forecasting and planning are key parts of achieving downward pressure on rates. Utility forecasts must be accurate and not lead to overbuilding of infrastructure, or electrification could cause upward pressure on rates. Utilities should base their distribution processes on realistic forecasts. Utility distribution planning processes should be flexible and adaptable, and should include possibilities for investment plans to be reshaped if it becomes clear that load will not appear when or where it was expected. Regulators and decision-makers also play an important role in ensuring that utilities build efficiently.

Even if electrification leads to downward pressure on rates, we cannot conclude that electric rates will fall. Other utility costs, such as wildfire mitigation, could cause rates to rise in aggregate. Moreover, effective policies, particularly around rate design, are needed to ensure that potential rate decreases are realized. For example, if EV owners are offered a preferential

[97] Cal Advocates, *Q2 2024 Electric Rates Report,* February 18, 2025. Available at: https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/250218-public-advocates-office-q4-2024-rates-report.pdf.

rate that does not include the appropriate costs, electricity rates for all other consumers could still rise.

3.2.3 Interpreting key differences among rate results

Each of the three charging behavior scenarios—High Peak, Moderate Peak, and Managed—assume identical degrees of load growth. Cost results vary, however: the Managed load shape produces the lowest costs, and thus the greatest downward pressure on rates, while the High Peak load shape produces the highest costs and the least downward pressure. In other words, with load fixed, lower costs translate into lower rates. High Peak

However, the Managed scenario does not incorporate potential costs associated with the implementation of managed charging. The rate impact of the Managed scenario may overstate the likely downward pressure on rates from any implementation of managed charging which passes the costs of implementation on to ratepayers through rates.

The three AAFS scenarios model different degrees of load growth and produce different costs. Of the three AAFS scenarios, AAFS 3 produces the highest degree of downward pressure on rates. The 2023 IEPR AAFS scenarios represent increasing adoption of electrification technologies. However, this does not always correspond to an increase in electricity consumption. For example, AAFS 3 models adoption of electric resistance water heaters. In AAFS 4, many of those water heaters are instead replaced with heat pump water heaters, which are significantly more energy efficient than resistance water heaters. This means the electricity consumption corresponding to electrified water heaters is actually lower in AAFS 4 than in AAFS 3, despite AAFS 4 representing more electrification overall. This difference is most prominent within SDG&E’s service territory, due to climate and economic factors. Because AAFS 4 is associated with higher uptake of more efficient water heaters, which can produce more strain on the grid but not necessarily lead to large increases in total consumption, AAFS 4 produces a lesser degree of downward pressure on rates than AAFS 3. However, the differences in rate impact among these scenarios is generally less than half a cent per kWh. This indicates that, within the boundaries of the AAFS scenarios modeled in DGEM 2025, different degrees of BE adoption are unlikely to have a significant effect on rates. This result may additionally suggest that downward pressure on rates from electrification is driven primarily by EV load, with BE load having a neutral impact on rates. However, further, more precise modeling would be required to confirm this suggestion.

3.2.4 Probing the boundaries of rate impact in our rate model

While DGEM 2025 does not quantify uncertainty, we do investigate the boundaries of the downward pressure on rates finding from our model. We do this in two ways.

First, we constructed a "small overbuild" scenario in the rate model by using the costs associated with AAFS 3 while using the smaller load associated with AAFS 2.5. This probes the rate impact of delayed adoption of BE, in a circumstance where compliance with state targets is slower than anticipated, while the IOUs build for BE as planned. Table 3-7 shows these rate impact results.

Table 3-7: Additional costs to ratepayers for a minor overbuild scenario, using AAFS 3 costs with AAFS 2.5 load growth.

Rate Impacts	**2030**			**2035**			**2040**		
in cents / kWh	AAFS 2.5	Overbuild	Difference	AAFS 2.5	Overbuild	Difference	AAFS 2.5	Overbuild	Difference
High Peak Shape									
PG&E	-1.6	-1.5	+0.1	-2.1	-2.0	+0.1	-2.6	-2.4	+0.2
SCE	-1.3	-1.2	+0.1	-1.0	-0.7	+0.3	-0.5	-0.3	+0.2
SDG&E	-1.7	-1.7	+0.0	-2.2	-2.1	+0.1	-2.6	-2.5	+0.1
Moderate Peak Shape									
PG&E	-1.9	-1.9	+0.0	-2.8	-2.6	+0.2	-3.4	-3.3	+0.1
SCE	-1.6	-1.5	+0.1	-2.2	-1.9	+0.3	-2.1	-1.8	+0.3
SDG&E	-2.1	-2.1	+0.0	-3.2	-3.2	+0.0	-3.9	-3.7	+0.2
Managed Shape									
PG&E	-2.1	-2.1	+0.0	-3.0	-2.9	+0.1	-3.7	-3.5	+0.2
SCE	-1.7	-1.7	+0.0	-2.5	-2.3	+0.2	-2.7	-2.4	+0.3
SDG&E	-2.3	-2.3	+0.0	-3.7	-3.6	+0.1	-4.4	-4.2	+0.2

This particular scenario shows that rate impacts are worsened by between zero and three tenths of a cent if utilities build for a slightly higher degree of load than appears in practice. While this difference may not seem significant, it shows that even small degrees of overbuild do impact rates. Precise planning and efficient spending will be key to achieving the highest degree of downward pressure on rates possible.

We also probe the boundaries of the downward pressure finding by directly modifying our inputs to the rate model. We probe a circumstance with substantially less load growth by artificially restricting load growth in the model (while keeping costs constant). Similarly, we probe a circumstance with higher costs by artificially increasing costs (while keeping load constant). Tables 3-7 and 3-8 show the results of this analysis. These circumstances do not represent any real forecast or estimate; they are provided simply to provide insight into the sensitivity of the rate impacts to different inputs and the boundaries of the downward pressure finding. We reiterate these results are best interpreted as directional sensitivity checks rather than as an accurate forecast of the future.

Table 3-8: Rough sensitivity of rates to costs, in 2035, as evaluated in the central scenario (AAFS 3 / Moderate Peak charging behavior).

Costs Multiplier	PG&E 2035 Modified Cost ($bn)	PG&E 2035 Rate Impact (¢/kWh)	SCE 2035 Modified Cost ($bn)	SCE 2035 Rate Impact (¢/kWh)	SDG&E 2035 Modified Cost ($bn)	SDG&E 2035 Rate Impact (¢/kWh)
0x (no cost of infrastructure at all)	$0	-4.4	$0	-3.3	$0	-4.2
0.8x	$6.1	-3.2	$4.2	-2.5	$0.6	-3.6
1x (base scenario)	$7.6	-2.9	$5.2	-2.3	$0.8	-3.4
1.2x	$9.1	-2.6	$6.2	-2.1	$1.0	-3.3
1.5x	$11.4	-2.2	$7.8	-1.8	$1.2	-3.0
2x	$15.2	-1.4	$10.4	-1.3	$1.6	-2.7
5x	$38	+3.0	$26	+1.5	$4.0	-0.4
10x	$76	+10.3	$52	+6.3	$8.0	+3.3

Table 3-9: Rough sensitivity of rates to load growth, in 2035, as evaluated in the central scenario (AAFS 3 / Moderate Peak charging behavior).

Load Growth Multiplier	PG&E 2035 Modified Consumption Growth (TWh)	PG&E 2035 Rate Impact (¢/kWh)	SCE 2035 Modified Consumption Growth (TWh)	SCE 2035 Rate Impact (¢/kWh)	SDG&E 2035 Modified Consumption Growth (TWh)	SDG&E 2035 Rate Impact (¢/kWh)
0x (no load growth)	0	+1.8	0	+1.1	0	+0.9
0.3x	8.1	+0.1	5.4	+0.0	1.6	-0.6
0.5x	13.4	-0.9	9.0	-0.7	2.7	-1.5
0.8x	21.5	-2.2	14.4	-1.7	4.3	-2.7
1x (base scenario)	26.9	-2.9	18.0	-2.3	5.4	-3.4
1.2x	32.2	-3.6	21.6	-2.8	6.5	-4.0

This analysis should not be seen as a precise estimate of possible outcomes. However, it does provide some general insights. First, the benefit due to the higher volume of energy sales from expected load growth in our model, ignoring the associated costs of infrastructure upgrades, is 3-4 cents per kWh of decreased rates in 2035. Second, the finding of downward pressure is quite robust across a wide range of outcomes: electrification is still net beneficial to electric rates even if only half the predicted load growth occurs, or even if costs are double those estimated in this scenario. Of course, multiple sources of error could compound to create upward rate pressure—for example, if costs are higher than expected and load growth is lower than expected. Additionally, while any downward pressure indicates a net benefit to ratepayers, it is the magnitude of downward pressure that matters, as greater degrees of downward pressure can more effectively counteract upward pressure on rates from other areas, such as wildfire mitigation.

These findings highlight the need to find an appropriate approach to electrification planning. Ratepayers will lose out on rate benefits both if grid constraints hamper load growth and if utilities construct unneeded infrastructure. With careful planning, efficient spending, and judicious decision-making, ratepayers will achieve the highest possible degree of benefit.

3.3 Overloads and necessary mitigations

DGEM 2025 calculates the number of feeder and substation mitigations needed in order to calculate the total cost of those mitigations. However, costs are highly uncertain. For some stakeholders, it may be more useful to estimate the numbers of feeders and substations which will experience overloads without converting those numbers into a cost.

3.3.1 Estimated feeder and substation mitigations by scenario

Tables 3-9 and 3-10 report the numbers of overload mitigations estimated by DGEM 2025 for feeders and substations, respectively. Figure 3-3 shows the fraction of each IOU's assets which become overloaded in the model over time if no infrastructure beyond that present in our data is built.

DGEM 2025 estimates future loads for 7,468 total feeders: 2,792 owned by PG&E, 3,956 owned by SCE, and 720 owned by SDG&E. In our central estimate (Moderate Peak / AAFS 3), 28% of feeders require an overload mitigation by 2040.

Table 3-10: Number of feeder mitigations estimated, by scenario, year, and IOU.

Number of Needed Mitigations	**2030**			**2035**			**2040**		
Feeder Overloads	AAFS 2.5	AAFS 3	AAFS 4	AAFS 2.5	AAFS 3	AAFS 4	AAFS 2.5	AAFS 3	AAFS 4
High Peak Shape	725	763	835	1782	1931	2040	2875	3046	3081
PG&E	411	420	454	859	900	962	1270	1338	1382
SCE	259	287	324	771	865	919	1350	1446	1451
SDG&E	55	56	57	152	166	159	255	262	248
Moderate Peak Shape	409	434	496	1058	1195	1285	1862	2075	2127
PG&E	237	238	270	610	666	716	967	1036	1089
SCE	148	170	199	385	462	506	769	896	916
SDG&E	24	26	27	63	67	63	126	143	122
Managed Shape	264	284	345	745	911	998	1450	1675	1729
PG&E	161	161	194	480	556	610	836	926	982
SCE	94	114	141	246	330	368	547	668	682
SDG&E	9	9	10	19	25	20	67	81	65

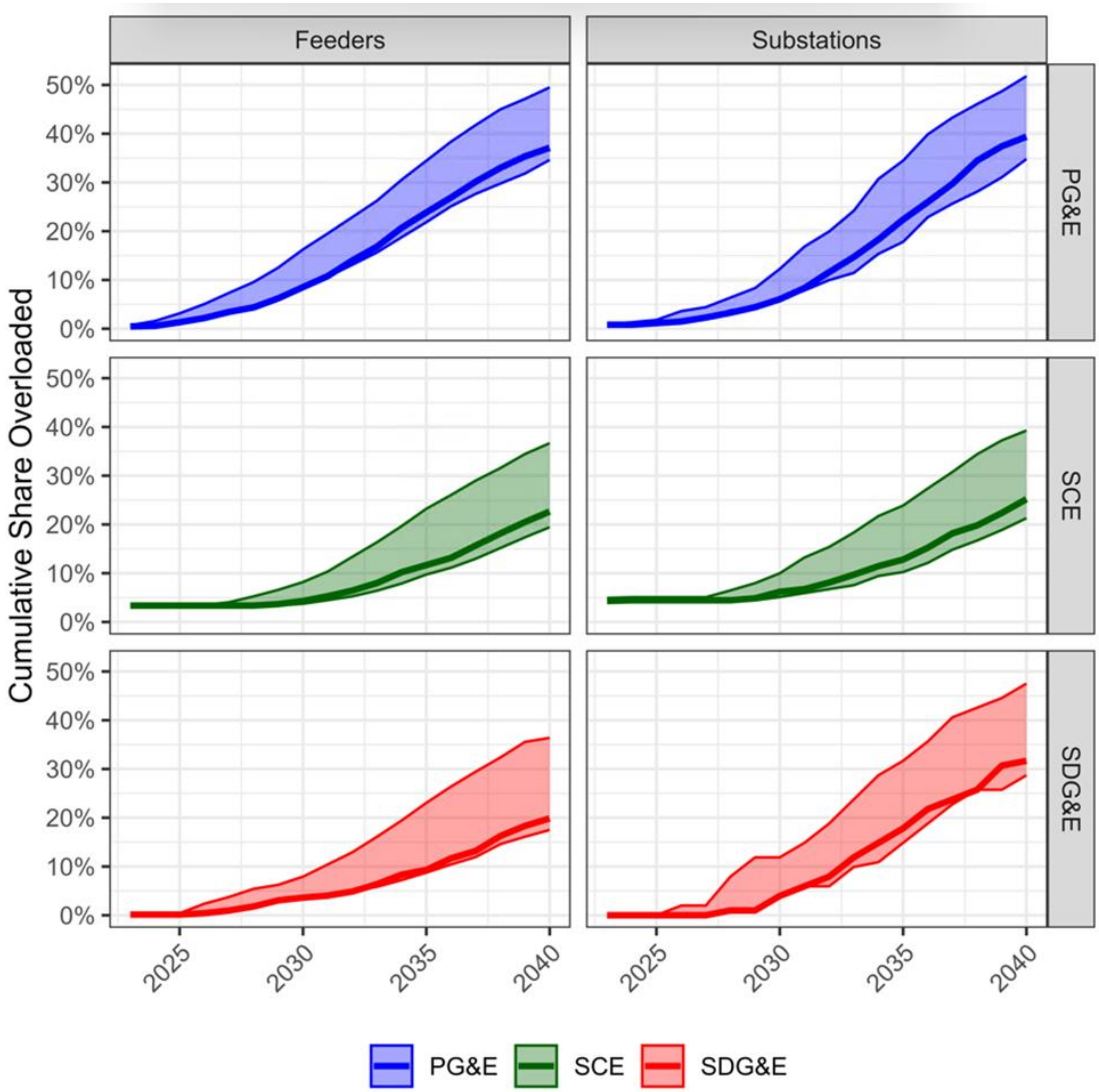
DGEM 2025 estimates future loads for 1450 total substations: 612 owned by PG&E, 737 owned by SCE, and 101 owned by SDG&E. In our central estimate (Moderate Peak / AAFS 3), 32% of substations require an overload mitigation by 2040.

Table 3-11: Number of substation mitigations estimated, by scenario, year, and IOU.

