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California Energy Commission

COMMISSION REPORT

Draft 2025 Integrated Energy Policy Report

Gavin Newsom, Governor

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ABSTRACT

The *2025 Integrated Energy Policy Report* discusses the California Energy Demand Forecast, accelerating interconnection and energization, California's progress toward the load-shift goal, and advancing clean and renewable hydrogen for electricity and transportation. It also includes appendices on Clean Transportation Program benefits, firm zero-carbon resources, and fossil gas price forecasts.

Keywords: California Energy Demand Forecast, energization, interconnection, load-shift goal, Hydrogen, Clean Transportation Program benefits, firm zero-carbon resources, fossil gas price forecasts

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TABLE OF CONTENTS

Page

LIST OF FIGURES

Page

LIST OF TABLES

Page

EXECUTIVE SUMMARY

The California Energy Commission (CEC) continues to advance the transition to a clean, affordable, and reliable energy system that benefits all Californians. The state remains steadfast in its commitment to climate goals, including achieving carbon neutrality by 2045 (Assembly Bill 1279, Muratsuchi, Chapter 337, Statutes of 2022). The CEC's demand forecast is a central input into state processes that plan for California's electricity system to use renewable and zero-carbon sources for 90 percent of its electricity by 2035 (Senate Bill 1020, Laird, Chapter 361, Statutes of 2022) and 100 percent by 2045 (Senate Bill 100, De León, Chapter 312, Statutes of 2018). Achieving these goals while prioritizing affordability and reliability requires careful planning, strong partnerships, and strategic investments in infrastructure and in research and development.

The *2025 Integrated Energy Policy Report (2025 IEPR)* provides updates on, and recommendations for, advancing the state's energy goals. The latest forecast of the state's energy demand — the 2025 California Energy Demand Forecast — is provided here as a critical element of energy planning. The report also includes updates on efforts to better connect new clean energy sources and loads to the rapidly evolving electricity grid, strategies to optimize the use of clean and renewable electricity, and the potential for using clean and renewable hydrogen to fuel electricity generation and transportation.

The Role of the Energy Demand Forecast

Understanding how California's energy demand will change and grow in the coming years is the backbone of the state's energy planning efforts. The energy demand forecast informs large-scale investments, including in power plants needed to meet the growing energy demand and the infrastructure necessary to deliver electricity to homes, manufacturing, schools, businesses, and more. To serve this need, the CEC develops the California Energy Demand Forecast, referred to hereafter as the "forecast" or the "IEPR forecast." The forecast is an assessment of future energy demand that includes scenarios for various possible futures — an especially useful tool in these times of uncertainty and rapid change.

The CEC, California Public Utilities Commission (CPUC), and California Independent System Operator (California ISO) agreed that the forecast will be used for planning and procurement in the California ISO's transmission planning and the CPUC's Integrated Resource Plan, resource adequacy, distribution system planning, and other planning processes.

The CEC uses the best science available to determine how numerous complex and dynamic factors will affect energy demand. These factors include:

- Changes in the economy and state demographics.
- Projected changes in utility rates and costs.
- Changing temperature trends due to climate change.

- Changes in energy demand from consumer adoption of technologies such as rooftop solar photovoltaic (PV), energy storage, and high-efficiency electric heat pumps (installed to cool and heat homes and other buildings).

Updated annually as part of the IEPR process, the CEC is dedicated to making continual improvements to forecasting methods and developing new products that best serve planning. This year's *IEPR* forecast assesses energy demand trends through 2045 and reflects:

- Improvements to the behind-the-meter (BTM) PV and storage data and account for recent policy changes. BTM refers to the consumer-side of the utility meter and includes, for example, rooftop PV generation, and other resources to supply on-site load.
- Updates on data centers.
- Updates on transportation to reflect recent policy changes.
- Updates on building electrification to reflect the latest information about zero-emission appliance standards and recent policy changes.
- Adds data on expected new energy loads (demand) into the local reliability scenario. (See page 12 for more information.)

The *2025 IEPR* forecast contains three baseline demand forecasts and several scenarios for forecast components that are more uncertain. The scenarios assume varying levels of growth in energy efficiency, fuel substitution (such as switching from gas to electric appliances), transportation electrification, data centers, PV, and storage. For electricity system planning, sets of the baseline forecasts and scenarios are combined into a "planning forecast" and a "local reliability scenario."

The 2025 IEPR baseline forecast projects initially lower near-term growth in annual energy sales compared to the previous forecasts. This is due to economic uncertainty, higher electricity rates, and increased energy efficiency. Deferred adoption of transportation and building electrification measures also cause the planning forecast to be substantially lower than the previous vintage over the entire forecast period. However, significant growth in data centers accounts for much of this difference in the local reliability scenario, since such growth is weighed more heavily in that forecast. The inclusion of known loads pushes the local reliability scenario even higher than the previous vintages.

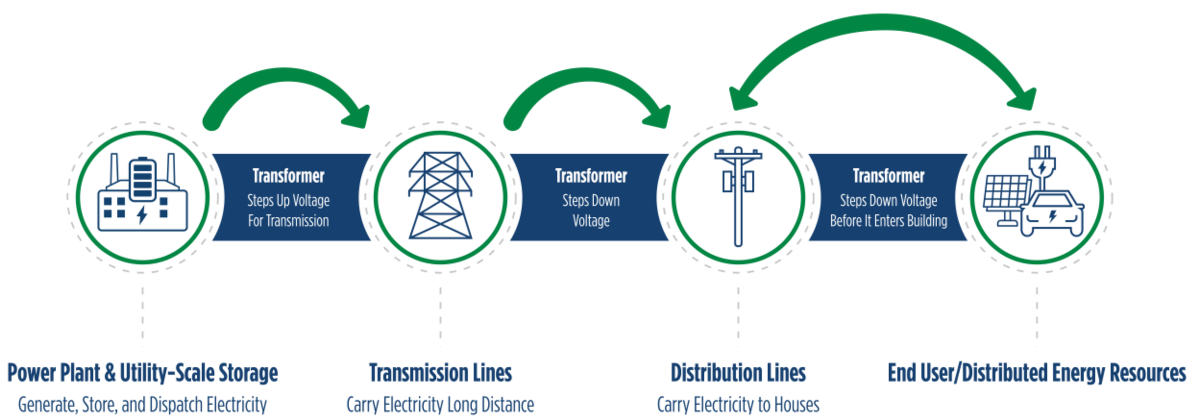
The 2025 IEPR planning forecast and local reliability scenario also project slightly lower near-term growth in peak demand compared to the previous forecast. However, for peak demand, the lower near-term growth is offset by a weather normal estimate of 2025 peak load that is higher than previously forecast.

Accelerating the Connection of New Resources and Loads to the Grid

An essential step for increasing California's portfolio of renewable and zero-carbon resources is to interconnect new resources with the grid. Separate processes are in place to connect utility-scale projects to the high-voltage, bulk transmission system and interconnect smaller, distributed resources to the lower-voltage distribution system. (Connecting new sources of energy generation is termed *interconnection*.) Further, distinct processes are used to connect end-use customers to the distribution system. (Connecting new sources of energy demand is called *energization*.) Figure ES-1 provides a simplified visual of the transmission and distribution systems.

During the two years since these issues were discussed in the *2023 IEPR*, the CEC, CPUC, and California ISO have increased coordination efforts with utilities, project developers, and various stakeholders to accelerate the deployment of clean energy resources. Despite this progress, the state will need to continue to address ongoing energy resource interconnection and customer connection (i.e. energization) issues to accelerate the pace of energy project development and meet its ambitious long-term climate and energy goals.

Figure ES-1: Bulk Transmission and Distribution Systems



Source: CEC

California's Progress Toward the Load-Shift Goal

Shifting electricity consumption away from times when electricity is expensive, polluting, and scarce to times when it is inexpensive, clean, and plentiful is another key tool in meeting the state's energy goals. Such efforts, termed *load shifting,* optimize how the grid is used and can lower ratepayer costs. Aligning customer demand with the supply of clean energy can help integrate intermittent and variable renewable energy sources (renewables) such as solar and wind onto the grid, reduce strain on the grid from connecting new electric load, and help maintain electric reliability. Given the potential value of cost-effective load shifting, in 2023, the CEC established a statewide load shift goal of 7 gigawatts by 2030 in the *Senate Bill 846 Load-Shift Goal Report*.

Progress has been made in load shifting, including through statewide default time-of-use rates, demand response programs, the launch of new, optional dynamic rates across much of the state, and programs to facilitate flexible service connections with customers. Still, analysis shows that agencies should continue to work together to address the policy issues identified in the *Senate Bill 846 Load-Shift Goal Report*. This report provided 18 policy recommendations to increase the load-modifying, resource procurement, and incremental emergency resources in the state by 2030.

Also, the CEC should further evaluate successful models from out-of-state markets for applicability in California while considering that the state's rate structures, tariffs, markets, and resource mix differ significantly from other states. The CEC will continue to investigate topics related to load flexibility potential under its Order Instituting Informational Proceeding on Distributed Energy Resources in California's Energy Future. Specifically, the CEC will update its analysis of load flexibility potential, incorporating the 2025 California Energy Demand Forecast.

Advancing Clean and Renewable Hydrogen for Electricity and Transportation

Senate Bill 1075 (Skinner, Chapter 363, Statutes of 2022) calls for the CEC to study and model potential growth for hydrogen in decarbonizing the electricity and transportation sectors. The analysis builds on the work in the *2023 IEPR* and explores a broader array of potential pathways for producing clean and renewable hydrogen than was covered in 2023. The analysis compares "what if," illustrative scenarios (high and low) of potential hydrogen demand to understand the implications for feedstocks, production technologies, and storage and transport for power generation and transportation in 2045. The analysis does not evaluate hydrogen transport via pipelines because the range of possibilities was too extensive to include.

Key takeaways include:

- Substantial use of hydrogen to replace fossil gas-fired electricity generation by 2045 would require pipelines, since opportunities for large-scale storage in California are limited. Building out hydrogen without storage (and without pipelines) would require overbuilding hydrogen capacity by as much as 1.5 to 4.5 times demand. For transportation fuel use in 2045, the distributed need for hydrogen could be met by storage infrastructure.
- Due to the intermittent seasonal and hourly variations in electricity needs in 2045, hydrogen generation from diversified feedstocks and technologies would create a more sustainable supply of hydrogen.

Assessing the Benefits and Contributions of the Clean Transportation Program

As required by statute, the *Draft 2025 IEPR* also includes an update on the CEC's Clean Transportation Program. Since 2008, the Clean Transportation Program has provided more than $2.8 billion in funding for a broad spectrum of zero-emission vehicles and infrastructure, alternative fuels and technologies, and workforce development projects. As technologies and market forces have evolved over the life of the Clean Transportation Program, the program has increasingly focused its resources on zero-emission transportation infrastructure. These investments have helped California establish the largest public charging and hydrogen refueling network in the nation while prioritizing benefits for disadvantaged and low-income communities. By driving innovation, market transformation, and equitable access, the program strengthens California's leadership in clean energy and helps keep the state on track to meet its climate and clean air goals.

Firm Zero-Carbon Resources

Achieving 100 percent clean electricity by 2045 requires replacing fossil generation with renewable and zero-carbon resources that can operate reliably. Senate Bill 423 (Stern, Chapter 243, Statutes of 2021) directed the CEC, in coordination with the CPUC, California ISO, and the California Air Resources Board (CARB), to assess emerging firm zero-carbon resources for the potential to strengthen local and system reliability while advancing policy goals. Firm zero-carbon resources are resources that can provide stable and dependable power output while producing low to no greenhouse gas emissions. Major findings from the assessment show that no single technology can meet all reliability and emission reduction needs, but a diverse portfolio of technologies can support a clean and reliable grid. California's ability to reliably meet its greenhouse gas reduction goals builds on continued funding for innovation, coordinated permitting and planning, and ongoing, cost-effective development of firm, dispatchable, zero-carbon capacity alongside variable and intermittent renewables co-located with storage systems.

CHAPTER 1:
California Energy Demand Forecast

Introduction

The California Energy Commission's (CEC's) California Energy Demand Forecast (also referred to as the forecast or IEPR forecast) is a foundational component of the state's energy planning.[1] The forecast provides a statewide and regional outlook on California's expected energy needs and is an input to various energy planning proceedings that ensure California will have adequate supplies of electricity and gas. Some examples of these proceedings include the California Public Utilities Commission's (CPUC's) Integrated Resources Plan (IRP) and processes that direct CPUC-jurisdictional load-serving entities' energy procurement, as well as the California Independent System Operator's (California ISO's) transmission planning process (TPP).[2]

The California Energy Demand Forecast includes:

- Annual electricity consumption and sales forecasts to 2045 by customer sector for eight planning areas and 20 forecast zones.[3]
- Hourly and peak electric system load to 2045 with different weather variants for eight planning areas.
- Annual gas consumption forecasts to 2045 by customer sector and three planning areas.

1 Public Resources Code (25301) requires that "at least every two years, the commission shall conduct assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices. The commission shall use these assessments and forecasts to develop and evaluate energy policies and programs that conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety."

2 See materials from the October 2, 2024, IEPR workshop on Forecast Use in Electricity System Planning for more information on how the CEC's demand forecast is used by these proceedings, https://www.energy.ca.gov/event/workshop/2024-10/iepr-commissioner-workshop-forecast-use-electricity-system-planning.

3 See GIS map of planning areas and forecast zones, https://cecgis-caenergy.opendata.arcgis.com/datasets/CAEnergy::california-electricity-demand-forecast-zones/explore.

- Annual projections of photovoltaic (PV) and other self-generation technologies, battery storage, electric vehicles (EVs), data centers, energy efficiency, and building electrification.

The CEC continuously updates and improves the forecast to meet the state's evolving planning needs. This chapter presents the process for developing the forecast, an update on the methods used, a description of the key drivers and trends, and planned enhancements to future forecasts. The CEC will continue to advance its forecasting capabilities as part of its focus on providing science-based planning tools needed in the transition to a clean energy future.

Forecast Uncertainties and Scenario Design

Significant new sources of uncertainty in the forecast have emerged in recent years. The CEC has responded by adding scenario analyses to better plan for rapid changes in data centers, transportation and building electrification strategies, and more extreme weather variability. In 2025, additional uncertainties were introduced around federal policy changes.

Table 1 shows some of the significant areas of uncertainty in the forecast and ways the CEC is addressing them.

Table 1: Uncertainties in the 2025 IEPR Forecast

Area of Uncertainty	How Area is Addressed in Forecast
Data Centers	Scenarios
Energization Requests (requests to connect new sources of energy demand), referred to as known loads in this chapter	Include impacts for local reliability scenario and monitor utility known loads data for project completions, delays, and cancelations
Climate Change	Global climate model simulations
Peak and Hourly Loads	Probabilistic hourly dataset and 1-in-X forecasts
Tariffs	Impacts not directly included in *2025 IEPR* forecast; will be included in *2026 IEPR Update* forecast
Tax Credits	Scenarios
California Air Resources Board (CARB) and Local Air District Regulations	Scenarios

Area of Uncertainty	How Area is Addressed in Forecast
Hydrogen	Hydrogen demand is part of the transportation energy demand forecast but does not guide system planning; hydrogen scenarios are included in the long-term demand scenarios project[4]

Source: CEC

Data centers are a leading source of growth in electricity demand and efforts to forecast the magnitude and timing of that growth continue to evolve as more information becomes available. Recent increases in the demand for artificial intelligence (AI) have contributed to a rise in utility energization requests for data centers. Uncertainty remains regarding the number of applications utilities will receive, how many proposed projects will ultimately be completed, timelines of projects, the anticipated load for each project, and longer-term market conditions. As described later in this chapter, the CEC develops a data center forecast using information from utilities, including project status and requested capacity. This information is processed with varying assumptions to create three scenarios for data center growth that reflect a range of possible outcomes. For example, projects with signed agreements are treated as higher confidence in the forecast than those at earlier stages of the application process.

The known loads dataset includes customer applications to connect new loads onto the utility distribution system. The estimated impacts from known loads add uncertainty to the overall forecast given uncertainty in project completion rates, energization timelines, utilization factors, and interactions with other components of the overall demand forecast. As discussed later, the impacts of known loads are included in the local reliability scenario to help align distribution and local transmission planning. As part of the 2026 IEPR cycle, CEC staff will undertake additional analysis to better understand trends in the known loads data.

Climate change is another area of uncertainty, especially for the peak demand forecast. There is inherent variability around the timing and severity of extreme heat events, which climate change will continue to amplify. In the mid- and long-term, there is uncertainty around the future frequency, length, and magnitude of these heat waves and other changes in California’s weather patterns. The CEC is working with contractors to incorporate data from global climate model simulations into its forecast to assess climate change impacts on electricity and gas demand.

4 CEC Long-Term Energy Planning web page, https://www.energy.ca.gov/data-reports/california-energy-planning-library/forecasts-and-system-planning/long-term-energy.

In general, the hourly and peak demand loads are highly influenced by weather. To support stochastic, or randomly determined, reliability assessments, these forecast products are now accompanied by a probabilistic hourly dataset, with distinct consumption and behind-the-meter (BTM) PV generation profiles correlated with a variety of historical weather patterns. The 1-in-X-year peak values are an output of the probabilistic hourly dataset, which give a range and likelihood for annual peak demand.

Tariffs and other changes in federal policy affect economic and demographic drivers, and thus energy demand. This forecast is based on economic and demographic data from May 2025, and at that time many of the tariffs were not yet finalized, so the impacts on the forecast are unknown. The economic inputs for the *2025 IEPR* reflect the preliminary effects and elevated uncertainty caused by the tariffs and other federal actions. Tariffs are expected to increase the prices of EVs, heat pumps, PV, and battery storage.

Residential customer-owned behind-the-meter PV and storage will no longer be eligible for the federal investment tax credit if installed after December 31, 2025. However, residential PV and storage owned by third parties — such as those under leases — remain eligible through the end of 2027. Combined commercial behind-the-meter PV and storage systems qualify for the investment tax credit if construction begins before July 4, 2026, or if in service by December 31, 2027. Tax credits remain intact for standalone commercial behind-the-meter storage projects beginning construction in 2033, at which point they will be phased out over the next two years. CEC staff produced four scenarios with varying assumptions for adoption of PV and storage.

Federal tax credits for light-, medium-, and heavy-duty EVs have also been eliminated, as well as some incentives for home electrification and efficiency improvements. Staff accounted for these changes in the scenarios developed for transportation electrification and fuel substitution.

There is also uncertainty around regulations for zero-emission appliances. Some standards from CARB and local air district regulations have been delayed or not adopted. These changes are closely monitored by the CEC, and adoption scenarios were included in the fuel substitution scenarios.

There is too much uncertainty around the role of hydrogen to include electricity demand for hydrogen production in the forecast. No short-term impacts to the forecast are anticipated. The longer-term potential for hydrogen in certain sectors is promising, and the CEC continues to monitor developments with partner agencies on this issue.

For the *2025 IEPR* Forecast, the CEC expanded on the previous scenario design strategy by developing and assessing combinations of scenarios. The CEC, in collaboration with the CPUC, California ISO, CARB, and other users of the forecast, determined appropriate scenario combinations for resource adequacy, integrated resource planning, and transmission system planning.

Background

Each year as part of the IEPR process, the CEC updates and improves its demand forecast by using the most recently available data and improving the methods and models. A summary of the major updates and improvements implemented for the 2025 IEPR forecast is below. The updates are vetted with forecast users and other interested parties through the public Demand Analysis Working Group (DAWG)[5] meetings and public IEPR workshops.[6]

Updates to the Annual Forecast

For each forecast cycle, the CEC obtains sales data from electricity and gas utilities via Quarterly Fuel and Energy Reports (QFER) consumption data reporting.[7] For the 2025 forecast, staff used historical data through the end of 2024. Staff also updated historical and forecast data for economic and demographic drivers, rates, and weather.

Typically, a full refresh of the electricity demand forecast is done in odd years, while even years are limited to input updates without large methodological changes. However, during the *2024 IEPR Updat*e process, the CEC received comments regarding the impact that large changes in results from one forecast vintage to the next can have on resource procurement costs to load-serving entities (LSEs). As a result, the CEC decided not to implement any major methodology changes for the planning forecast, which informs resource procurement, to allow more time to review changes and their impacts on the forecast with stakeholders. Staff anticipate implementing several method changes for the 2026 IEPR forecast, which are discussed in a later section.

In the past year, the federal administration has enacted several changes that go into effect before 2027. These changes greatly increase the amount of uncertainty with the electricity demand forecast and were important to capture in the *2025 IEPR* forecast, especially because it will be used to determine 2027 resource adequacy requirements. Therefore, the CEC developed an expanded suite of scenarios to capture that uncertainty. After draft results were

5 California Energy Commission. "Demand Analysis Working Group," https://www.energy.ca.gov/programs-and-topics/topics/energy-assessment/demand-analysis-working-group-dawg.

6 California Energy Commission. "2025 IEPR Workshops, Notices, and Documents," https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2025-integrated-energy-policy-report/2025.

7 Electricity and gas utilities are required to submit electricity and gas sales data quarterly to the CEC. https://www.energy.ca.gov/rules-and-regulations/energy-suppliers-reporting/quarterly-fuel-and-energy-reporting-qfer.

generated, the forecasting team assessed various combinations of scenarios with stakeholders to determine the best combination for each use case.[8]

The gas forecast is done biennially in odd years and was developed for the *2025 IEPR.* Various scenarios for the gas forecast were also developed and assessed, accounting for the interaction between the electricity and gas scenarios due to fuel switching.

Overview of Forecast Process and Components

Public Engagement

The CEC seeks input into its forecast development and methodological updates through various venues, including public workshops and public DAWG meetings. Staff invited utilities to speak at the July 16, 2025, DAWG meeting to discuss data centers and other large loads. The CEC continues to engage with utilities and industry groups individually on this topic. At the July 16, 2025, DAWG meeting and at an August 6, 2025, workshop, the CEC discussed forecast uncertainties, economic and demographic updates, and a proposed method for incorporating large known loads into the forecast. At an August 18, 2025, DAWG meeting and an August 26, 2025, workshop, staff sought input on proposed updates for the distributed generation, additional achievable energy efficiency (AAEE), additional achievable fuel substitution (AAFS), and additional achievable transportation electrification (AATE) components of the forecast.[9]

A DAWG meeting was held October 30, 2025, to discuss draft results for the load modifiers. An IEPR workshop was held on November 13, 2025, and a second was held on December 17, 2025, to present the results formally and receive final comments. The forecast was adopted at the CEC Business Meeting held on January 21, 2026.[10]

Forecast Components

The *2025 IEPR* forecast contains three baseline demand forecasts and several scenarios for forecast components that are more uncertain. For electricity system planning, sets of the baseline forecasts, data centers, PV, storage, and additional achievable scenarios are combined into a "planning forecast" and a "local reliability scenario." The CEC, CPUC, and

8 Draft results were presented at the November and December 2025 IEPR workshops.

9 The additional achievable scenarios for energy efficiency, fuel substitution, and transportation electrification capture a range of impacts from potential policy or technology changes beyond what are included in the baseline demand forecast, but which are still reasonably expected to occur.

10 CEC January 21, 2026, Business Meeting webpage, https://www.energy.ca.gov/event/meeting/2026-01/energy-commission-business-meeting.

California ISO agree to use specific combinations of this forecast set for planning and procurement, which will be documented in the final *IEPR*. The planning forecast is used for resource adequacy and integrated resource planning.

The local reliability scenario is used for planning activities with more granular geography, such as the California ISO's transmission planning process, local area reliability studies, and distribution planning process. The local reliability scenario historically assumes less BTM PV generation and storage, less energy efficiency, and more fuel substitution, resulting in higher demand than the planning forecast. Using the scenario with higher demand for local system planning addresses some of the increased uncertainty associated with disaggregating, or breaking down, the load forecast to study small local regions of the state.

The electricity demand forecast consists of the baseline forecast, impacts of energization applications (known loads), data centers, BTM distributed generation, AAFS, AAEE, and AATE.

- **Baseline forecast**: The baseline forecast assumes baseline economic, demographic, and fuel price assumptions. It considers policies and programs that are approved and funded and have an implementation plan detailed enough to reasonably measure the impact. The baseline forecast includes energization application impacts, data centers, and BTM distributed generation.
    - **Energization application impacts**: The investor-owned utilities (IOUs) submit their "known load" datasets to CPUC and CEC annually as part of the distribution system planning process. These datasets consist of energization applications for projects that have a high probability of being completed. Energization application impacts are only included in the baseline for the local reliability scenario that is used by the California ISO for local transmission studies.
    - **Data center scenarios**: The *2025 IEPR* forecast includes three data center scenarios that are based on different assumptions around the likelihood of completion for energization applications and inquiries.
    - **BTM distributed generation:** The *2025 IEPR* forecast includes PV, storage, combined heat and power, wind turbines, and other self-generation technologies. As most new distributed generation (DG) adoption consists of PV and storage, four BTM PV and storage scenarios were created based on different system cost assumptions.
- **AAFS:** AAFS consists of six scenarios of increasing fuel substitution, aligned with increasing scenario numbers. The lowest amount of fuel substitution occurs in Scenario One, while the greatest amount occurs in Scenario Six. Currently, AAFS assesses only the substitution of electricity for gas. These scenarios incorporate the combined impacts from programs and incremental codes and standards (PiCS), as well as potential regulatory or other market adoption impacts that are within the range of what is reasonably expected to occur.
- **AAEE:** Like AAFS, AAEE has six scenarios of increasing gas and electric energy efficiency savings of load, ordered by impact. These scenarios account for savings from

PiCS that go beyond baseline regulations but fall within the range of reasonably expected to occur. AAEE scenarios are affected by the increased electrification from AAFS, reducing the amount of gas efficiency available.

- **AATE:** For the *2025 IEPR* forecast, there are three AATE scenarios. AATE scenarios are numbered like AAEE and AAFS but are fewer in number due to the unique factors impacting the transportation sector. AATE scenarios consider a range of reasonably expected market transformations and policy impacts associated primarily with zero-emission vehicle adoption. Since the transportation forecast involves fuel types beyond electricity, associated model architectures differ from other forecasting tools.

As mentioned above, fuel substitution, energy efficiency, and transportation electrification use an additional achievable framework that captures a range of incremental potential market impacts beyond what are included in the baseline demand forecast but are within the range of what is reasonably expected to occur. The framework for additional achievable scenarios focuses on energy impacts from policies and programs that align with this criterion and have significant and unique effects on system load. Out of the components listed above, all but the energization application impacts are considered load modifiers.

A technology, program, or tariff is considered a load modifier for the forecast if the associated impacts are on the demand-side (behind-the-meter) and the associated load profile is different from the system load profile and, therefore, with large adoption would change the system load profile. To be considered load modifying, a program or tariff should modify load on a predictably consistent basis. Programs that modify load only during certain system conditions are integrated into the wholesale market, or both are not included in the demand forecast. For example, BTM technologies dispatched by system operators in response to system conditions, such as those used in some demand response programs, are not considered load modifiers.

Front-of-the-meter distribution system interconnected solar and storage are not included in the *2025 IEPR* forecast because of the challenges to the California ISO and CPUC planning processes that were documented in the *2024 IEPR Update*.[11] The CEC continues to explore this topic with industry, the California ISO, and CPUC.

11 Bailey, Stephanie, Mathew Cooper, Quentin Gee, Heidi Javanbakht, Jake McDermott, and Danielle Mullany. 2025. *Final 2024 Integrated Energy Policy Report Update*. California Energy Commission. Publication Number: CEC-100-2024-001-CMF. https://www.energy.ca.gov/publications/2024/2024-integrated-energy-policy-report-update.

The scenario designs for each component are described in more detail later in this chapter.

Forecast Framework

The scenarios that make up the planning forecast and local reliability scenario are outlined in Table 2. The CEC, along with the CPUC, California ISO, CARB, and other stakeholders, reviewed draft results to determine which scenarios should go into the planning forecast and local reliability scenario.

Table 2: Forecast Framework

Use Case/Scenario	Planning Forecast	Local Reliability Scenario
Example Use Cases	Resource Adequacy, CPUC Integrated Resource Planning	California ISO Transmission Planning Process local area reliability studies, Investor-Owned Utility distribution system planning
Economic, Demographic, and Price Scenarios	Baseline	Baseline
BTM PV and Storage Scenario	Mid	Low
Data Centers	Mid	High
Energization Applications (known loads)	Excluded	Included for Local Transmission Planning and Distribution system planning Excluded for Local Area Reliability Studies
AAEE Scenario	Scenario 3	Scenario 2
AAFS Scenario	Scenario 2	Scenario 3
AATE Scenario	Scenario 2	Scenario 3

Source: CEC

Analysis and Findings

As part of the IEPR process, the CEC typically develops and adopts forecasts of end-user electricity and gas demand every two years, in odd-numbered years. For the *2025 IEPR* forecast, the CEC decided not to make any major methodology changes because of comments received during the *2024 IEPR Update* process about the difficulties that large changes in forecast results can pose for resource procurement by LSEs. However, recent federal policy changes may have significant impacts on the forecast, as well as increasing overall uncertainty. Therefore, the CEC plans to expand its use of scenarios to cover a wider range of possible outcomes.

For the *2025 IEPR*, the CEC developed its forecast of electricity and gas demand with several improvements and expansions. The major changes to the baseline demand forecast consist of improved projections of data center load, incorporation of utility application (known loads) data, and updated accounting for the impacts of programs and standards. The CEC also updated the AAEE, AAFS, and AATE components for the *2025 IEPR*. Each of these is discussed further below.

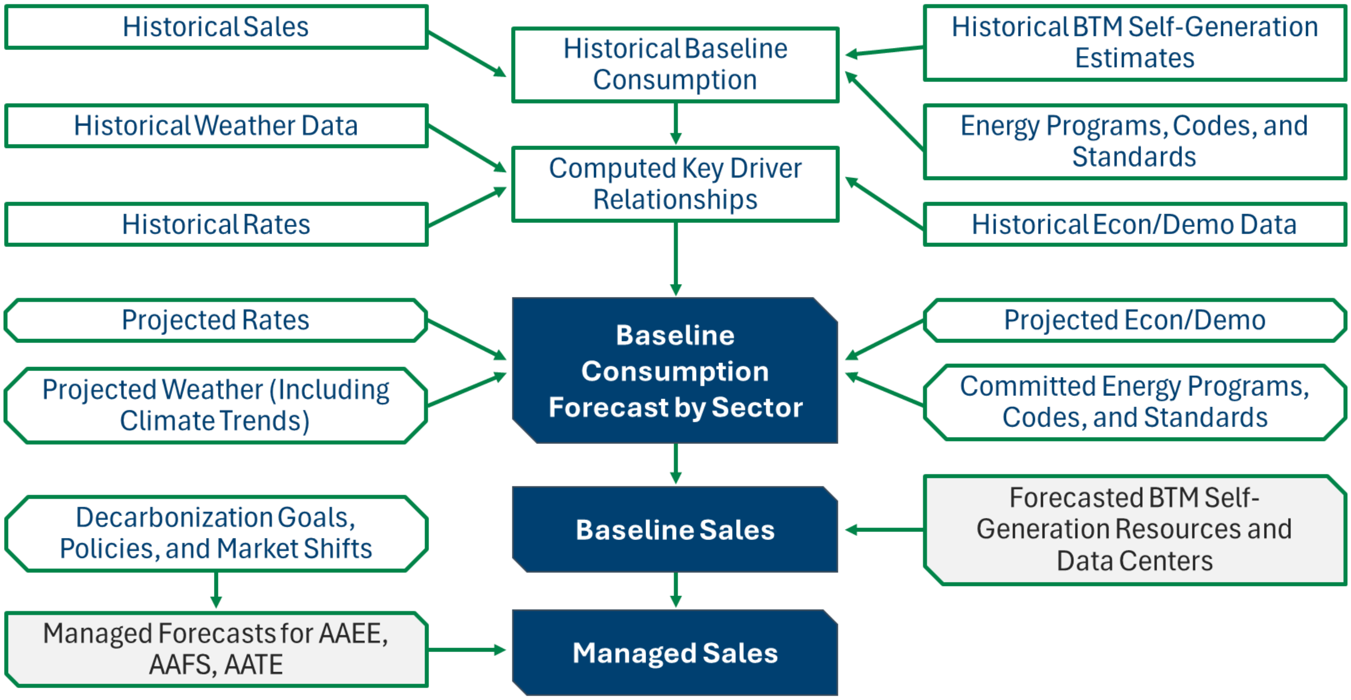
High-Level Method Overview

Historical energy consumption data are the foundation of the forecast. Electricity consumption is a combination of historical energy sales data and BTM self-generation estimates, while gas consumption is equivalent to gas sales. For both the electricity and gas forecasts, staff establishes correlations of historical energy consumption with economic and demographic data, weather data, and rates from the same historical period. The correlations are specific to each economic sector. Projections for future economic and demographic trends, weather (including climate trends), and rates are used with the correlations to extend energy consumption into the future. These projections are also specific to economic sector and region.

There are several modifiers to this process. Anticipated policy and technology changes, including the rise of EVs and data centers and the implementation of energy efficiency and fuel substitution measures, can cause significant deviations from historical trends and must be considered independently.

Figure 1 shows a flowchart of the general forecast process.

Figure 1: Flowchart of Electricity and Gas Demand Forecast Process



Many inputs are considered in forecasting energy demand, including historical trends; energy programs, codes, and standards; weather and climate projections; economic and demographic data; and decarbonization goals and policies.

BTM self-generation inputs apply only to the electricity forecast and do not impact the gas forecast.

Source: CEC

Changes and Updates for 2025

For the *2025 IEPR,* the CEC updated its forecast to use an additional year of historical data, updated economic and demographic projections, and updated electricity and gas rates projections. Other changes include:

- Improvements to BTM PV and storage models.
- Better accounting for the impacts of climate change on annual and hourly demand.
- Adjustments for the expected growth of data centers and known loads.
- Transportation forecast updates.
- Energy efficiency forecast updates.
- Building electrification forecast updates.
- Improvements to the hourly electricity forecast method, which has also been expanded to cover additional territories outside of the investor-owned utilities (IOUs).

For the *2025 IEPR* forecast, the energy demand forecasts are extended to 2045, in accordance with the 15-year minimum requirement established by Senate Bill 887 (Becker, Chapter 358, Statutes of 2022), to support the California ISO's transmission planning.

Updated Economic and Demographic Projections

Economic and demographic projections are key drivers of future energy demand and are primary inputs to the CEC's forecasting models. Every year, CEC staff updates the economic and demographic data used in the forecast.

In previous forecasts, "low", "mid", and "high" inputs were used to create "low", "mid", and "high" energy forecasts. However, starting with the *2023 IEPR* and later, the "low" and "high" economic and demographic scenarios were no longer used because the uncertainty surrounding potential policy and technology changes has a greater impact on the forecast than the alternative economic and demographic scenarios. The CEC continued this approach for the *2025 IEPR* Forecast.

Historical Energy Data

Up-to-date historical energy data are essential to forecasting and are used to identify trends and establish relationships with the input drivers. The most recent data also provide a starting point for the forecast, known as the "base year." In keeping with previous cycles, the base year for the *2025 IEPR* Forecast is 2024, and the first forecast year is 2025.

The historical data for electricity sales and gas sales are submitted by utilities in the form of a QFER. CEC staff standardizes and calibrates these data and aggregates them to the geographical areas used for forecasting.

For electricity, CEC staff pairs the QFER sales data with estimates of historical BTM DG to create a counterfactual history of electricity consumption. The CEC's forecasting models use consumption data, rather than sales, assuming that consumption is tied more directly to the input drivers. For gas, no adjustment is necessary because consumption is equivalent to sales.

BTM PV and Storage Distributed Generation Scenarios

CEC staff developed low, mid, mid plus Investment Tax Credit (ITC), and high BTM PV and storage adoption forecast scenarios to account for uncertainty in future BTM DG adoption. The uncertainty is driven by several factors, including, but not limited to, technology capital expenditure costs, including additional costs from trade tariffs, electricity rates, and policies, including incentives. Trade tariffs are excluded from the forecast due to the level of uncertainty at the time of development, including short- and long-term factors such as volatility in announced rates and limited visibility into how the PV and storage industries would respond or adapt. The BTM PV and storage adoption model uses the electricity rate forecasts discussed below and applies the net billing tariff (NBT),[12] across all scenarios. Scenarios are distinguished by using different assumptions for capital expenditure costs and incentives (Table 3).

Table 3: BTM PV and Storage Adoption Forecast Scenarios

Scenario	Capital Expenditure Costs	Investment Tax Credit
Low	High	None
Mid	Mid	None
Mid Plus ITC	Mid	Reinstituted 2030 - 2040
High	Low	None

Source: CEC staff

Capital expenditure cost projections for BTM PV and storage are derived from the National Renewable Energy Laboratory's (NREL) 2024 Annual Technology Baseline. Base-year technology costs are derived from interconnection data published through the CPUC's California Distributed Generation Statistics (DGStats) program.[13] In accordance with recent federal policy, the expiration of the ITC is incorporated across all scenarios, except for the Mid Plus ITC.[14] The Mid Plus ITC incorporates mid case capital expenditure costs along with a reinstatement of the ITC from 2030 to 2040, reflecting the possibility the tax credit could be reintroduced under future federal leadership.

For the high case, CEC staff also included projections of energy storage adoption as customers' net energy metering (NEM) tariff service expires and they transition to NBT service. The NEM tariff service expires 20 years from the stand-alone BTM PV interconnection date. When the NEM tariff service expires, the high case assumes customers will add energy storage to their PV system at the same pairing rate as new NBT customers. This method was

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12 The net billing tariff establishes electricity rates and credits for IOU customers with BTM DG, applying to all new interconnections.

13 Data available at California DGStats website, https://www.californiadgstats.ca.gov/.

14 Find more details on the Internal Revenue Service's "FAQs for Modification of Energy Credits and Deductions," https://www.irs.gov/newsroom/faqs-for-modification-of-sections-25c-25d-25e-30c-30d-45l-45w-and-179d-under-public-law-119-21-139-stat-72-july-4-2025-commonly-known-as-the-one-big-beautiful-bill-act-obbb. Date viewed August 25, 2025.

developed for the 2025 SB 100 Distributed Energy Resources Augmentation Sensitivity analysis.[15]

Continued Updates to Better Incorporate Climate Change

The methods and data used to account for climate change within the *2025 IEPR* Forecast are like those used in the *2024 IEPR Update* forecast. Changes made reflect ongoing refinements to the localization of downscaled climate simulations at specific weather stations important to CEC modeling.[16] Within the context of a warming climate, the previously standard practice of using 30 years of historical weather data to establish normal temperatures and weather patterns is no longer sufficient for demand forecasting, as past patterns do not reliably represent current or future climate conditions. To address this, IEPR forecasts are shifting toward simulated data derived from large-scale ensembles of global climate models (GCMs).

Consistent with this shift, the 2025 forecast incorporates outputs aligned with the Intergovernmental Panel on Climate Change's (IPCC) Sixth Assessment Report (AR6) Shared Socioeconomic Pathways (SSPs).[17] The SSP3-7.0 scenario was selected for downscaling GCM outputs. This scenario represents a world of regional rivalry, limited international cooperation, and higher greenhouse gas (GHG) emissions, resulting in relatively high radiative forcing.[18] Using SSP3-7.0 provides a conservative yet plausible planning case, ensuring that demand forecasts account for the potential of sustained warming and more frequent extreme heat events.

The downscaled GCM data were localized using the University of California, Los Angeles', bias-corrected Weather Research and Forecasting (WRF) results at 3-kilometer (km) and 9-km spatial resolution and hourly timescales. To operationalize these data, Lumen Energy Strategy

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15 Refer to the materials from the SB 100 webinar on August 7, 2024, for more details on the storage attachment method, https://www.energy.ca.gov/event/webinar/2024-08/senate-bill-100-demand-scenarios-staff-webinar.

16 Downscaled climate simulations at 3 km and 9 km resolution were localized to create a dataset associated with the weather stations that CEC uses to forecast energy demand.

17 IPCC 6th Assessment Report (AR6), https://www.ipcc.ch/assessment-report/ar6/,

18 *Radiative forcing* refers to the earth absorbing more energy than it radiates, leading to a warming planet.

Aydin, Mariko Geronimo and Cevat Onur Aydin. (Lumen Energy Strategy.) 2025. "De-Trended Climate Projections." p. 10. *WARP to Resilience,* https://lumenenergystrategy.com/uploads/1/3/6/3/136375767/2025-07-10_lumen_de-trended-climate-projections-techreportfinal.pdf.

applied a detrending[19] method on Cal-Adapt climate simulations spanning 2022 to 2050.[20] These detrended datasets were then used to calculate cooling degree days (CDD) and heating degree days (HDD) at the weather station, forecast zone, and planning area levels, providing inputs that can be used as direct inputs to the CEC's demand forecast models.

During the *2025 IEPR* cycle, CEC staff updated datasets for two key weather stations: Santee, located in the San Diego Gas & Electric (SDG&E) planning area, and Santa Barbara, located in the Pacific Gas and Electric (PG&E) planning area. The Santee weather station's historical record has significant segments of missing data at the hourly level. These missing data, because they particularly impacted night-time readings, introduced bias into the localization process. To remedy the issue, staff simulated the missing historical data and relocalized the downscaled climate simulations. For coastal areas, the localization process can produce biased results if the location is mapped to a largely ocean-based grid cell, as was the case with the Santa Barbara weather station during the *2024 IEPR Update* cycle. For the *2025 IEPR*, staff used relocalized simulations for which Santa Barbara was mapped to an alternative grid-cell more representative of local weather patterns.

AAEE and AAFS Scenarios

The framework for modeling AAEE and AAFS remains the same as in previous years. Staff, however, updated the nomenclature when referring to the components of these load modifiers. As before, AAEE savings and AAFS impacts capture a range of incremental market potential impacts beyond what is included in the baseline demand forecast, but within the range of what is reasonably expected to occur. The two modeling components comprising AAFS are still the impacts from programs and incremental codes and standards (now referred to as "PiCS") and the impacts from additional zero-emission (ZE) appliance adoption modeled, now referred to as "ZE AAFS." AAEE continues to consist solely of PiCS savings.

For 2025, staff revised the characterization of the ZE AAFS scenarios to reflect the various policy changes and increased uncertainties surrounding building electrification using the Fuel

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19 The detrending method can be summarized in two parts. First, a long-term trend is established over the full climate simulation period. Second, for a given forecast year, data for a 51-year window centered around that year are adjusted to remove the trend while retaining the level of warming as well as the weather patterns projected for the neighborhood around that year. A summary of the approach was provided in the *2023 IEPR*.

20 Cal-Adapt. "Analytics Engine," https://analytics.cal-adapt.org/.

Lumen Energy Strategy. "De-Trended Climate Projections." https://lumenenergystrategy.com/uploads/1/3/6/3/136375767/2025-07-10_lumen_de-trended-climate-projections-techreportfinal.pdf.

Substitution Scenario Analysis Tool (FSSAT).[21] Unlike the scenarios adopted in 2023, all six 2025 AAFS scenarios now include some adoption of zero-emission appliances beyond the adoption from PiCS.

PiCS modeling for both AAEE savings and AAFS impacts uses a suite of more than 40 workbooks that incorporate scenarios for various utility programs, beyond-utility programs, and incremental savings and impacts from codes and standards.[22] The utility programs are primarily modeled using the CPUC's *2025 Energy Efficiency Potential and Goals Study* and the *2025 Joint POU Energy Efficiency Potential Forecast for 2026–2034*, produced by the California Municipal Utility Association (CMUA).[23] Examples of beyond-utility fuel substitution programs include the Technology and Equipment for Clean Heating (TECH) initiative ("TECH Clean California") and the Equitable Building Decarbonization Program.[24] Examples of codes and standards include future enhancements of Title 20 appliance standards, Title 24 building standards, and federal appliance standards.

After modeling the impacts from ZE AAFS adoption beyond those from PiCS, FSSAT conducts a final adjustment to AAEE gas impacts, as the increased zero-emission appliance adoption reduces potential savings from gas energy-efficiency measures.[25] Combining the realized

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21 The Fuel Substitution Scenario Analysis Tool (FSSAT) is an energy model that models the cost, energy, and GHG emission impacts of "what if" scenarios of switching from gas to electric technologies, particularly in residential and commercial buildings.

22 The list of PiCS programs modeled in 2023 can be found here: 2023 AAEE & PiCS AAFS Scenarios Characterization Workbook. Docket 24-IEPR-03. TN#262297. March 21, 2025. https://efiling.energy.ca.gov/GetDocument.aspx?tn=262297&DocumentContentId=98813.

23 Guidehouse Inc. July 17, 2025. 2025 Energy Efficiency Potential and Goals Study – Final. California Public Utilities Commission. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-efficiency/2025-potential-goals-study/2025-group-e-potential--goals-study-final-report-20250717.pdf.

California Municipal Utilities Association. 2025. Energy Efficiency in California's Public Power Sector — 2025. https://www.cmua.org/Files/Reports/SB1037/2025_Energy_Efficiency_Report.pdf.

24 TECH Clean California is a statewide initiative to accelerate the adoption of clean, electric heating and water heating technologies, like heat pumps, in California homes. California's Equitable Building Decarbonization (EBD) Program aims to reduce greenhouse gas emissions from existing buildings by providing low- and moderate-income households with no-cost upgrades to electric and energy-efficient appliances, as well as other improvements.

25 FSSAT takes the AAEE and PiCS AAFS as inputs. The first order of operation for the FSSAT assigns the gas baseline forecast a reduction with a pre-specified PiCS AAFS scenario. It then runs an additional zero-emission adoption scenario (ZE AAFS) using the remaining eligible gas that can be fuel substituted. Finally, FSSAT calculates and applies the realized gas AAEE and applies the AAEE electricity savings.

savings and impacts from PiCS AAFS, ZE AAFS, and PiCS AAEE in a final module of FSSAT leads to the final AAEE and AAFS scenarios.

The 2025 AAEE and AAFS scenarios reflect recent state and federal policy changes. For example, Assembly Bill 130 (Committee on Budget, Chapter 22, Statutes of 2025) applies a moratorium on new or more efficient residential standards through June 1, 2031. Thus, the 2028 residential code update and updated reach codes for local jurisdictions do not apply. Non-residential 2028 code updates, however, continue to apply. At the federal level, uncertainty exists for federal appliance standards, as well as tax credits for building electrification and efficiency improvements under the 2002 Inflation Reduction Act, which expires at the end of 2025.[26] Staff captured these recent policy changes and uncertainties when updating the suite of PiCS AAEE and PiCS AAFS workbooks.

Characterizing the adoption of additional ZE appliances beyond those included in PiCS AAFS scenarios remains the most significant contributor to AAFS demand growth. There is some uncertainty regarding the amount of electrification, but staff created a reasonable range of ZE growth potential from either market transformation or likely policy impacts.

Before 2025, these ZE AAFS impacts were established primarily by zero-GHG emission space- and water-heater standards, as well as the zero-nitrogen oxide (NOx) emissions appliance standards passed or proposed by different state air quality management districts. As of February 2026, CARB is still pursuing a concept of a zero-emission space- and water-heater standard to be implemented in 2030 but timing for a board vote is undetermined.[27] In an August 2025 memo to the board and Assembly Bill 32 Environmental Justice Advisory Committee (EJAC) members, CARB staff members stated that they are exploring alternative regulatory approaches to a 100-percent zero-emission space- and water-heating new sales requirement.[28] Some of these alternatives include sales targets, credit programs, and

26 H.R.1 One Big Beautiful Bill Act 119th Congress 2025–2026.

27 Please see materials from CARB's Public Workshop for Zero-Emission Space and Water Heater Standards (December 11, 2025). https://ww2.arb.ca.gov/our-work/programs/building-decarbonization/zero-emission-space-and-water-heater-standards/meetings-workshops. The 2022 CARB State Implementation Plan (2022 CARB SIP) proposed a CARB board hearing for 2025 and implementation to begin in 2030 for a zero-emission standard for space and water heaters. Source: CARB. September 22, 2022. *State Strategy for State Implementation Plan,* pp. 101–103, https://ww2.arb.ca.gov/sites/default/files/2022-08/2022_State_SIP_Strategy.pdf.

CARB. "Zero-Emission Space and Water Heater Standards" proceeding web page: https://ww2.arb.ca.gov/our-work/programs/zero-emission-space-and-water-heater-standards.

28 Cliff, Steven, Ph.D., CARB memo to Chair Randolph, CARB Board Members, Assembly Bill 32 Environmental Justice Advisory Committee (EJAC) members, August 28, 2025, Page 2.

registration requirements for emissive equipment. As a response to this uncertainty, CEC staff made modifications to the ZE standard implementation schedule, which was staggered based on some appliance types.

The 2025 ZE AAFS scenarios modeled in FSSAT also exclude expected impacts from the South Coast Air Quality Management District's (SCAQMD) Proposed Amended Rules (PAR) 1111 and 1121, which were rejected by a 7-5 vote on June 6, 2025.[29] These PARs set targets for the adoption of zero-emission space and water heaters in that region. On July 18, 2025, a federal court upheld SCAQMD's PAR 1146.2, a regulation requiring large water heaters, small boilers, and process heaters to achieve zero-NOx emissions.[30] The Bay Area Air District's building appliance rules 9-4 and 9-6 were adopted in March 2023, and are set to take effect in 2027 for small water heaters and in 2029 for space heaters.[31] The ZE AAFS modeled scenarios incorporate PAR 1146.2 and the Bay Area Air District's standards.

Table 4 summarizes the ZE AAFS characterization for each of the six 2025 AAFS scenarios. The combined impact of a ZE AAFS scenario with the associated PiCS AAFS scenario impacts generates the final set of AAFS scenarios. When considering AAEE and AAFS load modifier combinations, an adjustment may be required for the final AAEE gas impacts since increased AAFS can result in a lower amount of potential PiCS AAEE gas savings.

Table 4: ZE AAFS Modeling Summary for the 2025 AAFS Scenarios

ZE AAFS Scenario	ZE AAFS Scenario Characterization for FSSAT Modeling
1	• End uses: space and water heaters

https://ww2.arb.ca.gov/sites/default/files/2025-08/09-11-2025%20Joint%20Meeting%20Building%20Decarbonization%20Memo.pdf.

29 The South Coast Air Quality Management District (SCAQMD) is a regional authority that works to reduce air pollution in a large portion of Southern California, including Los Angeles, Orange, Riverside, and San Bernardino counties.

30 Please go here for additional information about the SCAQMD's PAR 1146.2 proceeding: https://www.aqmd.gov/home/rules-compliance/rules/scaqmd-rule-book/proposed-rules/rule-1146-2.

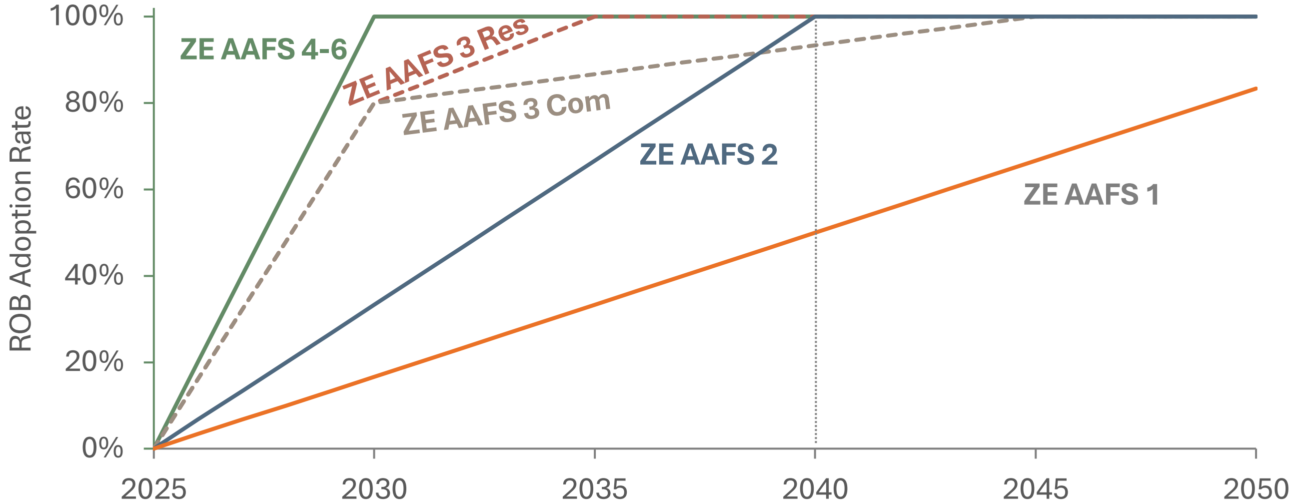
31 The Bay Area Air District is a regional air pollution control agency that regulates air pollution sources in the nine-county San Francisco Bay Area.

The Bay Area Air District is pursuing additional amendments that will target roughly twenty percent of appliances that would face electrification challenges. Please go here for the Bay Area's Rules 9-4 and 9-6 Building Appliances proceeding page: https://www.baaqmd.gov/rules-and-compliance/rule-development/building-appliances.

ZE AAFS Scenario	ZE AAFS Scenario Characterization for FSSAT Modeling
	• Statewide gradual transformation of replace-on-burnout adoption of 50 percent by 2040 • Excludes the modeling of the Bay Area Air District’s Rules 9-4 and 9-6 and SCAQMD’s PAR 1146.2 • Uses impacts from PiCS AAFS 1
2	• End uses: space and water heaters • Statewide gradual transformation of replace-on-burnout adoption of 100 percent by 2040 • Uses impacts from PiCS AAFS 2
3	• End uses: space and water heaters • Emulates CARB’s 2022 Scoping Plan proposed scenario adoption rates for the residential and commercial sectors • Uses impacts from PiCS AAFS 3
4	• End uses: space and water heaters • A 2022 CARB State Implementation Plan (SIP) concept for a zero-emission space and water heater standard with 100 percent compliance starting in 2030 • 100 percent adoption beginning in 2029 for new construction • Uses impacts from PiCS AAFS 4
5	• End uses: space heaters, water heaters, cooking, clothes drying • Same replace-on-burnout adoption rate as AAFS 4 • 100 percent adoption beginning in 2029 for new construction • Uses impacts from PiCS AAFS 5
6	• End uses: space heaters, water heaters, cooking, clothes drying, and residential propane end uses • Same replace-on-burnout adoption rate as AAFS 4 • 100 percent adoption beginning in 2029 for new construction • Uses impacts from PiCS AAFS 6

Source: CEC staff

Figure 2: ZE AAFS Scenario Replace-on-Burnout (ROB) Adoption Curves – ZE Appliance Adoption



Source: CEC

Figure 2 illustrates the ROB adoption curve rates of the 2025 ZE AAFS scenarios characterized in Table 5. The modeled rate of ROB adoption depends on the amount of PiCS AAFS. With more aggressive PiCS AAFS impacts, fewer eligible gas appliances are available for ROB ZE appliance adoption. The two ZE AAFS 3 adoption slopes represent the CARB Scoping Plan proposed scenario characterization for the residential and commercial sectors. The most noticeable difference between ZE AAFS 3 and ZE AAFS 4–6 occurs after 2030. Although the adoption rates for ZE AAFS 4–6 are the most aggressive, this adoption schedule is less aggressive than the *2024 IEPR Update*, which incorporated compliance dates as early as 2027 for residential water heaters.

In addition to the routine input updates for an IEPR cycle, staff made a few input assumption updates for the 2025 ZE AAFS scenarios to improve FSSAT. First, staff adjusted the efficiency mix of new electric water heaters to reflect that most new water heaters will use heat pump technology rather than resistance heating. This adjustment was informed by a 2029 United States Department of Energy (U.S. DOE) energy efficiency standard that renders electric resistance water heaters functionally obsolete.[32] The scenarios maintain the assumption that

32 The FSSAT cannot model the timing of the (un)availability of certain technologies. Thus, staff modified the efficiency weighting assumption, given that heat pump water heaters are likely to dominate the water heater market over the IEPR forecast horizon.

the adoption of the other end uses has an even mix of appliances by efficiency level. Second, staff updated the commercial heating, ventilation, and air-conditioning (HVAC) load shapes to improve the hourly analysis. Third, staff updated the residential air-conditioning penetration rates by climate zone and building type, using recent analysis of advanced metering infrastructure (AMI) data, for Southern California Edison (SCE) and PG&E territories.[33] These updated rates enhance the precision of modeling the increased air conditioning loads from heat pumps in single- and multi-family buildings that previously lacked air conditioning.

AATE Scenarios

The Transportation Energy Demand Forecast (TEDF) assesses future transportation energy demand. It forecasts all transportation fuels, not only electricity demand from transportation electrification. It is used by government agencies, utilities, fuel providers, and many others to plan infrastructure development, adjust energy policies, and implement emission reduction strategies. In essence, it enables better preparation for the evolving energy needs of California.

The *2025 IEPR* includes new AATE scenarios that reflect the uncertainty prompted by recent federal government actions and other policy changes. Tariff impacts, related vehicle price changes, and other economic factors that vehicle purchasers may face in the coming years will not be incorporated, due to limited data availability. The AATE scenarios consider different transportation electrification growth rates across light-, medium-, and heavy-duty vehicles, with a focus on how California may continue a trajectory toward meeting its ZE transportation goals.

U.S. DOE. April 30, 2024. "DOE Finalizes Efficiency Standards for Water Heaters to Save Americans Over $7 Billion on Household Utility Bills Annually," https://www.energy.gov/articles/doe-finalizes-efficiency-standards-water-heaters-save-americans-over-7-billion-household.

33 AMI data analysis for SDG&E was not available in time for this forecast.

Updates to Data Center Method

Due to the magnitude and geographic concentration of data center loads, the CEC developed a dedicated data center demand forecast for the *2024 IEPR Update*. The data center method used for the *2025 IEPR* forecast expands upon this approach with updated data from utilities and refinements to the modeling process.

The forecast relies on data center energization inquiries and applications received by electric utilities. Each potential data center project is characterized by its requested capacity in megawatts (MW), an expected timeline or ramping schedule, and application status.

For the *2025 IEPR* forecast, the CEC standardized data collection across utilities and categorized projects into three consistent groups based on application status:

- "Group 1" projects have a signed agreement for electric service with the local electric utility having jurisdiction over the project location. These projects have completed an engineering study, which provides information on required grid upgrades and associated timelines.
- "Group 2" projects have an active application for electric service with the utility but do not yet have a signed agreement.
- "Group 3" projects have submitted inquiries for electric service but have not filed an application with the utility.

Industry experts and utilities with experience serving data centers provided guidance to the CEC in developing utilization factors and reasonable ramping rates. Utilization factors are used to translate requested capacity into expected peak demand, while ramping rates are applied when project-specific schedules are unavailable or inconsistent with the project's application status. For example, some Group 2 projects reported service start dates in 2025, which was unlikely without a signed agreement. In these cases, staff adjusted the start date to 2028 to reflect a more realistic development timeline.

Because not all proposed projects ultimately proceed to construction and energization, staff applied confidence levels to each project group to estimate the portion of requested capacity expected to materialize. These confidence levels were informed by discussions with utilities regarding historical completion rates, application attrition, potential duplication of requests, and the likelihood that a data center may primarily use on-site generation and only rely on the grid for backup power. Projects with signed agreements were assigned the highest confidence, while inquiries were treated as an indicator of longer-term growth rather than near-term demand. Table 5 summarizes the key assumptions incorporated into the data center demand forecast. These assumptions will be revisited and refined in future IEPR forecasts as additional data are available.

Table 5: Summary of Data Center Forecast Assumptions

Assumption Category	Planning Forecast	Local Reliability Scenario	Notes
Utilization Factor	67%	67%	Based on discussions with utilities and observed operations
Ramp to full load	Ramp over 7 years	Utility-provided schedule	Linear ramp where schedules unavailable
Confidence level: "Group 1"	70%	100%	Higher confidence plus more conservative local planning
Confidence level: "Group 2"	33%	50%	Account for attrition and potential duplication
Confidence level: "Group 3"	0%	10%	Speculative, but useful for proactive long-term planning

Source: CEC staff

CEC staff also analyzed interval meter data from a sample of existing data centers to develop a representative hourly load profile. These profiles were used to translate the forecasted maximum demand, discounted by the previously mentioned assumptions, into hourly demand and to estimate the contribution to system peak demand from data centers. While existing data centers provide the best available proxy for typical hourly load shapes, staff recognize that future facilities may operate differently as business applications, computing technologies, and cooling strategies evolve.

CEC staff is also working to improve estimates of existing data center counts, annual electricity consumption, and hourly demand patterns using utility-provided data and interval meter analysis. This work is ongoing and will inform both the treatment of the existing applications, as well as future long-term forecasts.

For the *2025 IEPR* forecast, CEC staff developed three data center load growth scenarios. These scenarios were presented for stakeholder discussion at the October 30, 2025, DAWG meeting and November 13, 2025, IEPR workshop.

Incorporation of Energization Request Data Into the Local Reliability Scenario

New for the *2025 IEPR*, CEC staff included load impacts of energization request data from the IOUs' known load dataset as part of the local reliability scenario used for transmission local studies. The known loads dataset includes customer applications to connect new loads onto the utility distribution system. Examples of projects include new tract homes, commercial office buildings, EV charging stations, and industrial facilities (such as for hydrogen production).

Projects tracked in the known loads dataset were reviewed by utility distribution planning staff and are considered to have a high degree of certainty that projects will start construction and eventually be energized. However, some projects may be cancelled for various reasons, such as difficulty obtaining funding, or factors related to the broader economy, or other reasons. Roughly 23 percent of requested project capacity is for EV charging stations.

The known loads dataset is integral to the CPUC's High Distributed Energy Resources (DER) proceeding. One goal of this proceeding is to improve utility distribution planning to proactively plan for new types of load growth. In the distribution planning process, IOUs identify grid updates needed to accommodate energization requests.

CEC staff, working collaboratively with staff from the CPUC, issued data requests to IOUs to collect project-level data contained in the known loads dataset. CEC staff also collected load profile assumptions and meter IDs for completed projects to analyze interval meter data. In addition, staff from IOUs provided assumptions regarding project completion date, load ramp timelines, and utilization rates. Throughout the 2025 IEPR cycle, CEC staff presented on the proposed method and estimated load impacts of known loads projects at IEPR workshops and Demand Analysis Working Group (DAWG) meetings. Most recently, CEC staff presented updated known load impacts on the 2025 IEPR forecast at a January 5, 2026, DAWG meeting.[34]

Table 6 provides an overview of the sources of key assumptions to translate the customer requested capacity in the known loads data to the forecast. For the 2026 IEPR cycle, CEC staff will continue to examine data, including interval meter data, to refine some of the assumptions further.

Table 6: Known Loads Assumptions

Assumption	Value	Source
Cancellation Rates	Varies by IOU and sector	Based on August 2025 Grid Needs Assessments (GNA) filing with CPUC
Energization Date	Dates specific to each project	PG&E: dataset provided to CEC in December 2025 SCE: dataset provided to CEC in December 2025 SDG&E: dates from the August 2025 GNA filing
Ramp Rate	PG&E: 3 years SCE: 1 year SDG&E: 1 year	Use ramp rates provided by each IOU

34 January 5, 2026, DAWG meeting to discuss California Energy Demand Forecast: 2025 IEPR Revised Result webpage, https://www.energy.ca.gov/event/meeting/2026-01/ca-energy-demand-forecast-2025-iepr-revised-result.

Assumption	Value	Source
Utilization Factor	Varies by IOU and sector	Use adjustment provided by each IOU

Source: CEC

To translate capacity requested to load, CEC staff first aggregated project level capacity in the known loads dataset by CEC demand forecast zone, sector, and the year and month of the requested energization date. Second, based on this grouping, the aggregated capacity was adjusted for project cancellation rate, utilization rate, and extended over the forecast period. Finally, load profiles were applied to estimate the corresponding annual load impacts. The estimated annual load impact was then compared to the CEC's baseline sector sales forecast and only the incremental portion exceeding the CEC's baseline sector sales forecast was counted as load impacts attributable to known loads. While this helps avoid double counting impacts, CEC staff notes this approach provides an estimate of the impacts of known loads that may be on the high side due to other interactive effects with other forecast load modifiers, such as building electrification and customer-owned generation resources, that were not considered for this IEPR forecast cycle.

Forecasting impacts of known loads can be challenging due to several reasons:

- Limited Historical Data: Historical data on key metrics needed to estimate impacts are unavailable. Additionally, while IOUs routinely add new customer loads due to expansion plans or to construct new buildings, the volume of requests over the last several years is unprecedented.
- Energization Timelines: There is uncertainty with how many projects will finish construction and the timing of completed projects' energization.
- Load Ramping: The pace of how quickly the new load will ramp to its maximum load after the project is energized is another uncertainty in the forecast. If the completed projects ramp more quickly than assumed, then this will lead to higher annual sales and a higher contribution to system peak while a slower ramping schedule means lower sales and a lower contribution to system peak.
- Utilization Factor: There is uncertainty about the percentage of requested capacity that is actually used by the customer. CEC staff will continue to analyze meter data for completed projects to develop assumptions for utilization factors.
- Interaction with Other Forecast Components: The known load data do not include information about whether the requested capacity accounts for self-generation, whether the non-transportation loads include electric vehicle charging stations, or whether the project is all electric, and therefore these impacts may not be properly accounted for,

resulting in load estimates that are too high. CEC staff will look into this further for the 2026 IEPR forecast.

Because of these uncertainties, the impacts of known loads are only considered as part of the local reliability scenario used by the California ISO for local transmission studies. This will allow California ISO to identify local areas that may need transmission upgrades while allowing CEC staff more time to collaborate with stakeholders to better understand the impact of known loads before considering them in other electricity system planning processes.

As part of the 2026 IEPR cycle, CEC staff will explore new tools and methods to better support distribution system planning. CEC staff will also examine impacts of the "pending loads" data. The pending loads data is like the known loads data in that the two identify utility customer interest in connecting new loads to the utility distribution system. As with the known loads data, the purpose of the pending loads data is to support proactive distribution planning to accommodate new load growth and is covered as part of the CPUC's High DER proceeding. The difference between the two datasets is that the known loads data captures actual customer-initiated and utility approved projects while pending loads data reflects customer interest to add load, but an energization request has not been made. The load growth in the pending loads data may be further categorized based on some degree of confidence that a utility customer may proceed to undertake a project. While the uncertainty underlying the load growth identified in the pending loads data makes it a challenge to incorporate into the IEPR demand forecast, incorporating pending loads into the scenarios underlying the 2026 IEPR demand forecast may be the best path forward to reflect additional sources of load growth. CEC staff will monitor and participate in the CPUC's High DER proceeding and engage with stakeholders to understand the data sources and forecasts underpinning the pending loads data. CEC staff will also present its recommendations on how to incorporate pending loads data into the IEPR demand forecast, including discussing the potential incremental load impacts, as part of DAWG and IEPR workshops in 2026.

Hourly Forecast Updates

The CEC's hourly demand forecast forms the basis for its annual and monthly peak forecasts, which are critical inputs into a variety of electricity system studies conducted as part of the CPUC's Integrated Resource Plan and the California ISO's Transmission Planning Process. Moreover, hourly loads inform the California ISO's flexible capacity studies, and monthly peak day profiles are used to set total resource adequacy system requirements. During the 2023 and 2024 IEPR cycles, staff made several updates to improve the accuracy of the CEC's hourly consumption history, along with modeling improvements aimed at improving the CEC's forecast consumption profiles. Staff continues to explore options for better aligning certain aspects of these profiles with recent historical observations. These alignment issues were identified at an IEPR workshop held July 30, 2024, and include the timing of the annual California ISO system peak, as well as planning area coincidence with California ISO peaks during certain shoulder months in the spring and fall. Staff did not update the CEC's forecast consumption profile as part of the *2025 IEPR* cycle. Deferring updates to the *2026 IEPR*

Update cycle serves the dual purpose of avoiding any drastic changes to RA capacity requirements — specifically those that would be attributable to modeling changes. It also allows time for staff to review with stakeholders process changes that may reduce such impacts permanently. In addition, staff is developing new models to allow the CEC to produce hourly forecasts for planning areas outside the California ISO control area. To date, staff has developed hourly forecasts only for the PG&E, SCE, and SDG&E transmission access charge (TAC) areas, as well as the California ISO system as a whole. Staff intends to produce hourly forecasts for the remaining five CEC planning areas, including Northern California Non-California ISO, Los Angeles Department of Water and Power, Burbank/Glendale, Imperial Irrigation District, and Valley Electric Association. These hourly forecasts will better reflect the impact of load modifiers on the corresponding annual peaks and will improve the utility of the CEC's forecast within key system studies, such as the CPUC's IRP and the California ISO's TPP.

Summary of Key Drivers and Trends

The energy demand forecast has numerous underlying inputs and assumptions, including economic and demographic data and climate trends that affect how the state uses energy. It also accounts for policies and goals that guide forecast assumptions for energy efficiency, building and transportation electrification, DG, and battery storage technologies. Technology developments such as data centers and other large loads are also included.

Economic and Demographic Trends

Overall, economic projections for the *2025 IEPR* are slightly lower compared to the previous IEPR forecast inputs, although the uncertainty surrounding these projections is notably higher than in previous years. Recent historical data had a slight upward correction, but personal income, gross state product, manufacturing output, and commercial employment are expected to grow at slower rates than previously forecasted. Population projections for the *2025 IEPR* are lower than the previous *2024 IEPR Update* forecast but still higher than the *2023 IEPR* forecast. Household projections are higher in the *2025 IEPR* forecast. The details of these projections are discussed below. An overview of economic and demographic trends was discussed at the July 16, 2025, DAWG meeting[35] and the August 6, 2025, IEPR Workshop.[36]

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35 California Energy Commission. July 16, 2025, CA Energy Demand Forecast: Economic & Demographic Inputs; and Data Center Forecasting, https://www.energy.ca.gov/event/meeting/2025-07/ca-energy-demand-forecast-economic-demographic-inputs-and-data-center.

36 California Energy Commission. August 21, 2024, IEPR Commissioner Workshop on Energy Demand Forecast Inputs and Assumptions, https://www.energy.ca.gov/event/workshop/2025-08/iepr-commissioner-workshop-energy-demand-forecast-inputs-and-assumptions.

Population and Households

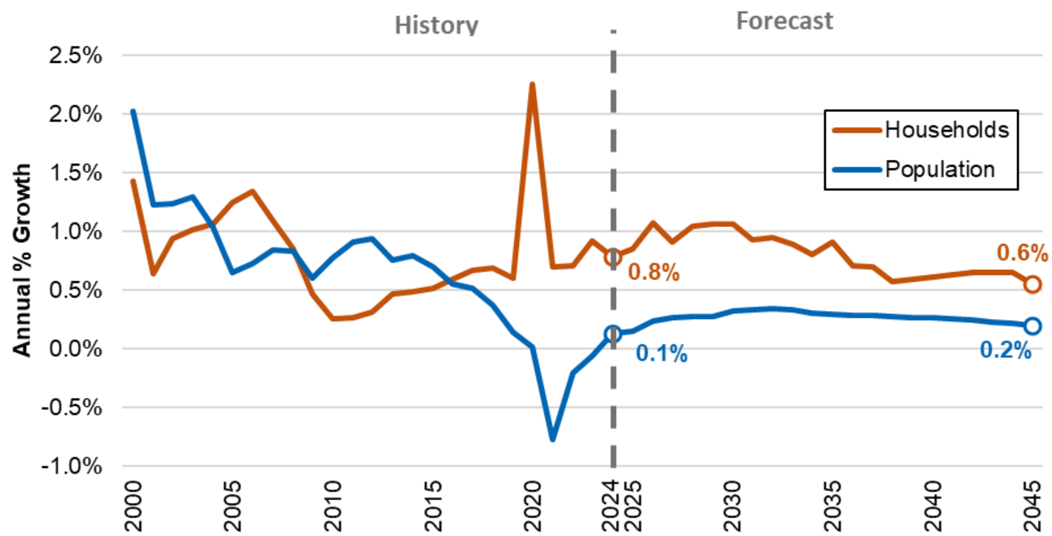
Based on data from the California Department of Finance (DOF), statewide population for the *2025 IEPR* forecast grows at an average of 0.27 percent annually from 2024 to 2045. This growth rate is marginally lower than the 0.29 percent growth rate assumed in the *2024 IEPR Update* for the same period but still higher than the 0.14 percent annual growth rate in the *2023 IEPR* forecast.[37] The 2025 total population for California is 39.2 million and is projected to reach roughly 41.4 million by 2045 (5.8 percent total growth).

During the period of 2020 to 2023, statewide population declined by about 1.1 percent, as noted in Figure 3. The *2023 IEPR* projected a continuation of this decline for the next few forecast years, primarily because of reduced immigration. However, 2024 showed growth again due to a return to normal migration patterns. The 2025 forecast indicates a continuation of growth, although at a slightly slower rate.

Statewide, the number of households is expected to grow at 0.80 percent annually from 2024 to 2045, slightly above the previous projections from DOF. DOF now estimates that there are 14.0 million households in 2025 and 16.4 million by 2045 (18.2 percent total growth). This reflects an ongoing trend toward smaller household sizes that has accelerated in recent years.