Number of Needed Mitigations	**2030**			**2035**			**2040**		
Substation Overloads	AAFS 2.5	AAFS 3	AAFS 4	AAFS 2.5	AAFS 3	AAFS 4	AAFS 2.5	AAFS 3	AAFS 4
High Peak Shape	128	132	161	367	399	419	606	642	653
PG&E	59	60	75	181	198	211	289	305	317
SCE	57	60	74	155	169	177	272	289	291
SDG&E	12	12	12	31	32	31	45	48	45
Moderate Peak Shape	78	87	102	200	250	279	400	460	474
PG&E	36	37	47	109	137	152	213	241	259
SCE	38	46	51	76	95	110	158	187	188
SDG&E	4	4	4	15	18	17	29	32	27
Managed Shape	55	63	78	162	193	222	304	366	383
PG&E	29	29	37	98	115	130	180	208	225
SCE	25	33	40	59	72	86	110	137	143
SDG&E	1	1	1	5	6	6	14	21	15

Considering only the current infrastructure of each IOU, our load forecasts indicate that about 35% to 50% of PG&E assets will be overloaded by 2040, about 20% to 40% for SCE, and about 15% to 50% for SDG&E.

Figure 3-4: Share of each IOU's equipment overloaded without any additional mitigations, by year. The range depicts our range of nine policy scenarios. The dark line depicts our central estimate (AAFS 3 / Moderate Peak charging behavior).



These overload, mitigation, and utilization results are highly dependent on our assumptions. DGEM 2025 assumes that every feeder overload will be mitigated in the same way and that every substation overload will be mitigated in the same way. Our assumptions are necessary simplifications but do not match how IOUs actually mitigate feeder and substation overloads. Each IOU will have its own set of approaches to mitigations. For more discussion of the divergence between our assumptions and the IOUs' actual behaviors, see Sections 4.5 - 4.7.

3.3.2 Utilization of new equipment

Peak utilization is a metric which measures how much capacity of a grid asset is being used. If peak utilization is 100%, that means the peak load on an asset equals its capacity, and all of its capacity is being used. If peak utilization is 50%, that means peak load on an asset equals half its capacity, and much of its capacity is not being used.

DGEM 2025 estimates an increase in peak utilization overall, as load grows across the system. The projected increase in peak utilization is driven by increases in utilization of existing infrastructure, not by high utilization of new infrastructure. As shown in Table 3-12 below, the utilization of the new infrastructure in DGEM 2025 is comparatively low, although it increases over time. We are exploring how the overall utilization of the distribution grid has changed over time in a separate project.

Table 3-12: Utilization of new infrastructure modeled in DGEM 2025 in the central scenario (AAFS 3 / Moderate Peak charging behavior).

IOU and Facility Type	2030 Average Peak Utilization	2035 Average Peak Utilization	2040 Average Peak Utilization
PG&E, New Feeders	12%	18%	25%
PG&E, New Substation Banks	8%	14%	22%
SCE, New Feeders	6%	7%	9%
SCE, New Substation Banks	10%	16%	20%
SDG&E, New Feeders	14%	15%	16%
SDG&E, New Substation Banks	13%	20%	33%

DGEM 2025 allocates upgrades in fixed increments: 12 MW feeders and 28 MW substation banks. This means small overloads can produce large incremental costs; for example, a 1 MW overload on a substation bank produces an incremental cost of $4.7 million, as DGEM allocates a new 28 MW substation bank to address that overload, producing 27 MW of unused capacity. This is an inefficient way to allocate new equipment, and produces low utilization on new infrastructure. The accuracy of our cost and utilization estimates depends on the flexibility of utility mitigations. If the utilities have a large number of low-cost ways to address small overloads, then DGEM 2025 is likely to systematically overestimate costs. However, if the utilities have a high planning and labor cost for *any* mitigation, regardless of the scale, then DGEM 2025 is more likely to accurately represent cost. Ideally, the utilities will be able to save additional spending by allocating new equipment more efficiently than DGEM 2025.

4 Assumptions and Limitations

California's electric distribution grids include thousands of distribution feeders spanning hundreds of thousands of miles, thousands of distribution substations, over a million service transformers, and countless capacitors, sectionalization devices, fuses, and other pieces of distribution infrastructure.[98] DGEM 2025 accounts for the addition of eleven million EVs, each of which may have a unique spatial and temporal charging profile over the course of the 8,760 hours in a year. Modeling such a vast and complicated system—to say nothing of forecasting fifteen years into the future—necessitates making many simplifying assumptions to make the problem tractable to computation and comprehension. These simplifying assumptions lead to limitations. This section describes and discusses each of the most important assumptions.

Future work, whether by Cal Advocates or others, could seek to provide greater certainty and reduce the need to use assumptions of the sorts described here. We have already performed some of this work in DGEM 2025, seeking to improve our BE load disaggregation and feeder unit cost analysis from DGEM 2023. Sections 5.5 and 6 discuss some of these further research needs.

4.1 Adherence to the CEC's 2023 IEPR forecast

DGEM 2025 spatially disaggregates the CEC's 2023 IEPR forecast. The IEPR forecast is produced by a large number of modeling experts, through an open, transparent process with the involvement of a large number of stakeholders. As such, it represents a very high quality of research and of forecasting. Nonetheless, as it touches a number of uncertain elements of California's future, the IEPR forecast itself contains uncertainties, all of which propagate into DGEM 2025.

We wish to highlight three such uncertainties:

1. **BE compliance risk:** Compliance with BE standards is difficult to predict. Many appliances are installed without permits and outside of the direct control of building standards, especially in existing residential buildings.99 Because of this, actual adoption rates of BE appliances are highly uncertain, especially for near-future goals. The IEPR

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[98] See EIS Part 1 at 115; PG&E, *Company Profile*, n.d., available at: https://www.pge.com/en_US/about-pge/company-information/profile/profile.page; SCE, *Powering Southern California for 130+ Years*, n.d., available at: https://www.sce.com/about-us/who-we-are; and SDG&E, *CPUC Rule 20 Programs: Overhead-to-Underground Conversion of Electric Power Lines*, n.d., available at: https://www.sdge.com/major-projects/Rule20Undergrounding.

[99] A 2017 CPUC-initiated study estimated the permitting rate of HVAC installations as between 8% and 29%. See CALMAC, *Final Report: 2014-16 HVAC Permit and Code Compliance Market Assessment (Work Order 6) Volume I – Report*, September 22, 2017. Available at: https://www.calmac.org/publications/HVAC_WO6_FINAL_REPORT_VolumeI_22Sept2017.pdf

represents the best available modeling on this subject, and the AAFS scenarios used in this report span a range of possibilities, but the future could nonetheless deviate substantially.[100]

2. **Fleet policy changes:** The 2023 IEPR assumes compliance with CARB's ACF regulation, which was withdrawn in 2025.[101] This means that the 2023 IEPR may overestimate fleet electrification, especially in the short term, and therefore affect our results.[102] However, California continues to pursue the goals of fleet electrification, so it is difficult to estimate the degree of overestimation at this time.[103]

3. **Data center loads:** The 2023 IEPR models data centers under base load growth.[104] Data center load forecasts are evolving rapidly, and the Draft 2024 IEPR Update highlights the CEC's adjustments for the expected load growth of data centers as a key change in their forecast between 2023 and 2024.[105] DGEM 2025 does not model data centers as a separate load type, and instead indirectly considers them as a contribution to non-electrification load growth. Data center load growth may have a significant impact on the distribution grid, but it is difficult to estimate how this might affect our results at this time.

4.2 Assumption: BE load arrives in proportion to existing electric load

Most BE load growth will arrive in proportion to existing gas consumption, as BE load growth is the direct result of fuel substitution. For example, in a given area, the amount of additional electricity consumed in the future by electric water heaters is likely to be proportional to the amount of gas currently consumed by gas water heaters.[106] One effective approach to estimate future BE electricity consumption would be to directly use gas system data to disaggregate BE loads. DGEM 2025 does not use this approach due to data and technical limitations: gathering

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[100] See 2023 IEPR at 119 and 120; "Many uncertainties exist with these zero-emission appliance standards and other regulations that will spur building decarbonization. There are legal, regulatory, and adoption and compliance uncertainties that will affect the pace of market transformation."

[101] EPA, *RE: Withdrawal of California's Request for a Waiver, Pursuant to Clean Air Act Section 209(b), and Request for Authorization, Pursuant to Clean Air Act Section 209(e)(2), for the Advanced Clean Fleets (ACF) Regulation, Docket ID EPA-HQ-OAR-2023-0589*, accessed October 14, 2025, available at: https://www.epa.gov/system/files/documents/2025-01/ca-acf-carb-withdrawal-ltr-2025-1-13.pdf

[102] See Box 1-1 for why DGEM 2025 uses the 2023 IEPR.

[103] Executive Department, State of California, *Executive Order N-27-25*, June 12 2025. Available at: https://www.gov.ca.gov/wp-content/uploads/2025/06/CRA-Response-EO-N-27-25_-bl-formatted-GGN-Signed-6-11-954pmFinal.pdf

[104] 2023 IEPR at 104.

[105] CEC, 2024 Integrated Energy Policy Report Update, *Draft Commission Report*, updated November 27, 2024. Available at: https://www.energy.ca.gov/publications/2024/2024-integrated-energy-policy-report-update

[106] Not all BE load will arrive in proportion to existing gas load. For example, some homes in warming climates will install new HVAC systems primarily for air conditioning, rather than as a replacement for gas heating.

precise gas consumption data and spatially mapping it onto electric feeders would be technically challenging.

DGEM 2025 instead assumes that BE load growth occurs in proportion to the existing *electric* load on each feeder, and in proportion to each feeder's load breakdown by customer class (residential, commercial, and low income). Existing gas loads and electric loads have common drivers,[107] so assuming BE load growth occurs in proportion to existing electric load provides a reasonable estimate.

Our approach may underestimate peak loads in cases where gas load is more heavily clustered than electric load, and it may overestimate peak loads in cases where circuits already contain electrified buildings. This approach also does not capture feeders which will be built in entirely new areas due to future loads, as we allocate all new load onto existing feeders. Nonetheless, this method is a major improvement over DGEM 2023, which allocated BE load in proportion to historic consumption for feeders across the state, without consideration of variations by building climate zone, customer class, or end use.

4.3 Assumption: EVs charge at their registration address

DGEM 2023 assumed that all vehicles charge at their registration addresses, and DGEM 2025 continues to use that assumption. Additionally**, DGEM 2025 assumes that the vehicle charges on the closest feeder to its registration address**—an assumption that may be incorrect in regions with heavily interlinked feeders. We make these assumptions to simplify our model and because the data needed for more robust modeling does not yet exist.

LD Vehicle Assumptions: For personal LD vehicles, the assumption that vehicles charge at their registration address is correct most of the time.[108] However, it is possible that certain feeders which serve commercial centers or office parks may see a significant enough quantity in workplace and public charging to create additional overloads—although that load would also be subtracted from other locations.

Fleet Vehicle Assumptions: For fleet vehicles, both personal and non-personal, the assumption that vehicles charge at their registration address is clearly incorrect. Fleet vehicles are usually registered to a corporate address but operate somewhere else entirely. However, DGEM 2023 found that different methods of spatially allocating fleet vehicles had a minimal impact on the

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[107] Factors including income, home sizes, and numbers of occupants are common drivers for both electricity and gas consumption. This means a higher or lower electric load can serve as a proxy for higher or lower gas consumption.

[108] Approximately 80% of personal vehicle charging occurs at the household. See Michael Blonsky et al., *Incorporating Residential Smart Electric Vehicle Charging in Home Energy Management Systems*, National Renewable Energy Laboratory, April 2021 at 1. Available at: https://www.nrel.gov/docs/fy21osti/78540.pdf.

cost, indicating that it is the number and not the precise location of these vehicles that is significant in aggregate.[109]

Fleet vehicle charging may be especially concentrated in comparison to LD vehicle charging, especially around ports and other transportation hubs. For short-term distribution planning, these concentrated centers have a significant impact on the cost, as they may involve new feeders and new substations allocated for individual large loads. However, for system-wide estimates, these concentrated locations of fleet vehicles have a comparatively smaller impact on total costs, as personal vehicles have a much higher total load. DGEM 2025 predicts a very large number of small overloads under 3 MW, so more heavily concentrating loads could actually reduce estimated costs, by removing many small overloads while creating a few larger overloads. A key focus of future work will be further investigation of the locational impact of fleet charging.

4.4 Assumption: Uniform statewide load shapes are good proxies for load shapes on individual feeders

DGEM 2025 uses statewide load shapes from the 2023 IEPR as applied to smaller loads on individual feeders. For example, the 2023 IEPR's LD EV load shape represents the aggregate load of hundreds of thousands of EVs across an entire IOU service territory; while no individual vehicle will charge according to the 2023 IEPR load shape, their charging behavior produces that shape in aggregate. DGEM 2025 assumes that these statewide load shapes can also be used on individual feeders, as feeders will also serve a large number of individual EVs.

However, a single feeder may only serve a few hundred EVs, or fewer, and these loads may not aggregate to the same shape. In reality, we would expect less aggregated load shapes (like the load shape on an individual feeder) to be more jagged in comparison to more aggregated load shapes (like the load shape across the entire state). See Box 4-1 for further discussion.

Feeders also likely have location-specific biases toward certain load shapes. For example, DGEM 2025 uses a single annual load shape for HVACs, and separates that load shape into two 24-hour load shapes for summer and winter. However, individual circuits will have strong biases toward more heating load in winter or more cooling load in summer depending on which region of the state they are in. While DGEM 2025 does control for the overall proportion of electrification load HVACs use based on the climate zone where the HVAC is located, it does not modify the HVAC load shapes. Heating load shapes are peakier in hot regions and cooling load shapes will be sharper in cold regions. This could lead to difficult-to-predict systematic error in DGEM 2025 overload estimations.

[109] For more information on the impacts of charging location of fleet vehicles and related assumptions, see DGEM 2023, Section 4.3 at 40.

In general, individual load shapes are not uniform across the state and are not identical to statewide load shapes. However, accurately predicting more realistic disaggregated load shapes would require expansive and specific data and significant computational resources. For this reason, **we assume that statewide load shapes are a good proxy for local load shapes.**

Box 4-1: Why Are Disaggregated Load Shapes Peakier?

In Box 2-1, we presented an example load shape of a building which turns on its lights from 8am to 5pm. Consider now three circuits, each with an identical building. One turns on 60 kW of lights from 12am to 8am; one from 8am to 4pm; and one from 4pm to 12am.

If we add all these load shapes together, we get a single flat load shape: one set of 60 kW lights is on all the time. Then imagine that we tried to split that flat load shape back into three. We might estimate that all three buildings have 20 kW of lights on all the time. But that's incorrect. Each building has a unique, sharp load shape.

This only works one way: load shapes get smoother as they add together. You can add up several spikes and end up with a roughly flat line. But you can't add up several flat lines and end up with a spike.

Consider our flat, aggregated, three-building load shape from above. If we wanted to estimate the load shape of each individual building, we might naively disaggregate it into three flat 20 kW loads, but we know this is probably incorrect. However, even though we know that each individual building should have a spikier load shape, it is difficult to anticipate what effect that would have on the grid. Imagine that each circuit has 30 kW of capacity all the time. Then our naive estimate—20 kW of lights all the time—wouldn't cause any overloads. But in reality, the 60 kW spikes *would* cause overloads, on all three circuits! In this circumstance, the disaggregation underestimates the strain on the grid.

Now imagine that each circuit has only 10 kW of capacity from 5pm-9pm, and 80 kW of capacity at all other times. Our naive estimate—20 kW of lights all the time—would cause overloads for all three circuits. But in reality, only the circuit with lights on in the evening would cause an overload. Here, the disaggregation overestimates the strain on the grid.

This same dynamic is present in DGEM 2025's load shapes. We know that individual feeders will probably have more variable load shapes than the system overall. However, what matters is not that higher peaks exist; what matters is when those peaks occur, and how they interact with existing time-dependent capacity on the grid, which generally tends to be most constrained for a few hours in the afternoon and evening. **More accurate disaggregations of load shapes are beyond the scope and capacity of DGEM 2025. Instead, we must accept a certain degree of uncertainty due to this limitation.**

4.5 Assumption: All three IOUs have infrastructure which costs and operates identically

DGEM 2025 overlooks a large amount of variance between the infrastructure of the three major IOUs. For example, SCE has a subtransmission system which operates at a voltage between transmission and distribution voltage, and operates two separate sets of subtransmission and distribution substations. PG&E uses higher-power transformer banks (primarily 45 Megavolt-Ampere, or MVA) in its substations than SDG&E and SCE (both primarily use 28 MVA banks). All three IOUs have different ranges of feeder operation voltages. SCE has dynamic connections between feeders and substation banks, which can be fairly easily switched, while PG&E has fixed connections between feeders and substation banks.

These differences will appear in the IOUs' respective approaches to mitigating overloads. IOUs have different networks, with different options available to them for transferring load. The three IOUs will face different issues due to load growth and will choose different resources to deploy to address those issues.

DGEM 2025 uses IOU-provided ratings for each piece of infrastructure considered in the model. However, because we cannot model to the degree of granularity necessary to distinguish between the IOUs' respective system operations, we elected to remove granularity in IOU costs. Cost data provided by the IOUs does indicate that the IOUs spend different amounts on new feeders, new substation banks, and new substations. But in an estimate as rough as DGEM, introducing new granularity can be misleading. For example, if one IOU uses larger, more expensive transformer banks, that IOU might also be more willing to pursue alternate mitigations not considered in DGEM 2025, such as load shifting between nearby substations. We want the cost variance between the three IOUs to accurately indicate the scale of the mitigation issues facing those IOUs, rather than being dominated by uncertain assumptions about the difference between unit costs among the IOUs.

Were we to use costs for each IOU derived only from data provided by that IOU, costs for PG&E and SDG&E would be comparatively higher, and costs for SCE would be comparatively lower.

4.6 Assumption: The IOUs will respond to all overloads by constructing new infrastructure

DGEM 2025 assumes the IOUs respond to all overloads by constructing new infrastructure. In contrast, the IOUs perform an engineering study before upgrading a piece of distribution infrastructure. An engineering study entails planning out the most cost-effective solution to resolve capacity exceedance on an asset, which could be significantly different from the simplified DGEM 2025 assumption of building a new feeder in this case. For example, DGEM 2025 will trigger the installation of a new feeder if an existing feeder is overloaded. In practice, an IOU might choose to switch load temporarily or permanently, particularly for small overloads, or to build a single new piece of equipment which addresses overloads on multiple nearby feeders, or to allow a piece of infrastructure to operate safely in an overloaded state.

DGEM 2025 therefore likely overestimates the number of new feeders and substation banks which would need to be constructed. If two feeders in the same vicinity each produce a 2 MW overload, a single new 12 kV feeder with a 12 MW rating could be constructed so as to transfer load from each of those feeders, rather than requiring the two new feeders that DGEM 2025 allocates. If one feeder in a region has a 2 MW overload, but another nearby feeder has 3 MW of capacity, utilities may be able to shift load from one feeder to another before requiring the construction of a new feeder. In some cases, transformer banks may be operated in an overloaded state, which may reduce the lifetime of the transformer without necessitating an immediate upgrade. However, DGEM 2025 does not achieve the degree of spatial resolution and circuit interconnection detail to estimate these specific mitigations.

Another limitation of DGEM 2025 is its treatment of feeders operating at archaic distribution voltages, mainly 4 kV. Because of the limitations of the available data, DGEM 2025 assumes that any 4 kV overloaded feeder in PG&E's service territory is upgraded to a 12 kV feeder, but does not assume so for SCE or SDG&E. In practice, an IOU will develop an infrastructure solution on a case-by-case basis, considering, among other things, the voltages of nearby feeders such that load transfers remain possible. Furthermore, we do not make any cost differentiation for these feeders, while in practice costs may be significantly different from the costs of more typical 12 kV primary distribution upgrades.

4.7 Assumption: New infrastructure has a fixed cost

The DGEM 2025 cost model is simple and identical across all IOUs, derived from the costs of historic feeder and substation upgrades. However, future upgrades may serve much more distributed loads than past upgrades (i.e., EVs at 100 houses versus one large industrial customer). Therefore, in the future, an IOU may need to upgrade a significantly greater length of each branching distribution feeder. This could lead to future costs significantly departing from historical costs.

We also assume that the IOUs build new feeders using the most common distribution voltage, regardless of the number of units of infrastructure required. For example, DGEM 2025 solves a 30 MW overload with three 12 MW (12 kV) feeders. In some regions, the IOU could instead install a single 34 MW (33 kV) feeder at a lower cost. Substation costs, too, have a significant degree of cost uncertainty. The cost of a substation can vary significantly with location. Additionally, we assume that utility infrastructure design standards remain static over time, while typical unit sizes may increase under electrification (for better economies of scale) and unit costs may otherwise inflate.

4.8 Assumption: Secondary distribution infrastructure has a cost proportionate to primary distribution infrastructure

DGEM 2025 directly assesses only primary distribution infrastructure needs, so **DGEM 2025's estimates of the costs of secondary distribution infrastructure are simple, drawn directly from EIS Part 1 (by ratio)**. Moreover, DGEM 2025 only accounts for upgrades needed for distribution infrastructure, not sub-transmission, transmission, or generation infrastructure.

In addition to not directly assessing the cost of secondary distribution infrastructure, DGEM 2025 does not assess the (potentially beneficial) impact that secondary distribution limits may have on electrification in practice. These effects could limit the actual cost of distribution upgrades because secondary infrastructure can limit the peak power that needs to be delivered by primary distribution infrastructure. For example, if the collective power ratings of service drops[110] (or service panels) connected to a particular service transformer are not sufficient to overload it, then that transformer is unlikely to require an upgrade unless those downstream components are first upgraded to support higher loads. Similarly, if the load capacity of service transformers is collectively insufficient to overload a feeder or transformer bank, investments in primary distribution infrastructure could be delayed or obviated.

How the limitations imposed by secondary infrastructure play out in practice is impossible to predict. But because there are, at present, wait times to upgrade service and costs that the customer must bear, there is a potential that the customer opts for a different solution, such as a smart service panel that manages load to limit peak load to what the customer's level of service allows. For some customers, installing a smart service panel could be cheaper and faster than requesting a service upgrade. Avoiding or deferring such upgrades could also reduce IOU investments (and so reduce sources of upward pressures on rates).

4.9 Managed charging assumptions

DGEM 2025 avoids making specific assumptions about the implementation of managed charging. No rate or program currently exists that is likely to achieve the degree of load shifting that our scenario describes. The CPUC has been exploring new rates and pilots which may make these outcomes possible, but it is not yet possible to draw conclusions about the future viability of load shifting at scale. Our constructed managed charging load shape is intended to roughly emulate the grid benefits of a variety of managed charging strategies, describing the potential output of incentivized active managed charging programs, dynamic rate charging incentives, or other managed charging structures. We assume 50% of LD vehicle participation and 20% of MDHD vehicle participation on each individual distribution circuit. We are unable to predict

[110] Service drops are the wires connecting the service transformer to the service panel.

actual, likely behavioral numbers for managed charging adoption, so we use these as extremely rough estimates. However, we wish to highlight three important additional limitations and concerns.

1. **Alternate optimizations:** DGEM 2025 only investigates managed charging for distribution grid optimization. However, there are other reasons to shift charging, such as generation and transmission costs and clean energy goals. The DGEM 2025 managed charging scenario tends to shift charging to night and early morning, but shifting charging to midday through a higher adoption of workplace charging might provide higher benefits for climate and the generation costs of electricity. DGEM 2025 does not examine these costs and benefits. Shifting charging to midday would require very different policy approaches than shifting charging to night—delaying vehicle charging after a commuter vehicle is plugged in at home is a different challenge than changing the location of that commuter vehicle charging to its daytime parking spot.

2. **Variation in value by circuit:** There are a large number of circuits which overload in all three load shape scenarios (High Peak, Moderate Peak, and Managed). While managed charging may delay such an overload to a later year, the circuit will nonetheless require mitigation at some point. Therefore, managed charging has minimal value on those circuits. This means that the benefits of managed charging may be most efficiently realized if adoption can be targeted to specific regions and specific circuits which provide the most relative benefit from controlling load. The DGEM 2025 Managed scenario assumes that every circuit across the state participates equally in managed charging, but this is unlikely, and different spatial adoption outcomes may have radically different impacts on the grid. Future studies with higher spatial resolution or a more diverse and specific array of mitigations might be able to better probe this possibility.

3. **Details of infrastructure costs:** The value of managed charging in any model is highly dependent on the exact cost structure the model applies. In a period of large load growth, utilities may benefit from economies of scale in building out large portions of their grid. Alternatively, early in this period, limitations on supply and labor may produce diseconomies of scale in upgrading much of the grid at once. The way that costs develop has a significant effect on the value of managed charging. DGEM 2025 assumes that each individual mitigation is expensive, regardless of its relative scale under 12MW. If the cost of each mitigation instead scales with the degree of overload, managed charging becomes more valuable, as it would shrink larger overloads into smaller ones. Alternately, if each mitigation carries a heavy fixed cost, and if the cost of each mitigation decreases with large numbers of mitigations (as one might expect in the economies of scale faced by IOUs), then managed charging becomes less valuable, as decreasing the relative size of an overload provides less benefit.

4.10 Assumption: Feeder overloads at the feeder head are the only significant overloads

DGEM 2025 only assesses loads at the feeder head (i.e., near the substation, where all load has developed). This is similar to the methods of prior studies.[111] It is possible that there are overloads at distant feeder segments with small conductors. We assume that this situation is rare and comparatively cheap to solve.

4.11 AMI and SCADA data accuracy

DGEM 2025 uses historical Advanced Metering Infrastructure (AMI) and Supervisory Control and Data Acquisition (SCADA) data to predict future non-electrification load. This technology is known to occasionally produce erroneous records. We remove specific, known examples of such errors from the data, and our median-based selection removes extreme outliers; however, some errors might remain which might influence load forecasts, and any systematic error in the AMI or SCADA data could directly influence our results.

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[111] See e.g. EIS at 118: "Kevala calculated the coincident peak at each of the 8,256 feeders and compared it to the feeder rating to determine the overload."

5 Key Findings

We highlight the key findings of our work below.

5.1 Grid upgrades to support electrification are estimated to cost $5 billion by 2030, $14 billion by 2035, and $25 billion by 2040.

The mass electrification of vehicles, buildings, and other sectors—which is crucial for meeting California's decarbonization goals—will result in higher energy usage and necessitate distribution grid infrastructure upgrades. Our study assesses the effects of projected load growth on the distribution systems of PG&E, SCE, and SDG&E from BE, EV, and non-electrification sectors through 2040 and the associated cost of upgrades to the system to meet the projected load. In our primary scenario, which follows the 2023 IEPR Planning Scenario, we find that load growth on the three IOUs' respective distribution systems will necessitate overload mitigations on 2,168 feeders and 478 substations by 2040, 29% of all feeders and 33% of all substations considered in DGEM 2025. We estimate the cumulative cost of necessary upgrades to be $5 billion by 2030, $14 billion by 2035, and $25 billion by 2040. However, this number has significant, unquantified uncertainty, and could be substantially lower or higher due to uncertainties in mitigation costs, load locations, load disaggregation, and other factors. See section 3.1 for further details.

No single study can definitively answer such a complex question as what the costs of distribution grid upgrades will be over the next 15 years, particularly at this early point in the electrification process while adoption trends are still nascent and technologies are still evolving. DGEM 2023 provided a variety of forecasts in an attempt to bound some of the uncertainties involved; DGEM 2025 provides a variety of forecasts in an attempt to highlight the impacts of specific outcomes for BE adoption and EV charging behavior. These forecasts reasonably align with prior research, lending credence to both DGEM 2025 and prior studies. Nonetheless, our results are best used to show relative sensitivities, instead of as a definitive estimation of the future. Our results support discourse on the costs and benefits of electrification in California, and on the most beneficial adoption strategies and policy goals.

5.2 Increased sales due to electrification may put downward pressure on rates of up to a few cents per kWh, but electrification will not be a solution to the rates crisis

DGEM 2025 estimates that the increase in electricity sales from electrification will outweigh the costs of distribution investments, resulting in downward pressure on rates compared to 2025 rates. Importantly, this downward pressure is resilient to different adoption assumptions, and persists across a range of load growth and cost outcomes. We predict downward pressure on rates for all scenarios used in DGEM 2025. In our central scenario (using AAFS 3 and the Moderate Peak EV charging load shape) we estimate a 2035 cost of $13.6 billion. We find downward pressure on rates even if that 2030 $13.6 billion cost were to double, or if the scenario's load growth were to be cut in half, reducing the increase in electricity sales.

These rate pressures are comparatively small, amounting to a few cents per kWh over the next 15 years. Electrification will not reverse the trend of recent increases in rates, which have risen more than 10 cents per kWh for all three IOUs over the last ten years.[112] Nor will rate decreases be realized if future costs and expenditures deviate from our modeling assumptions. See Section 3.2 for further details.

5.3 Mass shifting of peak EV load to beneficial times could save between $5 billion and $18 billion dollars in distribution grid costs by 2040

Our work on DGEM 2023 highlighted EV charging behavior as a key driver of distribution investments. If many EVs charge at the same time as significant non-EV loads—or, on circuits with high EV load, at the same time as each other—the peak load on the system and the need for new distribution investments can be significantly higher. This finding provided the inspiration to further examine EV charging times in DGEM 2025.

DGEM 2025 again finds that reducing the peak load has a significant impact on grid costs. The peaky High Peak load shape produces much higher grid costs than the more distributed Moderate Peak load shape, up to a $13 billion difference by 2040. Similarly, when 50% of LD vehicles and 20% of MDHD vehicles are placed on a feeder-specific block-based managed charging profile, grid costs reduce by up to an additional $5 billion by 2040.

This provides an uncertain estimate of the value of strategies which aim to reduce EV peak load, such as through some form of active managed charging: mass shifting of peak EV load to beneficial times, as described in the Managed scenario, could save between $5 and $18 billion dollars by 2040. Additionally, the value of managed charging to the grid varies significantly by circuit. See section 3.1.2 for further details.

Managed charging of the form investigated by DGEM 2025 will carry costs and technical challenges and may prove to be impossible to implement at a mass scale. While we do not specify the implementation of the load profiles we investigate, feeder-specific managed charging would require that customers receive complex time- and space-dependent signals. If the cost of managed charging is high, it could exceed the potential grid benefit.

[112] See CPUC, *Historical Electric Cost Data*. Available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/historical-electric-cost-data.