37 The *2023 IEPR* and *2024 IEPR Update* forecasts presented energy demand to 2040, but the economic and demographic projections used in the forecasts extended to 2050, enabling the comparisons described here.

Figure 3: Statewide Population and Households Growth, 2025 IEPR Forecast



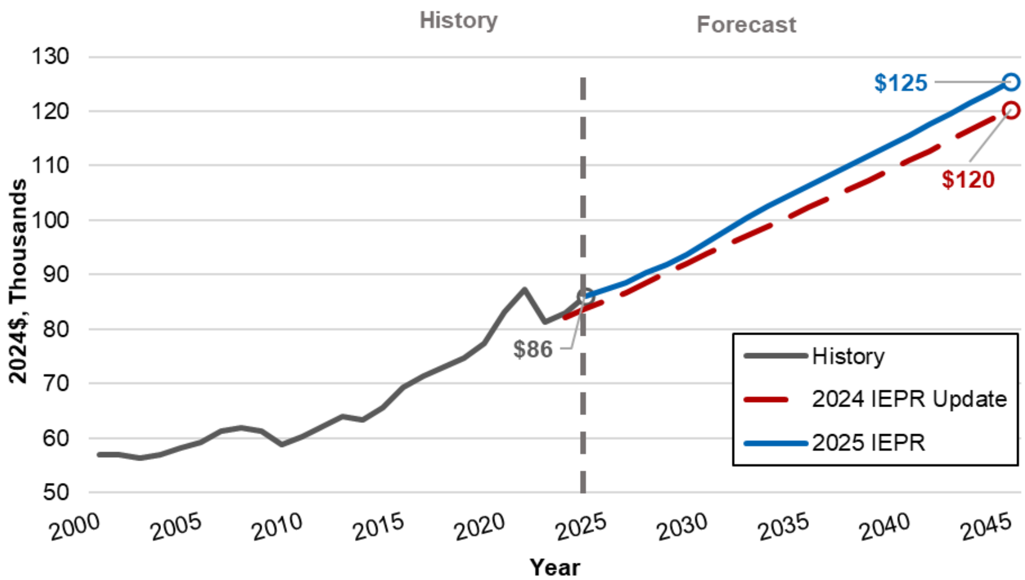
Statewide population grows at an average of 0.3 percent annually from 2024 to 2045. The number of households statewide is expected to grow at an average of 0.8 percent annually from 2024 to 2045.

Source: CEC using data from DOF

Per Capita Personal Income

Figure 4 compares statewide per capita income for the *2025 IEPR* forecast against the *2024 IEPR Update*. Statewide per capita income has a higher starting point in the *2025 IEPR* compared to *2024 IEPR Update* but is expected to grow at a slower rate in the near-term forecast years 2025 to 2028. Staff emphasizes that both forecasts have been converted to 2024$ for comparison. Income levels recover in the middle and late forecast years, giving an average annual growth rate of 1.7 percent from 2024 to 2045, for a total growth of 45.7 percent, with per capita income reaching $125,400 by 2045.

Figure 4: Statewide Per Capita Personal Income Comparison, 2025 IEPR Forecast

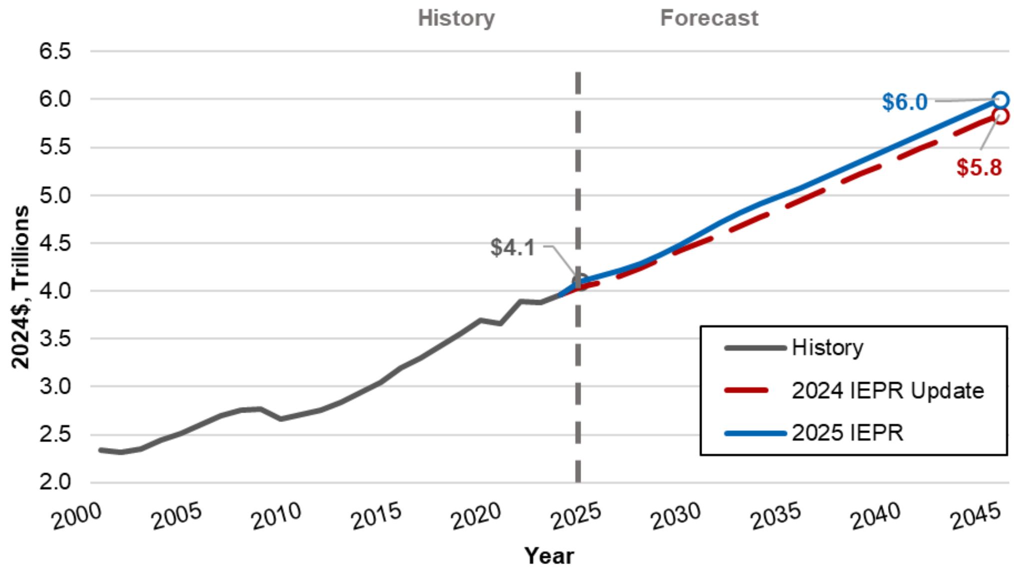


Source: CEC using data from Moody's Analytics and DOF

Gross State Product

Figure 5 compares gross state product projections for the *2025 IEPR* and *2024 IEPR Update*. The gross state product has a higher starting point in the *2025 IEPR* compared to the *2024 IEPR Update* but is expected to grow at a slower rate in the near-term forecast years 2025 to 2028 compared to the previous projections. However, this slowdown in growth is followed by a recovery in the middle and later years, so the average annual growth rate is 1.8 percent from 2024 to 2045, similar to the *2024 IEPR Update*. Over the same period, gross state product is expected to increase by 46 percent, reaching $6.0 trillion by 2045. While California's economy is expected to grow over the entire forecast period, there is significant uncertainty in the near term due to tariffs and other federal policy changes. The 2025 data are from May and do not reflect any subsequent economic developments, including the impacts of tariffs.

Figure 5: Gross State Product Comparison, 2025 IEPR Forecast

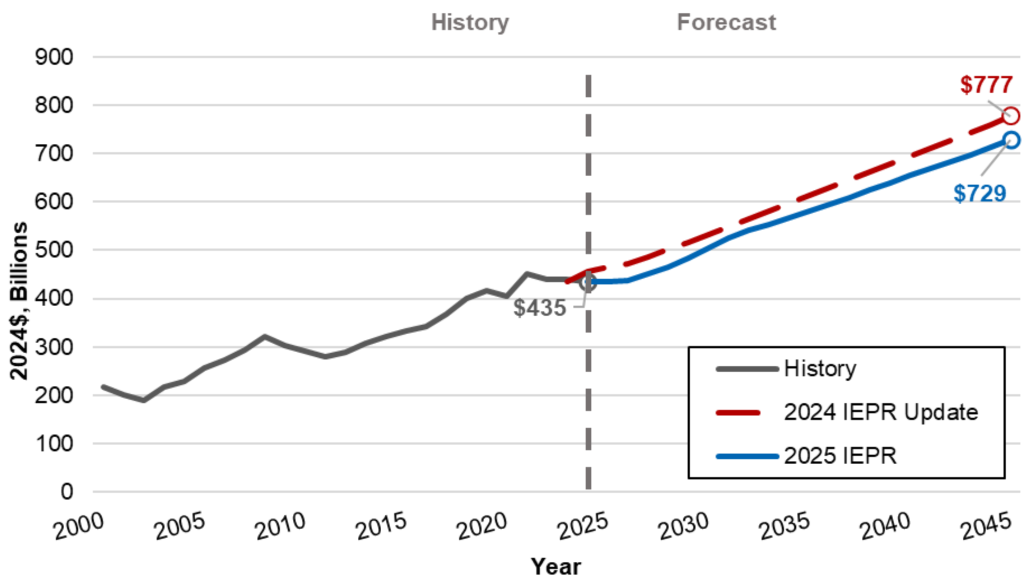


Source: CEC using data from Moody's Analytics

Manufacturing Output

Figure 6 compares gross manufacturing output projections for the *2025 IEPR* and the *2024 IEPR Update* forecasts. Gross manufacturing output was relatively flat over the last year and is expected to remain flat in 2025 and 2026, a departure from the growth predicted in the previous forecast. This prediction is due to broad uncertainty as well as a downward revision to the recent historical data. Volatility in manufacturing is due to global trade uncertainty driven by shifting international agreements, tariffs, and trade wars, leading to disrupted supply chains and volatility in import/export flows. However, a return to growth is predicted in 2027, and the annual growth rate is 2.5 percent from 2024 to 2045. Over the same period, gross manufacturing output is expected to increase by 67 percent, reaching $729 billion by 2045.

Figure 6: Gross Manufacturing Output, 2025 IEPR Forecast



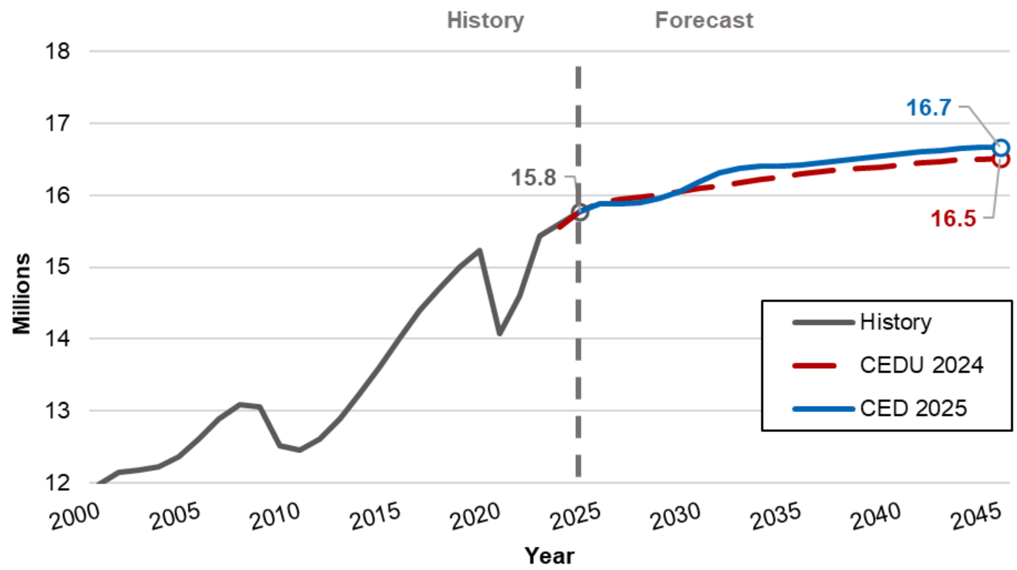
Source: CEC using data from Moody's Analytics

Commercial Employment

Figure 7 compares commercial employment[38] projections for the *2025 IEPR* and *2024 IEPR Update* forecasts. Like the other economic variables, commercial employment is expected to experience flat or slow growth in the near term compared to the previous projection, before rebounding in the year 2029. An average annual growth rate of 0.27 percent is expected from 2024 to 2045, resulting in a total increase of 5.7 percent. The flatter growth is partly due to the Bureau of Labor Statistics (BLS) revisions lowering historical estimates, in which 2024 ended up being weaker than anticipated due to high interest rates and inflation. Impacts from federal policy changes and general economic uncertainty are also slowing employment in the next few years.

38 Commercial employment is defined as "*Commercial Employment = Total Non-Ag Employment - Construction Employment - Manufacturing Employment - Natural Resources Employment.*"

Figure 7: Commercial Employment, 2025 IEPR Forecast



Source: CEC using data from Moody's Analytics

Rates

Electricity and gas rates are an input to the electricity and gas demand forecasts. The methods for forecasting electricity and gas rates, and the corresponding results are summarized below.

Electricity

The electricity rate forecast combines staff-developed projections of utility revenue requirements and retail electricity sales to calculate an annual average "all-in" electricity rate. This encompasses monthly fixed charges, demand charges, and volumetric rates.

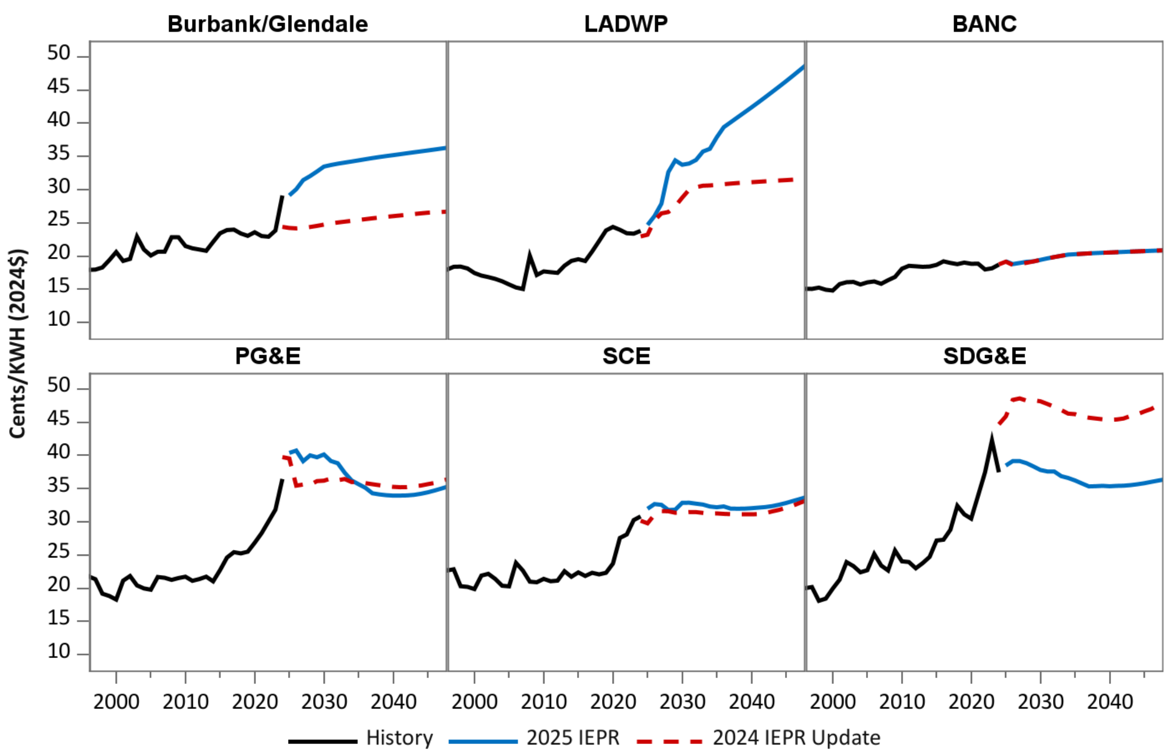
Revenue requirement projections are based on data submitted by LSEs, which include anticipated costs for generation, transmission, distribution, customer programs, and other operational expenditures. The forecast also incorporates incremental revenue requirements associated with new data center load growth and distribution-level investments needed to support electrification.

Staff compiled information on planned or approved rate increases from CPUC proceedings and public utility rate actions. Current rates were used to calibrate the forecast, and revenue requirements were allocated to customer sectors in alignment with current cost allocations.

Figure 8 presents historical and forecasted residential electricity rates for major utility planning areas. Among IOUs, rates have increased significantly faster than inflation since 2021. Key drivers include wildfire mitigation costs — such as grid hardening and vegetation management — and the financial impacts of net energy metering (NEM). NEM and NBT are causing a greater impact on rates in investor-owned utility (IOU) territories compared to publicly owned utility (POU) territories because of the disproportionately high number of rooftop solar systems in IOU territories, largely driven by a more favorable business case for solar companies and customers with BTM systems. Rising costs of generation procurement and grid upgrades contribute to rate increases across all utilities. The reduction in the forecast for SDG&E reflects lower transmission costs than previously forecast. The LADWP rate forecast includes significant rate increases needed to fund grid investment and implement the LA100 plan[39] for 100 percent renewable energy by 2035, although LADWP has not yet begun a formal rate action.

Figure 9 compares projected statewide average electricity rates by sector between the *2025 IEPR* and the *2024 IEPR Update.* Over the forecast period, continued utility investments to address climate risks and support decarbonization are expected. However, increased electricity sales from building and transportation electrification and data centers moderate upward pressure on customer rates, and inflation-adjusted rates stay relatively constant.

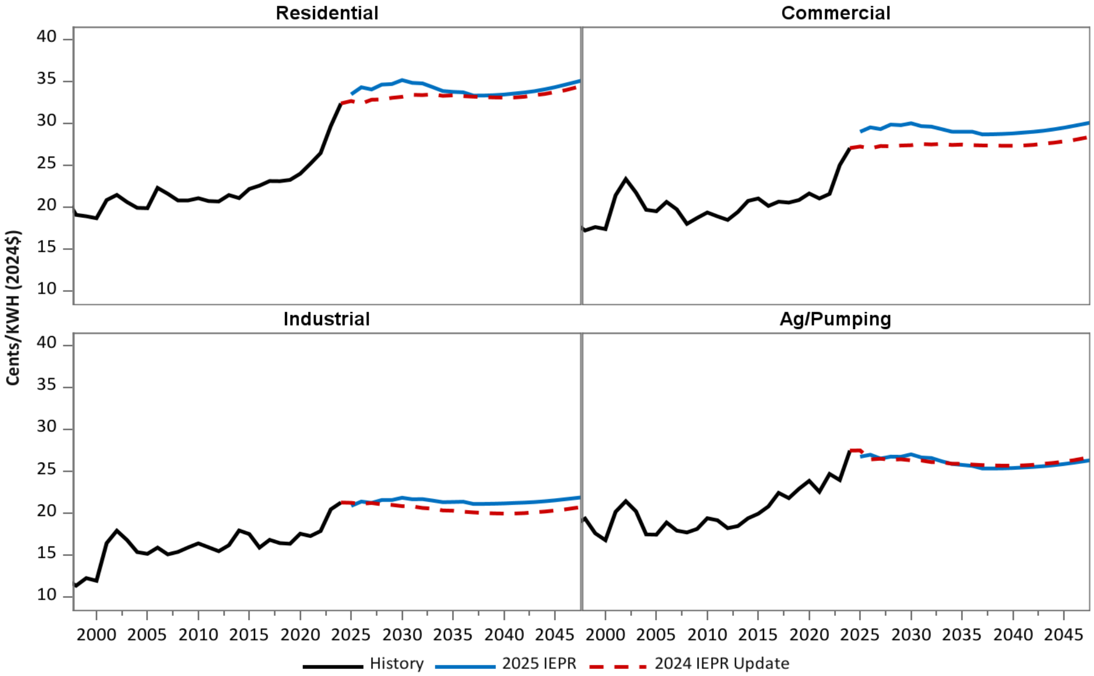
Figure 8: Residential Electricity Rates by Planning Area



Source: CEC

39 Los Angeles Department of Water & Power. "LA100 Plan." https://www.ladwp.com/who-we-are/power-system/la100-plan.

Figure 9: Statewide Average Electricity Rates by Sector



Source: CEC

Gas Rates

Total customer rates represent the final price customers pay for fossil gas — what a customer would see on their gas bill. The total customer fossil gas rate is a combination of the commodity price and transportation rate. The commodity price is for fossil gas at specific pricing hubs throughout North America and includes costs to explore, develop, extract, and transport fossil gas to the hub. Commodity price accounts for about 25 percent of the total customer rate in long-term modeling.

Transportation rates represent the cost of delivering fossil gas from the hubs to end-use customers. They account for around 75 percent of the total customer rate in long-term models. Staff forecast rates under scenarios based on four demand cases from 2023 and 2024 California Energy Demand-adopted fossil gas forecasts and considered a constant growth rate for the gas utility revenue requirement. The revenue requirement is the amount of money a utility needs to operate its gas system. Appendix D has more information about the method CEC staff used to prepare this forecast.

Total Customer Gas Rates Results

The most extreme rate increases occur in the residential sector under the AAFS 2 scenario gas impacts from the *2024 IEPR* forecast. The gas rate forecasts assume a constant growth in revenue requirements from 2025 through 2050 by utility from 2007 through 2023 (5.4 percent for PG&E, 5.5 percent for SoCalGas, and 4.6 percent for SDGE). The forecasted rates reported here for SoCalGas, PG&E, and SDGE residential customers are for the base demand case from the *2023 IEPR* forecast and the AAFS 2 scenario from the *2024 IEPR Update*.[40] The base demand case represents the business-as-usual forecast based on midlevel assumptions about economic, demographic, and policy conditions, while the AAFS 2 scenario assumes a gradual, statewide adoption of zero-emission technologies. For total customer fossil gas rates, staff forecast the following:

- SoCalGas — Under the base demand case, total customer rates start at $1.74/therm in 2025 and grow to $5.50/therm in 2050. Under AAFS scenario 2, total customer rates rise from $1.76/therm in 2025 to about $43.17/therm by 2050.
- PG&E — Under the base demand case, total customer rates rise from $2.52/therm in 2025 to $8.32/therm in 2050. Under AAFS scenario 2, total customer rates rise from $2.57/therm in 2025 to about $90.19/therm by 2050.
- SDGE — Under the base demand case, total customer rates under the base demand case grow from $2.70/therm in 2025 to $7.43/therm in 2050. Under AAFS scenario 2, total customer rates rise from $2.75/therm in 2025 to about $68.12/therm by 2050.

This sharp rise in forecasted fossil gas total customer rates in the later years is due to increasing revenue requirements and declining demand. The CPUC recently initiated an order instituting the long-term gas planning proceeding, where the CPUC intends to identify and act on opportunities for interim actions that can help reduce system and ratepayer costs and promote decarbonization in the nearer term, while long-term planning is underway.[41]

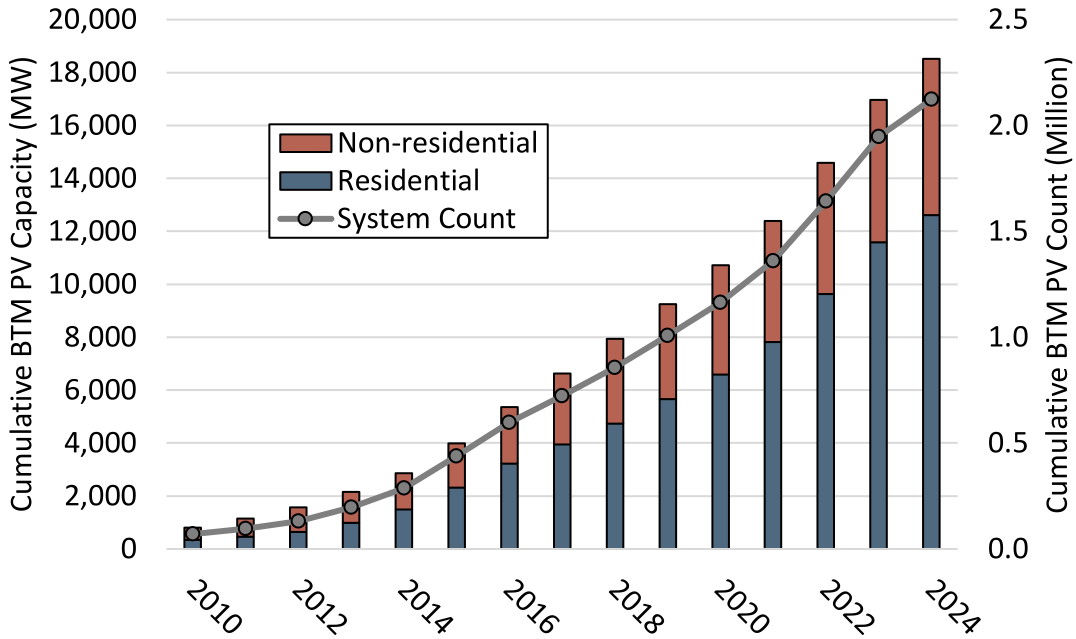
BTM PV and Storage Trends

BTM PV adoption has accelerated recently and about 57 percent of all BTM PV capacity in the state was interconnected from 2019 to 2024. CEC staff estimates 2.5 gigawatts (GW) of BTM PV capacity was interconnected in 2023 and 1.5 GW in 2024. By the end of 2024, CEC staff estimates there were 18.5 GW of BTM PV capacity and 2.1 million PV systems interconnected in California, as shown in Figure 10.

40 The gas demand forecast is updated every two years and the AAFS scenarios and corresponding electricity and gas impacts are updated annually.

41 CPUC. October 4, 2024. R. 24-09-012 — Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Long Term Gas System Planning. Pp. 2–3, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M542/K029/542029029.PDF.

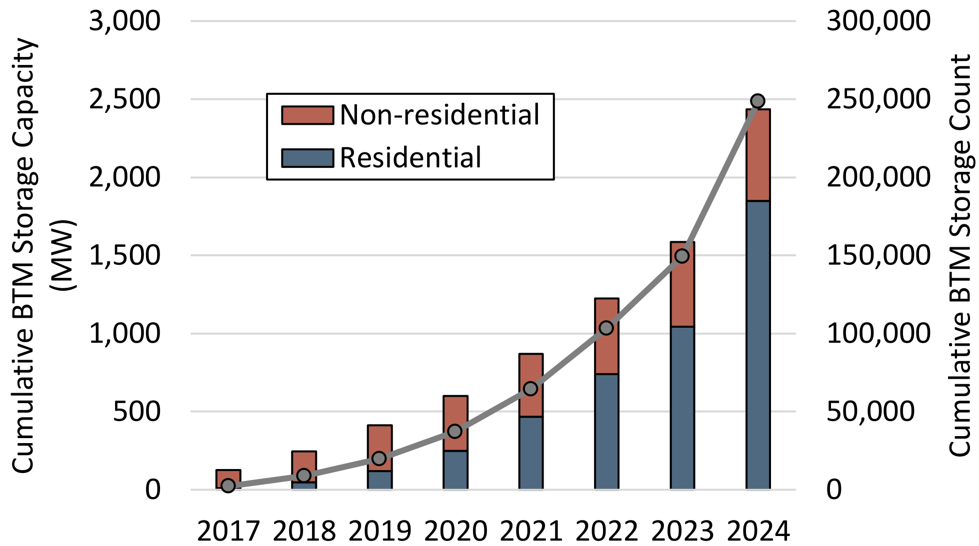
Figure 10: Cumulative BTM PV Capacity and System Count in California



Source: CEC analysis of Title 20 1304(b) interconnection data

BTM energy storage adoption is rapidly increasing in California, with a 54 percent (850 megawatts [MW]) increase in capacity from 2023 to 2024, the largest percent increase in capacity in the last five years. In 2024, a record 800 MW of residential storage capacity was interconnected, most of it paired with a PV system (Figure 11).

Figure 11: Cumulative BTM Storage Capacity and System Count in California



Source: CEC analysis of Title 20 1304(b) interconnection data[42]

According to the most recent CPUC interconnection data, BTM PV paired with energy storage systems accounted for 76 percent of residential NBT interconnections in 2024 due to the incentive design of the NBT that went into effect in April 2023 (Figure 12). The retail export compensation of the NBT is higher during evening hours, when there is more demand on the electric grid, and lower during hours when there is less demand and abundant solar generation already on the grid. The retail export compensation structure, combined with the NBT requirement to enroll in a highly differential time-of-use electricity rate, encourages PV adopters to also install energy storage. This installation allows customers to offset their grid electricity use and export excess electricity to the grid when evening electricity prices are higher. The NBT, however, also continues to increase costs for other customers, causing a cost shift that is 76 to 82 percent of the NEM cost shift.[43]

Since the adoption of the NBT, the median system size for residential stand-alone PV installations is 4 kilowatts (kW), while the median system size for residential PV paired with

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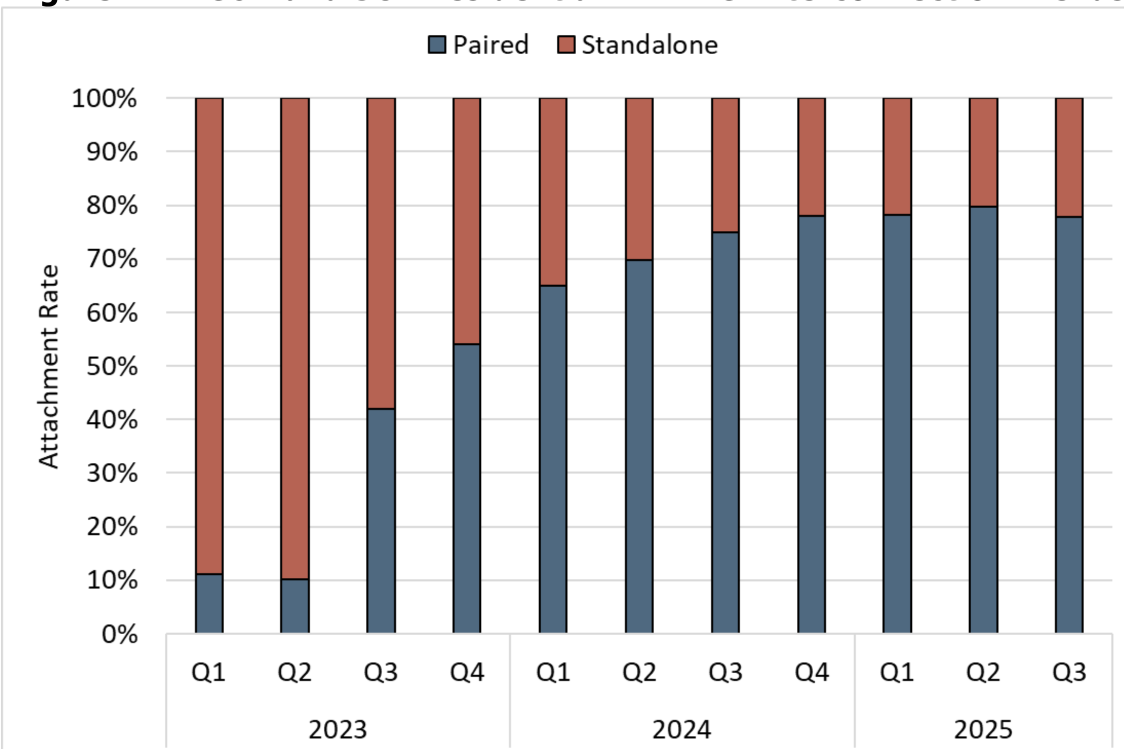
42 Find more details on the CEC's California Energy Storage System Survey web page, https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/california-energy-storage-system-survey.

43 CPUC's Response to Executive Order N-05-24, p. 12, https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/reports/cpuc-response-to-executive-order-n-5-24.pdf.

storage is 6.5 kW. The increased installed BTM PV capacity observed in paired systems is likely a result of the energy requirements associated with charging energy storage systems. Before the implementation of NBT, around 10 percent of interconnection applications included BTM PV paired with energy storage.

Figure 12: PG&E and SCE Residential BTM DG Interconnection Trends



Source: CEC analysis of CPUC interconnection data. Only systems interconnected under NBT are included post-April 15, 2023, to illustrate directional trends. Data current through September 30, 2025. SDG&E are excluded because paired systems are not detectable in the interconnection data.

Transportation Trends

Federal and State Policies and Goals

California has a long history of clean vehicle policies that have resulted in cleaner air and improved public health throughout the state. On June 12, 2025, Governor Newsom signed Executive Order N-27-25. This executive order calls for:

- Reaffirming the state's commitment to ZEV deployment.
- Initiating the development of new vehicle emission regulations regulation to advance new strategies for emissions reduction.
- Updating state purchasing requirements to align with manufacturers that continue complying with clean car regulations.
- Prioritizing funding for state incentive programs for clean manufacturers and fleets.
- Continuing Clean Truck Partnership work and requires reports on progress every six months.

- Directing state agencies to assess additional actions for ZEV adoption and issue recommendations, including strategies for consumer protection, infrastructure, voluntary efforts, and local partnerships.[44]

Federal policy changed in 2025 with the reversal of the Inflation Reduction Act. This included the removal of federal tax credits for ZEV purchases. The loss of these tax credits is incorporated in the LDV forecast.

Light-Duty Vehicle (LDV) Trends

More than 400,000 ZEVs were sold in California in 2025, bringing the cumulative number of ZEVs sold to over 2.5 million. However, the expiration of the federal ZEV tax credit led to a decrease in sales compared to 2024. Overall, the ZEV market share of total new LDV sales declined from 25.3 percent in 2024 to 22.9 percent in 2025.[45]

Medium-Duty and Heavy-Duty (MDHD) Trends

In the MDHD vehicle sector, ZEV adoption is increasing. The CEC ZEV Stats page shows the MDHD population as of 2024.[46] The continued growth in this sector reflects new vehicle offerings from many vehicle manufacturers and a wide range of vehicle types fitting varying needs of operators in this sector.

Building Electrification Trends

Federal and State Policies and Goals

California continues to develop policies and strategies that position the state to reach its building decarbonization goals of 6 million heat pumps by 2030, 3 million climate-ready and climate-friendly homes by 2030, and 7 million climate-ready and climate-friendly homes by 2035.[47] One major strategy for accomplishing these goals includes implementation of upcoming state and local air districts' ZE appliance rules and standards. Some of these

44 See "California moves forward on public health and clean vehicles as federal agencies move backwards," https://ww2.arb.ca.gov/news/california-moves-forward-public-health-and-clean-vehicles-federal-agencies-move-backwards.

45 See "New ZEV Sales in California," https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics-collection.

46 See "Medium- and Heavy-Duty Zero-Emission Vehicles in California," https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics-collection/medium.

47 Newsom, Gavin. July 22, 2022. "Letter From Governor Newsom to CARB Chair Liane Randolph," https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf.

standards and rules have encountered uncertainties given shifts in the state's ZE policy landscape. In some cases, local efforts to reduce emissions from residential gas and water heaters have faltered, such as the SCAQMD's rejection of PAR 1111 and 1121, while others are moving forward, such as the Bay Area Air District's adopted Rule 9-6, which goes into effect in 2027.

Trends for PiCS Modeling

AAEE and PiCS AAFS were developed using the same framework and general components as in 2023 and consist of six scenarios each, ranging from conservative (Scenario 1) to optimistic (Scenario 6). Input data with updated and major policy changes affecting energy saving and electrification impacts is reflected in the new 2025 analysis.

Significant considerations affecting modeling outputs for 2025 include:

1. The CMUA updates its potential study every four years, so new data have been obtained for 2025 which includes revised energy efficiency potential, as well as newly developed electrification potential for each of the 40 POUs.
    - AB 130 mandates a pause on new Residential Standards for the 2028 Title 24 Code Cycle, which is reflected in both AAEE and PiCS AAFS due to the prescriptive partial electrification baseline beginning with the 2022 and enhanced in the 2025 code cycle. The 2025 Title 24 vintage standards will persist for residential construction until 2031, at which time they may once again be improved. (Similar restrictions are not mandated for the Nonresidential Standards, so those will undergo improvement in 2028 as expected.) The CPUC reports higher IOU electrification levels in its energization data for new construction than that previously assumed in the CEC's T24 modeling, so those assumptions were updated.
2. Equitable Building Decarbonization Program funding was adjusted downward, resulting in diminished energy impacts. Early elimination of IRA funding and uncertainty around receiving approved or pending funds also affects programs relying on this source by reducing energy impacts.
3. The U.S. DOE placed 17 appliance standards measures on a list to rescind, nine of which may be preemptive (meaning that the state would not be able to continue enforcing them). As of February 2026, no action has been taken and the market is established for appliances complying with the existing standards. Still, this increases the uncertainty of the expected AAEE savings and the persistence of existing savings.

AMI — Analysis and Inferred Electrification

Electric line extension data from the IOUs provide a gauge on the energization of all-electric new construction projects compared to mixed-fuel projects.[48] For Quarter 1 (January–March), 2025, all-electric projects made up 79 percent, 36 percent, and 55 percent of new construction energization for PG&E, SCE, and SDG&E, respectively. Further, SCE saw a significant increase in the percentage of applications for all-electric new construction projects, nearly reaching half of all applications.

When looking at national space-conditioning and water-heating appliances, recent data from the Air-Conditioning, Heating, and Refrigeration Institute (AHRI) indicate that heat pump adoption continues to grow.[49] Compared to 2010, heat pump systems (including heat pumps only and air conditioning plus heat pump devices) doubled in 2024 nationally, from about 6.9 million in 2010 to 13.8 million in 2024. Considering the most recent full year of data, heat pump systems increased by 12 percent in 2024 compared to the previous year. National trends are difficult to translate into statewide trends because of different climates across the country. However, the continued growth of heat pump adoption nationally is likely to at least partially correlate with the market in California.

For the *2025 IEPR*, staff made improvements for tracking and forecasting heat pump adoption in California. Existing data sources, such as the CPUC's California Energy Data and Reporting System database, have been used to assist with developing CEC's heat pump tracking dashboard, which is still in development.[50] This dashboard will provide California specific heat pump data, updated quarterly.