5.4 Marginal changes in BE adoption have almost no effect on rates

DGEM 2025 investigates three degrees of BE adoption: AAFS 2.5, which represents the slowest degree of adoption, AAFS 3, which represents adoption in line with California's policy goals, and AAFS 4, which represents a rapid degree of adoption, with a higher and faster uptake of newer technologies. The differences in costs between these scenarios vary according to year and load shape scenario, spanning a range of $3.4 billion dollars in 2040.

We find that the marginal effects of the AAFS scenarios' additional load (MW) and additional consumption (MWh)[113] roughly even out in their impact on rates. While AAFS 3 consistently provides the highest degree of downward pressure on rates, the differences between the scenarios in most years are less than half a cent per kWh, and often less than two-tenths of a cent per kWh.

This "evening out" of marginal effects on rates indicates that the path of adoption of BE does not significantly impact rates, at least within the range of possibilities described by the three AAFS scenarios, and as long as utilities plan and build to match the actual pace and occurrence of electrification. See section 3.2.1 for further details.

5.5 Better data can improve study accuracy

Reliable and readily accessible datasets make research possible. The datasets required to forecast distribution upgrades and their associate costs vary widely in depth and quality. Our team had access to confidential datasets, such as the IOUs' historic load data, and vehicle registration data from the DMV, which made this study possible. These datasets are comprehensive and high-quality. Nevertheless, there are several areas where effective data were notably absent:

1. Data on the locations of current MDHD fleets and current and forecasted potential MDHD fleet charging sites is often proprietary, uncertain, or incomplete;
2. Data on the locations of public charging sites is incomplete or difficult to access;
3. Data describing the costs of secondary distribution infrastructure, such as service transformers, is incomplete;
4. Substation cost data is highly limited, as new substations are substantially rarer than new feeders;
5. Data associating the gas system and the electric system—which is necessary for studying BE—is incomplete and difficult to use.

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[113] Note that consumption and load are similar but different. *Consumption* is the overall usage of energy. The rate at which it used, however, is *load*.

Improvements in datasets will continue to improve studies and will contribute to improvements in the information available to decision-makers and planners.

6 Potential for Future Work

This publication aims to continue the discourse on distribution planning, the future of California's distribution grids, and electrification by representing potential cost outcomes due to adoption possibilities. Opportunities to strengthen our analysis remain. Below we outline the specific areas we intend to focus on in future work.

6.1 More detailed spatial treatment of charging, especially for MDHD vehicles

DGEM 2025 assumes that vehicles charge on the nearest feeder to their registration address. While this may approximate the behavior of the majority of personal vehicle drivers, it is highly inaccurate as applied to fleet vehicles, which may have very different charging behaviors. The incorporation of more detailed fleet location or charging location data may help provide a more accurate vision of the impact of fleet vehicles on the grid. However, our modeling has so far indicated that the spatial distribution of fleet vehicles is less important to final grid costs than their overall population, so we expect that this may account for only a small improvement in accuracy of cost estimates.

A more detailed spatial treatment of charging could also more specifically identify the number and location of circuits where managed charging is likely to have the most impact.

6.2 Use of gas system data to model BE adoption

DGEM 2025 assumes that BE adoption arrives in proportion with existing electric load, but this is inaccurate; BE adoption will arrive while replacing gas demand. Mapping expected gas system consumption onto electric feeders could provide additional insight into the spatial distribution of BE load.

6.3 More accurate mitigation modeling and cost data

DGEM 2025 assumes that every overload is addressed with a new piece of infrastructure. The costs of this infrastructure are highly uncertain, and further refinement, especially for substations, would increase our precision. With additional circuit data, we could potentially expand DGEM to consider additional kinds of mitigation, such as load shifting between connected circuits, or new feeders which address overloads on multiple feeders in a given region. With additional substation data, we could potentially expand DGEM to include precise information about the available capacity in each substation for additional banks, and thus reduce our reliance on ratio-based estimates for aggregate substation costs.

DGEM 2025 also allocates mitigations inefficiently, causing low utilization of new infrastructure. For simplicity, overloads are calculated for all years at once and compiled into a single table. This table is then used to determine the needed mitigations, with the number of mitigations equal to the size of the overload divided by the capacity of a new feeder or substation. This means that the effect of each new piece of infrastructure modeled by DGEM 2025 is not considered. For example, if a feeder is overloaded and another nearby feeder is nearing an overload, load can be shifted from both to a new feeder to delay a second overload. DGEM 2025 performs no such modeling, however, so it predicts more mitigations than would likely to be needed in reality. Operating on a single data table is fast, computationally efficient, and easy to program. The kind of iterative calculation needed to consider the effects of one mitigation on future overloads, and therefore the need for future mitigations, is much more intensive. With additional development time and computational resources, we could make this simplification more robust.

6.4 Treatment of the secondary distribution system

DGEM 2025 uses an estimate adapted from the EIS Part 1 to estimate secondary distribution costs. This estimate has a high degree of uncertainty. If data is available, we could develop new modeling to more accurately estimate the costs of upgrades to service transformers and better describe the impact of electrification on secondary distribution infrastructure.

6.5 Enhanced forecasting for EV adoption

DGEM 2025 currently uses a simple multiple linear regression to predict EV adoption. However, the likelihood of EV adoption is not linearly related to strong predictor variables such as household income and level of education. For this reason, more sophisticated prediction algorithms like simple machine learning models might more accurately predict EV adoption.

6.6 Use of year-long load shapes

DGEM 2025 collapses year-long 8760 load shapes to 48-hour load profiles. This has the effect of losing some variation in the makeup of the peak day by region and circuit. Preserving the 8760 load shapes would be computationally expensive,[114] but could improve the accuracy of our load forecasts and disaggregation, which would in turn improve the accuracy of our overload predictions and resulting costs.

[114] Specifically, a model based on an 8760-profile would take much longer to run and would require more memory, storage, and computing power than the current 48-profile used in DGEM 2025.

Appendix A Additional results

A.1. Variations in the Managed charging scenario

In the Managed EV charging behavior scenario, we construct a unique load shape for each feeder which represents the behavior of vehicles participating in active managed charging. We assign 50% of LD consumption and 20% of MDHD consumption to that load shape, representing the participation of those vehicles in active managed charging. Here we show the cumulative cost outputs of the model with variations in those participation rates. Table A-1 shows the outputs of the Managed Scenario (with AAFS 3 as the BE scenario) while varying the degree of LD participation. Table A-2 shows the outputs while varying the degree of MDHD participation. Note that, because of the spatial uncertainties in our MDHD modeling, this analysis may underestimate the marginal value of MDHD charging management.

Table A-1: Managed charging scenario costs with varying LD participation rates.

Scenario	2030 Cumulative Cost	2035 Cumulative Cost	2040 Cumulative Cost
10% LD Participation	4.4	12.8	23.2
30% LD Participation	3.6	11.5	21.2
50% LD Participation (Managed scenario)	3.4	10.4	19.6
70% LD Participation	3.1	9.8	18.2
90% LD Participation	2.9	9.2	17.3

Table A-2: Managed charging scenario costs with varying MD and HD participation rates.

Scenario	2030 Cumulative Cost	2035 Cumulative Cost	2040 Cumulative Cost
10% MDHD Participation	3.4	10.5	19.8
20% MDHD Participation (Managed scenario)	3.4	10.4	19.6
30% MDHD Participation	3.2	10.3	19.5
40% MDHD Participation	3.2	10.3	19.3
50% MDHD Participation	3.2	10.2	19.2

A.2. Additional cost result tables

This section contains additional cost tables. These tables repeat information from Table 3-1 in the Main Body (repeated below as Table A-3) in different formats, showing cost differences and costs as percentages.

Table A-3: Estimated distribution grid upgrade costs by adoption scenario, IOU, and year. Repeat of Table 3-1 in the Main Body, included here for convenience of reference.

COSTS	**2030**			**2035**			**2040**		
in 2025 $BILLION	AAFS 2.5	AAFS 3	AAFS 4	AAFS 2.5	AAFS 3	AAFS 4	AAFS 2.5	AAFS 3	AAFS 4
High Peak Shape	**7.9**	**8.4**	**9.4**	**20.9**	**22.6**	**23.8**	**34.8**	**36.9**	**37.5**
PG&E	4.3	4.4	4.9	10.3	10.9	11.6	16.3	17.2	17.9
SCE	3.0	3.3	3.8	8.8	9.8	10.4	15.5	16.6	16.7
SDG&E	0.6	0.7	0.7	1.8	1.9	1.8	3.0	3.1	2.9
Moderate Peak Shape	**4.6**	**4.9**	**5.6**	**11.7**	**13.6**	**14.9**	**21.9**	**24.6**	**25.3**
PG&E	2.5	2.5	2.9	6.7	7.6	8.3	11.7	12.7	13.5
SCE	1.8	2.1	2.4	4.3	5.2	5.8	8.7	10.2	10.4
SDG&E	0.3	0.3	0.3	0.7	0.8	0.8	1.5	1.7	1.4
Managed Shape	**3.1**	**3.4**	**4.0**	**8.6**	**10.4**	**11.6**	**17.0**	**19.6**	**20.4**
PG&E	1.8	1.8	2.1	5.5	6.3	7.0	10.0	11	11.8
SCE	1.2	1.5	1.8	2.9	3.8	4.3	6.2	7.6	7.8
SDG&E	0.1	0.1	0.1	0.2	0.3	0.3	0.8	1.0	0.8

Table A-4: Final cost differences against central scenario in billions of dollars. Central cells in gray and italics show the absolute cost results of the central scenario.

COST DIFFERENCES FROM CENTRAL SCENARIO	**2030**			**2035**			**2040**		
in 2025 $BILLION	AAFS 2.5	AAFS 3	AAFS 4	AAFS 2.5	AAFS 3	AAFS 4	AAFS 2.5	AAFS 3	AAFS 4
High Peak Shape	**3.0**	**3.5**	**4.5**	**7.3**	**9.0**	**10.2**	**10.2**	**12.3**	**12.9**
PG&E	1.8	1.9	2.4	2.7	3.3	4.0	3.6	4.5	5.2
SCE	0.9	1.2	1.7	3.6	4.6	5.2	5.3	6.4	6.5
SDG&E	0.3	0.4	0.4	1.0	1.1	1.0	1.3	1.4	1.2
Moderate Peak Shape	**-0.3**	***4.9***	**0.7**	**-1.9**	***13.6***	**1.3**	**-2.7**	***24.6***	**0.7**
PG&E	0.0	*2.5*	0.4	-0.9	*7.6*	0.7	-1.0	*12.7*	0.8
SCE	-0.3	*2.1*	0.3	-0.9	*5.2*	0.6	-1.5	*10.2*	0.2
SDG&E	0.0	*0.3*	0.0	-0.1	*0.8*	0.0	-0.2	*1.7*	-0.3
Managed Shape	**-1.8**	**-1.5**	**-0.9**	**-5.0**	**-3.2**	**-2.0**	**-7.6**	**-5.0**	**-4.2**
PG&E	-0.7	-0.7	-0.4	-2.1	-1.3	-0.6	-2.7	-1.7	-0.9
SCE	-0.9	-0.6	-0.3	-2.3	-1.4	-0.9	-4.0	-2.6	-2.4
SDG&E	-0.2	-0.2	-0.2	-0.6	-0.5	-0.5	-0.9	-0.7	-0.9

Table A-5: Final costs expressed as percentages against central scenario in billions of dollars. Central cells in gray and italics show the absolute cost results of the central scenario.

PERCENTAGE DIFFERENCES FROM CENTRAL SCENARIO	**2030**			**2035**			**2040**		
	AAFS 2.5	AAFS 3	AAFS 4	AAFS 2.5	AAFS 3	AAFS 4	AAFS 2.5	AAFS 3	AAFS 4
High Peak Shape	**61%**	**71%**	**92%**	**54%**	**66%**	**75%**	**41%**	**50%**	**52%**
PG&E	72%	76%	96%	36%	43%	53%	28%	35%	41%
SCE	43%	57%	81%	69%	88%	100%	52%	63%	64%
SDG&E	100%	133%	133%	125%	138%	125%	76%	82%	71%
Moderate Peak Shape	**-6%**	***4.9***	**14%**	**-14%**	***13.6***	**10%**	**-11%**	***24.6***	**3%**
PG&E	0%	*2.5*	16%	-12%	*7.6*	9%	-8%	*12.7*	6%
SCE	-14%	*2.1*	14%	-17%	*5.2*	12%	-15%	*10.2*	2%
SDG&E	0%	*0.3*	0%	-13%	*0.8*	0%	-12%	*1.7*	-18%
Managed Shape	**-37%**	**-31%**	**-18%**	**-37%**	**-24%**	**-15%**	**-31%**	**-20%**	**-17%**
PG&E	-28%	-28%	-16%	-28%	-17%	-8%	-21%	-13%	-7%
SCE	-43%	-29%	-14%	-44%	-27%	-17%	-39%	-25%	-24%
SDG&E	-67%	-67%	-67%	-75%	-63%	-63%	-53%	-41%	-53%

Appendix B Additional scenario: Fully optimized and unconstrained electric vehicle charging behavior

B.1. Purpose and Methodology

In Section 2.5.2 of the Main Body, we describe the three different charging load shapes we use to estimate the impact of electric vehicle charging on the grid, producing three electric vehicle charging behavior scenarios. We construct one additional load shape which allows vehicles to freely charge at any time during a single 24-hour period. This load shape probes the grid impacts of a future in which electric vehicle charging is much more flexible than we anticipate, all vehicles participate in managed charging for grid benefits, and vehicles are able to respond to precise grid conditions. We do not believe this future is likely. We provide the results of this load shape here as a bookend to the total possible savings from electric vehicle load flexibility, but we do not suggest that they be used to estimate the actual value of realistic managed charging adoption.

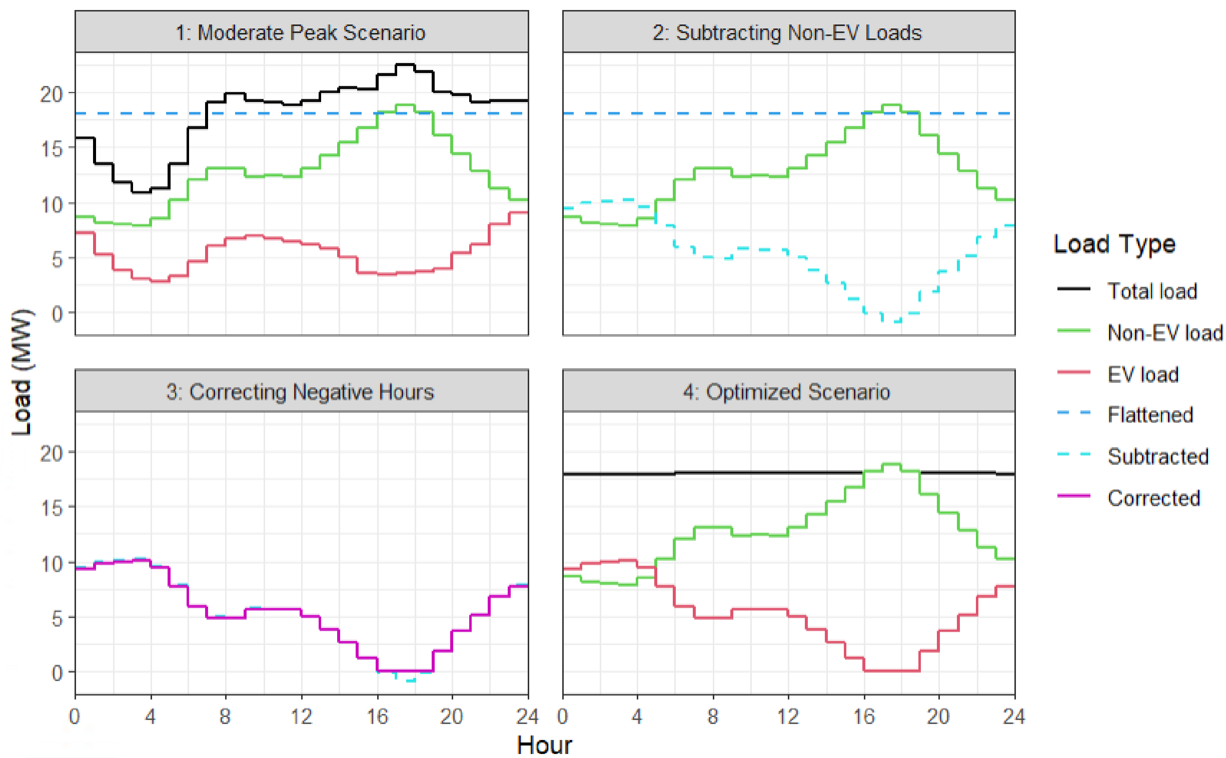
We call this additional electric vehicle behavior scenario the Optimized scenario. We construct the Optimized load shape using a similar method to our construction of the Managed load shape, described in Section 2.5.2 of the Main Body and Appendix D.2.2. At the point that we construct the Optimized load shape, we have already calculated the hourly peak-day non-EV load for each circuit in each year, as well as the peak-day EV load for the Moderate Peak charging behavior scenario. To construct the Optimized load shape, we create a flat peak-day load shape which matches the total electricity consumed in our Moderate Peak charging behavior scenario on each circuit. For example, if our peak-day load shape on a given circuit consumes 48 MWh of electricity, we create a new flat load shape of 2 MW each hour. This provides our target load shape: we are optimizing for perfectly flat consumption so as to minimize needed distribution upgrades. We do not consider optimization for any other purpose, such as minimizing generation costs or GHG emissions.

We then subtract the calculated non-EV load shape from this flat load shape. This provides an electric vehicle load shape which perfectly mirrors the projected non-EV behavior on the circuit, while consuming the correct amount of total energy. However, on circuits with low EV load, this may produce a load shape with *negative* consumption in certain hours. In these cases, we set all negative loads to zero, then rescale the load shape so that it still consumes the correct total energy.

In total, this process produces a load shape which either (a) produces a completely flat total load, using EV load to balance out the existing load, or (b) does not contribute at all to peak circuit load, shifting all load away from the existing circuit peak. As discussed earlier, this charging behavior is extremely unrealistic, and would require total participation of all EVs in active managed charging, as well as extremely precise circuit load forecasting which allows charging operators to ensure the circuit does not produce unexpected peaks.

Figure B-1 below shows this process on an example feeder. Panel 1 shows the non-EV loads on an example circuit, as well as a flat line showing the idealized flat load shape with the same total consumption. Panel 2 shows the subtraction of those non-EV loads from the idealized flat load to create an EV load shape. Note that the EV load shape is negative for three hours at peak time. Panel 3 shows that EV load shape with a corrected version where negative hours have been set to zero and the overall load shape has been slightly scaled down to maintain the correct total consumption. Panel 4 shows the resultant total load, which is nearly flat except for a small number of hours when the non-EV consumption exceeds the average load.

Figure B-1: Constructing feeder-specific, idealistic optimized EV charging load shapes.



B.2. Results of optimized charging scenario

Figure B-1 shows cost results for this scenario and includes cost results for the Moderate Peak and Managed scenarios for comparison. Table B-2 shows rate impact results for this scenario.

Table B-1: Cost results for the optimized scenario in billions of dollars.

UPGRADE COSTS	**2030**			**2035**			**2040**		
in 2025 $BILLION	AAFS 2.5	AAFS 3	AAFS 4	AAFS 2.5	AAFS 3	AAFS 4	AAFS 2.5	AAFS 3	AAFS 4
Moderate Peak Shape	**4.6**	**4.9**	**5.6**	**11.7**	**13.6**	**14.9**	**21.9**	**24.6**	**25.3**
PG&E	2.5	2.5	2.9	6.7	7.6	8.3	11.7	12.7	13.5
SCE	1.8	2.1	2.4	4.3	5.2	5.8	8.7	10.2	10.4
SDG&E	0.3	0.3	0.3	0.7	0.8	0.8	1.5	1.7	1.4
Managed Shape	**3.1**	**3.4**	**4.0**	**8.6**	**10.4**	**11.6**	**17.0**	**19.6**	**20.4**
PG&E	1.8	1.8	2.1	5.5	6.3	7.0	10.0	11	11.8
SCE	1.2	1.5	1.8	2.9	3.8	4.3	6.2	7.6	7.8
SDG&E	0.1	0.1	0.1	0.2	0.3	0.3	0.8	1.0	0.8
Optimized Shape	**2.2**	**2.3**	**2.9**	**6.1**	**7.5**	**8.4**	**11.3**	**13.9**	**14.6**
PG&E	1.2	1.1	1.4	4.1	4.7	5.3	7.3	8.6	9.2
SCE	1.0	1.2	1.5	1.9	2.6	3.0	3.7	4.8	5.1
SDG&E	0.0	0.0	0.0	0.1	0.2	0.1	0.3	0.5	0.3

Table B-2: Rate results for the Optimized scenario.

Rate Impacts	**2030**			**2035**			**2040**		
in cents / kWh	AAFS 2.5	AAFS 3	AAFS 4	AAFS 2.5	AAFS 3	AAFS 4	AAFS 2.5	AAFS 3	AAFS 4
Moderate Peak Shape									
PG&E	-1.9	-2.1	-2.0	-2.8	-2.9	-2.8	-3.4	-3.6	-3.5
SCE	-1.6	-1.7	-1.4	-2.2	-2.3	-1.7	-2.1	-2.3	-1.7
SDG&E	-2.1	-2.2	-1.8	-3.2	-3.4	-2.7	-3.9	-4.0	-3.4
Managed Shape									
PG&E	-2.1	-2.2	-2.2	-3.0	-3.1	-3.0	-3.7	-3.8	-3.7
SCE	-1.7	-1.9	-1.6	-2.5	-2.6	-2.1	-2.7	-2.8	-2.2
SDG&E	-2.3	-2.4	-2.0	-3.7	-3.9	-3.2	-4.4	-4.5	-3.8
Optimized Shape									
PG&E	-2.2	-2.4	-2.3	-3.3	-3.5	-3.4	-4.1	-4.2	-4.1
SCE	-1.7	-1.9	-1.6	-2.8	-3.0	-2.4	-3.2	-3.4	-2.8
SDG&E	-2.3	-2.5	-2.0	-3.8	-4.0	-3.4	-4.7	-4.9	-4.2

Appendix C Data sources and data processing in detail

The CEC, the DMV, and the three major electric IOUs – PG&E, SCE, and SDG&E – provided the majority of the data we used in DGEM 2025. We also accessed additional information from public sources, reports, and stakeholders. This section details all the data we used in the core modeling for DGEM 2025, as well as our methods for processing the data. For the data and inputs we used in the rate modeling, see Appendix D.

C.1. Utility provided data

PG&E, SCE, and SDG&E each provided the following data sets. The exact data reported by each utility is discussed in more detail below:

- **Feeder loading data:** The hourly electrical load across a multi-year span on each distribution feeder operated by the utility.
- **Ratings data:** The rating of each feeder and substation operated by the utility.
- **Hierarchy data:** The name of the substation providing power to each feeder operated by the utility.
- **Location data:** The location of each feeder operated by the utility.
- **Annual energy consumption data:** The annual energy consumption of each customer class (commercial, residential, and low income) on each feeder in 2023.
- **Cost data:** Costs for all major new feeder and feeder upgrade projects over the last few years.

The first five of these data sets each contain feeder identifiers, which must be matched across all the data sets. Not all feeders are present in all data sets; our study excludes those feeders which could not be matched to all data sets. We requested information from the utilities about those excluded feeders, and the utilities provided justifications for the absence of unmatched feeders from their data sets. For example, some feeders are not currently in operation, and so would, for example, appear in ratings data as soon to be operational, but not in feeder-level net load data, which only represents currently operational assets. Between the relatively low proportion of missing feeders and the justifications provided by the utility, we do not believe that these unmatched feeders suggest any significant issues with the underlying data quality.

C.1.1. Matching and joining data sets

Because each set of data comprises a slightly different set of feeders, the overlap between all sets is not total. By the time we begin modeling electric load, the number of feeders which are present in all datasets is 6 – 15% smaller than the average number of any individual set. This relatively small attrition indicates that the majority of our data is consistent and high quality across data sets.

Table C-1: Feeder attrition across data sets.

Data Set	PG&E	SCE	SDG&E
Hierarchy	3,486	4,196	829
Ratings	4,659	Same as hierarchy	Same as hierarchy
Loading	3,142	4,196	809
AEC	3,335	4,617	1,056
Location	3,140	4,333	796
Final - Merged	3,005	4,054	781
Approximate Attrition	15%	6%	10%

C.1.2. Feeder loading data spans

The IOUs provided feeder-level net loading data in response to data requests. Table C-2 summarizes the time range of load measurements spanned by each data set and the time resolution of said measurements.

Table C-2: Feeder-level net loading data details per IOU.

IOU	Data range	Observations per year
PG&E	1/1/2020 – 9/10/2023	8,760 (hour interval)
SCE	1/1/2020 – 12/31/2024	8,760 (hour interval)
SDG&E	1/1/2018 – 1/1/2025	105,120 (5-minute interval)

C.1.3. PG&E data in detail

PG&E provided us with the following information:

1. Hierarchy data: for each feeder, the name and number of the substation it receives power from, provided in June 2024.
2. Infrastructure load ratings, representing thermal limits, for each feeder, bank, and bank group for summer and winter, provided in June 2024.
3. 8,760-hour AMI net loading data for each feeder, provided in June 2024. These data span from 2020 to 2023, and were created by PG&E by aggregating AMI data to the feeder level.
4. AEC data for each feeder, broken down by customer class (e.g. residential, commercial, etc.), for the year 2023, provided in June 2024.

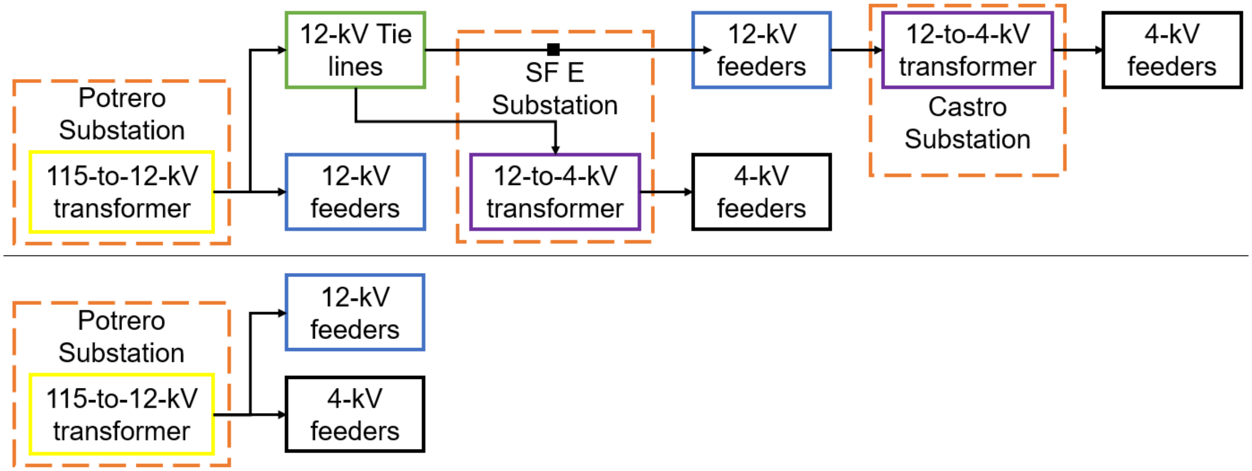
5. Spatial locations of each feeder, provided as part of the confidential version of the Q4 2023 Wildfire Mitigation Plan.
6. Cost data for every new feeder constructed between Q1 2022 and Q3 2024, except those installing less than 500 circuit feet of primary feeder, provided in February 2025. This data set included feeder names, lengths, descriptions of work done, and a breakdown of costs between costs done on the feeder and within the substation boundary.

Within DGEM 2025, we calculate the total present substation capacity by summing bank capacities across each substation. However, PG&E conveyed that this type of information is not useful for distribution planning because loading of each bank is important for reliability. While we understand PG&E's concerns with this approach, we use this information not for planning substation builds but to estimate future costs, as discussed in more depth in Appendix D.4.

Some of PG&E's infrastructure in the San Francisco Bay Area has complex hierarchical structures. For example, PG&E's Potrero Substation feeds 12-kV feeders *and* 12-kV tie-lines. The 12-kV tie-lines feed 12-kV feeders connected to the SF E Substation (which are, therefore, not fed by the transformer banks in the SF E substation). The SF E Substation also feeds 4-kV feeders through 12-to-4-kV transformers. Finally, one of the 12-kV feeders wired into the SF E Substation feeds a 12-to-4-kV transformer in the Castro Substation which in turn feeds a 4-kV feeder.

To use the Bay Area feeder data in our study, the hierarchical infrastructure needs either an advanced topology analysis to allow arbitrary levels of hierarchical information or introducing simplifications to flatten into the typical distribution substation-to-feeder hierarchy. We opt for the latter approach, as depicted in the lower half of Figure . While a significant amount of information is lost, this information is inconsequential since PG&E is unlikely to expand its 12-to-4-kV substations. Instead, consistent with PG&E's (and SCE's) general approach of eliminating 4-kV feeders during upgrades, it is likely that PG&E would replace the 4-kV feeders with 12-kV feeders and eliminate the corresponding substations, if practical. Our cost accounting approach is consistent with this interpretation though it does not account for these replacement costs being higher than typical. This approach eliminated all of PG&E's 4-kV substations from the DGEM study.

Figure C-1: Full hierarchy (top) and assumed hierarchy (bottom).



One shortcoming of our approach is that substation hierarchies above 4 kV are not cleanly mapped. For example, a 21-to-12 kV substation *should* be dealt with using the full hierarchy. Since the full hierarchy approach adds too much complexity to the DGEM, we follow load from a 4 kV feeder to the 12 kV substation but not back up to the 21 kV substation that feeds that 12 kV substation. In practice, there are very few transformers with both high-side and low-side voltages at distribution voltages above 4 kV (between 12 and 44 kV) in PG&E's service territory.

C.1.4. SCE data in detail

SCE provided us with the following information:

1. A list of feeder and substation ratings that also includes hierarchy, provided in June 2024.
2. 8,760-hour AMI net loading data for each feeder, provided in June 2024. These data span from 2020 to 2024 and were created by SCE aggregating AMI data to the feeder level.
3. AEC data for each feeder, broken down by customer class (e.g. residential, commercial, etc.), for the year 2023, provided in June 2024.
4. Spatial locations of each feeder, provided as part of the confidential version of the Q4 2023 Wildfire Mitigation Plan.
5. Cost data for every new feeder constructed between 2020 and 2024 intended to serve load growth, provided in February 2025. This data set included feeder names, lengths, descriptions of work done, and a breakdown of costs between costs done on the feeder and within the substation boundary.