Although not included in the *2025 IEPR*, CEC staff plans to implement advanced techniques for detecting heat pumps with AMI data in the future. Also, the CEC is creating data collection

48 Electric line extension data are collected by the CPUC as part of its Phase 3B decision that eliminates the subsidies provided to mixed-fuel new construction for electric line extensions. For more information on this decision, please refer to this link: CPUC. December 14, 2023. D.23-12-037 — Decision Eliminating Electric Line Extension Subsidies for Mixed-Fuel New Construction and Setting Reporting Requirements, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M521/K890/521890476.PDF.

49 AHRI is a North American trade association representing manufacturers of heating, ventilation, air conditioning, commercial refrigeration, and water heating. AHRI develops standards for measuring and certifying product performance, provides industry data, advocates for the industry on policy issues, and helps consumers identify products that meet efficiency and performance requirements.

AHRI. "Monthly Shipments," https://www.ahrinet.org/analytics/statistics/monthly-shipments.

50 CPUC. "CEDARS Database," https://cedars.cpuc.ca.gov/.

regulations to assist with the tracking of water-heating and space-conditioning appliances installed across the state, particularly focusing on heat pump appliances.[51]

Data Centers Trends

The CEC develops the data center demand forecast using information provided by electric utilities on data center energization requests. For the *2025 IEPR* forecast, seven utilities provided data: Silicon Valley Power, the City of Palo Alto, PG&E, SCE, SDG&E, the City of Burbank, and Valley Electric Association (VEA). Table 7 summarizes data center capacity requests by utility and project status. Projects with an "agreement" status have signed an electric service agreement with the utility and are the farthest along in the energization process, with the highest likelihood of being completed. Projects with an "application" status have submitted an energization application but may still be waiting additional information, such as the results of an engineering study, before executing a service agreement. Projects with an "inquiry" status means that a data center developer contacted the utility to ask questions about locating a data center within their territory. These projects have the greatest uncertainty, as no application for service has been submitted.

Table 7: Data Center Capacity Requests in MW by Utility and Status

Status	Agreement	Application	Inquiry	Total
PG&E	4,356	3,617	6,774	**14,747**
SVP	644	196	198	**1,038**
Palo Alto	14	0	55	**69**

51 (Docket 24-OIR-03) TN#264545, Request for Information (RFI) Energy Data Collection Phase 3 — Space Conditioning And Water Heating Equipment Data Tracking, https://efiling.energy.ca.gov/GetDocument.aspx?tn=264545&DocumentContentId=101418.

For more information on the Phase 3 data collection regulations (including comments), use this link (Docket 24-OIR-03), Energy Data Collection — Phase 3: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=24-OIR-03.

Status	Agreement	Application	Inquiry	Total
SCE	72	3,174	1,378	**4,623**
SDG&E	0	0	100	**100**
Burbank	0	0	100	**100**
VEA*	0	2,600	0	**2,600**
Total	**5,086**	**9,587**	**8,604**	**23,278**

Source: CEC with data from the utilities. *The VEA data center applications are for locations in Nevada but within California ISO.

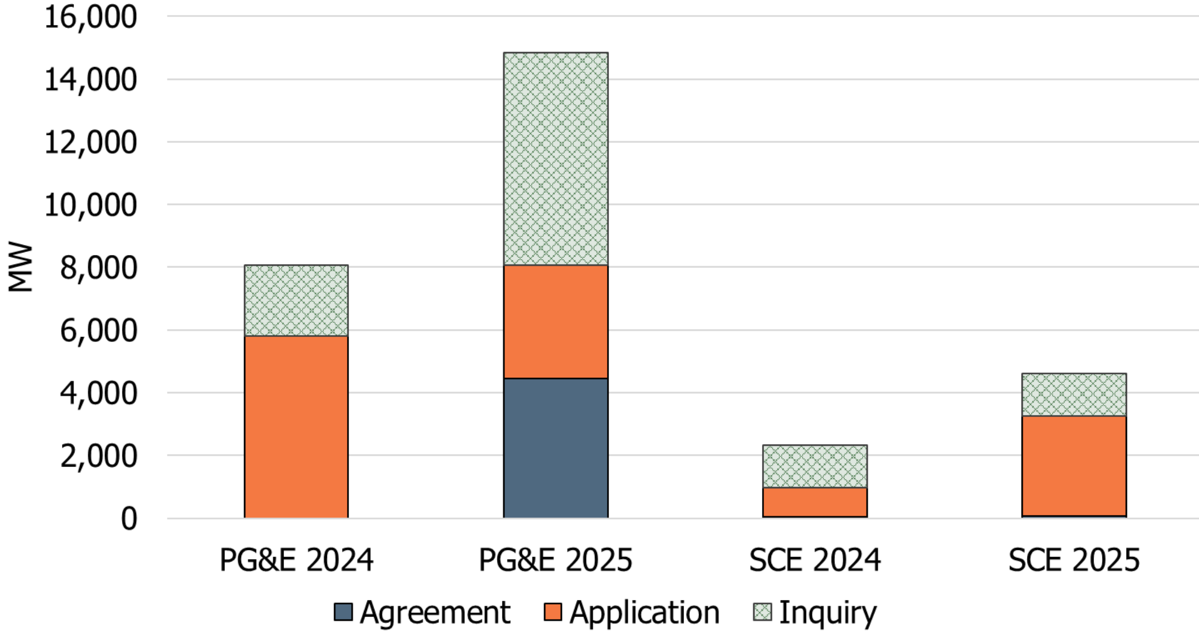
Among utilities reporting data, PG&E has the largest amount of data center capacity with signed agreements, totaling just less than 4,400 MW, followed by Silicon Valley Power with a little more than 600 MW. PG&E also has substantial potential growth, with about 3,600 MW of data center capacity at the active application stage. SCE has nearly 3,200 MW of active applications, while VEA reported 2,600 MW of data center applications within California ISO territory.

Since the *2024 IEPR Update,* data center capacity requests reported by PG&E and SCE have changed significantly, underscoring the dynamic and uncertain nature of data center development. Figure 13 compares data center capacity requests in PG&E and SCE territories as of December 2024 and December 2025. The December 2024 data were used to develop the final *2024 IEPR Update* data center forecast.

As shown, several PG&E projects advanced from the application stage to signed agreements over the past year, while other projects withdrew or were replaced by new applications. In December 2024, PG&E reported approximately 5,800 MW of data center capacity at the application stage. As of December 2025, PG&E had signed agreements for about 4,400 MW and applications for 3,600 MW. Over the same period, reported inquiries in PG&E territory increased from nearly 2,300 MW to just less than 6,800 MW.

SCE experienced a similar increase in data center interest. At the end of 2024, SCE reported just less than 1,000 MW of data center applications. As of December 2025, active applications in SCE territory had increased to nearly 3,200 MW.

Figure 13: Data Center Capacity Requests for PG&E and SCE Territories as of December 2025



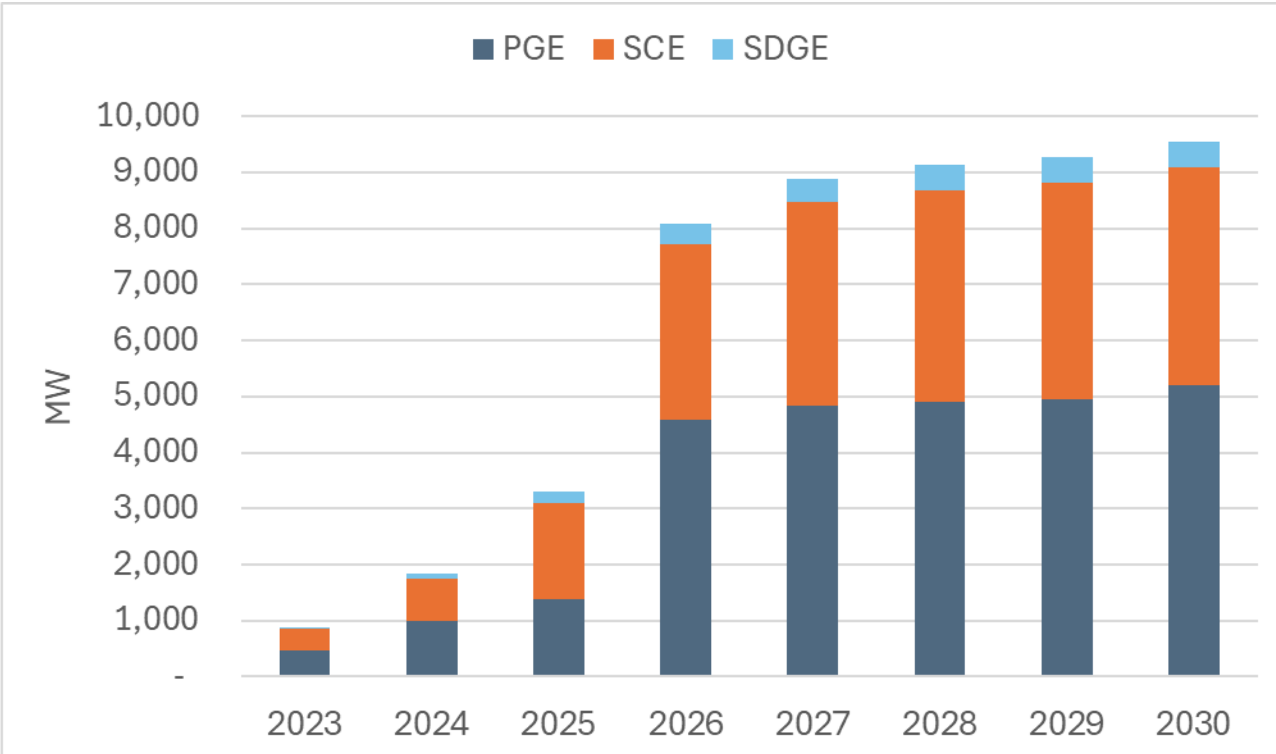
Source: CEC with data from the utilities.

Energization Application (Known Load) Trends

The CEC uses the known loads data from the IOUs to estimate load impacts due to customer energization requests. The known loads data includes expected energization dates, customer sector, project capacity, and location for each energization request. Examples of projects are new housing, office buildings, EV charging stations, and industrial facilities. Generally, commercial buildings and residential housing development accounted for the bulk of known loads projects, varying between 55 percent of total 2030 cumulative capacity for PG&E, 60 percent for SCE, and 66 percent for SDG&E.

The volume of projects in the known loads data increased dramatically in recent years, as shown in Figure 14, which for some IOUs created delays in the timely energization of projects. To address delays, the CPUC initiated a proceeding to set reasonable energization timeframes, a process for customers to report delays, and within in the CPUC's High DER proceeding, implement changes to distribution planning process that will allow IOUs to plan more proactively for system upgrades.[52]

Figure 14: Cumulative Known Loads Capacity by Utility and Sector



Source: CEC Staff

By 2030, CEC staff projects known load energized projects in each IOU service territory will total about: 5,200 MW for PG&E, 3,900 MW for SCE, and 450 MW for SDG&E.

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52 CPUC Energization webpage, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/energization.

CPUC Distribution Planning webpage, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/distribution-planning.

Electricity Demand Forecast Results

Table 8 presents the final electricity demand forecast results.

Statewide electricity consumption was nearly 281,000 GWh in 2024. Consumption is projected to reach more than 417,000 GWh in 2045 in the mid baseline used in the planning forecast, more than 434,000 GWh in the high baseline used in the local reliability scenario without known loads, and more than 452,000 GWh in the high baseline with known loads included. The baseline consumption for the planning forecast includes 32,630 GWh of data center load growth from 2024 to 2045, and the local reliability scenario includes 49,626 GWh of data center load growth over the same period. The known loads contribute nearly 18,000 GWh by 2045. Data centers and known loads are presented in greater detail below.

The baseline sales forecast represents the amount of electricity load-serving entities will need to provide to their customers and is derived by subtracting projected customer generation from the baseline consumption forecast. Baseline statewide sales were more than 243,000 GWh in 2024 and grow to nearly 356,000 GWh in 2045 in the mid baseline used in the planning forecast. Sales in the high baseline used in the local reliability scenario without known loads grow to nearly 377,000 GWh in 2045, and to nearly 395,000 GWh when known loads are included.

The managed sales forecasts incorporate the projected impacts of AAEE, AAFS, and AATE. For the planning forecast, statewide managed sales grow to nearly 394,000 GWh in 2045. For the local reliability scenario, statewide managed sales grow to nearly 434,000 GWh without known loads, and to nearly 452,000 GWh when known loads are included.

Table 8: Summary of Statewide Electricity Forecast Results in 2045

	Planning Forecast (Annual GWh)	Local Reliability Scenario without Known Loads (Annual GWh)	Local Reliability Scenario with Known Loads (Annual GWh)
Baseline Consumption	417,558	434,366	452,361
Behind-the-Meter	61,721	57,431	57,431

	Planning Forecast (Annual GWh)	Local Reliability Scenario without Known Loads (Annual GWh)	Local Reliability Scenario with Known Loads (Annual GWh)
Distributed Generation[53]			
Baseline Sales (Baseline Consumption — BTM DG and Storage)	355,837	376,935	394,930
AAEE	28,438	24,259	24,259
AAFS	34,694	39,993	39,993
AATE	31,862	41,319	41,319
Managed Sales (Baseline Sales – AAEE + AAFS + AATE)	393,955	433,988	451,983

Source: CEC

The peak demand forecast is derived from the annual consumption forecast by applying hourly load profiles to projected annual consumption. Peak forecasts are developed for balancing authorities rather than for the state. The 2025 IEPR planning scenario peak forecast for the California ISO, which manages roughly 80 percent of California's load, reaches 66,026 MW by 2045. The local reliability without known loads scenario peak forecast reaches 71,176 MW by 2045, and 74,872 MW when known loads are included.

Data Center Results

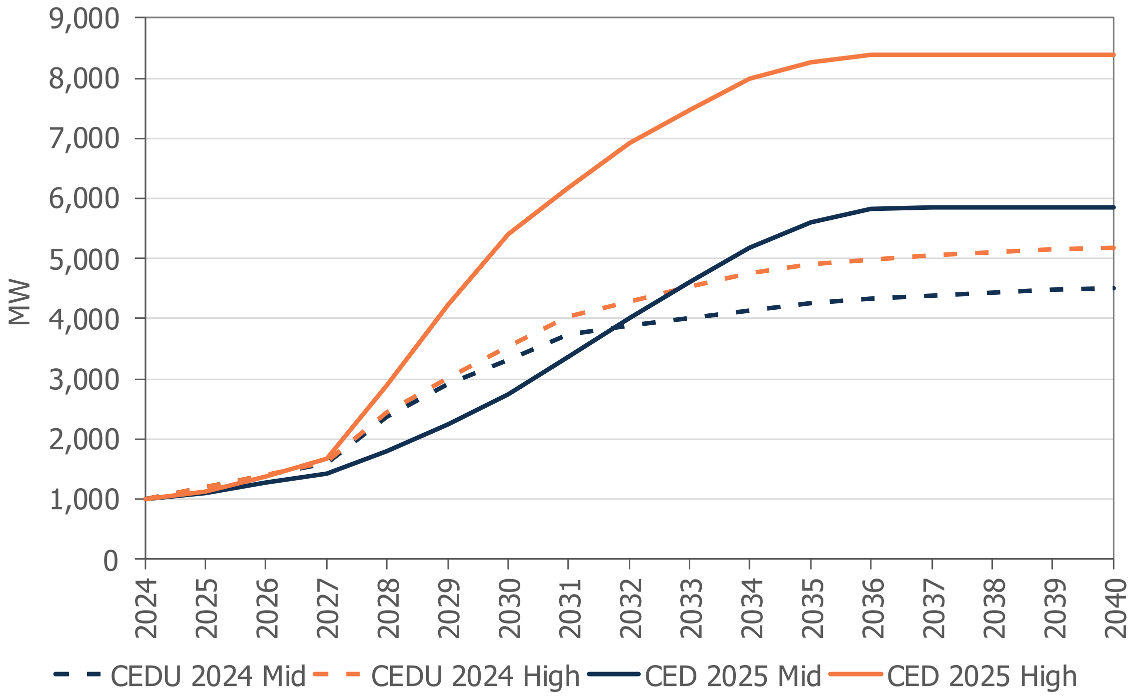
Based on utility data as of December 2025, the CEC estimates that electricity demand from data centers will increase over the next decade, contributing to both system peak demand and overall electricity consumption. Growth in data center demand is concentrated in the early

53 Includes BTM PV and other self-generation technologies.

years of the forecast and levels off in the mid-2030s under both the mid case and high case scenarios. This pattern reflects the project-based nature of the forecast, which utilizes currently known data center energization requests rather than assumed long-term growth rates.

As in prior IEPRs, staff developed data center demand scenarios using utility application data, with the mid case used for the planning forecast and the high case used for the local reliability scenario. Figure 15 shows projected data center maximum demand within the California ISO balancing authority area under the mid case and high case scenarios, including existing load. Under the mid case, data center maximum demand increases from about 1,000 MW in 2024 to about 5,800 MW by 2040. Under the high case, data center maximum demand grows to about 8,400 MW by 2040. In both cases, most of the growth occurs between the late 2020s and the mid 2030s, after which demand plateaus as the forecast exhausts projects in existing utility energization queues.

Figure 15: Statewide Data Center Maximum Demand Forecast (MW)



Maximum demand include data center projects served by VEA because these loads are connected to the California ISO system and therefore contribute to California ISO system peak demand. Data center peak demand represents the estimated maximum demand across the year and is not necessarily coincident with the California ISO system peak hour.

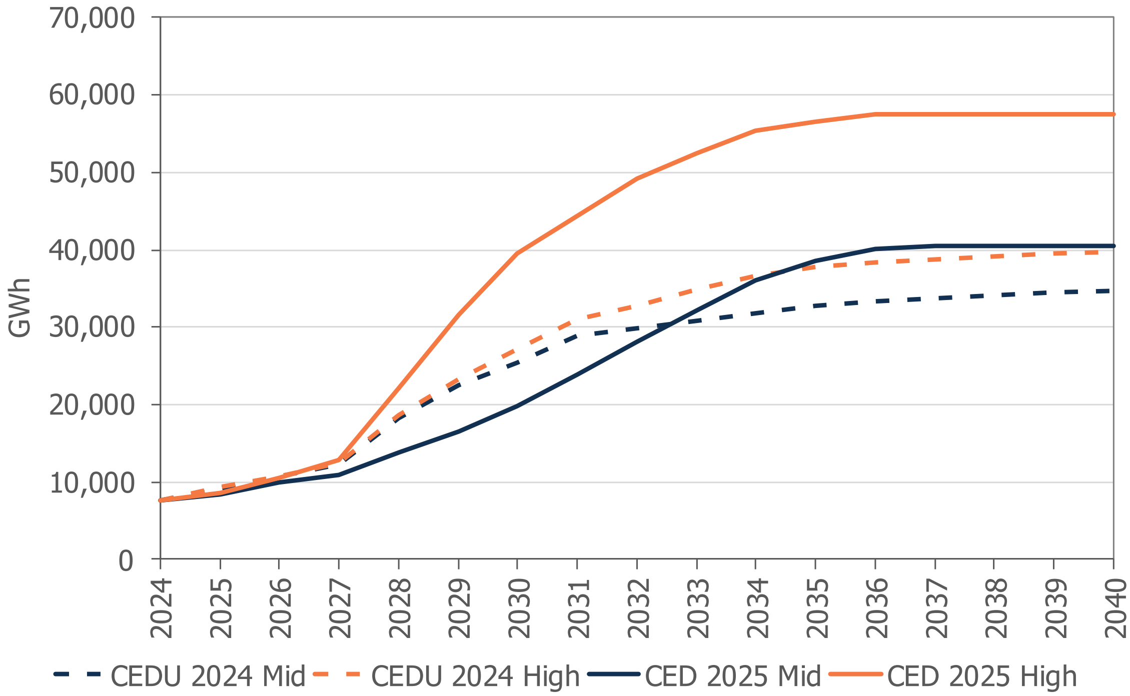
Source: CEC staff based on utility data as of December 2025

Compared to the *2024 IEPR Update*, the *2025 IEPR* forecast shows higher data center maximum demand under both scenarios. By 2040, mid case maximum demand is about 1,300 MW higher than in the *2024 IEPR Update*, while the high case maximum demand is roughly

3,200 MW higher. These differences are driven by refined assumptions and updated utility application data that were not reflected in the prior forecast.

Figure 16 shows projected statewide annual electricity consumption from data centers under the mid case and high case scenarios. Under the mid case, statewide data center electricity consumption increases to about 40,000 GWh by 2040. Under the high case, annual consumption reaches about 57,000 GWh by 2040. As with maximum demand, most of the increase in electricity consumption occurs through the mid-2030s, after which growth levels off due to the queue-based structure of the forecast.

Figure 16: Statewide Data Center Annual Electricity Consumption (GWh)



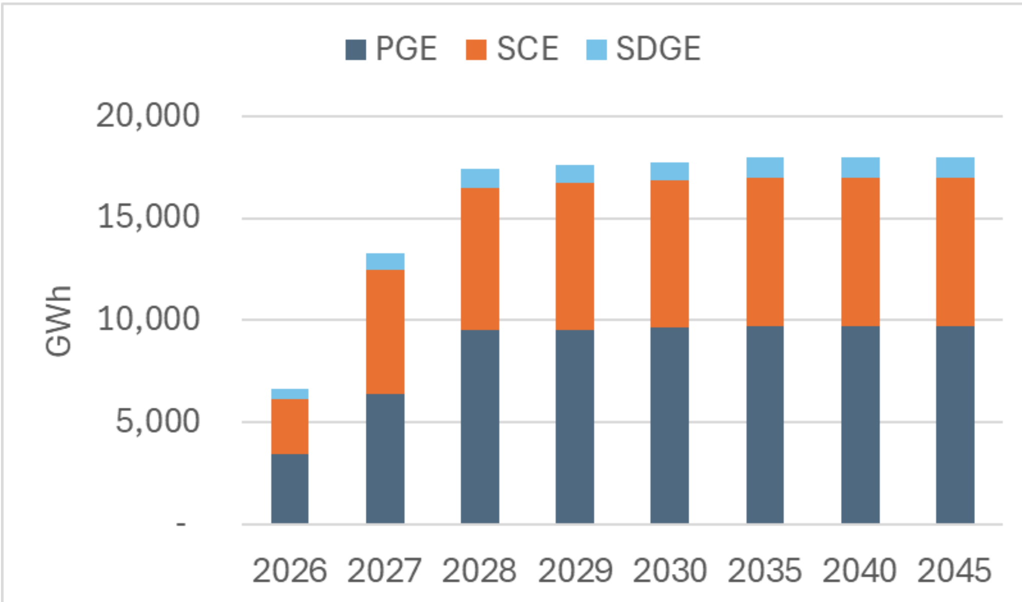
Statewide annual electricity consumption totals exclude data center projects located outside of California, including those in the Nevada portion of VEA's service territory, to ensure consistency with the geographic scope of statewide energy consumption reporting.

Source: CEC staff based on utility data as of December 2025

Relative to the *2024 IEPR Update*, the *2025 IEPR* forecast shows higher data center electricity consumption in both scenarios. By 2040, mid case consumption is roughly 6,000 GWh higher than in the *2024 IEPR Update*, while high case consumption is roughly 18,000 GWh higher. These increases are driven by updated information on known projects and revised assumptions.

Energization Application (Known Load) Impacts This section provides statewide results of translating project level capacity from the known loads data into estimated load impacts. EV charging station projects were excluded from this analysis since EV projects are examined separately. The estimated load impacts will be included as part of the local reliability scenario used for local transmission studies. Figure 17 shows cumulative load impacts by utility for select years. Overall, impacts are highest in PG&E service area followed by SCE and SDG&E. Total impacts are forecasted to grow from 6,600 GWh in 2026 to about 18,000 GWh by 2030.

Figure 17: Known Loads Impacts by Utility



Source: CEC Staff

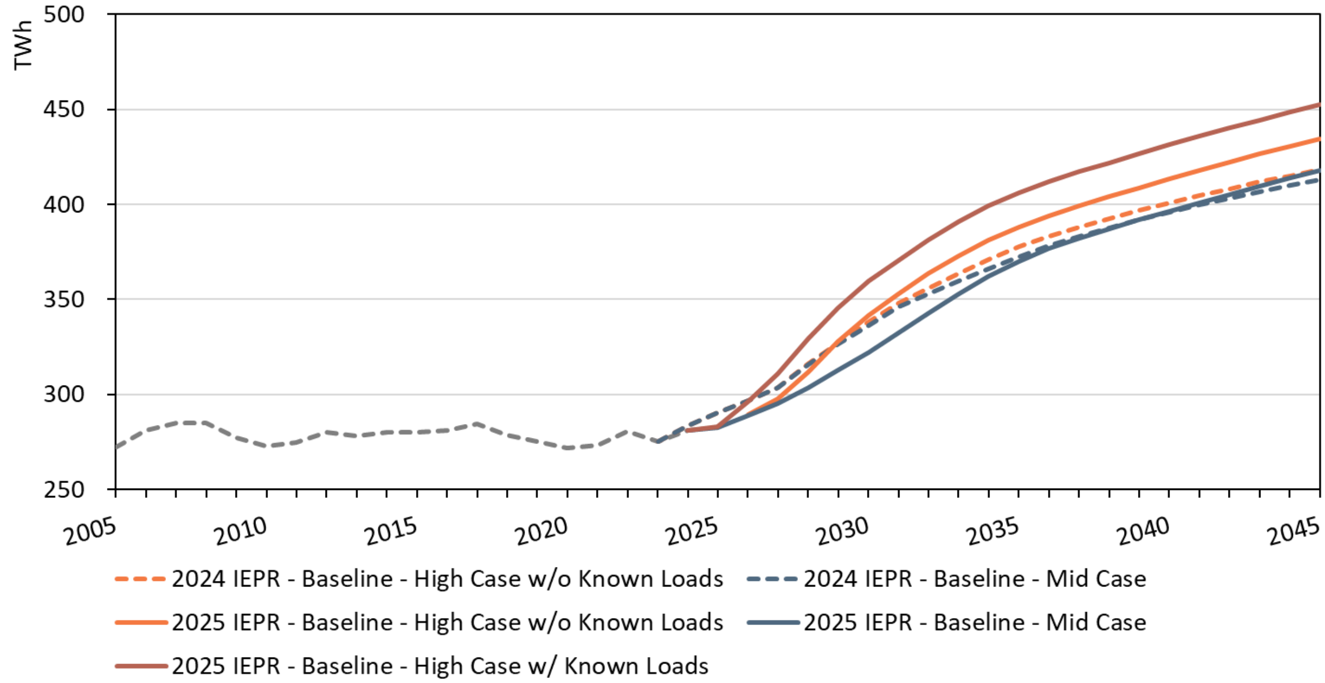
The commercial sector accounts for the largest share of load for all utilities followed by the residential and manufacturing sectors, respectively. For SDG&E, the commercial sector alone accounts for nearly 70 percent of load impacts by 2030. SCE is forecasted to have significant load growth occurring in the agricultural sector while PG&E is forecasted to have growth in the manufacturing sector.

Baseline Electricity Consumption Results

Electricity consumption grows at 1.9 percent annually through 2045 in the mid case baseline forecast, 2.1 percent annually in the high case without known loads, and 2.3 percent annually in the high case with known loads. The early years of the *2025 IEPR* forecast grow more slowly than previous forecasts, but a significant increase in electricity demand is still forecasted, and by 2045 mid case baseline consumption is 1.1 percent higher than the *2024 IEPR Update* mid case. The high case baseline without known loads is 3.9 percent higher than the *2024 IEPR Update* and is 8.2 percent higher with known loads included. Increases in both the mid and high data center forecasts and the inclusion of the known loads cause the forecasts to be higher than the previous forecast, despite the more pessimistic economic outlook.

By 2045, baseline electricity consumption will be more than 417,000 GWh for the mid case used in the planning forecast, more than 434,000 GWh for the high case used in the local reliability scenario without known loads, and more than 452,000 GWh for the high case used in the local reliability scenario with known loads included. The difference between the consumption forecasts is due entirely to the use of mid and high case data center scenarios and the inclusion or exclusion of known loads. Data center and known loads forecast results were provided in a previous section.

Figure 18: Statewide Baseline Electricity Consumption



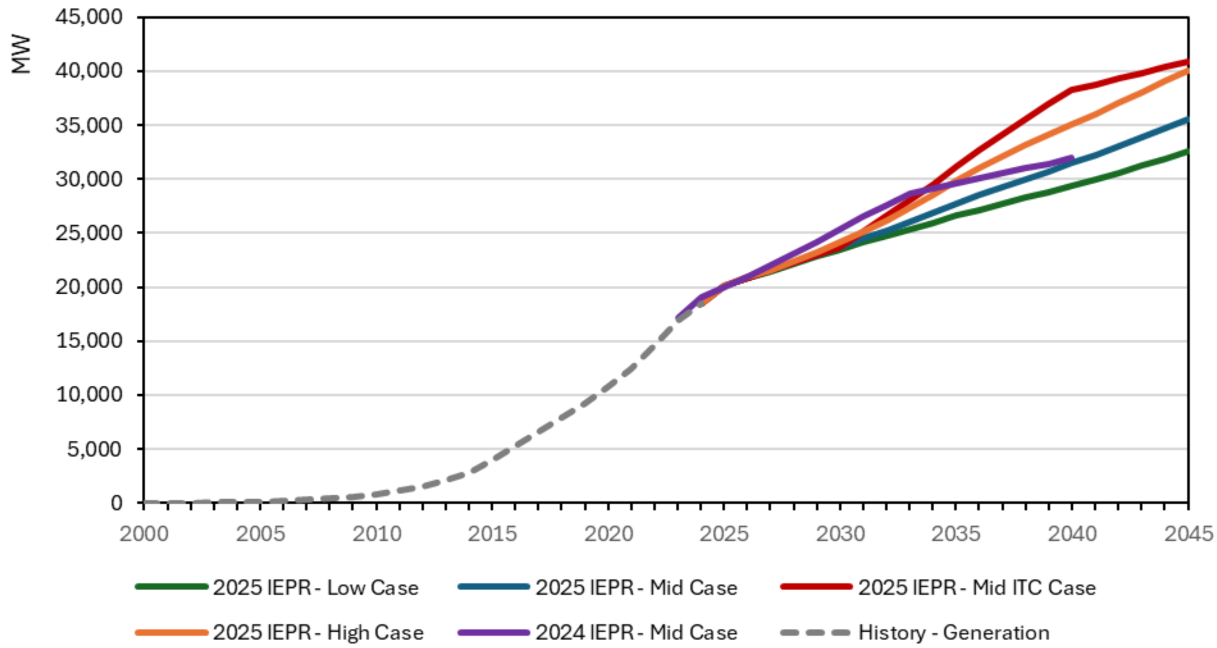
The *2025 IEPR* forecasted baseline electricity consumption grows at a rate of 1.9 percent (mid case), 2.1 percent (high case without known loads) or 2.4 percent (high case with known loads) annually from 2024 to 2045.

Source: CEC analysis

Behind-the-Meter Distributed Generation Results

The 2025 low and mid BTM PV and storage scenarios are incorporated in the planning and local reliability scenarios, as shown in Table 3. There were 18,500 MW of BTM PV capacity installed statewide through 2024. By 2045, BTM PV capacity is forecast to reach roughly 32,500 MW in the low case and 35,500 MW in the mid case. Figure 19 includes the annual BTM PV capacity forecasts compared to the 2024 IEPR mid case.

Figure 19: Cumulative Behind-the-Meter PV Capacity Forecast



Source: CEC Staff

When compared to the 2024 IEPR results, the 2025 IEPR forecasts slower near-term growth in PV and storage adoption, due to the elimination of the federal Investment Tax Credit (ITC), which leads to longer payback periods — defined as the amount of time for consumers to recoup the funds invested — for solar adopters. However, there is still growth in both markets, due to lower installation costs driven by research and development innovations, coupled with modest reductions to operation and maintenance expenses.[54] Growth from improved economics is accompanied by additional development resulting from the Title 24 building standards, which mandate PV and storage installations on newly constructed buildings. Table 9 presents the compound annual growth rates, which indicate the average annual percentage increase in BTM PV capacity over specified time periods for each 2025 IEPR forecast scenario. Among all scenarios, the Mid Plus ITC case demonstrates the greatest growth rate beyond 2030, when the ITC is reintroduced in that scenario, effectively lowering BTM PV purchase costs by 30 percent, resulting in the lowest costs among all scenarios. By 2045, there are

54 For more details on cost considerations, see staff's Demand Analysis Working Group presentation entitled "Distributed Generation Scenarios: Inputs and Assumptions": https://www.energy.ca.gov/sites/default/files/2025-08/Distributed_Generation_Scenarios_Inputs_and_Assumptions_ada.pdf.

5,300 MW, or 15 percent, more PV capacity in the mid plus ITC case compared to the mid case.

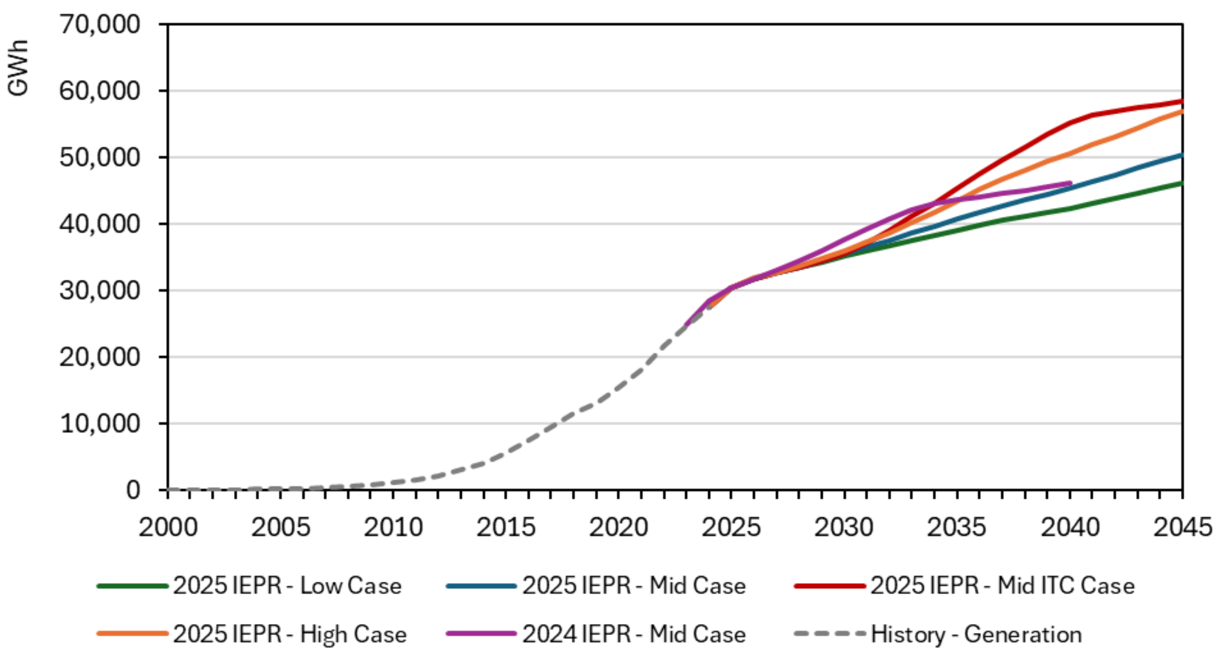
Table 9: Compound Annual PV Capacity Growth Rates

Case	2024-2030	2030-2045
Low	4.0%	2.2%
Mid	4.2%	2.7%
Mid Plus ITC	4.2%	3.7%
High	4.5%	3.4%
2024 IEPR, Mid	4.9%	2.3% (to 2040)

Source: CEC Staff

Staff estimate that 18,500 MW of BTM PV generated roughly 27,400 GWh in 2024. By 2045, that number nearly doubles to 50,000 GWh in the mid case and 46,000 GWh in the low case, equivalent to nearly 20 percent of current statewide electricity demand. Figure 20 includes the annual BTM PV generation forecasts compared to the 2024 IEPR mid case.

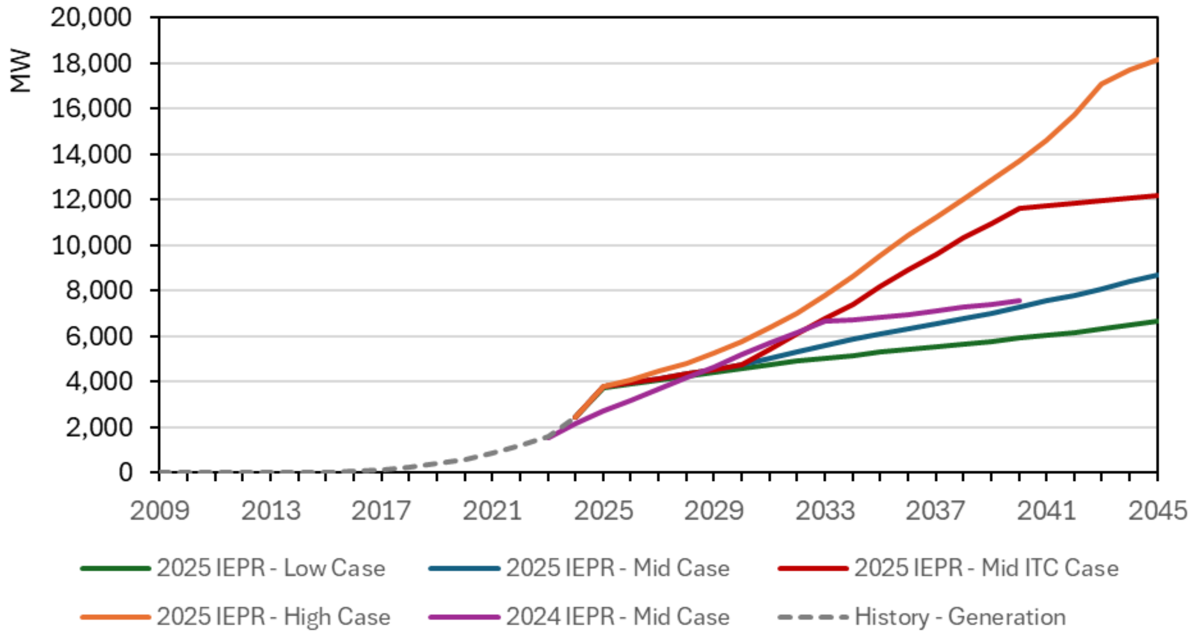
Figure 20: Annual Behind-the-Meter PV Generation



Source: CEC Staff

There was just over 2,400 MW of BTM storage capacity installed statewide through 2024, and by 2045, that number is forecast to more than double to roughly 6,600 MW in the low case and triple to nearly 8,700 MW in the mid case. Forecasted BTM storage capacity in the mid and low cases through 2040 is lower than in the 2024 IEPR mid case forecast. This decrease reflects the reduced BTM PV forecast, as many storage installations are paired with PV. However, in the high case, cumulative storage capacity is over twice as high as the mid case in 2045, due in large part to retrofit storage installations when customers switch from NEM to NBT service. All cases, as well as the 2024 IEPR mid case, are shown in Figure 21.

Figure 21: Annual Behind-the-Meter Storage Capacity Forecast



Source: CEC Staff

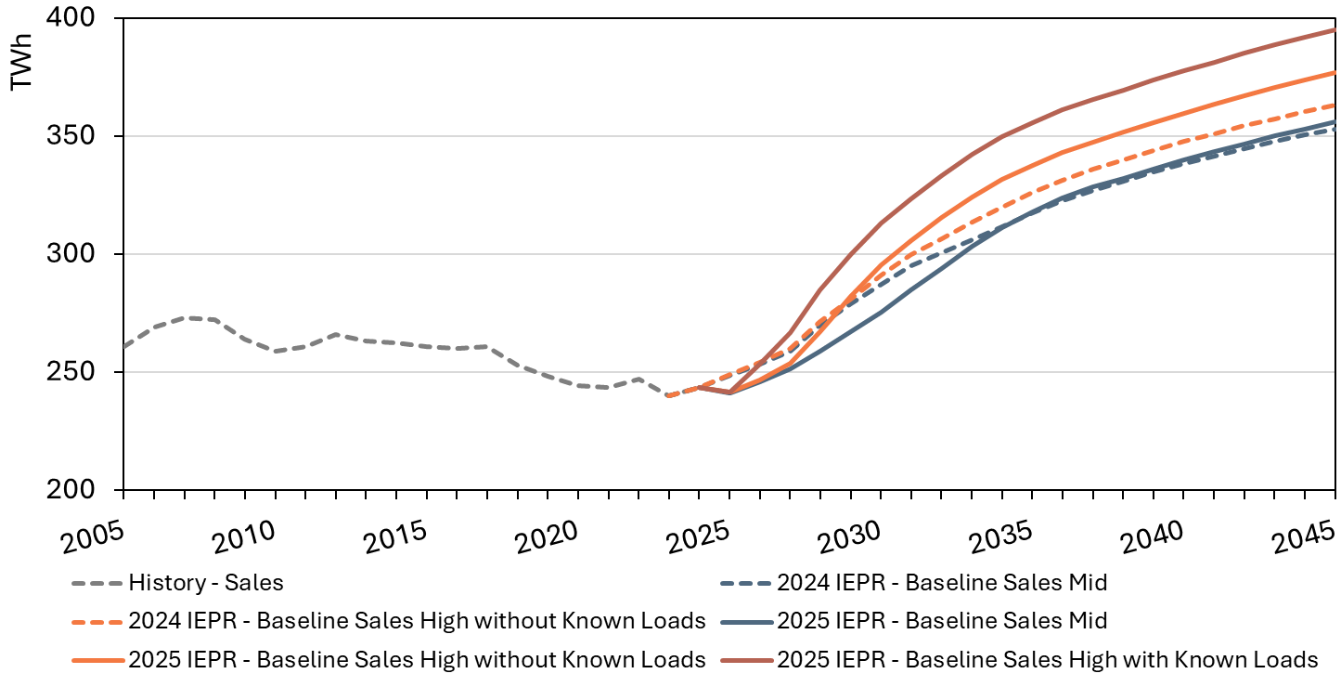
Baseline Electricity Sales

The sales forecast represents the amount of electricity load-serving entities will need to provide to their customers and is derived by subtracting projected customer generation from the consumption forecast. The statewide sales forecast therefore reflects many of the same characteristics as the consumption forecast, but the incremental BTM distributed generation added each year reduces annual growth relative to consumption. From 2024 to 2045, self-generated energy (including solar PV and other technologies) grows by 2.4 percent annually in the mid case and 2.1 percent in the low case.

Electricity sales grow at 1.8 percent annually through 2045 in the mid case baseline forecast, 2.1 percent annually in the high case without known loads, and 2.3 percent annually in the high case with known loads. As with the consumption forecasts, the *2025 IEPR* sales forecasts initially grow more slowly than the *2024 IEPR Update* sales forecasts but eventually exceed them. By 2045, mid case baseline sales are 0.8 percent higher than the previous mid case. The high case baseline without known loads is 3.9 percent higher than the *2024 IEPR Update* and is 8.8 percent higher with known loads included.

By 2045, baseline electricity sales will be nearly 356,000 GWh for the mid case used in the planning forecast, nearly 377,000 GWh for the high case used in the local reliability scenario without known loads, and nearly 395,000 GWh for the high case used in the local reliability scenario with known loads included. The difference between the sales forecasts is due to the use of mid and high case data center scenarios, the inclusion or exclusion of known loads, and the use of mid and low self-generation scenarios.

Figure 22: Statewide Baseline Electricity Sales



The *2025 IEPR* forecasted baseline electricity sales grow at a rate of 1.8 percent (mid case), 2.1 percent (high case without known loads) or 2.3 percent (high case with known loads) annually from 2024 to 2045.

Source: CEC analysis

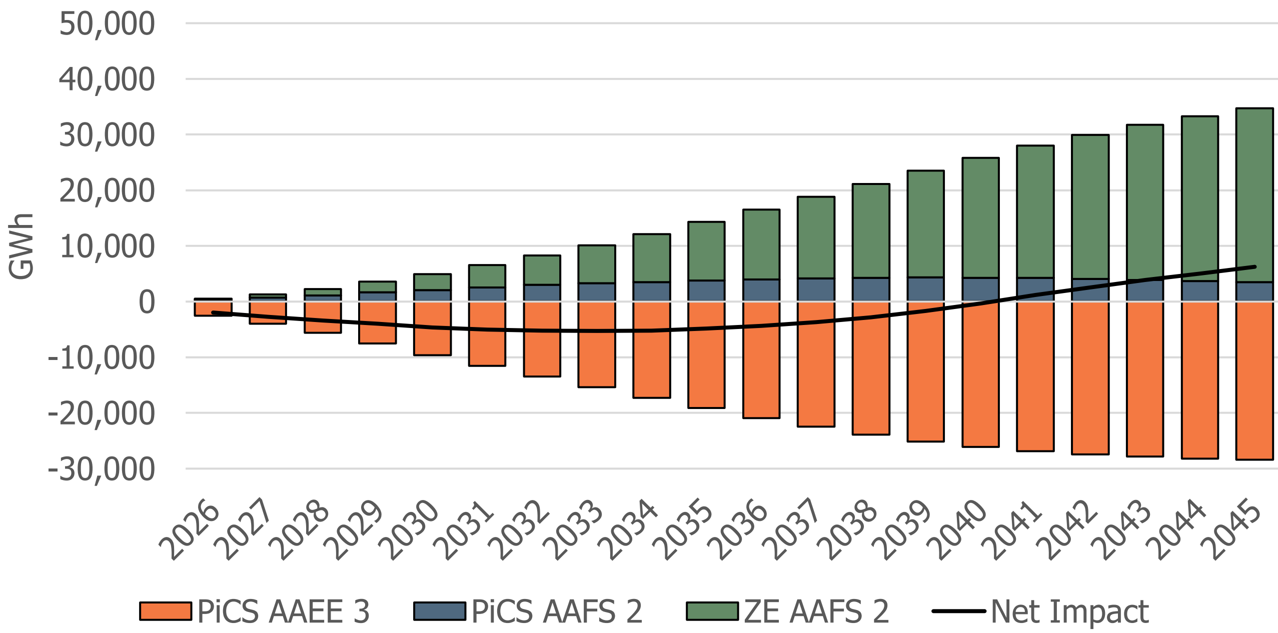
Additional Achievable Energy Efficiency and Fuel Substitution Electricity Impacts

The AAEE savings and AAFS impacts are based on results from six gas PiCS AAEE scenarios, six electricity PiCS AAEE scenarios, six PiCS AAFS scenarios, and six ZE AAFS scenarios. This section focuses on the results of the AAEE and AAFS combinations used for the electricity-system planning forecast and local reliability scenario. There are a few notable observations when comparing the 2025 impacts to 2023 and 2024. For example, updates to the 2025 PiCS AAEE and PiCS AAFS resulted in greater electricity energy-efficiency savings and fuel substitution impacts. While the slower electrification characterized in the 2025 ZE AAFS scenarios reduced the electric load fuel substitution impacts. Overall, the 2025 combined AAEE and AAFS impacts used for the forecast result in lower load growth than in previous forecasts.

Figure 23 and Figure 24 report the net electricity impacts from the PiCS AAEE, PiCS AAFS, and ZE AAFS scenarios included in the planning forecast and the local reliability scenario, respectively. They represent the statewide AAEE and AAFS electricity impacts from the residential, commercial, industrial, and agricultural sectors. As seen in both figures, the electricity savings from PiCS AAEE reduce (but do not fully offset) the additional electricity from all fuel substitution activities. The black net impact lines in each figure show that the AAEE and AAFS load modifiers add more electricity than they save starting in 2041 for the planning forecast and 2029 for the local reliability scenario. For the overall energy impacts of these AAFS scenarios, ZE AAFS has the greatest impact on added electric load for both forecast scenarios.

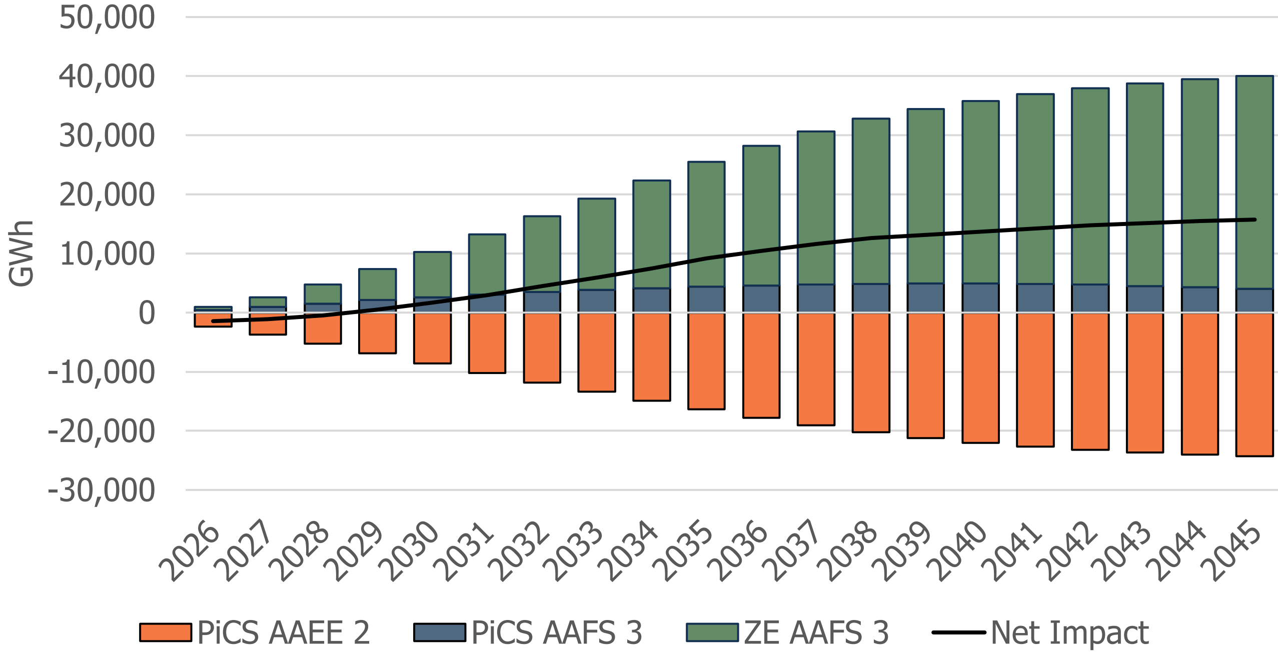
As shown in Figure 23, the planning forecast has a net increase of around 6,200 GWh in 2045. The local reliability scenario has a net increase in electric load of around 15,700 GWh in 2045. The difference in electricity impacts between the two scenarios is most substantial during the early years of the forecast, largely caused by the ZE adoption rates used in AAFS 2 versus AAFS 3. The more gradual adoption of ZE space and water heating appliances in existing buildings in ZE AAFS 2 results in slower growth than in ZE AAFS 3 (see adoption curves in Figure 24**Error! Reference source not found.**). The ZE AAFS 3 scenario includes the i mpacts from local air districts' zero-NOx regulations and follows the adoption rates used for the 2022 CARB Scoping Plan's proposed scenario.

Figure 23: Saved/Added Electricity from All Sectors for the Planning Forecast (GWh)



Source: CEC Staff

Figure 24: Saved/Added Electricity from All Sectors for the Local Reliability Scenario (GWh)



Source: CEC Staff

Staff's analysis of forecasted electric heat pump installations from PiCS AAFS and ZE AAFS, combined with the estimated 1.9 million existing heat pumps in California in 2024, suggests that the local reliability scenario meets the 2030 six-million heat pumps goal.[55] The planning forecast, however, falls short, even if the installed electric resistance water heaters in ZE AAFS 2 were replaced with heat pump units. Staff will continue to explore additional data sources, including AMI data, to track installations, monitor market trends, and improve modeling for fuel substitution and energy efficiency.

The impacts from the ZE AAFS scenarios used for both scenarios are lower than the impacts modeled in the previous forecast. This reduction across IEPR vintages is due to several factors. Statewide adoption of ZE appliances in new construction was removed from ZE AAFS 2 and 3, as this adoption is instead modeled in PiCS AAFS scenarios. Additionally, all ZE AAFS scenarios

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55 The 1.9 million heat pump estimate is for existing space and water heating appliances through Q4 of 2024. There are 2.2 million heat pumps as of Q3 2025. The latest heat pump count is available on the heat pump tracking dashboard hosted here by the California Heat Pump Partnership. https://heatpumppartnership.org/.

prioritize installing efficient heat pump water heaters over electric resistance units, which reduces the electric impact of fuel substitution for gas water heating. Finally, ZE AAFS 2 excludes local air district zero-NOx regulations, and ZE AAFS 3 reflects CARB's Scoping Plan scenario with less aggressive statewide ZE appliance adoption compared to earlier concepts of ZE space and water heater standards.

Similarly, the updates to the PiCS AAEE and PICS AAFS scenarios resulted in major differences in impact relative to 2023.[56] Over 40 workbooks representing various programs, incremental codes and standards, are updated and used to generate the impacts. These various impacts are categorized as IOU programs, POU programs, beyond-utility programs, and codes and standards. Figure 25 shows the increase in PiCS AAEE Scenario 3 impacts in 2025 compared to 2023. This increase in energy efficiency savings, particularly from codes and standards, is primarily due to two reasons. First, the 2025 updates to the federal appliance standards workbook significantly increased the impacts relative to 2023. The 2025 data updates included the addition of standards that were neither modeled nor known in 2023.[57] Second, the 2025 updates better preserve the T24 impacts beyond 2030, particularly for non-residential buildings, which were not accounted for based on 2023 data.

Figure 25 shows an increase in electric impacts from PiCS AAFS Scenario 3 compared to 2023. The increase stems from two reasons. First, like PiCS AAEE, the updated data assumptions better preserve T24 codes and standard impacts beyond 2030. Secondly, the 2025 data revealed greater electrification efforts from existing beyond-utility programs than documented in 2023.[58] The 2025 model updates reflect this finding. However, the lower impacts of IOU and

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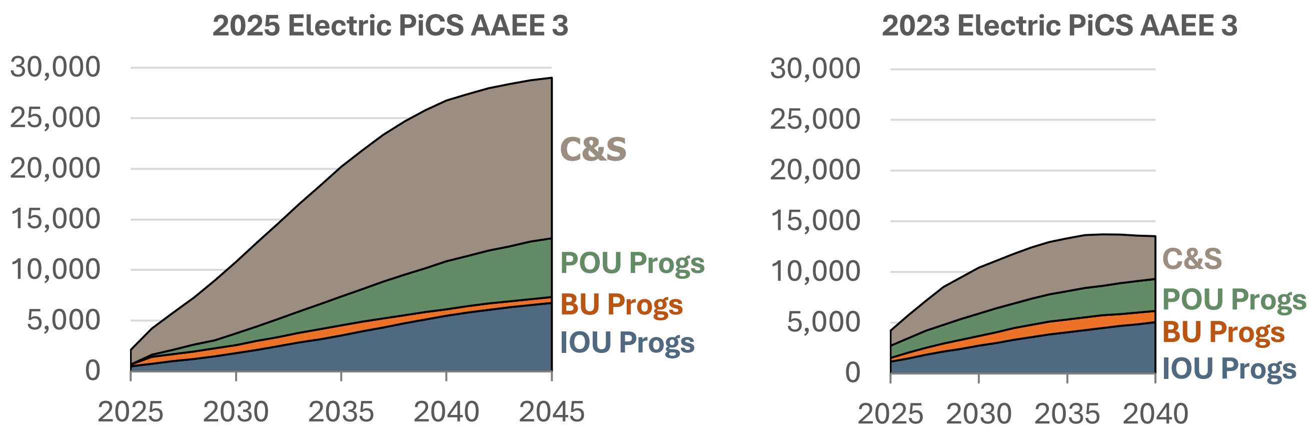
56 The PiCS AAEE and PICS AAFS scenarios are updated every two years, in the odd years. This schedule aligns with the timing of the CPUC's Potential and Goals Study, which is a major input for the PiCS AAEE and PiCS AAFS

57 Staff identified the need for major updates to the outdated federal appliance standards workbooks and completed the work for the 2025 IEPR. The 2023 analysis captured the impacts from federal standards in the baseline forecast rather than in the PiCS AAEE scenarios. See Appendix E of the [2025 CPUC Potential and Goals Study Report](https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-efficiency/2025-potential-goals-study/2025-group-e-potential--goals-study-final-report-20250717.pdf) for a full list of 2025 modeled codes and standards. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-efficiency/2025-potential-goals-study/2025-group-e-potential--goals-study-final-report-20250717.pdf.

58 CEC staff learned about this pattern of greater electrification from beyond-utility programs through the 2025 data collection process, which involves interviewing and collecting data from program administrators to update the various PiCS modeling workbooks. For example, the DOE approved in January 2025 California's Home Efficiency Rebates (HOMES) Pay-for-Performance program, which is expected to provide 100% heat pump installation compared to the previously assumed energy efficiency retrofits (See [here](https://www.energy.ca.gov/programs-and-topics/programs/inflation-reduction-act-residential-energy-rebate-programs) for HOMES program description). https://www.energy.ca.gov/programs-and-topics/programs/inflation-reduction-act-residential-energy-rebate-programs.

POU programs mitigated the increase in fuel-substitution impacts. Factors such as the elimination of IRA incentives and the competitiveness of energy-efficiency measures reduced the potential for these utility fuel substitution programs.

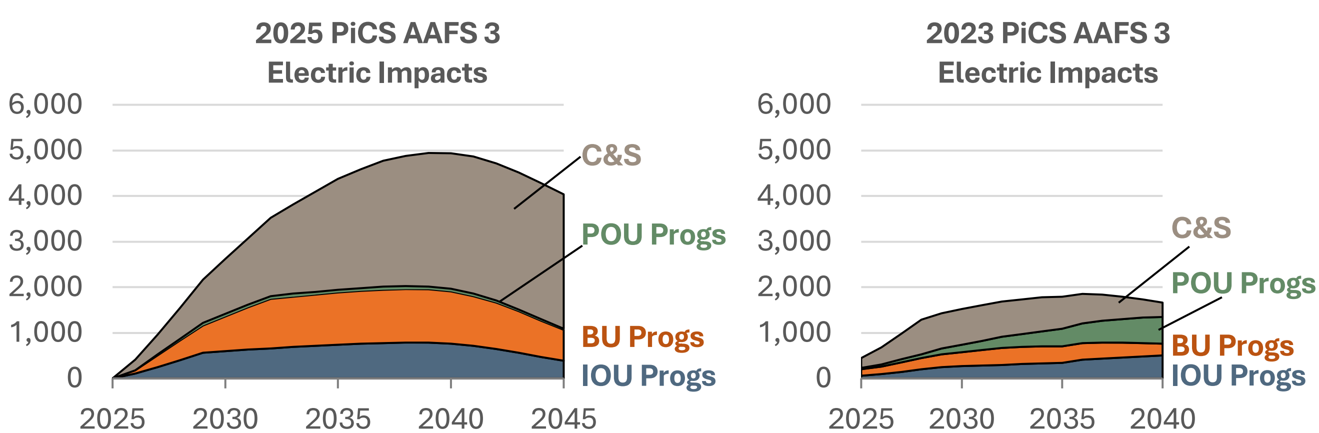
Figure 25: Electric PiCS AAEE Scenario 3 Savings 2023 and 2025 Comparison (GWh)



IOU Progs = investor-owned utility programs, POU Progs = publicly owned utility programs, BU Progs = beyond-utility programs, and C&S = incremental codes and standards

Source: CEC Staff

Figure 26: Electric PiCS AAFS Scenario 3 Impacts 2023 and 2025 Comparison (GWh)



IOU Progs = investor-owned utility programs, POU Progs = publicly owned utility programs, BU Progs = beyond-utility programs, and C&S = incremental codes and standards

Source: CEC Staff

Additional Achievable Transportation Electrification Impacts

The TEDF helps to assess future transportation energy demand. It is used by government agencies, utilities, fuel providers, and many others to plan infrastructure development, adjust energy policies, and implement emission reduction strategies. In essence, it enables better preparation for the evolving energy needs of California.

The TEDF includes a baseline forecast that reflects existing market conditions including continued consumer adoption of existing and new ZEV models, and implementation of regulations that are being actively enforced. The AATE scenarios reflect accelerated growth rates for ZE light-, medium-, and heavy-duty vehicles.

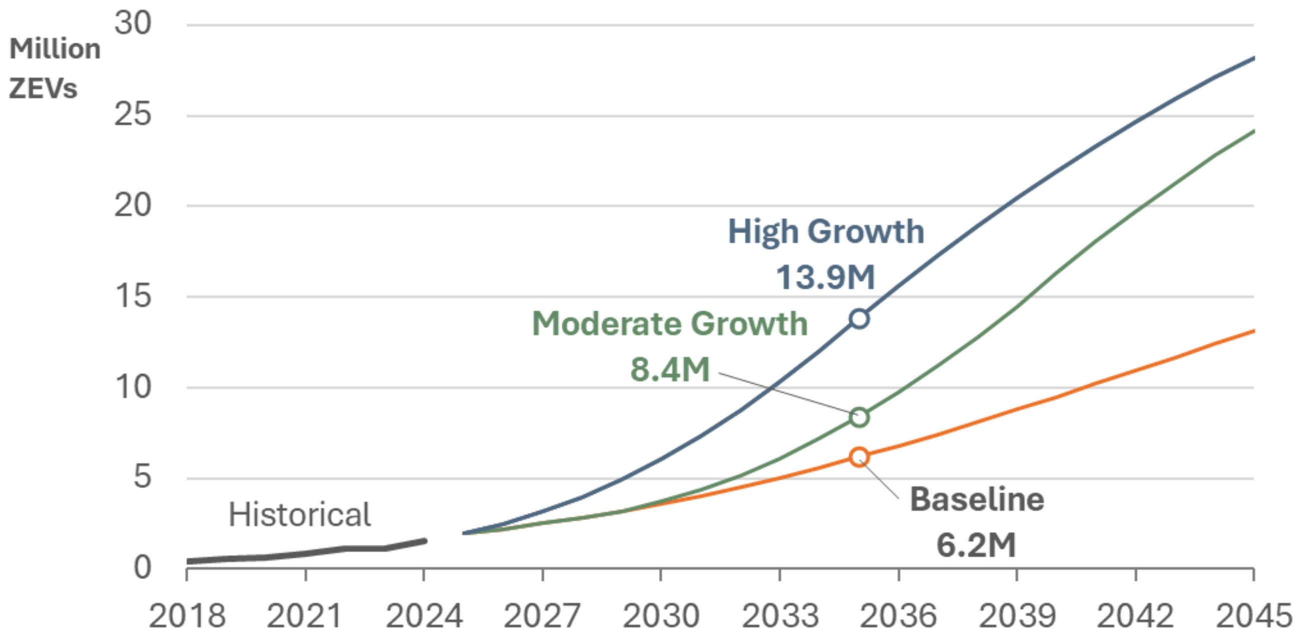
Table 10: Transportation Electrification Scenarios

Forecast Case	Scenario	Light-Duty ZEV Growth	Medium- and Heavy-Duty ZEV Growth
Baseline	Baseline	Baseline	Baseline
Planning Forecast	AATE 2	Moderate Growth	Baseline
Local Reliability	AATE 3	High Growth	Baseline
Policy Growth	AATE 4	High Growth	High Growth

Source: CEC Staff

Historically, sales and market share of new ZEV sales have grown considerably. Comparing the 2035 various managed forecasts' populations of light-duty ZEVs under the baseline, moderate-growth, and high-growth scenarios, there are roughly 6.2 million, 8.4 million, and 13.9 million, respectively.

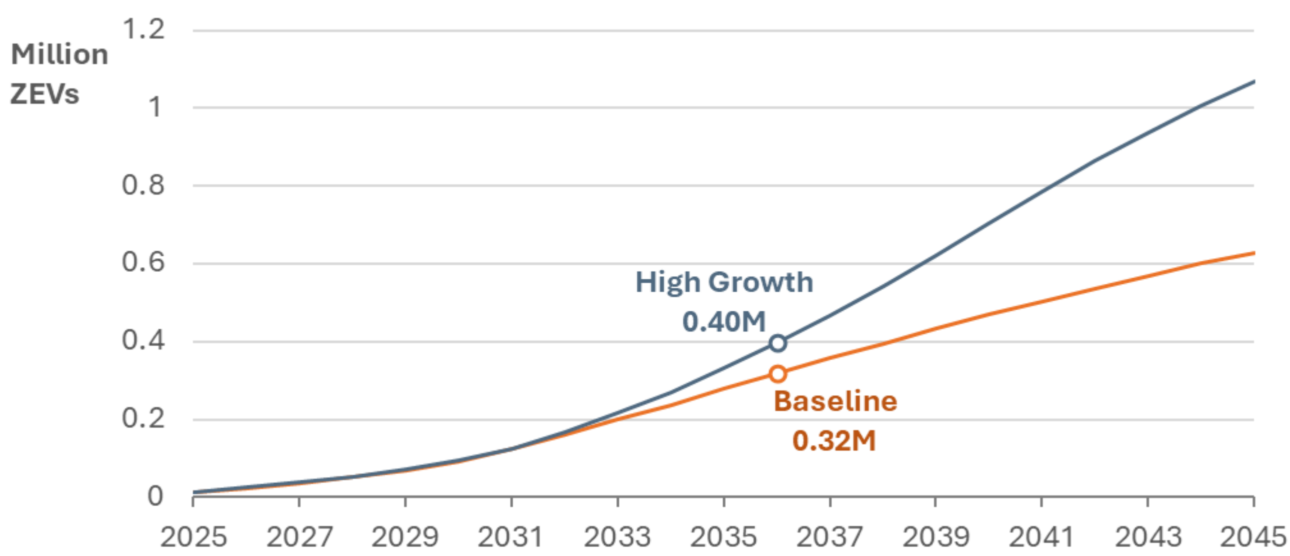
Figure 27: Light-Duty ZEV Stock



Source: CEC Staff

There has also been growth in the population of ZE medium- and heavy-duty vehicles, as an increasing number of ZEV models have become commercially available. For 2035, there is a baseline projection of roughly 278,000 vehicles, and 330,000 vehicles in the high-growth scenario.

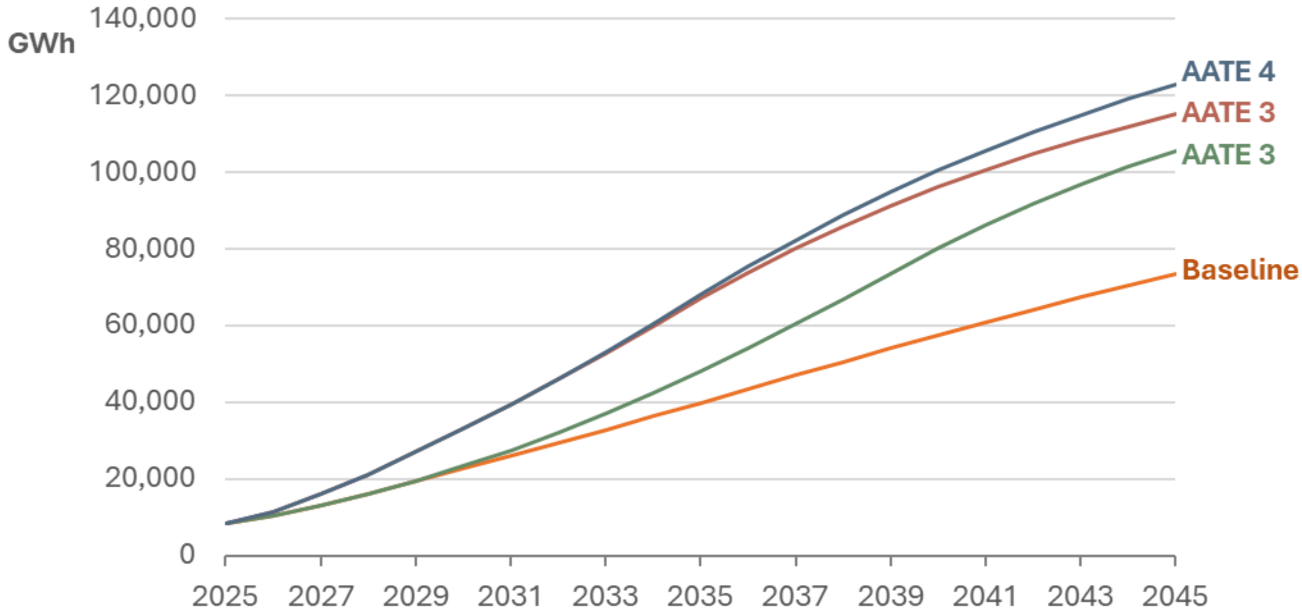
Figure 28: Medium- and Heavy-Duty ZEV Stock



Source: CEC Staff

Electricity demand driven by the growing adoption of ZEVs rises steadily throughout the forecast period. The forecasted electricity demand from on-road light-, medium, and heavy-duty electric vehicles is shown in Figure 29 below.

Figure 29: Total On-Road Transportation Electricity Demand



Source: CEC Staff

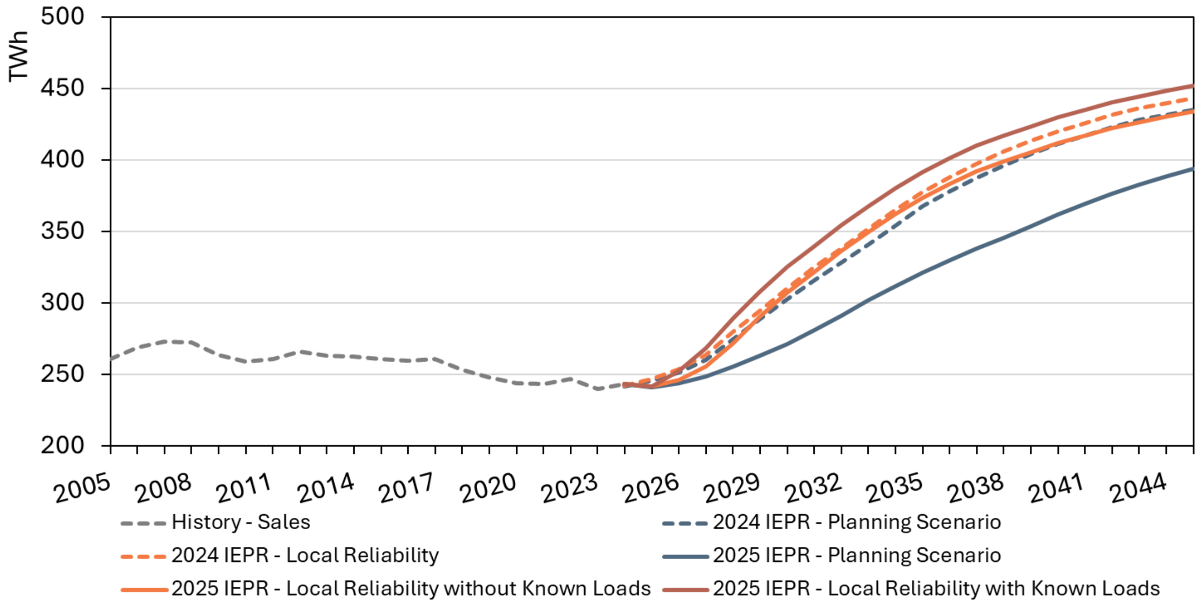
Managed Electricity Sales

The baseline electricity sales forecasts combined with AAEE, AAFS, and AATE scenarios create the managed sales forecasts. For the *2025 IEPR*, the planning forecast is a managed forecast that is a combination of the "mid case" baseline sales forecast, AAEE Scenario 3, AAFS Scenario 2, and AATE Scenario 2. The *2025 IEPR* local reliability scenario is a managed forecast that is a combination of a "high case" baseline sales forecast, AAEE Scenario 2, AAFS Scenario 3, and AATE Scenario 3. The high case sales forecast uses a higher data center load and lower self-generation estimates compared to the mid case sales forecast. As detailed in previous sections, there are two variations of the high case baseline sales forecast, one with known loads excluded and one with known loads included. There are likewise two variations of the local reliability scenario as well, one with known loads excluded and one with known loads included.

By 2045, the *2025 IEPR* planning forecast reaches nearly 394,000 GWh annually, the Local Reliability forecast without known loads reaches nearly 434,000 GWh, and the Local Reliability forecast with known loads included reaches nearly 452,000 GWh.

The *2025 IEPR* Planning forecast initially grows more slowly than the *2024 IEPR Update* Planning forecast, which used a different set of scenarios. The *2025* IEPR managed sales forecasts use AAFS and AATE scenarios corresponding to lower electricity demand, to reflect the deferred adoption of both transportation and building electrification measures in response to federal policy uncertainty. The *2025 IEPR* local reliability scenarios also include a lower set of scenarios than in previous forecasts, however the larger data center forecast offsets this difference. When known loads are included, the local reliability scenario exceeds the *2024 IEPR Update* for the entire forecast period after the year 2026.