SCE does not rate its feeders differently between winter and summer. Unlike PG&E and SDG&E, SCE selects infrastructure capacity ratings from Planned Loading Limits, which include operational flexibility considerations in addition to factors like thermal limits.

C.1.5. SDG&E data in detail

SDG&E provided the following information:

5. Feeder net loading SCADA data at 5-minute intervals at the approximate connection of the feeder to the substation. These data span from 2018 to 2024.
6. SDG&E also provided 576-profile loading data for circuits with no SCADA sensors. This smaller set of data is for the year 2023 only.
7. Each feeder's gross load capacity, in MW, and the substation name to which the feeder is connected, as well as aggregate adjusted transformer ratings in MW for each substation, provided in June 2024.
8. AEC data for each feeder, broken down by customer class (e.g. residential, commercial, etc.), for the year 2023, provided in June 2024.
9. Spatial locations of each feeder, provided as part of the confidential version of the Q4 2023 Wildfire Mitigation Plan.
10. Cost data for every new feeder constructed between 2021 and 2024, intended to serve more than 1 MW of load growth. This data set included feeder names, lengths, descriptions of work done, and a breakdown of costs between costs done on the feeder and within the substation boundary.

SDG&E also provided a list of feeders which they stated, for various reasons, should not be considered for modeling. We excluded these feeders from our analysis. Like PG&E, SDG&E draws infrastructure capacity limits from thermal limits.

C.2. Vehicle data

DGEM 2025 uses vehicle data provided to the CPUC by the California DMV in 2024. The CPUC shared the data set with Cal Advocates. This data set contains the address, class, gross vehicle weight rating, body style, and body type of every registered vehicle in California in 2022. We also use this data as a proxy for building type data; we assume any address with a unit number is a multi-unit building, and any address without a unit number is a single-unit building.

C.2.1. Geocoding and matching vehicles

Cal Advocates used StreetMap Premium, an ESRI tool, to match each address to a geographic latitude and longitude. This matching process is called geocoding. Of the 30,834,731 records originally included in the DMV dataset, we could not geocode 653,178 (2.1%) of the records. This reduces the functional number of vehicles in the study to 30,181,553. We therefore assume our existing vehicle counts are undercounts by 2.1%.

We divided these vehicles, now each associated with a latitude and longitude, by IOU service territory. We removed vehicles not registered within PG&E, SCE, or SDG&E's service territory from the data set, resulting in 75.6% of the original vehicles being retained in the study. Finally, we matched vehicle registration locations with both California census tracts and with the nearest feeder; we preserved all vehicles through this step.

C.3. IEPR data

The CEC provided Cal Advocates with a variety of data outputs that the CEC used in their own electric sector modeling for the 2023 IEPR. The CEC generated all of these data outputs with their own complex methodologies and input data sets, through a transparent process with many opportunities for stakeholder engagement. The CEC provided the following data:

1. **Statewide and IOU-specific hourly load forecasts from 2023 to 2040.** These load forecasts contained hourly total load estimates for each hour of each year from 2023 to 2040, for PG&E, SCE, SDG&E, and California overall.[115] The CEC provided the total net load included in their forecast, as well as subcomponents of the forecast, including LD EVs, MDHD EVs, and the AAFS, Additional Achievable Energy Efficiency (AAEE), and Additional Achievable Transportation Electrification (AATE) load modifiers. DGEM uses only these load forecasts for the Planning Scenario, which uses AAFS Scenario 3, AAEE Scenario 3, and AATE Scenario 3.

2. **Annual HVAC and water heating energy consumption forecasts for each BCZ in California from 2023 to 2040, for AAFS Scenarios 2.5, 3, and 4.** These AEC forecasts are intermediate results that the CEC used in its IEPR modeling and that we repurposed for our own BE modeling.

3. **Estimated hourly load shapes for HVAC and water heating consumption, for a single year**. The CEC modeled these load shapes based on 2018 data. The CEC modifies the load shapes for their own forecasting for each future year, but we used only this single starting load shape for our own modeling.

4. **Forecasted EV stock and characteristics.** The CEC provided their forecasted EV stock (including both BEVs and PHEVs) by vehicle type for each year from 2023 to 2040. The CEC also provided estimated annual VMT (including specifically electric VMT for PHEVs) for each vehicle type, and vehicle efficiencies, converting electric power into

[115] All years have the same number of hours; the CEC ignores leap years in their modeling.

VMT, for each year from 2023 to 2040. We assumed a charging efficiency of 1, meaning no significant power loss at the charger.

C.4. ACS census data

DGEM uses publicly available data from the 2016-2020 American Community Survey as inputs for our EV propensity model.[116] These data provide averages in each California census tract of the following variables: household income, household education, home ownership, and commute times. The ACS provides demographic and socioeconomic factors at the Census block group level, the most granular scale provided by the Census Bureau and the most reliable dataset at a scale closest to the household scale. The Census Bureau defines a block group as a statistical division of census tracts that generally contain between 600 and 3,000 people.[117]

C.5. Infrastructure cost data drawn from EIS Part 1

DGEM 2025 supplements utility-provided cost data (detailed above in Appendix C.1) with inputs from Kevala's EIS Part 1. We used much of this supplemental data in DGEM 2023 as well. For DGEM 2025, we prioritized updating feeder cost over substation cost data, so we performed only a partial update to substation cost data. We use Kevala data for the following types of cost:

Table C-3: Kevala data used for DGEM 2025.

<table>
<tr><th>Cost type</th><th>Condition cost occurs under</th></tr>
<tr><td>Unit cost of a new substation transformer bank</td><td>Substation overload (i.e., sum of loads of feeders connected to substation exceed that substation's maximum capacity)</td></tr>
<tr><td>Substation upgrade frequency: the probability of needing to construct a new substation in order to accommodate a new transformer bank</td><td rowspan="2">Any substation-related costs; we multiply these two terms and add the result to the unit cost of any other upgrade with some facility-specific nuance (see D.4 for further information)</td></tr>
<tr><td>Substation marginal cost: the cost of building a new substation</td></tr>
<tr><td>Secondary ratio: the ratios of costs spent on primary feeder and substation infrastructure to additional costs spent on secondary feeder infrastructure</td><td>Any primary feeder or substation upgrade (see D.4 for further information)</td></tr>
</table>

[116] U.S. Census Bureau, 2016-2020 5-year ACS data. Available at: https://data.census.gov/. At the time of carrying out the DGEM 2025 EV propensity modeling, the 2016-2020 5-year ACS data were the most up-to-date dataset available.

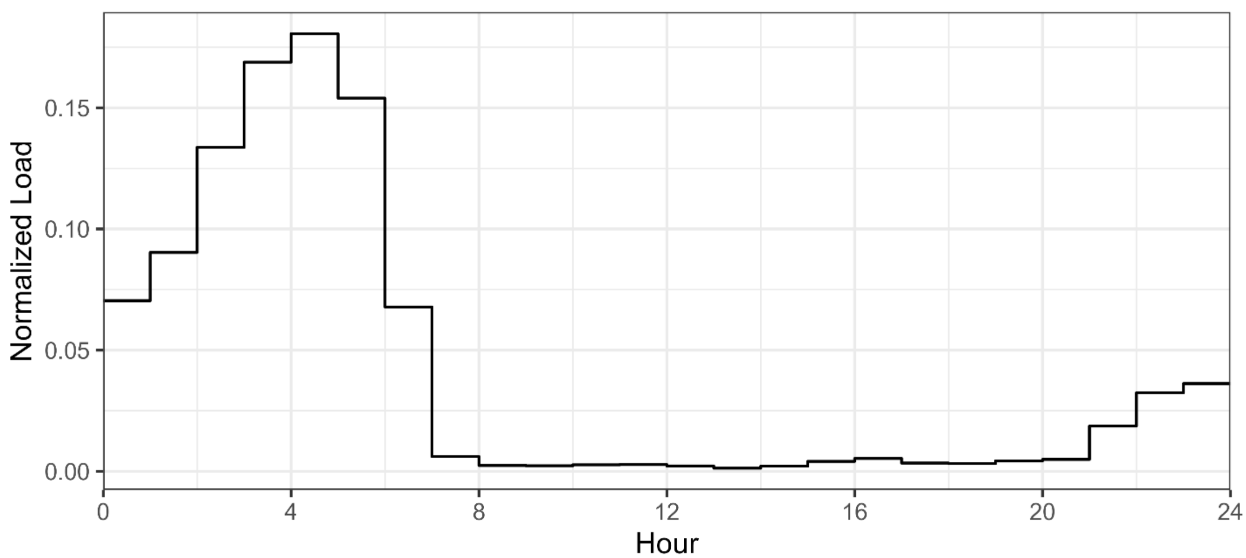
[117] U.S. Census Bureau, *Glossary*, n.d. Available at: https://www.census.gov/programs-surveys/geography/about/glossary.html#par_textimage_4.

For these cost categories, we also used Kevala EIS Part 1 data in DGEM 2023. In DGEM 2025, we changed the interpretation, aggregation, and use of some of these data. See D.4 for further information.

C.6. WeaveGrid cohort data

WeaveGrid, an electric vehicle managed charging provider, provided Cal Advocates with a dataset containing one month of aggregated, normalized charging data from each of four pilot cohorts. These pilot cohorts contained optimizations for different degrees of managed charging. Cal Advocates did not use any of this data directly as an input into DGEM, but we did inspect the data to learn about the behavior of enrollees in a managed charging program. We used a cohort of drivers enrolled in a TOU rate and a program of distribution-focused active managed charging as our example. The aggregated load shape over two months of weekday charging is shown below.

Figure C-2: Aggregated load shape provided by WeaveGrid.



This load shape demonstrates the following elements, which we used in our own managed charging load shape modeling:

- An on-peak charge rate of under 0.5% of daily charge per hour, sustained over 13 hours
- An off-peak charge rate of over 15% of daily charge per hour, sustained over 3 hours

In order to produce a slightly less optimized load shape to avoid overfitting to extremely specific grid conditions on some circuits, we modified these constraints: our on-peak low-charge segment is only 10 hours, and our off-peak high charge segment is extended to 5 hours.

Appendix D Methodology in detail

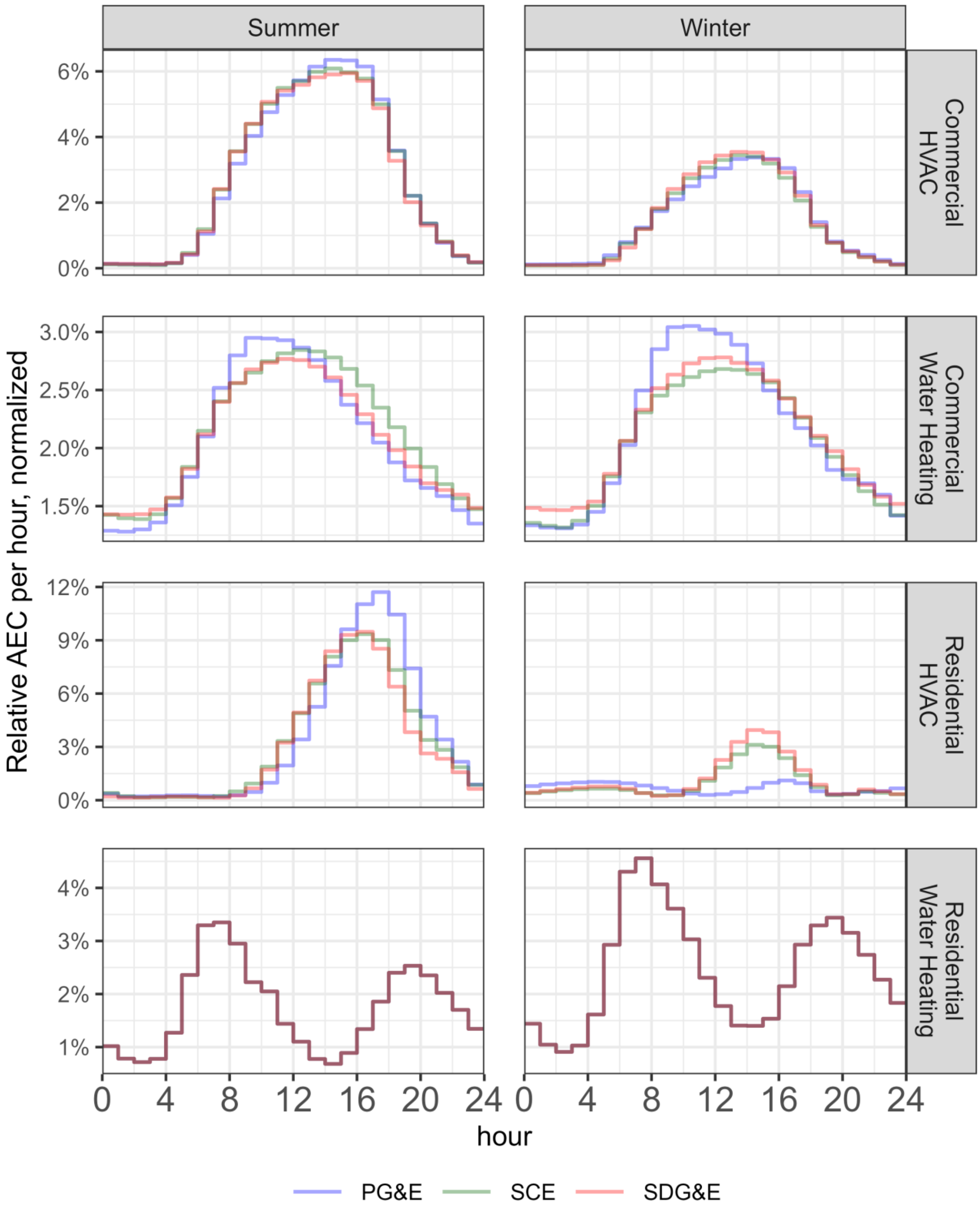
D.1. Phase 1: BE modeling in further detail

Section 2.4 of the Main Body and Box 2-2 of the Main Body together provide a complete description of our BE modeling. Here we provide example graphs of our 48-hour BE load shapes for additional context.

D.1.1. BE load shapes

DGEM 2025 considers two end uses of BE load broken down by season and customer class. The two end uses are HVAC and water heating. The two seasons are the same as the rest of DGEM 2025: summer (May-October) and winter (November-April). In allocating consumption to feeders, we consider three customer classes: residential, commercial, and low income. We use the same load shapes for residential customers and low income customers.

Figure D-1: BE load shapes.



D.2. Phase 2: EV load modeling in further detail

Section 2.5 and Box 2-2 of the Main Body provide a description of our EV modeling. We here provide additional details on two elements of our EV modeling: the logistic regression which produces our personal vehicle propensity model, and the construction of the Managed scenario load shape.

D.2.1. EV Personal vehicle propensity model

In order to estimate the future locations of electric vehicles, we use location-specific factors which can be used to estimate future electric vehicle adoption. Researchers have found several factors which are correlated with personal LD EV adoption. We selected factors that corresponded to higher rates of EV adoption and were available at a spatial scale that corresponded to the household scale of the DMV dataset. For these reasons, we considered the following factors in the LD propensity model: income, commute length, educational attainment, home ownership, building type, and household size. We used the U.S. Census Bureau's five-year American Community Survey (ACS) data for 2016-2020 and the DMV vehicle registration data set.[118] Table D-1 summarizes the factors we considered in the DGEM's propensity regression model for personal vehicles, along with their justification, source, and the spatial scale at which data were available.