Figure 30: Statewide Managed Electricity Sales



The *2025 IEPR* forecasted managed electricity sales grow at a rate of 2.3 percent (Planning forecast), 2.8 percent (Local Reliability without known loads) or 3.0 percent (Local Reliability with known loads) annually from 2024 to 2045.

Source: CEC analysis

Hourly and Peak Electricity Demand

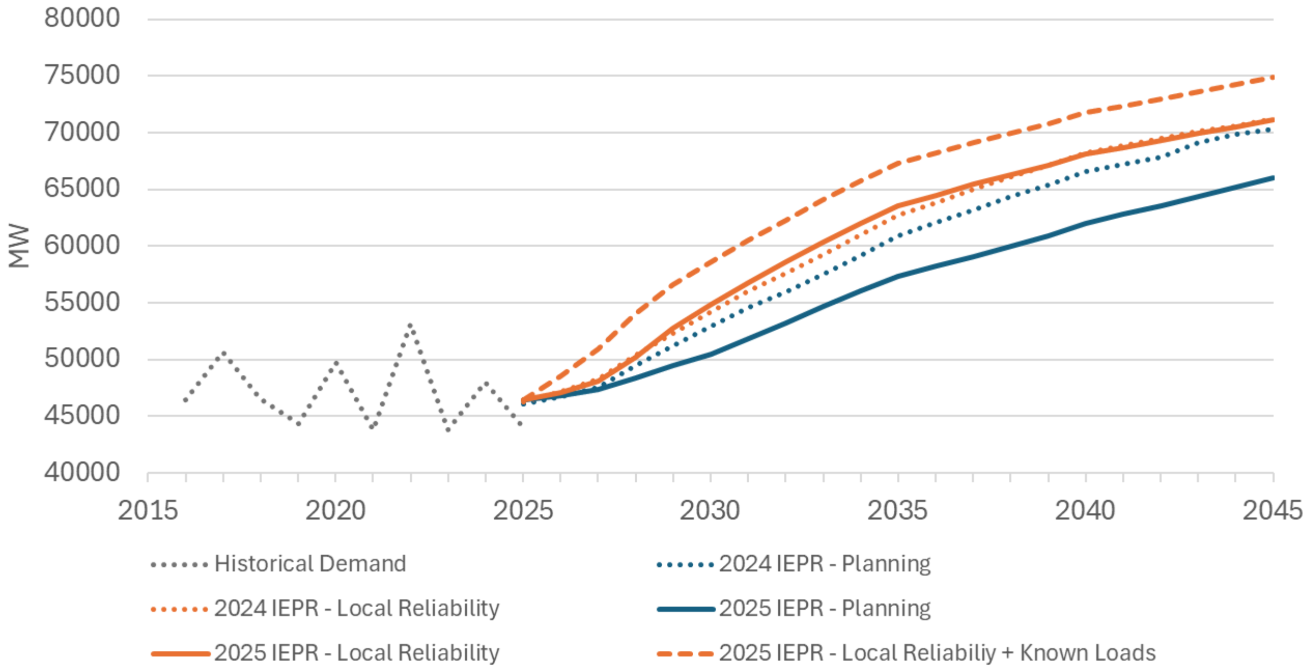
The peak demand forecast is derived from the annual consumption forecast by applying hourly system load profiles to projected annual consumption. Staff benchmarks the peak forecast to weather-normalized peaks from the most recent historical year — from summer 2025, in this case. The planning forecast projects the California ISO system peak to grow at a rate of 1.7 percent annually, reaching 66,025 MW by 2045.

Though starting at a higher level, the 2025 IEPR planning forecast for the California ISO system crosses the 2024 IEPR planning forecast in 2027 and is lower throughout the remainder of the forecast period. The decrease is driven largely by higher levels of additional achievable energy efficiency and lower levels of both transportation electrification and fuel substitution.

The 2025 IEPR local reliability scenario — which, by definition, assumes lower levels of efficiency and higher levels of electrification than the planning forecast — is comparable to its previous vintage, growing at a rate of 2.2 percent annually and reaching 71,176 MW by 2045.

When layered on top of the local reliability scenario, staff analysis of utility known loads contributes an additional 3,800 MW to the 2045 peak.

Figure 31: Managed System Peak Demand (California ISO)



Source: CEC Staff

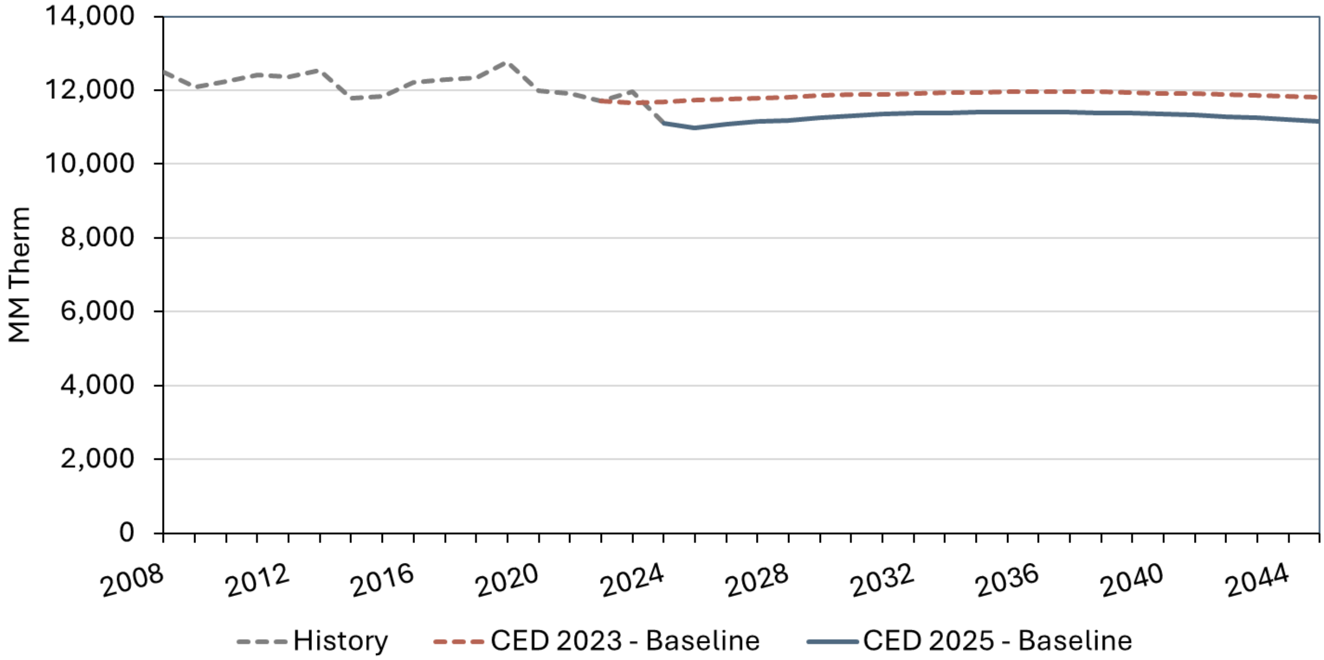
Gas Forecast Results

The gas forecast is updated every two years, in odd years. There is no self-generation for the gas forecast, so consumption is equivalent to sales. There is only a single "mid case" baseline forecast for gas because none of the scenarios differentiating the electricity mid and high forecasts (data centers, known loads, and self-generation) apply to the gas forecast.

Baseline Gas Consumption

Statewide gas consumption was a little more than 11,000 MM Therms in 2024, a decline from nearly 12,000 MM Therms in 2023. In the baseline forecast, consumption is projected to be relatively flat and is roughly 11,000 MM Therms in 2045. The *2025 IEPR* gas forecast is lower than the previous *2023 IEPR* gas forecast due to calibrating to 2024 historical data and a greater level of economic uncertainty in the forecast drivers in the first few years. However, the annual growth rate over the forecast period remains similar to previous forecasts at roughly zero percent.

Figure 32: Statewide Baseline Gas Consumption



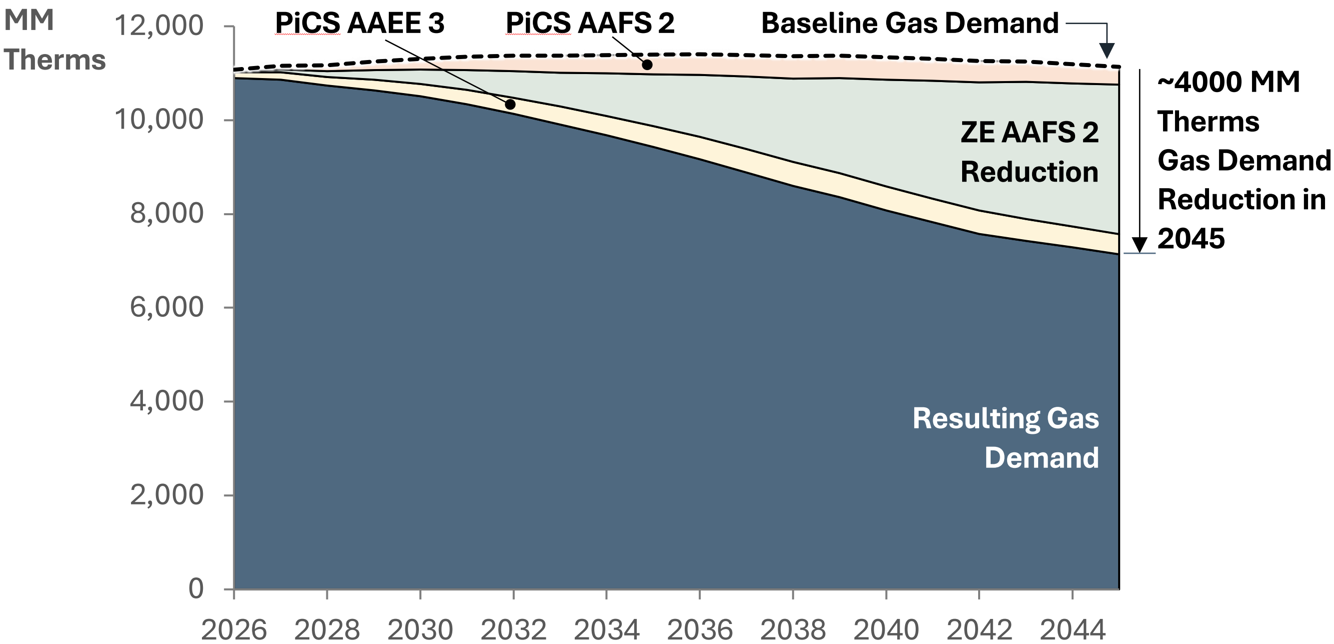
The *2025 IEPR* forecasted baseline gas consumption grows at a rate of 0.0 percent annually from 2024 to 2045, similar to the *2023 IEPR* forecast.

Source: CEC analysis

AAEE Savings and AAFS Impacts for Gas Demand

The gas demand implied by the electricity system planning scenario can show how statewide gas demand changes in accordance with electrification and efficiency. Figure 33, for example, shows the combined gas-displacement impacts of the load modifiers relative to the baseline gas-demand forecast for all sectors. The implied gas reductions are not as large as those modeled in 2024. The implied gas savings in 2045 from PiCS AAEE 3, PiCS AAFS 2, and ZE AAFS 2 are 430 MM therms, 379 MM therms, and 3,186 MM therms, respectively, contributing to total gas savings of 3,995 MM therms. Of the total gas savings for AAEE and AAFS in 2045, almost 80 percent of the reductions come from ZE AAFS, illustrating the significant (and uncertain) impact the ZE AAFS modeling has on reducing gas demand.

Figure 33: Gas Demand Forecast Reductions from the Electricity System Planning Scenario



Source: CEC analysis

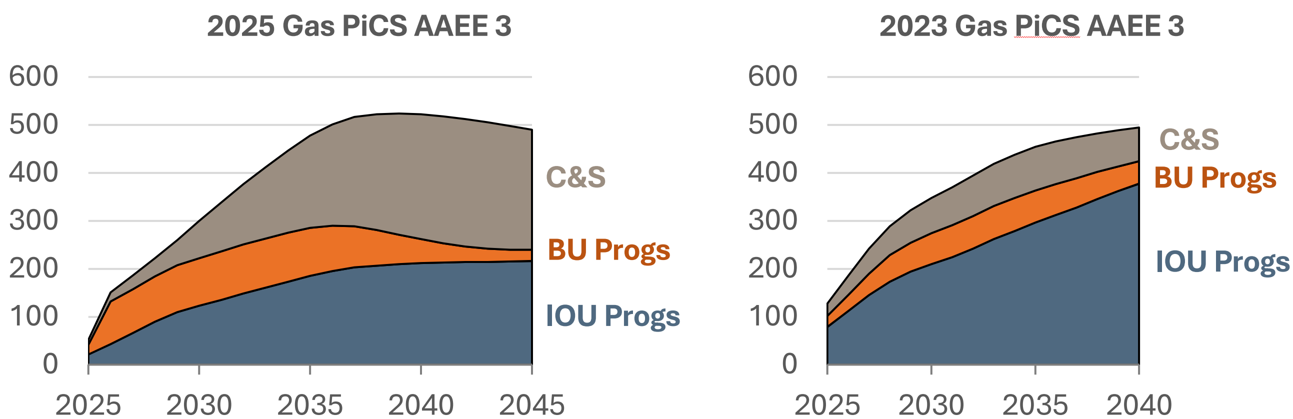
Overall, compared to previous forecasts, the 2025 PiCS AAFS scenario gas impacts are larger, while the PiCS AAEE have similar gas savings. For example, see the 2023 and 2025 comparisons of the combined impacts of PiCS AAEE 3 and PiCS AAFS 3 in Figure 34 and Figure 35. As seen in Figure 34, the gas energy efficiency savings have similar total projections but with different values for components. As with the PiCS AAEE electricity savings, the 2025 updates better preserve the T24 impacts beyond 2030, particularly for non-residential buildings, which were not accounted for in 2023. Further, the decrease in the IOU program impacts reflects the phasing out of gas energy efficiency programs.[59] The aggregate impacts

59 The April 2023 CPUC 23-04-035 Decision had not been approved before the drafting of the 2023 CPUC Potential and Goals Study. The study did consider the potential impacts of the partial phase-out of gas energy efficiency incentives (See pp. 91-92 in the 2023 CPUC Potential and Goals Study). https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-efficiency/2023-potential-goals-study/final-2023-group-e-pg-study-report.pdf.

CPUC, D.23-04-035, April 6, 2023, *Decision Addressing Codes and Standards Subprograms and Budgets and Staff Proposal on Reducing Ratepayer-Funded Incentives for Gas Energy Efficiency Measures*. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M505/K808/505808197.PDF.

resulted in similar PiCS AAEE savings across the scenarios. The PiCS AAFS scenarios, however, show greater gas displacement than in 2023 (See Figure 35). The PiCS AAFS 3 gas displacement reported is directly tied to the electric PiCS AAFS impacts in Figure 34. Thus, the same explanations discussed above about the differences in PiCS AAFS across years also apply here.

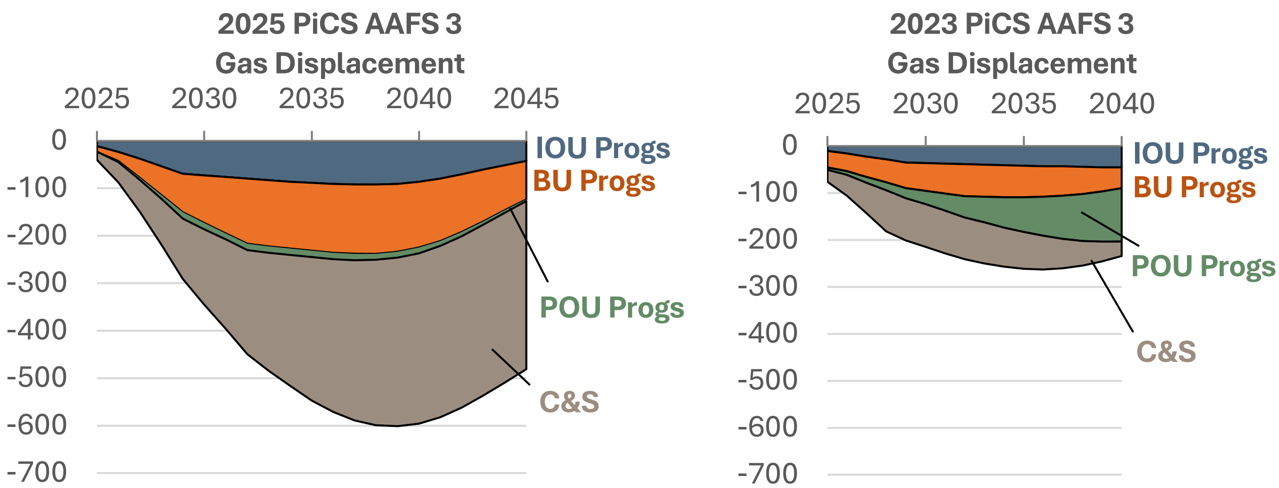
Figure 34: PiCS AAEE Scenario 3 Gas Savings 2023 and 2025 Comparison (MM Therms)



IOU Progs = investor-owned utility programs, POU Progs = publicly owned utility programs, BU Progs = beyond-utility programs, and C&S = incremental codes and standards

Source: CEC Staff

Figure 35: PiCS AAFS Scenario 3 Gas Displacement 2023 and 2025 Comparison (MM Therms)



IOU Progs = investor-owned utility programs, POU Progs = publicly owned utility programs, BU Progs = beyond-utility programs, and C&S = incremental codes and standards

Source: CEC Staff

Choice of a Single Managed Forecast Set for Electricity Planning

The baseline electricity demand in combination with the following scenarios adopted by the CEC on January 21, 2026, create managed electricity forecasts. These managed forecasts constitute options for a "single forecast set" to be used for planning in CEC, CPUC, and California ISO (the joint agencies and California ISO) proceedings and processes.[60] The scenarios are as follows:

- One scenario for known loads (energization applications at the distribution system level)
- Four behind the meter distributed generation (BTM DG) scenarios
- Three data center scenarios

60 Memorandum of Understanding Between the CPUC, CEC, and California ISO regarding Transmission and Resource Planning and Implementation, https://www.energy.ca.gov/sites/default/files/2023-01/MOU_Dec_2022_CPUC_CEC_ISO_signed_ada.pdf.

- Six AAEE savings scenarios
- Six AAFS scenarios
- Three AATE scenarios

The staff of the joint agencies and California ISO have agreed that specific elements of this forecast set will be used for electricity planning and procurement in CPUC's resource adequacy program, California ISO's local studies, and other planning processes as outlined below, whereas the California ISO's TPP bulk system, economic, and policy studies and CPUC's IRP will use the *2024 IEPR Update* Planning Forecast. The rationale is explained below. The combination of scenarios used for electricity system planning are not recommended for gas system planning. The details of this agreement will adapt as the needs of planning and procurement evolve.

The term "single forecast set" clarifies that the forecast is not a single number, but a set of forecast numbers adopted by the CEC on January 21, 2026, as part of the *2025 IEPR*. This set includes managed forecast scenarios that combine baseline forecasts using alternative weather variants; BTM DG, data center, known load, AAEE, AAFS, and AATE scenarios; and hourly load forecasts for TAC areas.[61] Agreement on a single forecast set includes specification on the use for each component of the set.

The single forecast set consists of components of the IEPR electricity demand forecast:

- A baseline forecast of annual energy and peak demand, with peak event weather variants (for example, 1-in-2, 1-in-5, and 1-in-10)
- Hourly loads for the baseline forecast for each of three IOU TAC areas
- One known load scenario described by annual energy and hourly load impacts
- Four scenarios of BTM DG described by annual energy and hourly load impacts
- Three scenarios of data center load growth described by annual energy and hourly load impacts
- Six scenarios of AAEE described by annual energy and hourly load impacts
- Six scenarios of AAFS described by annual energy and hourly load impacts

61 A *TAC area* denotes a portion of the California ISO balancing authority area that has been placed in the California ISO's operational control through an agreement with an electric utility or other entity operating a transmission system component. A TAC area typically consists of an IOU and several publicly owned utilities using the transmission system owned by the IOU.

- Three scenarios of AATE described by annual energy and hourly load impacts

The combination of the baseline forecast using a specific weather variant plus a known load, BTM DG, data center, AAEE, AAFS, and AATE scenario depends on the use. The practices and procedures used in electricity local studies address uncertainty about the location-specific impacts of various assumptions by systematically using adverse assumptions about weather-induced peak load, and conservative load modifiers to base loads. For example, AAEE Scenario 2 is used for local studies because it is more conservative than Scenario 3, which is used in planning studies. For fuel substitution, AAFS Scenario 3 is used for local studies and Scenario 2 is used in planning studies. For transportation electrification, Scenario 3 is used for local studies and Scenario 2 is used for planning studies.

To account for unforeseen uncertainties, variations of adopted IEPR forecast outputs that diverge from the single forecast set may be used in planning and procurement processes under specific circumstances with consensus from the joint agencies and California ISO leadership and subject to subsequent adoption by CEC. Variations of adopted IEPR forecast outputs or CEC's long-term demand scenarios may be used for proposed portfolio and sensitivity analyses. However, the joint agencies and California ISO agree that planning and procurement processes will generally align with the single forecast set.

The following list describes the current agreement among the joint agencies and California ISO:

- CPUC IRP Reference System Plan, Preferred System Plan, and California ISO TPP economic studies:[62]
    - 2024 IEPR baseline annual energy and annual peak demand
    - 2024 IEPR data center mid case
    - 2024 IEPR BTM DG mid case
    - 2024 IEPR AAEE Scenario 3 annual energy and peak demand
    - 2024 IEPR AAFS Scenario 3 annual energy and peak demand
    - 2024 IEPR AATE Scenario 3 annual energy and peak demand
    - 1-year-in-2 peak event weather conditions from the 2024 IEPR

62 In consultation with the CEC and California ISO, the CPUC may authorize procurement using an alternative weather variant.

- California ISO TPP policy studies and bulk system studies:
  - 2024 IEPR baseline annual energy and annual peak demand
  - 2024 IEPR data center mid case
  - 2024 IEPR BTM DG mid case
  - 2024 IEPR AAEE Scenario 3 annual energy and peak demand
  - 2024 IEPR AAFS Scenario 3 annual energy and peak demand
  - 2024 IEPR AATE Scenario 3 annual energy and peak demand
  - 1-year-in-5 peak event weather conditions from the 2024 IEPR
  - 2024 IEPR planning forecast hourly loads
  - Staff allocations of the 2024 IEPR data centers, AAEE, AAFS, and AATE to load buses used in transmission studies
- California ISO TPP local area reliability studies:
  - Baseline annual energy and annual peak demand
  - Known load impacts
  - Data center high case
  - BTM DG low case
  - AAEE Scenario 2 annual energy and peak demand
  - AAFS Scenario 3 annual energy and peak demand
  - AATE Scenario 3 annual energy and peak demand
  - 1-year-in-10 peak event weather conditions
  - Staff allocations of known loads, data centers, AAEE, AAFS, and AATE to load buses used in transmission studies
- California ISO local capacity technical studies:
  - Baseline annual energy and annual peak demand
  - Data center high case
  - BTM DG low case
  - AAEE Scenario 2 annual energy and peak demand
  - AAFS Scenario 3 annual energy and peak demand
  - AATE Scenario 3 annual energy and peak demand
  - 1-year-in-10 peak event weather conditions
- California ISO Maximum Import Capability allocation for CPUC's system resource adequacy requirements for LSEs:
  - Monthly peak demand derived from the planning forecast managed sales hourly loads

- ○ Hourly loads for the monthly system peak-day demand derived from planning forecast managed sales hourly loads
  - ○ Data center mid case hourly loads by California ISO area
  - ○ BTM DG mid case hourly impacts by California ISO area
  - ○ AAEE Scenario 3 hourly impacts
  - ○ AAFS Scenario 2 hourly loads
  - ○ AATE Scenario 2 hourly loads
  - ○ 1-year-in-2 peak event weather conditions
- CPUC resource adequacy LSE system requirements:[63]
  - Hourly loads for the monthly system peak-day demand derived from planning forecast managed sales hourly loads
  - Data center mid case hourly loads by California ISO area
  - BTM DG mid case hourly impacts by California ISO area
  - AAEE Scenario 3 hourly impacts
  - AAFS Scenario 2 hourly loads
  - AATE Scenario 2 hourly loads
  - 1-year-in-2 peak event weather conditions[64]
- CPUC IOU distribution planning:[65]
  - Baseline hourly demand and hourly loads from the data center, BTM DG, AAEE, AAFS, and AATE scenarios.[66]

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63 Resource adequacy under the CPUC jurisdiction shifted to using a slice-of-day approach starting in 2025, which requires hourly loads. Non-CPUC jurisdictional load-serving entities have not shifted to a slice-of day-framework. System resource adequacy obligations in the California ISO's systems and processes (which account for CPUC and non-CPUC jurisdictions) continue to be based on annual and monthly coincident peak demand.

64 In consultation with the CEC and California ISO, the CPUC may authorize procurement using an alternative weather variant.

65 In October 2024, the CPUC adopted Decision (D).24-10-030 that requires large investor owned electric utilities to make various improvements to the distribution planning process. Ordered improvements include how distribution planning utilizes the CEC's forecast but does not change this joint agency and California ISO recommendation on what forecast elements shall be used in distribution planning.

66 Following a May 11, 2020, CPUC Distribution Resources Plan Ruling (R.14-08-013), the same IEPR datasets are used by each IOU. The IOUs meet and confer to establish which IEPR datasets to use and present a listing of

- California ISO flexible capacity studies for resource adequacy:[67]
    - Baseline hourly loads by California ISO area
    - Data center mid case hourly loads by California ISO area
    - BTM DG mid case hourly impacts by California ISO area
    - AAEE Scenario 3 hourly impacts by California ISO area
    - AAFS Scenario 2 hourly loads by California ISO area
    - AATE Scenario 2 hourly loads by California ISO area
    - 1-year-in-2 peak event weather conditions

Changes in this agreement compared to the *2024 IEPR Update* are summarized below. These changes respond to uncertainties introduced in the 2025 IEPR forecast cycle regarding known loads, data centers, and impacts of recent federal policy changes. In 2026, CEC staff will review historical known load data to develop independent assumptions or confirm assumptions informed by the IOUs where feasible. Staff will continue to evaluate the interaction of known loads with other forecast components. CEC staff will also continue to monitor data center applications for energization as well as the impacts of recent federal policy changes that introduce uncertainty regarding the choice of load modifiers for forecast scenarios this cycle. Changes include the following:

- For resource adequacy:
    - System RA requirements, maximum import capability studies, and flexible capacity RA studies for 2027 will use the 2025 IEPR planning forecast without known loads.

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the selected datasets to CPUC staff for approval. In all cases, IEPR datasets are used where feasible for disaggregation and forecasting, and the IOUs clearly state in their filings which datasets were used.

Each IOU uses its own known loads data for distribution planning and will begin to use pending loads data consistent with the directives of CPUC Resolutions E-5413 and E-5414.

67 The method for assessing flexible capacity using the hourly CEC forecast was first used for flexible capacity resource adequacy planning for 2020. The joint agencies and California ISO are collaborating to evaluate this use case into the overall CEC demand forecasting workflow and the California ISO’s flexible capacity projection method. The joint agencies and California ISO are evaluating and potentially modifying the flexible capacity analysis going forward. Until finalization of evaluation and potential changes are made, the California ISO will continue to use the CEC’s hourly forecast.

  - Local Capacity Technical studies used to derive Local RA requirements for 2027-2029 will use the 2025 IEPR local forecast without known loads.
  - To manage potential reliability risks for 2027, should the pace of load growth exceed the adopted 2025 IEPR forecast, joint agency and California ISO staff will closely monitor and analyze system load trends and the progress and pace of known load energizations in 2026 and 2027.
  - This approach allows CEC staff additional time to study the impacts and interactions of known loads in the planning forecast and establishes a plan to closely monitor for and mitigate potential reliability risks in advance of 2027.
- For IRP and bulk system transmission planning:
  - California ISO TPP economic, policy, and bulk system studies for the 2026-2027 TPP, and CPUC IRP will continue to use the 2024 IEPR planning forecast.
    - California ISO TPP economic, policy, and bulk system studies for the 2026-2027 TPP will use the 2024 IEPR planning forecast as well as an IRP portfolio from CPUC based on the 2024 IEPR planning forecast.
    - California ISO TPP economic, policy, and bulk system studies for the 2027-2028 TPP will use an IRP portfolio from CPUC based on the 2024 IEPR planning forecast.
  - This approach manages volatility and promotes stability in electric system resource and infrastructure planning currently underway.
  - Known loads and data centers increase demand while recent federal policy changes reduce the impacts of electrification — however, significant uncertainty remains regarding the net impact of these factors on the system forecast in the mid-term.
  - This approach allows CEC staff additional time to collect and review historical data, observe the impacts of known loads, data centers, and recent federal policy changes, and refine forecast approaches as needed.
- For local transmission planning:
  - California ISO TPP local area reliability studies will use the 2025 IEPR local reliability forecast with known loads.
  - This approach promotes alignment between distribution planning and local transmission planning processes and allows for lead time for long-term infrastructure planning and development.

Staff of the joint agencies and California ISO have developed a process by which the CPUC or California ISO can make a formal request to the CEC for a desired demand forecast variant or combination that is not yet produced. If the CEC does not have the resources to develop such a variant, then lead staff from the requesting agency may consider deviating from this agreement to independently develop and use such a variant for the period until the CEC is able to develop it. Such requests should also be made and approved using appropriate procedures of the requesting agency to ensure all interested stakeholders are aware of such a deviation.

Managed Gas Forecast Set

When the CEC adopts the IEPR forecast, it adopts all AAEE and AAFS scenario components as well as the combinations used for the planning forecast and local reliability scenarios. The adoption of load modifier combinations for the planning and local reliability scenarios supports electricity system planning and the energy planning proceedings that ensure California has a reliable and adequate electricity supply. The CEC does not currently recommend IEPR forecast scenarios for gas system planning. Gas system planning faces reliability concerns distinct from those in electricity system planning. Thus, the downstream gas demand associated with the adopted electricity system planning forecast and electricity system local reliability scenario should not necessarily be used for gas system planning.

Updates Planned for the 2026 IEPR Update Forecast

Staff is working on several updates for the *2026 IEPR Update* Forecast. These updates will be shared with stakeholders in spring and summer 2026 for input. Updates include modernized and updated commercial and industrial sector models, improvements to estimating known load impacts, updated EV charging load shapes, expanding AAFS to the industrial and agricultural sectors, and estimating demand flexibility impacts.

Modernized Commercial Sector Forecast Model

The Commercial Sector Forecast Model (CFM) is an end-use annual electricity and gas demand forecasting model. The first version of the model was developed in the late 1970s by CEC staff and was built in FORTRAN. The main source of the input data is the Commercial End-Use Survey (CEUS).[68] The CFM accounts for commercial sector growth, as well as the savings associated with each cycle of Building and Appliances Standards.

During 2025, staff worked with a contractor to migrate the FORTRAN code to the R programming language and is also implementing the following improvements and enhancements:

- Updating the model input files with data from the latest CEUS and other available sources and incorporating the latest codes and standards and committed energy efficiency programs savings
- Improving capability to easily change (increase or decrease) the number of utilities, forecast zones, building types, and end uses included in the forecast

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68 California Energy Commission, "California Commercial End-Use Survey," https://www.energy.ca.gov/data-reports/surveys/california-commercial-end-use-survey.

- Setting up the framework for data centers to be a new and stand-alone building type.

The modernized and updated CFM will be used for the *2026 IEPR Update* forecast.

Industrial Model Improvements

The industrial model uses regression models for groups of North American Industry Classification System (NAICS) codes[69] to forecast energy demand based on economic inputs. For the 2026 forecast, staff migrated the regression models from Microsoft Excel to the Python programming language. Staff is exploring moving to a panel data model where, for each NAICS grouping, each forecast zone is a panel. Moving the model to Python allows staff to test variations of economic inputs more easily, leading to improved industrial sector forecasts.

Improvements to Estimating Known Load Impacts

As part of the 2026 IEPR Update cycle, CEC staff will explore new tools and methods to better support distribution planning. This is an active area of research and CEC staff will continue to collaborate with staff from the other energy planning agencies and the IOUs for their input.

Updated EV Load Shapes Based on AMI Data Analysis

The TEDF includes assumptions about normalized hourly load shapes for EV charging. Inputs for load shapes consist of many types of charging patterns for light-, medium-, and heavy-duty vehicles. These inputs include load shapes typically seen at single-family homes, multifamily homes, and away-from-home charging, as well as more specialized load shapes for commercial, government, and rental vehicles.

As California's EV charging network continues to evolve, there is a need for analysis of new AMI data that reflects the changing real-world usage patterns. For the *2026 IEPR Update*, staff will use recently collected AMI data to create updated EV load shapes. These data will improve the accuracy of hourly load projections and provide insight into how changes in EV policies will impact the transportation sector's load profile.

AAFS Expanded to Include Industrial and Agricultural Sectors, for Electricity and Hydrogen

In 2024, CEC staff upgraded the agricultural and industrial module used in FSSAT. FSSAT has always included an agricultural and industrial module, but it has never been used for the

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69 NAICS codes classify businesses according to the type of economic activity engaged at individual locations. The NAICS system is the standard used for collecting data and reporting statistics in the United States, Mexico and Canada. "North American Industry Classification System," https://www.census.gov/naics/

forecast. The upgrade allows for fuel substitution from gas to electricity and from gas to hydrogen. Staff presented an overview of the module enhancements at the August 2025 DAWG meeting.[70] The module works similarly to the residential and commercial sectors in FSSAT but does not track technologies. It models fuel substitution by NAICS subsector industries.

For hydrogen substitution, it models the fuel substitution potential of high-process-heating uses, which are the most difficult to electrify. Table 11 summarizes the electricity and hydrogen fuel substitution types for the industrial sector. The module can also model the localized production methods and transport methods (onsite production, pipeline, and short- or long-distance trucking).

Table 11: FSSAT Fuel Substitution in the Industrial Sector

Industry Applicability (NAICS)	End-Uses for Fuel Substitution	Type of Fuel Substitution
Generic	Non-Thermal End Use	Gas → Electricity
Generic	Process Heat-Low	Gas → Electricity
Generic	Water Heat	Gas → Electricity
Generic	Process Heat-High	Gas → Hydrogen
211, 212 (Oil & Gas Extraction)	Process Heat-High	Gas → Hydrogen
3272 (Glass)	Process Heat-High	Gas → Hydrogen
3273 (Cement)	Process Heat-High	Gas → Hydrogen

Source: CEC

Although CEC staff used a version of this module for the 2023 Long-Term Demand Scenarios Project, the module will not be available until, at the earliest, the *2026 IEPR Update* forecast

70 DAWG meeting on CA Energy Demand Forecast: Load Modifier Assumptions. August 18, 2025, https://www.energy.ca.gov/event/workshop/2025-08/ca-energy-demand-forecast-load-modifier-assumptions.

when more improved data become available.[71] Staff anticipates that, with sufficient developments that can increase certainty, the module may be used for the more aggressive load modifier scenarios. The *2025 IEPR* forecast includes industrial and agricultural AAEE savings and PiCS AAFS impacts.

Potential Demand Flexibility Interactions

The CEC engaged with a technical support firm to develop a tool to estimate statewide potential for demand flexibility. This tool explores long-term demand flexibility potential estimates that can be used in the CEC's statewide long-term demand scenarios project. This tool is a further development of a previous tool used for setting California's Load Shift Goal, adopted by the CEC in 2023 pursuant to Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022).[72]

The current tool models different impacts of demand flexibility for load shed and shift across various end uses and enabling technologies by hour. It includes DERs such as EVs and BTM storage. The tool draws on data and research presented in the California Demand Response Potential Study[73] conducted by Lawrence Berkeley National Laboratory and supported by the CPUC. The outputs of the tool are a series of GW demand flexibility potentials for every hour of a forecast year that could be flexed to reduce regional demand.

The characteristics and capabilities of the tool for estimating demand flexibility make it useful for some planning purposes. For example, staff put demand flexibility tool outputs and a series of operational parameters into a production cost model that selects for optimal dispatch of flexible demand resources. Results of the production cost model can provide operational and reliability metrics that can help inform planning.