[118] U.S. Census Bureau, 2016-2020 5-year ACS data. Available at: https://data.census.gov/. At the time of carrying out the DGEM 2025 EV propensity modeling, the 2016-2020 5-year ACS data were the most up-to-date dataset available.

Table D-1: Factors included in DGEM 2025's propensity regression model.

Factor	Justification	Literature Citations	Data Source	Spatial Scale
Household income	Studies have correlated higher income with higher rates of EV adoption.	Coffman et al., 2018; Gehrke et al., 2021; Langbroek et al., 2017; and Westin et al., 2018.[119]	ACS 5-year estimate (2016-2020)	Census block group
Educational attainment	Studies have linked higher rates of education with an increase in EV ownership.	Langbroek et al., 2017; Coffman et al., 2018; and Westin et al., 2018.[120]	ACS 5-year estimate (2016-2020)	Census block group
Home ownership	Homeownership has been connected to EV adoption.	Campbell et al., 2012; and Tiwari et al., 2020.[121]	ACS 5-year estimate (2016-2020)	Census block group
Commute time	Studies have found that EVs are typically used for shorter and briefer commutes rather than longer commutes.	Coffman et al., 2018; and Jakobssen et al., 2016.[122]	ACS 5-year estimate (2016-2020)	Census block group

[119] See Michael Coffman et al., *Who Are Driving Electric Vehicles? An Analysis of Factors That Affect EV Adoption in Hawaii*, The Economic Research Organization at the University of Hawaii, May 30, 2018 (Coffman et al.). Available at: http://www.ourenergypolicy.org/wp-content/uploads/2018/06/Hawaii-EVs.pdf; Steven R. Gehrke et al., *Patterns and Predictors of Early Electric Vehicle Adoption in Massachusetts*, International Journal of Sustainable Transportation, June 1, 2022 (Gerhke et al.). Available at: https://www.tandfonline.com/doi/abs/10.1080/15568318.2021.1912223; Joram Langbroek et al., *Electric Vehicle Users and Their Travel Patterns in Greater Stockholm*, Transportation Research Part D: Transport and Environment, May 1, 2017 (Langbroek et al.). Available at: https://doi.org/10.1016/j.trd.2017.02.015; and Kerstin Westin et al., *The Importance of Socio-Demographic Characteristics, Geographic Setting, and Attitudes for Adoption of Electric Vehicles in Sweden*, Travel Behaviour and Society, October 1, 2018 (Westin et al.). Available at: https://doi.org/10.1016/j.tbs.2018.07.004.

[120] Langbroek et al.; Coffman et al.; and Westin et al.

[121] Amy R. Campbell, *Identifying the Early Adopters of Alternative Fuel Vehicles: A Case Study of Birmingham, United Kingdom*, Transportation Research Part A: Policy and Practice, October 1, 2012. Available at: https://doi.org/10.1016/j.tra.2012.05.004; and Vibhor Tiwari et al., *Public Attitudes towards Electric Vehicle Adoption Using Structural Equation Modelling,* Transportation Research Procedia, Recent Advances and Emerging Issues in Transport Research – An Editorial Note for the Selected Proceedings, January 1, 2020. Available at: https://doi.org/10.1016/j.trpro.2020.08.203.

[122] See: Coffman et al.; and Niklas Jakobsson et al., *Are Multi-Car Households Better Suited for Battery Electric Vehicles? – Driving Patterns and Economics in Sweden and Germany*, Transportation Research Part C: Emerging Technologies, April 1, 2016. Available at: https://doi.org/10.1016/j.trc.2016.01.018. Even though these papers find that early EV adopters tend to use their EVs for shorter commutes and trips that take less time, it is important to note that newer EVs have longer battery range, which makes newer EVs able to fill more of the same functions as a conventional vehicle.

Factor	Justification	Literature Citations	Data Source	Spatial Scale
Building type (i.e., stand-alone household or multi-unit dwelling)	Research has found that people who live in stand-alone households are more likely to own an EV than people who live in apartment buildings	Langbroek et al., 2017; Gehrke et al., 2021; and Westin et al., 2018.[123]	2021 DMV vehicle registration dataset	Household

In order to match the socioeconomic data with the registered vehicles, we join vehicles to 2020 Census block groups. The block group level is as close to the household scale that our study can achieve and is the most comprehensive, efficacious dataset on local socioeconomic characteristics available. However, even at this level, our study assumes that all registered vehicles in a block group share the same characteristics.[124]

The ACS does not provide data on building type. Research indicates that owners of single-family homes are more likely to adopt an LD EV, in part because stand-alone houses have more room for EV chargers and more accessible parking for private vehicles. In order to represent building type in the non-fleet propensity model, we distinguish between address types – stand-alone buildings and multi-unit buildings by the presence of a unit number with the address. We employ this method because, to the best of our knowledge, there is no publicly available dataset showing building type (e.g., single family residential, multi-unit dwellings) available for all of California.

We train a logistic regression model on the DMV registration data within the Study Area, achieving the following parameters:

[123] See Langbroek et al.; Westin et al.; and Gehrke et al.

[124] The DGEM's usage of U.S. Census Bureau data for local socioeconomic and demographic information reflects the industry standard. Researchers studying the grid impacts of electric vehicle adoption have made similar assumptions, given the trustworthiness and availability of U.S. Census Bureau data. For example, see Gehrke et al., and Coffman et al.

Table D-2: Logistic regression model parameters.

Term	Coefficient	P Value
Vehicle is registered to building without a sub-address	0.48	0
Share of households earning $150,000 or more annually	0.93	0
Share of households earning $200,000 or more annually	0.24	0
Share of residents with bachelors as highest degree	2.41	5.63E-46
Share of residents with a postgraduate degree	2.53	0
Share of owner-occupied units	-0.07	0
Share of commutes 20-45 minutes	0.29	8.84E-27
Share of commutes 45+ minutes	0.58	3.19E-216

Applying these coefficients to all personal LD non-EV vehicles in our Study Area produces a propensity score for each vehicle.

D.2.2. Construction of the Managed load shape

Section 2.5.2 of the Main Body describes the Managed load shape. Here we describe in more detail our construction of this load shape.

We first construct an unmanaged total load shape for each circuit, representing all loads except for 50% of the LD EV load and 20% of the MDHD EV load. To construct this unmanaged load shape, we use several intermediate outputs of the Moderate Peak EV charging behavior scenario:[125] 24-hour BE, EV, and non-electrification load shapes for all years from 2023 to 2040, for summer and winter, for each circuit. From these load shapes we construct an unmanaged total load shape for each circuit, which is the sum of all these loads *except* for 50% of the LD EV load and 20% of the MDHD EV load (i.e. non-electrification + BE + 0.5 (LD EV) + 0.8 (MDHD EV). We also use the Moderate Peak scenario EV load shapes to calculate the total daily charge necessary to serve 50% of the LD EVs and 20% of the MDHD EVs on each circuit. We refer to this daily charge as the "managed daily consumption."

We use this unmanaged load shape to construct a new load shape which describes the behavior of the 50% of LD EV load and 20% of MDHD EV load actively participating in charging management. Table D-3 describes the characteristics of this load shape.

[125] This process is conducted separately for each BE load level scenario, using the corresponding scenario with the IEPR load shape. For example, the AAFS 3 / Managed scenario load shape is constructed using intermediate products from the AAFS 3 / IEPR scenario modeling.

Table D-3: Description of load shape blocks.

Shape block	Number of hours	Hourly power constraint	Notes
High charge block	5 contiguous hours	At most 15% of managed daily consumption	On many circuits, this will occur during the early morning, often between 12am and 6am. This is analogous to the super off-peak time during a TOU rate, and is the time with the most distribution capacity available.
Medium charge block	10 contiguous hours, which can be broken by the high charge block	At most 5% of managed daily consumption	On many circuits, this will occur during the late evening and early in the day, often including the period from 10pm to 12am and the period from 6am to 12pm. This is analogous to an off-peak time for a TOU rate when charging is not heavily incentivized or disincentivized.
Low charge block	The remaining 9 hours, usually contiguous, but can be broken by either or both blocks in rare cases.	0.5% of managed daily consumption	On many circuits, this occurs during the afternoon and evening, often from 3pm to 12am. This is analogous to an on-peak time for a TOU rate when charging is disincentivized.

It is very difficult to predict the future behavior of charging vehicles. To our knowledge, there is no industry standard data set or formula which can be used to develop a specific, highly likely flexible load shape given underlying circuit conditions. We construct a shape with this very simplistic structure in order to avoid creating overly specific and unrealistic load shapes in response to very specific circuit conditions, and in order to remain agnostic to the actual implementation method of charging management. For example, in reality, on a given circuit, the best available time for vehicles to charge might be longer or shorter than 5 hours. Similarly, charge rates above 15% of managed daily consumption might be achieved during some hours on some circuits. Certain charging management strategies may allow charging to vary rapidly among adjacent hours. However, the more of these parameters we make flexible in our modeling, the more circuit-specific and difficult to achieve the load shape becomes. 0 provides the results of a scenario with a fully optimized load shape on every circuit, the extreme version of this flexibility. For the Managed scenario, we chose a load shape construction which we believe produces load shapes which are plausible to implement and beneficial to the grid.

In order to compute this load shape, we first construct and place the high charge block at the unique time when it produces the lowest new peak when added to the unmanaged load shape. On circuits with a high proportion of EV load, this new peak may exceed the peak of the existing unmanaged load shape, creating a "timer peak" or "secondary peak." In this case, we reduce the load during the high charge block such that the new peak instead is equal to the existing unmanaged peak.

We then remove the five hours of the unique charge block from the unmanaged load shape and follow the same process to add the medium charge block to the load shape at the unique time when it produces the lowest new peak. This means the ten-hour medium charge block may surround (and usually does) the five-hour high charge block – for example, the five-hour charge block might be 1am to 6am while the medium charge block is 9pm to 1am and 6am to 12pm. The remaining hours form the low charge block.

Finally, we scale the load shape to match the actual managed daily consumption. If both charging blocks were placed in the load shape without any reduction due to a secondary peak, the constructed load shape will have an actual consumption equal to 129.5% of intended consumption.[126] In this case, we scale the load shape proportionally down to 100% consumption. If charging blocks were reduced to below the actual AEC, we add a flat rate to all hours to match the correct consumption.

This process provides our load shape which we apply to 20% of MDHD and 50% of LD vehicle load in our study. We add this constructed load shape to the unmanaged load shape on each feeder to calculate the total load.

D.3. Phase 3: non-electrification load and peak load on each circuit in further detail

Section 2.6 of the Main Body describes our construction of non-electrification load, and the summation of non-electrification load, BE load, and EV load to calculate the peak load on this circuit. We here elaborate on our construction of 48-hour profiles from historic load.

As described in Appendix C.1.2, our historic load data spans multiple years for each IOU. We first construct a 48-hour historic load profile for each year of data provided, for each asset in the data set. This 48-hour load profile covers 24 hours in summer (May-October) and 24 hours in winter (November-April). For a given year, we select the highest-load hour in each category. Take our 2022 SCE load data for a given asset as an example. For the 12am summer hour in the 2022 SCE load profile, we look at all loading values on that asset at 12am between May and October of 2022. If the maximum loading is 1.23 MW, then 1.23 MW becomes the value for the 12am summer hour in our collapsed 48-hour load profile. We treat SDG&E's data slightly

[126] This oversizing is intentional, in order to allow for some variability between the exact amount of consumption in the high charging block and the medium charging block.

differently, as SDG&E measures loading in 5-minute increments rather than hourly increments. To avoid being overly sensitive to noise and small data errors, we take the 99th percentile value rather than the maximum from SDG&E's data for each year.

Repeating this for each asset and each year of data, we now have a 48-hour load profile for each asset for each year of data. We next collapse all of these years of data to a single 48-hour load profile by taking the median across all years. We take a median to avoid being overly affected by extreme weather; were we to take only the most recent year's data (2023), our results would be artificially lowered as 2023 had lower average loading than the years surrounding 2023. For example, imagine that we have loading data for only three years for a given feeder, and we have constructed a summer load profile for each of those three years, with the 12am summer hour for that feeder having a value of 1.2 MW in 2021, 1.4 MW in 2022, and 1.1 MW in 2023. In that case, we would select 1.2 MW, the median of those values, as the value for our multi-year load profile. We repeat this for each hour; each hour may be selected from a different year of data, varying by feeder.

In addition to calculating the peak load on each feeder, we also sum the peak load of all connected feeders to estimate the peak load on each substation. SCE and SDG&E provided substation rating data, and we abstract PG&E substation ratings by summing the individual transformer ratings that PG&E provided us.

D.4. Phase 4: estimating mitigation costs in further detail

Section 2.7 of the Main Body describes our estimates of the number of necessary mitigations to address projected overloads and our estimates of the cost of each overload. Here we provide a more detailed comparison of our cost modeling changes between DGEM 2023 and DGEM 2025. While DGEM 2023 estimated the cost of constructing new feeders by using per-unit length cost data and using different length scenarios, DGEM 2025 draws on the cost data of recent new feeder projects. Figure D-2 shows cost results through time for all nine main analysis scenarios for each IOU. Table D-4 lays out the changes in each cost category.

Figure D-2: Estimated distribution grid upgrade costs by adoption scenario.