In the *2026 IEPR Update* process, staff will pursue pathways to consider integration of demand flexibility into the forecast. However, demand flexibility is responsive to current conditions, and additional demand flexibility programs do not have a consistent and scale-

71 CEC. November 20, 2024. "Staff Workshop on Demand Scenarios Project," https://www.energy.ca.gov/event/workshop/2024-11/staff-workshop-demand-scenarios-project.

72 Please see here for CEC staff documentation and a recorded overview of the Demand Flexibility Tool at a February 28, 2025, Demand Analysis Working Group (DAWG) meeting. https://www.energy.ca.gov/event/meeting/2025-02/demand-analysis-working-group-dawg-meeting-overview-cecs-demand-flexibility.

73 Lawrence Berkeley National Laboratory, U.S. DOE / the University of California. "2025 California Demand Response Potential Study - Charting California's Demand Response Future: Final Report on Phase 2 Results," https://buildings.lbl.gov/publications/2025-california-demand-response.

established pattern. As such, demand flexibility does not satisfy the definition of a load modifier and cannot function in the same way as, for example, BTM solar. Staff will continue to work with partner agencies and the public to help best integrate demand flexibility into the forecast.

CHAPTER 2: Accelerating Interconnection and Energization

Introduction

California is working to reduce the pace, magnitude, and costs of climate change impacts by strengthening energy infrastructure resiliency and reducing greenhouse gas (GHG) emissions, among other efforts. The state has a comprehensive plan to manage the transition to carbon neutrality and clean energy and is on track to achieve 100 percent clean electricity by 2045. In 2023, 67 percent of the state's electricity came from renewable and zero-carbon resources.[74] From 2018 through mid-2025, battery storage capacity increased from 500 megawatts (MW) to more than 16,900 MW.[75] Further, almost 2.5 million zero-emission vehicles have been sold in the state through December 2025.[76]

While substantial progress toward the state's goals have been made, California must sustain an unprecedented expansion of clean electricity generation and storage, along with continued electrification of the transportation, residential, and industrial sectors, while controlling costs. The buildout of new transmission and upgrades to existing lines is also essential to achieving the state's goals.

Over the last decade, interconnection and energization challenges emerged, lengthening the time required to bring new resources and loads on-line.[77] There are separate processes for connecting new resources to the transmission grid and connecting distributed energy resources (DERs) — including generators like rooftop solar, stationary storage, and bidirectional EV chargers — to distribution grids. The *2023 Integrated Energy Policy Report*

74 Renewable resources include solar, wind, geothermal, biomass, and small hydro generation. While zero-carbon electricity includes large hydro and nuclear generation. The web page "Clean Energy Serving California" has more information, https://www.energy.ca.gov/data-reports/clean-energy-serving-california.

75 The web page "Clean Energy Storage System Survey" has more information, https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/california-energy-storage-system-survey.

76 New ZEV Sales in California, https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics-collection/new-zev.

77 *Interconnection* refers to the process of connecting a generating facility or other resource such as energy storage to the transmission or distribution grids. *Energization* refers to the process to connect new load to the distribution system.

(*2023 IEPR*) provided an in-depth analysis of barriers and solutions to accelerating interconnection and energization processes for clean energy resources and loads.

In the two years since the *2023 IEPR* was completed, the California Energy Commission (CEC), California Public Utilities Commission (CPUC), and California Independent System Operator (California ISO) have worked to enhance coordination efforts with utilities, project developers, and various stakeholders. CEC, CPUC, and California ISO have also worked to improve existing planning, interconnection, and permitting processes to accelerate deployment of clean energy resources to the grid. While there has been marked progress, the processes that govern how new resources and loads are connected to the transmission and distribution systems must continue to evolve to ensure they are timely and efficient.

Assembly Bill 1373 (Garcia, Chapter 367, Statutes of 2023) requires the CEC, in consultation with the CPUC, to assess barriers to electricity interconnection and energization and provide recommendations on how to accelerate those processes, as appropriate, as part of the *2025 IEPR*. This chapter builds on the work of the *2023 IEPR* and provides an update on new developments related to these issues and recommendations on continued progress.

Background

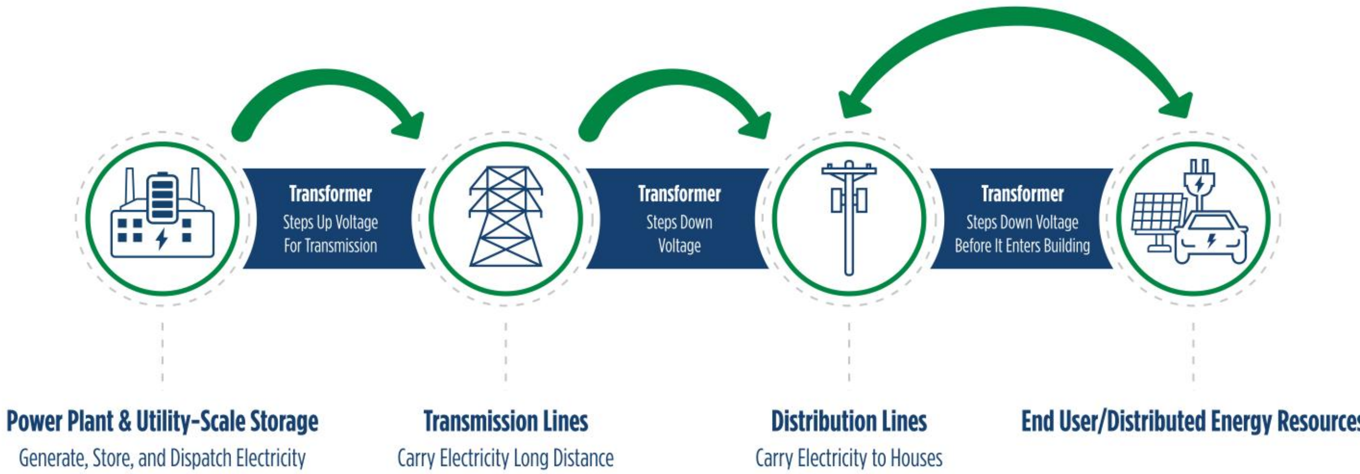
The complex systems comprising the electricity grid in California can be generally divided into two components, as shown in Figure 36:

- The *bulk transmission system* — a collection of high-voltage lines intended to carry electricity from large generators over long distances
- The *distribution system* — a network of lower-voltage lines carrying electricity from the transmission grid to end-use customers and exports from end-use customers' distributed energy resources to the transmission grid.

As California continues to add clean resources and electrify its economy, the state must continue exploring opportunities for queue reform and coordinated planning.[78]

78 *Queue reform* is a set of interconnection process enhancements developed to address the large volume of interconnection requests in the California ISO generator interconnection queue (or list of project interconnection requests). The reforms were developed in response to both state policy goals and FERC Order No. 2023.

Figure 36: Bulk Transmission and Distribution Systems



Source: CEC, 2025

Bulk Transmission System

California is part of a larger integrated electricity system in the western United States known as the Western Interconnection, which includes all or parts of 14 western states as well as Alberta, British Columbia, and Baja California, Mexico. All the electric utilities in the Western Interconnection are electrically tied together and operate at a synchronized frequency. In California, the California ISO and several other balancing authorities, including those that serve publicly owned utilities (POUs), plan and operate transmission systems.[79] High-voltage connections between utilities' systems allow the transfer of electrical energy from one part of the bulk grid to another.

California's bulk transmission grid balances generation and storage resources with customer loads on a moment-by-moment basis to reliably deliver low-cost electricity to ratepayers. The bulk transmission grid promotes competitive wholesale electricity markets and provides

79 A *balancing authority* is responsible for the planning and operation of a transmission control area. It matches generation with load and maintains consistent electric frequency of the grid, even during extreme conditions. In California there are eight balancing authorities, including the Balancing Authority of Northern California, California Independent System Operator, Los Angeles Department of Water and Power, Imperial Irrigation District, and others.

ancillary services and emergency support in the event of unplanned outages and extreme weather events.[80] The California ISO plans and operates the bulk transmission grid for the large investor-owned utilities (IOUs) and other members who participate in the California ISO wholesale electricity market.

The California ISO also manages the interconnection processes for 80 percent of the grid that it oversees under federal law and regulations established by the Federal Energy Regulatory Commission (FERC).[81] Requests to interconnect utility-scale renewables and storage projects surged dramatically over the last decade. The volume of queued projects and the complexity of studying a continuously changing mix of resources made processing interconnection requests increasingly challenging under existing practices.

The increased requests prompted significant reforms in 2023, conducted through the California ISO's multiyear Interconnection Process Enhancements (IPE) and in response to FERC Order 2023.[82] These interconnection reforms entailed updating the interconnection queue process to prioritize commercially viable projects and encouraged project development and procurement in areas where transmission is planned or available, based on state and local resource plans.

Distribution System

At the distribution level, for California's large IOUs, interconnection of DERs like rooftop solar to the electric grid is governed by the CPUC Rule 21 or the FERC-jurisdictional wholesale distribution access tariff (WDAT) for wholesale projects. Customer load energization such as connections for electric vehicle (EV) chargers or new building loads is regulated under CPUC Rules 2, 15, 16, and EV-specific Rules 29 and 45.

The unique demands of high-capacity, fast-charging stations and large commercial electrification projects are pushing the limits of traditional distribution infrastructure, which was not designed for such rapid or locationally concentrated growth. For loads that trigger

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80 *Ancillary services* are essential functions beyond the sale of electricity that maintain power grid stability, reliability, and quality by balancing supply and demand, controlling voltage, and easing system restoration after an outage.

81 The FERC is an independent federal agency that regulates various aspects of the energy sector under the Natural Gas Act, the Federal Power Act, and the Interstate Commerce Act, including interstate transmission and wholesale electricity markets.

82 FERC Order 2023. Improvements to Generator Interconnection Procedures and Agreements, https://www.federalregister.gov/documents/2023/09/06/2023-16628/improvements-to-generatorinterconnection-procedures-and-agreements.

system upgrades upstream of the customer, construction timelines for necessary grid upgrades can take several years.

Project developers, fleet operators, public agencies, and community-serving organizations consistently highlight that uncertainty in grid connection time frames creates major barriers to investment, increases project costs, and leads to inequitable outcomes, especially in underserved and disadvantaged communities with grid capacity constraints. Long timelines can also challenge the state's ability to support zero-emission vehicle infrastructure goals and building decarbonization strategies.

At the distribution level, the growing number of large load projects, including EV charging depots and industrial facilities such as data centers, calls for strengthened planning capabilities, faster processing of applications and permits, and transparent data on local capacity. Getting this policy environment right will help unlock the next wave of clean energy projects and grid modernization investments.

2023 IEPR — Accelerated Deployment of Clean Energy

As previously noted, the *2023 IEPR* identified barriers that have delayed the interconnection and energization of critical energy infrastructure needed to meet the state's clean energy goals. Projects that have been delayed include utility-scale renewable generation and storage seeking to connect to the bulk transmission system, as well as DERs seeking to connect to the distribution system. The *2023 IEPR* discussed the need for constructing new and upgraded electric grid infrastructure and enhancing aging infrastructure, while containing costs to manage impacts on electricity bills.

2023 IEPR Barriers and Recommendations

The *2023 IEPR* identified interrelated barriers that limit the pace and scale at which new clean resources can connect to the transmission and distribution systems. External factors such as supply chain constraints for key components have also delayed project deployment timelines. These issues are not unique to California and are impacting deployment timelines in other states and countries. There are numerous efforts underway in California to address these challenges and provide solutions that can help accelerate a broader global transition needed to address climate change concerns.

The *2023 IEPR* highlighted five major barriers to accelerating deployment of clean energy resources, including the following:

- Infrastructure planning and oversight are challenged by the pace, scale, and uncertainty of market- and policy-driven deployment.
- The growing number and size (or electric demand) of projects applying for interconnection or energization can clog processes to transmission and distribution systems that may lack sufficient capacity to connect.
- Ratepayer impacts need to be managed while preparing grid infrastructure.
- Available capacity, connection and upgrade processes, and timelines for completion are not always transparent or consistently tracked.

- Permitting can take a long time, and the scale of deployment will need broader public engagement.

Building on ongoing efforts, the *2023 IEPR* provided recommendations to accelerate deployment of clean energy resources on the transmission and distribution systems, such as:

- Monitoring and expanding proactive investment in electric grid infrastructure.
- Promoting flexible service connections and deploying temporary power solutions to connect projects while permanent infrastructure is constructed.
- Exploring alternative sources of funding for upgrades and maximizing load flexibility to limit ratepayer burden.
- Increasing transparency into grid capacity and connection processes through publicly available tools and datasets.
- Supporting faster permitting decisions including through expanding the capabilities of automated permitting tools for local authorities.

Progress on Accelerating Bulk Transmission System Interconnections

Over the last five years, the California ISO has added record-breaking amounts of clean energy resources to the transmission grid. Since 2020, it added over 25,000 MW of nameplate capacity in its footprint, plus an additional 2,000 MW of dedicated imports.[83] These new resources provide more than 18,000 MW of net qualifying capacity to serve the reliability needs of the grid.[84] The California ISO also interconnected more than 400 new projects, of which more than 200 included storage, providing 69 percent of new reliability capacity.[85]

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83 Sterkel, Molly. August 11, 2025. Presentation on Bulk Grid Interconnection: Status & Improvements. 2025 IEPR Commissioner Workshop on Accelerating Interconnection and Energization. CEC, https://efiling.energy.ca.gov/GetDocument.aspx?tn=265538&DocumentContentId=102389.

84 Net qualifying capacity is the specific value assigned to electricity resources, such as generators and demand response programs, that represents their actual, deliverable capacity available to meet California's electric grid reliability needs and the resource adequacy (RA) requirements set by the CPUC and the California ISO.

85 Sterkel, Molly. Presentation on Bulk Grid Interconnection: Status & Improvements.

Some of these initiatives include: Transmission Project Review Process (https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/transmission-project-review-process). Transmission Development Forum

These results reflect the focused coordination across the development landscape, including procuring and permitting, resolving supply chain issues, and interconnecting these resources to the bulk grid. Bringing these new resources on-line requires upgrades of interconnection equipment and transmission infrastructure, both project-specific and across the grid.

The CEC, CPUC, and California ISO have also implemented initiatives to increase the transparency of data related to interconnection progress, transmission project development and cost tracking, and mapping of the transmission system. At the same time, the CPUC updated regulations to accelerate transmission permitting timelines, including California Environmental Quality Act (CEQA) review and various other streamlining measures.

This section discusses enhancements made since 2023 across transmission planning, interconnection, data transparency, and permitting processes to accelerate the deployment of clean energy resources to the electric transmission grid.

Transmission Planning and Development

Transmission development is a long, multiyear process that is critical to enabling timely delivery of reliable, diverse, secure, and affordable clean energy resources. Because transmission lines are capital intensive, high voltage, long linear facilities that can span tens to hundreds of miles, the process of planning, financing, permitting, and constructing these facilities is inherently complex, difficult, and time-consuming. New and upgraded transmission facilities are needed so that renewable and clean electricity resources can be effectively integrated and efficiently deployed.

California has well-established transmission planning and permitting processes to develop least-cost transmission projects needed for reliability and to meet state policies. The California ISO and other balancing authority planning processes adhere to the reliability standards set by the Western Electricity Coordinating Council and the North American Electric Reliability Corporation. There is a coordinated electric system planning process for the California ISO system, which covers roughly 80 percent of the state's electricity demand, including IOUs and

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(https://www.caiso.com/meetings-events/topics/transmission-development-forum). Tracking Energy Development (TED) Taskforce (https://www.caiso.com/meetings-events/topics/transmission-development-forum).

CPUC. January 30, 2025. Decision 25-01-055, https://www.cpuc.ca.gov/-/media/cpuc-website/proceedings-and-rulemaking/documents/general-orders/go-131-e.pdf.

other load-serving entities (LSEs). Further, POUs conduct planning for transmission either for their individual service territories or as a member of a balancing authority.

Recent Legislation and Regulatory Actions

The California Legislature has passed several bills in recent years to improve transparency and accelerate the planning, permitting, financing, and execution of transmission projects, discussed below.

Senate Bill 1174 (Hertzberg, Chapter 229, Statutes of 2022) required utilities that own electrical transmission facilities to report to the CPUC any changes to previous in-service dates of transmission and interconnection facilities that provide transmission deliverability to eligible renewable or energy storage resources with executed interconnection agreements. The report must also identify the reason for any changes to in-service dates. Since 2023, the CPUC has analyzed this IOU-reported information to generate transmission system assessments included in its annual RPS report to the Legislature. These assessments identify the magnitudes and reasons for transmission project delays, and the impact of these delays on in-development renewable energy and storage resources.

Senate Bill 529 (Hertzberg, Chapter 357, Statutes of 2022) directed the CPUC to authorize transmission projects to use the simpler permit-to-construct (PTC) process rather than the more complex certificate of public convenience and necessity (CPCN) process or allows an applicant to file for a permit exemption, for certain projects.[86] SB 529 allows an applicant to file a PTC application or claim an exemption to construct an extension, expansion, upgrade, or other modification to an electric public utility's existing electrical transmission facilities irrespective of whether the electrical transmission facility is above a 200-kV voltage level. The CPUC addressed the provisions of SB 529 in a decision to clarify and update General Order (GO) 131-D, the CPUC's permitting regulations for transmission infrastructure, as discussed in the transmission permitting section.

Assembly Bill 1373 (Garcia, Chapter 367, Statutes of 2023) requires the CPUC to establish a rebuttable presumption regarding the need for a proposed transmission project that has been approved by the California ISO. The CPUC addressed the provisions of AB 1373 in a decision updating GO-131-D to GO 131-E, as discussed in the transmission permitting section.

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86 A CPCN application is required for new transmission and certain upgrades to existing transmission facilities at 200 kilovolts (kV) and above, while a PTC application is required for new transmission and certain upgrades to existing transmission facilities between 50 kV and 200 kV.

Senate Bill 319 (McGuire, Chapter 390, Statutes of 2023) requires the CEC, CPUC, and California ISO to jointly prepare an electrical transmission infrastructure development guidebook that describes the state's electrical transmission planning and permitting processes. The guidebook outlines the different stages of transmission infrastructure development and presents average time frames for planning and permitting. The guidebook also describes the roles, responsibilities, and decision-making authority of federal and state agencies and coordination needed for reviews required under CEQA and the National Environmental Policy Act (NEPA). The Draft Electrical Transmission Infrastructure Development Guidebook in Response to Senate Bill 319 was published on December 12, 2025.[87]

SB 319 also requires the CPUC, in consultation with California balancing authorities, to submit a biennial report to the Legislature that includes a description and status of electrical transmission project applications submitted to the CPUC. The report also provides the estimated transmission capital cost added to the rate base for each transmission project that was either approved by the California ISO or issued a CPCN by the CPUC. The CPUC released the first biennial report in December 2024.

Senate Bill 254 (Becker, Chapter 119, Statues of 2025) creates the California Transmission Infrastructure Accelerator at the Governor's Office of Business and Economic Development (GO-Biz) to develop financing and development strategies for eligible transmission projects, with the goal of maximizing ratepayer savings. It establishes a fund to provide financial assistance for these projects and offers a 20 percent tax credit (up to $20 million per year) for qualified expenditures related to transmission projects from 2026 to 2036.

Federal Regulation of Long-Term Transmission Planning

FERC regulates the planning of interstate transmission at the wholesale level. FERC has long established (in Order No. 890) nondiscriminatory access to transmission and requirements (in Order No. 1000) for open transmission planning processes that consider public policy requirements, among other things.

On May 13, 2024, FERC issued Order Number 1920, directing transmission planners, such as the California ISO, to analyze transmission needs over a 20-year planning horizon. This long-term planning process must include at least three "plausible and diverse" scenarios developed with state input, along with sensitivity analysis of extreme weather impacts on each scenario. The California ISO and other western planning entities must begin their first long-term

87 CEC. December 12, 2025. Draft Electrical Transmission Infrastructure Development Guidebook in Response to Senate Bill 319. Available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=267900&DocumentContentId=104909.

planning cycle within two years after their compliance filing deadline.[88] FERC Order 1920 will necessitate changes to the California ISO's transmission planning process over the next several years.

Transmission and Resource Planning Memorandum of Understanding

The CEC, CPUC, and California ISO resource and transmission planning processes are coordinated under a memorandum of understanding (MOU) that was signed in 2010. In renewing and updating the MOU in 2022, the agencies reaffirmed the linkages driving the future infrastructure of the grid, so that the CEC's load forecasts and the CPUC's forward-looking resource portfolios remain the key assumptions for California ISO's assessment of transmission needs. This MOU among the three entities is unique among state regulators and a FERC-regulated independent system operator; this ongoing coordination has been fundamental to California's success in advancing new transmission to meet the state's clean energy goals.[89]

Resource Interconnection Processes

Developers of clean generation and battery storage projects seeking to connect to the grid must apply to the transmission operator and undergo a system impact study before they can build or participate in wholesale electricity markets. FERC establishes standardized rules and processes for interconnecting generators or storage resources to the systems of utilities and regional grid operators, such as the California ISO. In general, interconnection processes define the required technical aspects and equipment, cost estimates, and allocation equipment costs, as well as determining new transmission upgrades needed to connect a project to the system. The lists of projects awaiting interconnection are known as *interconnection queues.*

Projects within the California ISO balancing authority area are connected either to an ISO-controlled high-voltage transmission line or to lower-voltage power or distribution lines controlled by a member utility. Projects that interconnect with lower-voltage distribution systems must follow the interconnection processes established by the investor-owned or publicly owned utilities responsible for those systems. (See distribution system discussion.)

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88 On November 21, 2024, FERC issued Order Number 1920-A, which builds upon Order Number 1920 by enhancing the role of state regulators in long-term regional transmission planning, particularly their role in shaping scenario development and regional cost-allocation rules.

89 CEC. August 11, 2025. 2025 IEPR Commissioner Workshop on Accelerating Interconnection and Energization, https://www.energy.ca.gov/event/workshop/2025-08/iepr-commissioner-workshop-accelerating-interconnection-and-energization.

Federal Regulation of Interconnection

As noted above, FERC regulates bulk grid interconnection, and the California ISO manages interconnection under the terms and conditions of a FERC-approved tariff. On July 28, 2023, FERC issued Order Number 2023 (FERC Order 2023), which requires transmission providers to better align transmission interconnection and planning processes and consider multiple future scenarios for different loads, resources, and transmission needs, among other changes.[90] In the compliance filings, transmission providers, including regional transmission organizations and independent system operators, identified how they would implement the requirements outlined in the final rule. The final rule took effect November 6, 2023. The California ISO submitted the first compliance filing May 16, 2024, which was accepted May 15, 2025.

FERC Order 2023 included many requirements that the California ISO already had in place, such as having a cluster study in lieu of a serial study (first come, first served). However, there are new improvements being implemented that will impact interconnection customers , as summarized below:

- Requiring the California ISO to disseminate public interconnection information with a heat map of available capacity.
- Eliminating customer-specific scoping meetings and results meetings, which take months to conduct during the interconnection process.
- Eliminating the feasibility study, enabling the potential transition to a single-phase study process.
- Requiring interconnection customers to have site control with their interconnection request, with limited exceptions on public land.
- Increasing financial commitments for projects progressing in queue.
- Requiring studies to consider grid-enhancing technologies that could preclude traditional upgrades.

California ISO Interconnection Process Enhancements

For many years, the process for connecting new generating capacity to the California ISO grid was based on a first-come, first-served practice where each project was analyzed sequentially.

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90 FERC Order Number 2023. September 6, 2023. Improvements to Generator Interconnection Procedures and Agreements, https://www.federalregister.gov/documents/2023/09/06/2023-16628/improvements-to-generatorinterconnection-procedures-and-agreements.

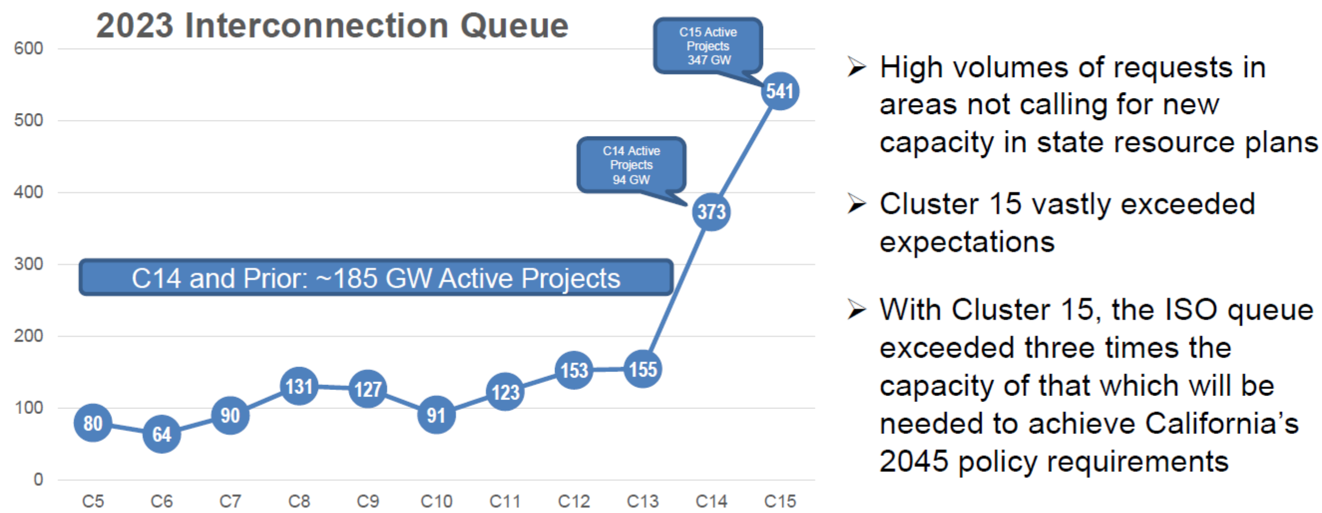
The high volume of interconnection requests over the last decade created challenges for the California ISO in conducting timely and meaningful analysis to ensure safe and reliable interconnection. Project developers also struggled because they were unable to get useful information on interconnection costs without the results of the California ISO's analysis. As a result, they often submitted multiple interconnection requests for the same project, which further populated the interconnection queue.

As the number of projects seeking interconnection increased, the California ISO initiated process reforms, the most important of which was the creation of *cluster studies* in 2008. The clustering approach entailed grouping interconnection applications, rather than analyzing each application on a stand-alone basis. The interconnection process started annually with an open application window in April and a two-year study process.

While the clustering approach improved the interconnection process, the volume of projects seeking interconnection continued to challenge the California ISO's ability to conduct meaningful studies and manage the queue. For example, in the decade between 2011 and 2021, the California ISO received an annual average of 113 queue cluster interconnection requests.[91] By mid-2021, the California ISO received 373 interconnection requests totaling 94 GW, in what is referred to as the Cluster 14 *supercluster*. In 2023, Cluster 15 interconnection requests grew further, totaling 541 projects and 347 GW as shown in Figure 37.

91 Millar, Neil to the California ISO Board of Governors. July 7, 2021. "Memo to California ISO Board of Governors: Decision on Cluster 14 Interconnection Process," https://www.caiso.com/Documents/Decision-Cluster-14-Interconnection-Procedures_Memo-July-2021.pdf#search=Decision%20on%20Cluster%2014%20Interconnection%20Procedures.

Figure 37: Growth in Interconnection Requests



Source: California ISO, 2025

To manage this influx of renewable resource and battery storage projects, the California ISO implemented a series of changes to streamline and make its interconnection process more efficient. The process focuses on aligning with state resource planning and selecting the most viable projects to advance to the study process. Under the new process, the California ISO first identifies and prioritizes transmission zones with available or planned capacity, then limits the capacity studied in each zone to 150 percent of available transmission capacity for each zone.

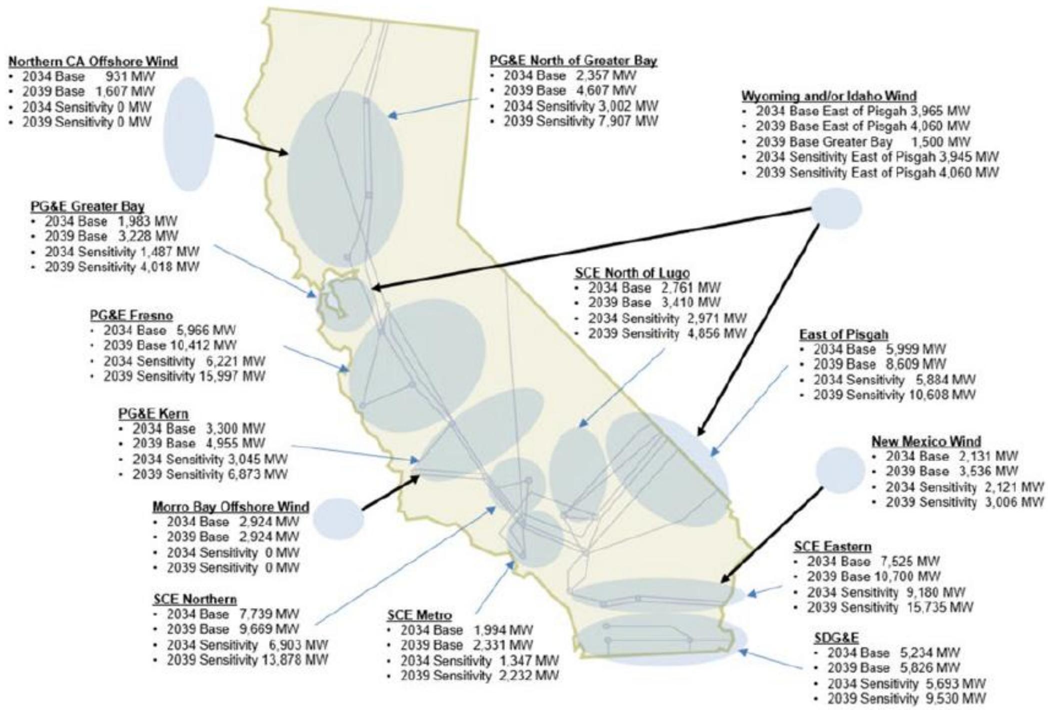
The California ISO also changed the way costs and refunds were treated. Several interconnection issues were later addressed in a second phase of enhancements that were approved by the California ISO Board of Governors on October 25, 2022.[92] Transmission interconnection zones, as shown in Figure 38, were first identified in the California ISO 2022–2023 Transmission Plan. Transmission zones where available transmission capacity exists, or new transmission has been approved, are likely to be areas where new generation can get on-

92 Emmert, Robert, Deb Le Vine, Steve Rutty, Linda Wright. September 13, 2022. *California ISO Interconnection Process Enhancements 2021, Phase 2: Longer Term Enhancements Final Proposal*, http://www.caiso.com/InitiativeDocuments/FinalProposal-InterconnectionProcessEnhancements2021Phase2.pdf.

Memorandum Memo to California ISO Board of Governors regarding Decision on Interconnection Process Enhancements — Phase 2. October 19, 2022, http://www.caiso.com/Documents/DecisiononInterconnectionProcessEnhancementsPhase2-Memo-Oct2022.pdf.

line more quickly than in other areas. For example, zones that lack available capacity or do not have future TPP projects approved are given lower priority or will not be studied at all.

Figure 38: California ISO Transmission Zone Map



Source: *California ISO 2024–2025 Transmission Plan*

This zonal approach also allows better coordination between the California ISO's planning and interconnection processes and signals the best locations for development and procurement to load-serving entities. The California ISO also imposed new processes to score projects and advance only the most viable projects to the study process to improve the accuracy and value of the studies themselves.

The California ISO further explored changes to the process for allocating transmission plan deliverability, which ensures that a project can provide capacity to the system when system conditions are stressed, in the next track of the 2023 Interconnection Process Enhancements initiative. These changes provided more transparency on the transmission planning and deliverability allocation processes for public policy upgrades, especially upgrades for long lead-time generation. The California ISO also created an "intracluster prioritization" process for reliability network upgrades with long lead times, to enable some resources to come online using available capacity on the system while other projects wait for longer lead-time upgrades.

The timeline for approval and implementation of the California ISO recent interconnection reforms is summarized below:

- Track 2 Reforms: Addressed transformational changes needed to the interconnection request intake process to prioritize the most commercially viable projects, which were fully implemented with Cluster 15 resubmissions. Approved by FERC on September 30, 2024, and implemented October 1, 2024.
- Track 3 Reforms: Clarified the methodology for allocating deliverability among projects. Filed April 25, 2025, and approved by FERC June 24, 2025.

Since the implementation of the IPE Track 2 and 3 reforms in 2024 and 2025, the California ISO saw a significant reduction in Cluster 15 resubmissions based on the new process. Cluster 15 interconnection study capacity was reduced by 80 percent from 347 GW to 68 GW worth of projects advancing to studies. The 68 GW worth of projects that will be studied in Cluster 15 are more closely aligned with California's future resource need.

The California ISO analyzes projects up to 150 percent of available transmission capacity, increasing the likelihood that the most viable and cost-effective projects can advance without being delayed by study of excessive volumes of less feasible projects. The reforms, which are also designed to keep down costs by making the entire process more efficient, also include a path forward for projects that are outside a geographic area with existing or planned transmission.

Recently, the California ISO launched IPE 5.0 to identify additional opportunities for process improvements. The primary objective is to address commitments the California ISO made while developing the FERC-approved IPE 2023 foundational changes to its interconnection procedures, and to make any necessary modifications before the opening of the Cluster 16 Interconnection Application window in October 2026.

Status of Interconnection

The California ISO connected roughly 7 GW of resources to the grid in 2024, and about 20 GW since 2021,[93] which is on pace with the anticipated need to meet near-term reliability requirements and policy targets.[94] The California ISO's interconnection queue has roughly 228

93 California ISO press release. April 1, 2025. "California ISO Releases 2024–2025 Draft Transmission Plan," https://www.caiso.com/about/news/news-releases/california-iso-releases-2024-2025-draft-transmission-plan.

94 CPUC. "Resource Tracking Data as of July 2025," https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-july-2025-release.pdf.

GW of resources in it.[95] For near-term interconnections, the California ISO has awarded transmission plan deliverability to roughly 68 GW of resources in the interconnection queue,[96] which aligns well with the roughly 60 GW of resources needed to come on-line by 2035, according to the 2025–2026 TPP base portfolio.[97] These resources are already poised to provide resource adequacy and achieve commercial operations once power purchase agreements[98] are executed and associated network upgrades are complete.

Interconnection process enhancements implemented in 2024 and 2025 have significantly reduced the Cluster 15 to a more manageable volume that is scaled to the need for resources over the next 15 years. Nevertheless, the California ISO has committed to monitoring key elements of the reformed interconnection process and is considering changes to the process based on any lessons learned.

Investor-Owned Utility Interconnection

Physical interconnections to the grid are generally guided by the California ISO tariff under its Generator Interconnection Deliverability Allocation Procedures. Customers with generation and storage projects they wish to interconnect should coordinate closely with the utility to which they are interconnecting to ensure that these resources can safely and reliably be brought on-line. The three large IOUs, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E), make up roughly 80 percent of the California ISO transmission grid; thus, most interconnection requests involve these utilities.[99]

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95 California ISO. August 11, 2025. Presentation. "Accelerating Interconnection and Energization," https://statics.teams.cdn.office.net/evergreen-assets/safelinks/2/atp-safelinks.html.

96 Emmert, Bob, and Danielle Mills. July 23, 2025. Presentation. "Briefing on the Status of Interconnection Process Enhancements and the Interconnection Queue." California ISO Board of Governors meeting, General Session, https://www.caiso.com/documents/briefing-on-the-status-of-interconnection-process-enhancements-and-the-interconnection-queue-jul-2025.pdf.

97 CPUC Fact Sheet: *Decision Transmitting Electric Resource Portfolios to the California Independent System Operator for the 2025–2026 Transmission Planning Process (R.20-05-003)*. February 20, 2025, https://www.cpuc.ca.gov/-/media/cpuc-website/about-cpuc/documents/transparency-and-reporting/fact_sheets/fact-sheet-irp-022025.pdf.

98 A power purchase agreement is an agreement or contract to purchase energy from a generator at a set rate or price, with terms and conditions for delivery.

99 Other participating transmission owners within the California ISO make up the remaining 20 percent. A list of participating transmission owners is available at https://www.caiso.com/documents/list-of-participating-transmission-owners.pdf.

In physically interconnecting new resources to the grid, each IOU governs its own process for coordinating with interconnection customers after the California ISO approves a request. The IOUs determine whether a project can interconnect with or without additional system upgrades by performing technical design and engineering studies. Ultimately, an interconnection agreement between the IOU and interconnection customer is negotiated in which the scope of upgrades, timelines, and distribution of upgrade costs are agreed upon. Following the execution of an interconnection agreement, the IOU and interconnection customer work together to construct needed capital improvements, interconnect the new resource, and bring it on-line.