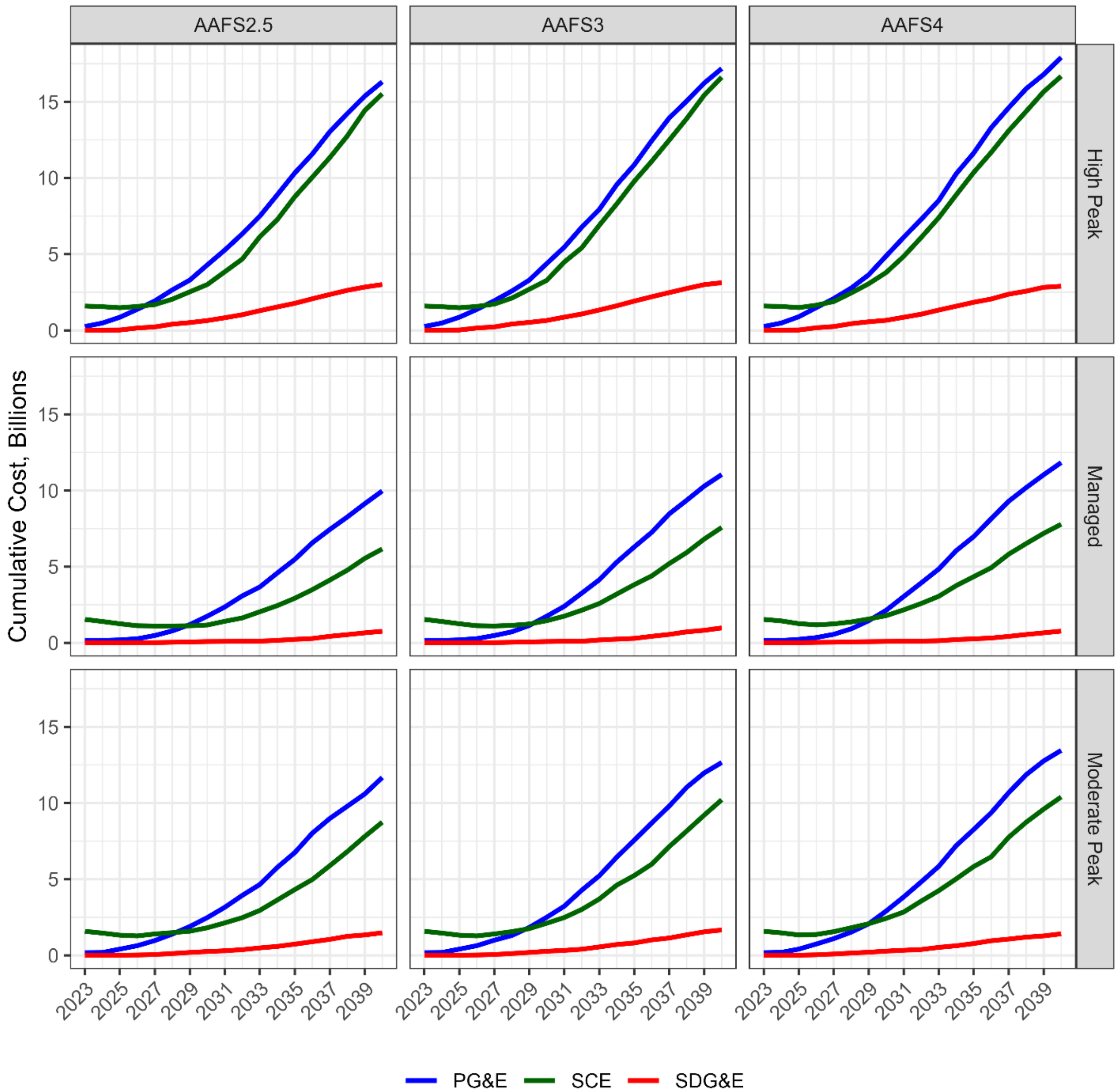


Table D-4: Summary of 2023 and 2025 sources and calculations per cost category.

	Unit Cost Represents the cost of building a new 12kV primary feeder, or a new transformer bank.	**Probability of Upgrade** Represents the probability of a substation upgrade associated with a new feeder (e.g. expanding the substation), or the probability of needing to build a new substation.	**Substation Marginal Cost** Represents the cost of substation-related upgrades associated with a new feeder, or the cost of building a new substation.	**Secondary Ratio** Represents the cost of the secondary feeder, as a ratio of primary + substation costs.
Feeders	**2023** Obtained primary feeder unit costs by averaging PG&E and SDG&E overhead and underground conductor unit costs and estimating the length of future feeders, using three cost scenarios.	**2023** Was not considered for feeders; assumed to be zero.	**2023** Was not considered for feeders; assumed to be zero.	**2023** Was calculated as per-IOU median of 2035 projections of secondary-to-primary cost ratios (tables 3 and 4)[127] over Kevala scenarios 2-5.
	2025 Now calculated as the mean cost of new feeder projects, for all kV inputs and all circuit lengths.	**2025** Now the ratio of feeder upgrade projects which involved substation work to all new feeder projects we received data for.	**2025** Now calculated as the mean of substation-related costs for new feeder projects.	

[127] See EIS Part 1 at 27 and 28.

<table>
<tr><th></th><th><u>Unit Cost</u>
Represents the cost of building a new 12kV primary feeder, or a new transformer bank.</th><th><u>Probability of Upgrade</u>
Represents the probability of a substation upgrade associated with a new feeder (e.g. expanding the substation), or the probability of needing to build a new substation.</th><th><u>Substation Marginal Cost</u>
Represents the cost of substation-related upgrades associated with a new feeder, or the cost of building a new substation.</th><th><u>Secondary Ratio</u>
Represents the cost of the secondary feeder, as a ratio of primary + substation costs.</th></tr>
<tr><td rowspan="2"><u>Substations</u></td><td>2023
Was calculated as the cost of a new transformer bank using Kevala’s data.</td><td>2023
Provided on a per-IOU basis by Kevala’s EIS Part 1 team.</td><td>2023
Used Kevala’s substation unit costs data.[128]</td><td rowspan="2">2025
Now calculated as the median of 2025, 2030, and 2035 projections of secondary-to-primary cost ratios (tables 3 and 4)[129] over Kevala scenarios 1-5. The same value (0.4758) is used for both feeder and substation upgrades, for all three IOUs.</td></tr>
<tr><td>2025
Now calculated as the median of Kevala’s unit costs for a new transformer bank</td><td>2025
Used the median of Kevala’s three upgrade frequencies (20.4%) for all IOUs.</td><td>2025
Now calculated as the median of Kevala EIS Part 1 new substation costs for all three IOUs, rather than per-IOU.[130]</td></tr>
</table>

To calculate total costs, we first calculate all feeder and substation costs, and multiply this total by the secondary ratio to estimate secondary distribution system costs. The total costs for each year are the sum of feeder, substation, and secondary distribution costs.

To find the cost of substation mitigations (triggered whenever the sum of loads of feeders connected to a substation exceeds that substation’s capacity) we use the following equation.

[128] See EIS at 117.

[129] See EIS Part 1 at 27 and 28.

[130] See EIS at 117, Table 17.

$$\begin{aligned}&(\text{Unit Cost}_{\text{transformer bank}} \times \text{ Num. Units})\\&\qquad + \Big[\text{Substation Marginal Cost}\\&\qquad \times \text{Probability of Upgrade} \times \left(1 + \left\lfloor\frac{Num.Units}{2}\right\rfloor\right)\Big]\end{aligned}$$

For substation overloads, the number of units (transformer banks) needed to mitigate an overload is equal to the size of the overload divided by the IOU's size of transformer bank.[131] We consider the substation marginal cost to represent the cost of building an entirely new substation, and the probability of upgrade (a.k.a. substation upgrade frequency) to represent the likelihood that any given substation project involves the construction of an entirely new substation. It is challenging to establish when a new substation might be needed. New substations are expensive for utilities to build. The utility will only build a new substation if it cannot site additional transformers within the existing substation footprint. However, establishing whether there is space in each substation requires a case-by-case study of each substation and requires data which were not available to us. Because of this, we assumed a share (see Table D-4) of new transformers in substations would trigger building a new substation. This share is represented by our "Probability of Upgrade".[132]

There is, however, an additional layer to this simplification. We assume that this "Probability of Upgrade" is proportional to the number of transformer banks a utility needs to mitigate a substation overload. We model this proportionality as one plus half of the number of new substation banks that the utility needs to mitigate the overload, rounded down. This assumes that each substation starts with one transformer bank and has room for two more, after which we calculate marginal costs to either expand the substation or build a new one. In DGEM 2025, the maximum number of new transformer banks needed to mitigate a substation overload is 4. In practice, this means that if a utility needs one or two new substation banks to mitigate a substation overload, we add 20.4% of the estimated cost of a new substation, and if a utility needs three or four new substation banks (which is rare in the model), we add 40.8% of the estimated cost of a new substation.

DGEM 2025 does not consider mitigations which could support multiple feeders or substations. Each overloaded feeder receives at least one corresponding new feeder; each overloaded substation receives at least one new substation bank. This is due to our model's limited spatial

[131] For example, if a substation has a capacity of 100 MW, is loaded by 200 MW, and its IOU uses 28 MW transformer banks, the substation is overloaded by 100 MW, and will require four new transformer banks to mitigate the overload.

[132] See DGEM 2023 at 76.

resolution, and likely causes a systematic overestimation of the number of new pieces of infrastructure. We also do not assess non-wires mitigations, which could include changes to TOU rates that might obviate the need for upgrades, infrastructure such as DERs that may provide mitigations at a lower cost, and load transfers between feeders or substations.

D.5. Phase 5: rate impact in further detail

To estimate the residential rate impact, we account for the expected increase in distribution capital and maintenance expenses allocated to residential rates, plus forecasted transmission and generation costs allocated to residential rates, and weigh them against the forecasted increase in residential electricity sales.

$$\Delta Rate = \frac{RR_{2025} + \Delta RR_{distribution} + \Delta RR_{transmission} + \Delta RR_{generation}}{ES_{2025} + \Delta ES} - \frac{RR_{2025}}{ES_{2025}}$$

The incremental change in residential rate is equal to the new residential rate (the left half of the equation) minus the 2025 residential rate (the right half of the equation). The 2025 rate is equal to the 2025 revenue requirement (RR_{2025}) divided by the 2024 energy sales (ES_{2025}). We allocate all rate components, including sales and revenue requirements, to residential using the currently representative factors for each IOU. We calculate the new rate from the new revenue requirement divided by the new energy sales. The new revenue requirement is equal to the 2023 revenue requirement plus the incremental revenue requirements from distribution, transmission, and generation (the three ΔRRs). The new sales are equal to the 2023 sales plus the incremental sales associated with electrification (ΔES). Table D-5 provides the 2025 sales and revenue requirements.

Table D-5: 2025 residential revenue requirements and sales for the three IOUs.

IOU	System residential revenue requirement ($ Billion)	System residential sales (GWh)
PG&E	$8.263	26,463
SCE	$8.209	26,720
SDG&E	$1.889	6,059

We calculate the revenue requirement for distribution infrastructure by depreciating capital over forty years and including the depreciation and the return on undepreciated capital (at the weighted-average cost of capital) in the revenue requirement. To account for distribution O&M, we assume an incremental O&M cost of 3.5 percent per year on the undepreciated value of incremental capital. This is informed by data from the most recent general rate cases of PG&E,

SCE, and SDG&E and accounts for wildfire mitigation costs.[133] We add the residential component of this cost to the revenue requirement.

Table D-6 shows the weighted-average cost of capital and the residential allocation of distribution costs alongside the residential allocation of generation costs (discussed later).

Table D-6: Weighted average cost of capital and residential allocation of distribution costs for the three IOUs.

IOU	Weighted-average cost of capital[134]	Residential allocation of distribution costs	Residential allocation of generation costs
PG&E	7.80%	41%	41%
SCE	7.87%	49%	43%
SDG&E	7.67%	43%	40%

We account for transmission costs through the TAC, which the CAISO projects to rise to $17.04 per megawatt hour (MWh) in 2029 and $20.86/MWh in 2035.[135] We use this growth rate to forecast increases in the current IOU-specific TAC and then multiply by the incremental energy sales (ΔES) to account for the new transmission revenue requirements associated with the sales.

Table D-7 summarizes the TACs we use in our rates analysis.

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[133] For PG&E, we used data from A.21-06-022. Electric distribution rate base for 2020 through 2023 was drawn from workpapers to Exhibit PG&E-10, Chapter 15 (at 15-1, 15-4, 15-7, and 15-10). Distribution expenses were drawn from workpapers to Exhibit PG&E-4, Chapter 2 (at 2-2) excluding costs of "Customer Request & Load Growth" and "Risk Reduction." For SCE, we used data from A.23-05-010. Distribution rate base for 2025 was drawn from workpapers to Exhibit SCE-07 Vol.02 Book A (at 11) and compared to O&M expenses including inspections and maintenance, substation, poles, vegetation management, and "other" from Exhibit SCE-02 Vol. 10 at 1. For SDG&E, we used data from A.22-05-016. Distribution capital for 2021-2024 were drawn from workpapers to Exhibit SDG&E-35-R (at 12) and compared to distribution capital expenses, from workpapers to Exhibit SDG&E-12-R (at 2) plus wildfire expenses from workpapers to Exhibit SDG&E-13-R at 1.

[134] Energy Division, *Resolution E-5306. Approves Energy Division's non-standard disposition that approved Pacific Gas and Electric, San Diego Gas and Electric, Southern California Edison, and Southern California Gas Company Implementation of the Cost of Capital Formula Adjustment Mechanism for 2024*, July 11, 2024 at 4. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M536/K032/536032007.PDF.

[135] California ISO, *2023-2024 Transmission access charge forecast model* data library, September 20, 2024. Available at: https://www.caiso.com/library/2023-2024-transmission-access-charge-forecast-model.

Table D-7: Summary of TACs we use in our rate model, in cents per kWh.

Year	PG&E	SCE	SDG&E
2025	0.8	0.4	2.0
2026	0.8	0.4	2.1
2027	0.8	0.4	2.2
2028	0.9	0.4	2.5
2029	1.1	0.5	2.8
2030	1.1	0.5	2.9
2031	1.1	0.5	3.0
2032	1.2	0.5	3.0
2033	1.2	0.6	3.2
2034	1.3	0.6	3.4
2035	1.3	0.6	3.4
2036	1.3	0.6	3.4
2037	1.3	0.6	3.3
2038	1.2	0.6	3.3
2039	1.3	0.6	3.4
2040	1.3	0.6	3.5

We derive generation costs from the 2024 avoided cost calculator (ACC),[136] including costs associated with generation energy, generation capacity, ancillary services, greenhouse gases, and high global warming potential gases. Generation costs are a pass-through cost, so the revenue requirement is equal to the cost per MWh of generation multiplied by the incremental energy sales (ΔES). We calculate the cost per MWh of generation from the hourly ACC values weighted by the hourly peak consumption change (i.e., the electrification load minus additional self-generation, energy efficiency, etc.).[137] We use the same ACC values for all IOUs as we observe little variation in weighted-average price across the three IOUs.[138]

Table D-8 summarizes the average prices from the ACC and the weighted average prices that we use in our rate model. We calculate the revenue requirement from incremental generation as the product of the weighted-average price, the incremental sales (see below), and the share of generation costs that each IOU allocates to residential customers.

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[136] See CPUC, *2022 Distributed Energy Resources Avoided Cost Calculator Documentation,* June 22, 2022. Available at: 2022-acc-documentation-v1a.pdf.

[137] Average hourly consumption would provide a better representation. But since DGEM does not produce full hourly load profiles, only hourly peak loads, these data were not available.

[138] We used values for SCE climate zone 9.

Table D-8: Summary of ACC prices and weighted average prices we use in our rate model, in cents per kWh.

Year	Average price	Weighted-average price, High Peak load shape	Weighted-average price, Moderate Peak load shape	Weighted-average price, Managed load shape
2025	7.9	8.4	8.3	8.3
2026	8.5	9.2	9.1	9.1
2027	9.2	10.1	9.9	9.9
2028	9.1	10.1	9.9	9.8
2029	9.4	10.2	10.0	10.1
2030	11.1	12.3	11.9	12.0
2031	11.8	13.2	12.8	12.9
2032	12.2	13.9	13.3	13.4
2033	13.1	15.1	14.4	14.5
2034	12.1	13.9	13.1	13.2
2035	12.8	14.7	13.9	14.0
2036	13.5	15.5	14.6	14.7
2037	14.3	16.4	15.3	15.5
2038	15.0	17.3	16.1	16.3
2039	15.8	18.3	17.0	17.3
2040	16.5	19.2	17.7	18.1

In order to forecast residential electricity sales, we apply the growth rate of energy sales to the baseline system residential sales for each IOU. One limitation of the DGEM is that it does not estimate total energy consumption directly, only hourly total peaks and annual EV energy. We use the annual EV energy from the DGEM combined with non-EV forecasts from the 2023 IEPR hourly and annual tables provided by the CEC to derive total energy to serve load (see Appendix C.3).