The 2025 SB 1174 CPUC staff assessment of transmission project delays among the state's large IOUs is in progress. The assessment indicates that the roughly 21 GW of in-development renewable generation and storage resources, with in-service dates between 2025 and 2031, depend on delayed transmission projects and over 8 GW (41 percent) of these resources will be unable to meet their expected in-service dates because of the delayed transmission upgrades that they depend on. As reported by the IOUs, the most common reasons for these transmission project delays include:

- Material delays related to the procurement of long-lead-time equipment necessary for transmission projects and network upgrades (such as circuit breakers, transformers, and specialized steel structures).
- Bundling dependencies (a chain reaction of delays of dependent transmission projects).
- Customer action delays, in which the actions (or inaction) of an interconnection customer prevent necessary upgrades from being completed. These customer-side delays can happen for many reasons and IOUs do not always have visibility into the reasons why these delays occur.
- Project financing delays.

Stakeholders have raised concerns around how delays in network upgrades negatively affect the state's ability to meet its resource adequacy needs by hindering the ability of projects to obtain deliverability status, in addition to increasing curtailment.[100] There is also an increased

100 SB 1174: Assessment Of Transmission Project Delays. Edmund Dale. CPUC Energy Division Transmission Development Forum April 9, 2025. https://www.caiso.com/documents/presentation-cpuc-transmission-development-forum-apr-09-2025.pdf.

urgency to bring wind and solar projects in development into service by December 31, 2027, so that these projects can maintain eligibility for the recently phased-out federal tax credits.

Investor-Owned Interconnection Process Enhancements

As the entities responsible for interconnecting new resources, IOUs have worked to identify and address barriers to transmission development. Recent IOU efforts to improve timelines for interconnection to the transmission system include:[101]

- **Process streamlining** — Creating new software to streamline customer intake process, developing pro-forma contracts, conducting technology testing standardization and improvements, and implementing work order process improvements.
- **Procurement strategies** — Developing long-range sourcing strategies; expanding the pool of approved high-voltage equipment suppliers; demand forecasting for, and bulk procurement of, long-lead-time materials (such as circuit breakers or transformers); securing developer production slots; and purchasing circuit breakers that can handle high short-circuit duty resulting from generation and transmission buildout.
- **Technology improvements** — Exploring alternative transmission technologies (for example, advanced conductors, power flow controllers, and tower raises) to optimize the existing network, delay new investments, or increase transmission capacity cost-effectively on new and existing rights-of-way; and developing improved modeling, validation, or simulation tools or a combination.

Publicly Owned Interconnection

POUs in California that own generation and transmission assets, such as Imperial Irrigation District (IID), Sacramento Municipal Utility District (SMUD), and Los Angeles Department of

101 Nedrud, Jens. August 11, 2025. "Improving Bulk Grid Interconnections." PG&E. CEC IEPR Commissioner Workshop on Accelerating Interconnection and Energization, https://efiling.energy.ca.gov/GetDocument.aspx?tn=265451&DocumentContentId=102305.

PG&E. April 9, 2025. "PG&E's Generation Interconnection Process Improvements." California ISO Transmission Development Forum, https://www.caiso.com/documents/presentation-pge-transmission-development-forum-apr-09-2025.pdf.

SCE. August 11, 2025. "Bulk Grid Interconnection Improvements. CEC IEPR Commissioner Workshop on Accelerating Interconnection and Energization, https://efiling.energy.ca.gov/GetDocument.aspx?tn=265447&DocumentContentId=102310.

SCE. April 9, 2025. "SCE's Generation Interconnection Process Improvements." California ISO Transmission Development Forum, https://www.caiso.com/documents/presentation-sce-transmission-development-forum-apr-09-2025.pdf.

Water and Power (LADWP), perform their own resource and transmission planning. Investments in new infrastructure are authorized by local governing boards. POUs vary in size, load profile, energy resources, and whether they own or operate any transmission facilities.

Generally, POUs follow interconnection processes like those of the California ISO and IOUs when receiving interconnection requests. This process involves scoping of the project, a study of transmission system upgrades needed to accommodate the interconnection request, an interconnection agreement, and construction of needed facilities before interconnection.

POUs are generally not subject to FERC regulation under the Federal Power Act (Section 201) because they do not typically engage in the sale of wholesale electricity in interstate commerce. However, the large POUs have voluntarily adopted open access transmission tariffs to ease the flow of electricity for buyers and sellers, as well as generator interconnection to their systems.[102] As a result, they may voluntarily align with FERC regulations established for utilities under FERC jurisdiction. For example, in 2023, FERC issued Order Number 2023 and a revision in Order Number 2023-A in 2024, both implementing improvements to generator interconnection procedures and agreements. SMUD developed and released an interactive point-of-interconnection heatmap in alignment with this order.

Publicly Owned Interconnection Process Enhancements

Generally, the large POUs have moved from, or are in the process of moving from, a serial interconnection process (for example, processing and studying interconnection requests in the order they come in) to a cluster study process, like that of the California ISO. An advantage of the cluster study process over the serial study process is that any downstream effects from a project dropping out of the interconnection queue are generally limited, as is the amount of study needed to reassess the impact of other remaining interconnection requests on the transmission grid.

With the rise in interconnection requests over the years, large POUs interconnecting resources to their transmission grids face issues like those faced by IOUs, including queue congestion challenges. To ensure that only the most viable projects are studied and move forward, LADWP, for example, has tightened customer readiness requirements and offered nonbinding informational studies to aid developers in assessing the feasibility of their projects.

102 An Open Access Transmission Tariff is a set of rules and conditions that requires public utilities to provide non-discriminatory access to their electric transmission system for a fee, enabling the sale and transmission of bulk power.

Transmission Information Transparency

As well as changes aimed at improving interconnection timelines, the California ISO and CPUC have initiated several transparency efforts. Since 2022, the California ISO has hosted a biannual forum known as the Transmission Development Forum (TDF). This forum is held in the first and third quarters of each year to provide interconnection customers and stakeholders with up-to-date information on transmission upgrades needed to bring new resources on-line. For each forum, participating transmission owners provide public spreadsheets detailing expected in-service dates and permitting and construction status for California ISO-approved upgrades.[103] Stakeholders may ask questions at the forum or provide written comments and questions on the California ISO platform. This effort has provided more timely updates on interconnection timelines and additional transparency into the various causes of delays to transmission upgrades needed for interconnection.

In 2023, the CPUC established the Transmission Project Review (TPR) Process for the three large IOUs under its jurisdiction in which they biannually submit detailed information on transmission projects expected to total $1 million or more, with capital expenditures in the last five years and actual or forecasted capital expenditures in the current year and future four years. The TPR process encompasses a larger set of projects than the California ISO’s TDF, as the IOUs report on California ISO-approved projects, as well as utility self-approved projects. Information submitted in this forum broadly includes project description, location, purpose, project type, environmental and safety factors, planning and permitting status, and project schedule and costs.

The TPR Process includes opportunities for stakeholders to submit written comments and questions to which the IOUs must respond, and the IOUs convene stakeholder meetings twice a year. Limited to the three large IOUs, the TPR Process does not include information from non-IOUs, which are playing an increasing role in the California ISO-controlled grid. Therefore, following the establishment of the TPR process, the CEC in 2024 adopted similar reporting requirements for transmission entities not subject to the CPUC’s TPR process under its IEPR T-1 form to track transmission throughout the state and not only within IOU territories.

Since 2023, the CPUC (under SB 1174) has included in its annual Renewables Portfolio Standard Report systemwide assessments identifying the magnitudes and reasons for transmission project delays. The report also identifies the impact of these delays on in-

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103 Projects are approved via the TPP or as part of network upgrades for generator interconnection transmission upgrades.

development renewable energy and storage resources based on information submitted by IOUs under its jurisdiction.

These data transparency efforts have provided several opportunities for regulators and stakeholders to gain insights into transmission buildout timeline delays, a major barrier to interconnecting new resources to the bulk transmission grid. Tracking the most common and impactful causes of transmission project delays and establishing policies to address bottlenecks in the processes will be key to reducing buildout delays, now and in the future.

Transmission Permitting and GO 131-E Revisions

The CPUC has permit jurisdiction and conducts CEQA review for the construction of electrical transmission lines (at or above 200 kV), power lines (between 50 kV and 200 kV), distribution lines (under 50 kV), substations, and certain electric generation facilities. Projects that affect federal lands or receive federal funding are subject to the National Environmental Policy Act (NEPA). The transmission permitting process is conducted under GO 131-E, in which the CPUC and permit applicants engage in a multistep process to evaluate proposed projects and adopt or certify the appropriate CEQA documents.

Depending on project specifics, a project proponent applies for a certificate of public convenience and necessity (CPCN), a permit to construct (PTC), or an exemption. The CPUC adopted revisions to GO-131 from GO-131-D to GO 131-E in January 2025 to streamline and clarify permitting that:[104]

- Allows more types of transmission projects to apply for the simpler PTC rather than CPCN review by clarifying definitions for exemptions, expansions, modifications, and upgrades of transmission infrastructure.
- Allows applicants to submit draft CEQA documents instead of filing a preliminary environmental assessment.[105]
- Formalizes prefiling consultation (not less than six months before filing) with CPUC staff regarding a CPCN or PTC application.

104 CPUC Rulemaking 23-05-018. "General Order 131-D Update," https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/permitting-and-environmental-review/general-order-131-d-update.

105 CEQA documents include an initial study, negative declaration (ND), mitigated negative declaration (MND), environmental impact report (EIR), addendum, or analysis of the applicability of an exemption from CEQA in applications.

- Directs CPUC staff to conduct a pilot to further study ways to streamline CPCN or PTC and CEQA review, with a staff report every even year starting December 1, 2026.
- Adds language that the CPUC will strive to meet CEQA timelines (consistent with CEQA guidelines) and endeavor to complete proposed final mitigated negative declarations (MNDs) and negative declarations (NDs) without federal agency involvement within 270 days of deeming a PTC or CPCN application complete and proposed final environmental impact reports (EIRs) without federal agency involvement within 455 days of deeming an application complete.
- Establishes a rebuttable presumption regarding the need for a transmission project and adds language that transmission project needs specified in the California ISO TPP shall be used as the basis of the statement of objectives required by CEQA.
- Clarifies that CPUC may limit the range of reasonable alternatives to the proposed project.

Recommendations and Opportunities for Transmission Interconnection

While there has been significant progress in reforms to existing planning, interconnection, and permitting processes and new data reporting to enhance transparency and accountability, ongoing attention to these processes are critical to ensuring that the projected results are realized. This section identifies recommendations intended to support that progress.

Interconnection Process Improvements

- **Continue monitoring the performance of California ISO interconnection improvements so that the backlog of interconnection requests and new requests are handled in a timely and efficient manner to meet California's clean energy goals**. Interconnection process enhancements at the California ISO are well underway, with major reforms completed since 2021. These interconnection process enhancements address subsequent issues arising from those reforms in connecting new clean resources to the California ISO grid.

Integrating Transmission Planning and Interconnection Processes

- **Continue efforts to integrate transmission planning and interconnection processes more closely so that transmission additions and upgrades are better matched to the pace of clean energy project development**. The California ISO, CPUC, and CEC have a well-established transmission planning process implemented through the updated MOU that guides resource and transmission development. The California ISO has already implemented improvements to better integrate transmission interconnection into planning and is exploring additional ways to better incorporate information from the interconnection queue into transmission planning (*builds from 2023 recommendations*).

Improve Transparency and Tracking of Interconnection and Transmission Development

- **Continuously improve tracking interconnection and transmission project development progress to increase transparency and ensure accountability.** The California ISO, in conjunction with the CPUC, and the participating transmission owners host biannual transmission development forums to provide status updates and timelines for completion of transmission projects and upgrades identified in transmission planning and interconnection studies. Recent changes to this process provide greater transparency to developers and stakeholders relying on additional transmission capacity to interconnect and reliably deliver electricity. Stakeholder forums are an important part of the state's collective effort to plan, develop, and interconnect resources needed to meet state reliability and clean energy goals (*builds from 2023 recommendations*).
- **Continue improving and expanding the scope of publicly available tools and datasets on transmission systems while maintaining security and appropriate confidentiality**. Web-based geospatial mapping tools (such as the California ISO's Points of Interconnection heatmap), publicly available energy resource datasets (such as the California ISO's grid management charge or Resource Interconnection Management System or WECC's anchor data set), and other reports (such as the California ISO's transmission capability estimates white paper) are important tools used in resource portfolio development, busbar mapping, and transmission planning. These tools and data sets also promote stakeholder and public engagement in resource and transmission planning and help guide developer decisions, including timelines for pending upgrades and capacity addition projects (*builds from 2023 recommendations*).

Deployment of Advanced and Grid-Enhancing Transmission Technologies

- **Explore opportunities to increase the capacity and throughput of existing rights-of-way at the lowest cost with advanced and grid-enhancing transmission technologies and other strategies**. State policy supports the use and enhancement of existing rights-of-way before considering new greenfield transmission projects.[106] Enhancing existing rights-of-way for increased transmission capacity can avoid the costly, multi-year land acquisition and permitting efforts required for greenfield projects. Advanced transmission technologies, such as advanced conductors, advanced power flow controllers, high-voltage direct current transmission, and other grid-enhancing technologies can

106 A *greenfield transmission project* is a new transmission line constructed on undeveloped land with no existing infrastructure.

improve the efficiency of existing transmission infrastructure. For example, dynamic line rating (DLR) technology continuously monitors and adjusts line ratings based on real-time data, allowing transmission planners and operators to better understand and maximize the use of existing grid infrastructure (*builds from 2023 recommendations*).

Landscape-Level Planning

- **Explore opportunities to conduct corridor planning with high-level landscape environmental and permitting assessments to advance long-term transmission project development**. Conducting environmental assessments of transmission corridors for projects identified in the California ISO 20-Year Transmission Outlook in advance of project development may create a smoother path from planning and project identification to permitting, environmental review, and construction. Corridor planning can identify, avoid, and minimize potential impacts on sensitive resources, habitats, and lands and provide opportunities for stakeholders and tribal engagement early in planning (*builds on web-based tools and land-use planning recommendations from 2023*).
- **Consider how the CEC's transmission corridor designation authority could improve efficiency and reduce the scope of environmental reviews needed in the permitting process for individual projects.** Preparation of a programmatic environmental document as part of the corridor designation process may help narrow the identification and review of project specific environmental impacts and mitigation, building on streamlining in CPUC's GO-131-E (see below). Because environmental review can be one of the most time-consuming aspects of the permitting process, tiering from a programmatic corridor designation CEQA document may reduce future permitting timelines and support local and stakeholder engagement (*builds from 2023 recommendations*).

Permitting

- **Apply lessons learned from implementing revisions to the CPUC's GO-131-E transmission permitting process and pilot projects to streamline transmission permitting**. Recent changes to the CPUC's transmission permitting process have been designed to implement important legislative directives and reduce permitting time frames. The CPUC has initiated a pilot project to assess factors that affect permitting timelines for different types of transmission projects and implement continuous process improvement in transmission permitting (*builds from 2023 recommendations*).

Progress on Accelerating Energization and Interconnection for Distribution System

Historically, distribution system planning has been reactive and conservative. Customers would request to interconnect or energize a new resource or load onto the existing distribution system, and the respective utility would start a study to see if additional work is needed before adding the project to the system. Expansion of the distribution system is triggered when it is needed rather than preparing infrastructure for future additions. To accelerate the energization and interconnection for the distribution system, a more proactive and transparent approach is necessary to overcome the challenges with energizing or interconnecting to the distribution system.

Overview of Distribution Interconnection and Energization Processes

The distribution planning and execution process is a core function for the IOUs; they own, control, and operate and manage the distribution system. Introduced in 2018, the Distribution Investment Deferral Framework process required IOUs to file annual grid needs assessment and distribution deferral opportunity reports (renamed the Distribution Upgrade Project Report in 2024) to provide transparency to the CPUC and stakeholders, which allows better insight into distribution planning issues (such as capacity constraints or energization delays). The two types of projects connecting to the electric distribution grid are interconnection and energization.

Interconnection refers to the process of connecting a generating facility or other resource such as energy storage (projects that not only receive energy from the grid but can provide energy to it). The two tariffs that govern IOU interconnection are the CPUC's Electric Rule 21 and FERC's WDAT. Rule 21 governs the interconnection, operation, and metering requirements for CPUC-jurisdictional generating facilities connecting to IOU distribution grids. Rule 21 allows for interconnection of both export and non-export to the utility grid. The WDAT is a FERC-jurisdictional tariff and provides open access for wholesale customers to interconnect their generating facilities to the distribution systems of the IOUs for the purpose of selling electricity at wholesale (into the California ISO market).

Energization refers to the process to connect new load to the distribution system (projects that receive energy only from the grid). For CPUC-jurisdictional utilities, the rules that govern energization of loads are Rule 15 (distribution line extensions), Rule 16 (service extensions), Rule 2 (special facilities), and Rules 29/45 (EV infrastructure).[107]

Although tariffs provide guidance to help customers connect projects to the grid, utilities still face issues with timely energization and interconnection. Future energization delays can impact all of California's major economic sectors, including agriculture, building,

107 Rule 15 applies when an extension of the electric distribution lines from the nearest permanent and available distribution facilities to commercial areas or neighborhoods is required, and costs are generally covered by ratepayers through an allowance and a portion from the customer. Rule 16 applies when service facilities connect distribution lines to customers' electric meters. This interconnection is generally needed with new customer facilities, and the cost share is handled the same as Rule 15. Rule 2 applies to nonstandard facility installation, and the entire cost is covered by the customer. Rule 29/45 is an optional alternative to Rule 16, strictly for non-single-family residential EV infrastructure projects and generally covers all infrastructure on the utility side of the meter service and distribution facilities, and costs are covered mostly by ratepayers.

transportation, and industrial. Finding an efficient method to scale up and plan for future energization and interconnection projects remains a challenge. The CPUC and IOUs have ongoing efforts to reduce delays and improve energization and interconnection projects.

Recent Process Improvement Efforts

The CPUC recently opened a new rulemaking to update the existing Rule 21 proceeding.[108] Under the new proceeding adopted August 14, 2025, the CPUC plans to modernize interconnection procedures in response to rapid evolution of DER technologies, including, but not limited to, storage and EVs. Topics under the new Rule 21 Proceeding include:

- Streamlining transmission upgrade assessments to reduce delays.
- Improving interconnection timelines.
- Addressing technical requirements for nonexporting storage and vehicle-to-grid systems.
- Developing frameworks for cost sharing on multiple interconnections.
- Costs.
- Reforming net energy metering and net billing tariff.
- Evaluating technology communications.
- Ensuring consistency between Rule 21 and WDAT.

Under Senate Bill 410 (Becker, Chapter 394, Statutes of 2023), the CPUC is directed to define and establish reasonable target energization periods and establish a process for reporting energization delays to the CPUC. SB 410 also directs the CPUC and large IOUs to improve distribution planning and provide IOUs the option to request the use of a ratemaking mechanism for energization related costs above existing authorizations. The CPUC developed the Energization Proceeding, which was opened in January 2024 and has led to the CPUC defining the energization timelines and criteria for timely service, customer process to report delays, and annual energization reporting requirements. Under Decision D.24-09-020,[109] the CPUC adopted timelines based on the utilities' historical energization data and party comments. The timeline CPUC developed for the Electric Rules are listed in Table 12 below.

108 CPUC. "Electric Rule 21: Generating Facility Interconnections," https://www.cpuc.ca.gov/rule21/.

109 CPUC. September 17, 2024. Decision D.24-09-020, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M540/K806/540806654.PDF.

Table 12: Timelines for Energization Application

Application Type	Average Timeline	Max Timeline
Rule 15	6 months	1 year
Rule 16	6 months	11 months
Combined Rule 15/16	6 months	10 months
Rule 29/45	6 months	11 months
Application Decision	0.3 months	1.5 months
Main Panel Upgrade	1 month	1.5 months

Source: CPUC D.24-09-020

The CPUC established timelines for large IOUs to upgrade or install large equipment or new substations triggered by energization projects. These projects include all types of energization requests such as new or upgraded circuits, substation upgrades, and installation of new substations. The timeline CPUC developed for IOUs major distribution upgrades and installation are listed in Table 13 below.

Table 13: Timelines for Distribution Upgrades and Installation

Distribution Upgrades	Max Timeline
New/Upgraded Circuit	2 years
Substation Upgrades	3 years
New Substation Installation	9 years

Source: CPUC D.24-09-020

Under the High DER Proceeding, the CPUC is improving the distribution planning process. The CPUC seeks to transition the current reactive distribution planning process to a more proactive process to support timely energization. Under Decision D.24-10-030,[110] IOUs are directed to make various improvements to the existing distribution planning process. These improvements include:

110 CPUC. October 17, 2024. Decision D.24-10-030

- Enhanced forecasting with scenario planning using new and improved data (which include pending loads).
- Community outreach and coordination.
- Faster connection using bridging solutions.
- Improving equity metrics and transparency.
- Enhancing integrated capacity analysis (ICA) by incorporating limited generation profiles.

The CPUC's ongoing efforts include implementing flexible service connections. A *flexible service connection* (FSC) is a bridging solution that allows high-energy users like data centers and EV charging stations to connect to the grid before full infrastructure upgrades are complete. By doing so, customers can operate normally with some limitations while IOUs are able to complete necessary long-term infrastructure upgrades in the area.[111] The CPUC is collecting stakeholder feedback on how to scale flexible service connections for customers who cannot receive their full requested capacity in a timely manner.

PG&E and SCE are also offering eligible customers limited load and limited generation profiles. Limited load profile agreements set load limits that must be adhered to during certain times of the day or year when the distribution infrastructure is constrained. The limited generation profiles allow 24 unique export limits during the year that can vary by month and hour of the day. Customers can choose among three configurations, which are called "Block," "18-23," and "Hourly." The IOUs are also piloting more dynamic approaches that require connecting to customers' energy management systems and sending hourly power limit forecasts a day in advance.

Key Themes From the August 11, 2025, IEPR Workshop on Interconnection and Energization

On August 11, 2025, the CEC hosted a remote-access workshop addressing barriers and solutions to accelerating clean energy interconnection and energization, as directed by

111 For example, see PG&E's Flex Connect pilot, https://www.pge.com/assets/pge/docs/clean-energy/electric-vehicles/flexible-service-connection-pilot-overview.pdf.

Assembly Bill 1373 (Garcia, Chapter 367, Statutes of 2023).[112] This workshop was designed to build on the work of the *2023 Integrated Energy Policy Report (IEPR)* on interconnection and energization and provide an update on new developments related to these issues. The workshop agenda addressed these topics at the bulk grid and distribution levels.

A panel on distribution interconnection and energization included a consumer choice aggregation (CCA) representative, an IOU representative, an EV charging network provider, and an environmental and sustainability consultant to tribes and local governments. The panel highlighted several key themes.

One theme was the need to strategically use the approach of "right-sized electrification." Since residential electric panel capacity may often be an electrification roadblock, right-sizing is an alternative solution that can help avoid costly upgrades and delays. *Right sizing* electrification matches electric equipment and infrastructure to specific customer load needs to help prevent overbuilding and ensure efficiency needs. Tools like circuit controllers, smart panels and breakers, and 120-volt equipment can be used to help minimize costs and have seen an average customer bill savings of 20 percent.

Another theme was the need to continue efforts to streamline energization and interconnection. Specifically mentioned was the need for improved coordination between the various energization and interconnection processes (for example, for IOUs, these are processes associated with CPUC Rules 15, 16, 21, 29/45), as well as more consistency between energization and interconnection processes across all utilities in California.

There also continues to be a need for better, more accessible distribution capacity information and data. Although the IOUs have made progress in developing improved public data access portals for interconnection, energization, and distribution planning data, there continue to be gaps relative to customer application of a utility's integrated capacity analysis (ICA) to develop limited load profiles to enable flexible service connections.

Another theme covered was the need to encourage and support collaboration on environmental and sustainability issues with tribes, local governments, and nongovernmental organizations (such as nonprofits). There is a continued need to promote BTM clean DER investments. There is also a need to be consistent and meaningful resources for tribes, local

112 CEC. August 11, 2025, IEPR Workshop on Accelerating Interconnection and Energization web page, https://www.energy.ca.gov/event/workshop/2025-08/iepr-commissioner-workshop-accelerating-interconnection-and-energization.

governments, and nongovernmental organizations to participate and advocate with IOUs and state agencies.

Stakeholder Feedback From the August 11, 2025, IEPR Workshop

Following the workshop, several stakeholders submitted written comments identifying areas that would benefit from further improvement. A major theme identified in the comments was flexible service connection (FSC); it was frequently mentioned as a critical tool, but one that still needs further improvement. In general, stakeholders believe that FSCs should be easily accessible to all customers through a standardized process, form, tariff, or portal.

It was suggested that the *IEPR* should further explore FSCs and ways to unlock this pathway throughout the state, including in POU service territories. Others believe that a roadmap is needed that will lead to California utilities offering FSCs to all customers facing energization delays. One stakeholder suggested that customers who opt for FSCs should be provided a share of the avoided distribution upgrade costs. Another sentiment was that a statewide framework is needed for review of nonexport storage as a mitigating element for capacity constraints and to ensure developers do not have to apply under multiple rules for a single system. Streamlining permitting for customer-owned storage was offered to help FSCs provide a bridging solution. Another proposed area of improvement would be to use ICA to develop limited load profiles as is done today to develop generation profiles. Stakeholders recommend that the ICA should be applied to develop limited load profiles.

Another common theme was the need for more coordination and synergies among Rule 15 (distribution line extension), Rule 21 (interconnection), and Rule 29/45 (EV infrastructure) to reduce upgrade timelines, cost, and complexity. Timelines, studies, and upgrade costs should be cohesively analyzed. For example, a single energy storage request for a digital current fast charging site should travel with the project through all three rules without requiring developers to coordinate studies and upgrades or costs between different departments at the same utility.

Grid capacity, FSCs, onsite solar, onsite battery storage needs, and technology options need to be treated holistically rather than addressed in different dockets and different rate schedules at each utility. Rule 15 line extension work is assessed without considering the capacity implications of BTM energy storage submitted in parallel with Rule 21, which can overstate upgrade needs and extend timelines. Further reform of Rule 15 was recommended by stakeholders. More work is needed on fast interconnections for Rule 21 nonexports (for a customer that plans to add energy storage to their site to address power import limits).

Stakeholders also cited the need for process improvements related to the interconnection and energization of EV chargers. Some stakeholders state that the interconnection fees for grid-parallel bidirectional charging systems in California may be among the highest in the nation and should be reassessed. These stakeholders point out that the high cost of interconnection reduces the financial incentive of customers to adopt bidirectional EVs. They suggest that California needs to find solutions to reduce interconnection costs for bidirectional EVs.

Another issue needing attention is that of utility notice requirements. One stakeholder stated that there should be no utility notice requirements for EVs that are used only for mobility (for example, EVs that never discharge when isolated nor when grid-connected) and that they should not need to notify their utility of a backup power generator or start the Rule 21 interconnection process. For bidirectional EVs that serve as mobility resources and backup generators, this same stakeholder suggested that each utility should create a separate, robust backup generator notification process that's separate from Rule 21.

For EV fleet customers, stakeholders cite a need for more proactive distribution grid planning to anticipate fleet charging needs and solutions that may be needed, and utilities should offer FSCs for EV fleet charging sites. A final EV-related issue raised was regarding high metering costs. For non-NEM customers, the meters inside EV supply equipment can be used as submeters to avoid the costs of net generation output meters. Stakeholders point out that NEM customers are excluded from this eligibility and believe this is a barrier for NEM customers to use EVs to help smooth out their demand curve at sunset.

CHAPTER 3: California's Progress Toward the Load-Shift Goal

Introduction

Load flexibility, also called *demand flexibility*, has many interpretations in the literature. For this report, load flexibility is the capability to shift or shed electric demand away from times when electricity is expensive, polluting, and scarce to times when it is inexpensive, clean, and plentiful. This shift can be accomplished by the consumer or an operator. Load flexibility can help grid operators respond to grid constraints and improve system use and reliability, with minimal to no impact on consumers in most cases. Load flexibility can support the grid in short-duration events, such as extreme heat, or in the longer term to support renewable integration and distribution congestion relief.

Millions of new electric vehicles (EVs), heat pumps, and other electric loads are expected to come onto the grid by 2045, which could increase potential load flexibility but may also increase required investments in grid infrastructure to support new loads. California has an opportunity to expand load flexibility as a large-scale grid resource. If properly designed and deployed, increased load flexibility from new and existing electric loads can improve reliability, grid use, optimize grid infrastructure investments, and reduce costs for electric ratepayers.

Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) directed the CEC to develop a goal for shifting load to reduce net peak electrical demand and recommend policies to increase demand response and load shifting, along with other actions to support California's clean energy transition and grid reliability. In May 2023, the CEC published its *SB 846 Load Shift Goal Report*,[113] which estimated California's load flexibility potential as 5.1 gigawatts (GW) to 8.1 GW by 2030 under a reference demand scenario and average weather conditions. Based on these findings, the CEC established a statewide load-shift goal of 7 GW by 2030.

113 Neumann, Ingrid and Erik Lyon. May 2023. *Senate Bill 846 Load-Shift Goal Report*. CEC. Publication Number: CEC-200-2023-008, https://www.energy.ca.gov/publications/2023/senate-bill-846-load-shift-goal-report.

Key Distributed Energy Resource (DER) Concepts

The term *DER* refers to any grid resource on the distribution system or behind a customer meter, including, but not limited to, energy generation, storage, load flexibility, and energy efficiency.[114]

Load flexibility is offered to customers in the form of two broad applications: event-based customer programs or retail rate-based flexibility. These applications refer to the ways customers are incentivized for load flexibility, which are different than the other categories of load flexibility related to resource planning. Demand flexibility via event-based programs that can be achieved through a call for behavioral participation or be automated through smart devices managed by automation service providers (ASPs).[115] On the other hand, rate-based flexibility is rooted in providing pricing incentives to encourage consumers to shift their electricity use to times when clean energy is abundant and avoid consumption when it puts strain on the grid. Tools for rate-based flexibility include time-varying rates such as time-of-use (TOU) rates, critical peak pricing, and real-time or dynamic pricing. The resource impacts from demand response and rate-based load flexibility may change over time depending on market conditions (for example, smart meter deployments) and consumer preferences.

Several key agency documents adopted the term *load flexibility* in early 2020, including the CEC's staff report on Load Management Standards[116] and Senate Bill 49 (Skinner, Chapter 697, Statutes of 2019), which required the CEC to develop Flexible Demand Appliance Standards.[117] Later in 2022, the CPUC's staff white paper *Advanced Strategies for Demand Flexibility*

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114 Distributed energy resources (DER) are defined in Public Utilities Code Section 769(a) as distribution connected renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies, https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?lawCode=PUC&sectionNum=769.

115 An *ASP* is a commercial entity that provides a portfolio of advanced technological solutions to DER owners to realize electrical bill savings through demand side management including energy efficiency, load flexibility and self-generation.

116 Herter, Karen B. and Gavin Situ. 2021. *Analysis of Potential Amendments to the Load Management Standards*. CEC. Publication Number: CEC-400-2021-003, https://www.energy.ca.gov/publications/2021/analysis-potential-amendments-load-management-standards.

117 CEC web page on flexible demand appliances, https://www.energy.ca.gov/proceedings/active-proceedings/flexible-demand-appliances.

Management and Customer DER Compensation[118] triggered the CPUC's first demand flexibility proceeding.

Load flexibility is sometimes incorrectly used interchangeably with virtual power plants. While there is a significant overlap, the terms load flexibility and virtual power plants are not interchangeable, and in some cases, can refer to completely different applications. For instance, load flexibility programs may include behavioral and rate-based interventions. Virtual power plants are a type of DER, including solar generation, that aggregates and automates resources via software and can receive dispatch signals from grid operators.

Load Flexibility in California's Resource Planning

Grid planning is a proactive process, with interactions among resource planning, market design, and infrastructure decisions. There are several steps that a load-serving entity (LSE) takes to ensure resources are available to meet demand. First, it forecasts its future peak load and may account for certain demand-side interventions that help reduce that load. These are often initiatives like TOU rates. Next, LSEs need to ensure that they procure resources to meet that peak. This process may include procuring demand response in addition to generation resources. Outside traditional resource planning processes, the state or LSEs can implement emergency DR programs to support the grid during extreme weather events that fall outside traditional planning standards.

In 2023, the CEC's *SB 846 Load Shift Goal Report* introduced three categories of load flexibility as shown in Figure 39.[119] The following discusses how these groups differ and how they are accounted for in California's load forecasting and resource planning frameworks. Loss-of-load-expectation (LOLE) refers to an analysis that quantifies the expected risk of a supply shortfall (such as when available system generation is less than system load). The typical standard is to analyze a loss-of-load event no more than once every 10 years.

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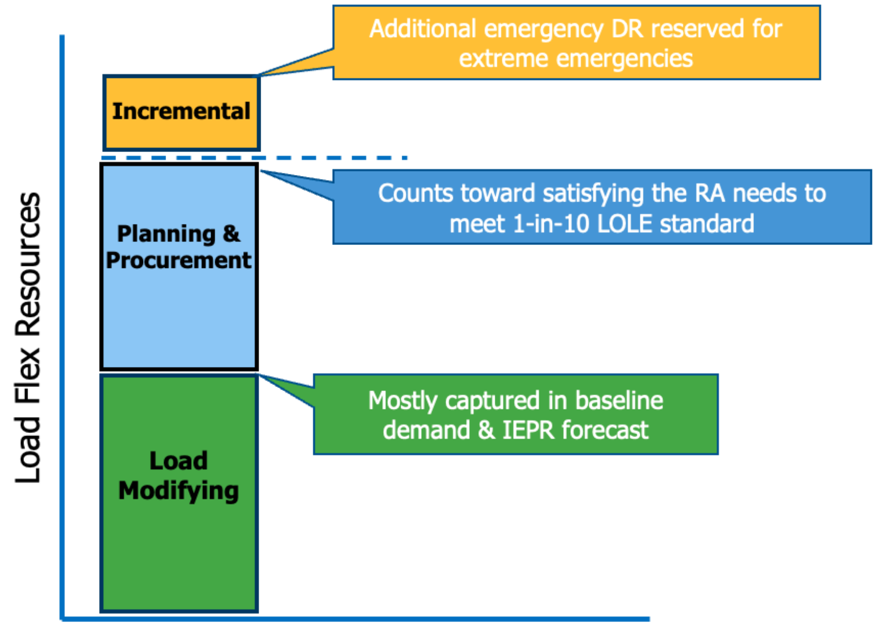
118 CPUC. June 22, 2022. *Advanced Strategies for Demand Flexibility Management and Customer DER Compensation*, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/ed-white-paper---advanced-strategies-for-demand-flexibility-management.pdf.

119 Neumann, Ingrid and Erik Lyon. May 2023. *Senate Bill 846 Load-Shift Goal Report*. CEC. Publication Number: CEC-200-2023-008, https://www.energy.ca.gov/publications/2023/senate-bill-846-load-shift-goal-report.

Figure 39: Load-Flexibility Categories in Resource Planning



Source: CEC

Group 1: Load-Modifying Resources. Load-modifying resources are the load flexibility interventions that are used by LSEs to reduce their projected peak demand and optimize load shape at the system level or on distribution circuits. Load-modifying resources can be seen as a general category to capture all load-flexibility resources that are not counted for on the supply side or not accounted for in the incremental emergency programs. The most common category of load-modifying flexibility is time-varying rates, such as TOU rates, critical peak pricing, and highly dynamic rates. Load-modifying resources are generally captured in the CEC's demand forecast in various stages, such as within the baseline demand, or as an incremental load modifier or accounted in the final adjusted forecast for LSEs.[120]

Group 2: Resource Planning and Procurement Load Flexibility. Resource planning and procurement load flexibility either count toward RA requirements or reduce RA requirements as determined by an LSE's regulatory body. Utility-run DR portfolios are typically accounted for as an RA credit, thereby reducing RA requirements. Third-party DR contracts are directly counted toward meeting RA requirements. Under CPUC requirements, market-integrated DR

120 The load-modifying resources for SB 846 Load-Shift Goal analyses may differ from other types of load modifiers reported in different programs, such as the load modifiers in the IEPR load forecast or the load modifiers reported by LSEs in their integrated resource plans.

(also called supply-side DR) must be registered in the California ISO's energy market as either an economic or reliability DR resource. While economic DR participates in California ISO markets similar to generators, reliability DR is activated by the California ISO under emergency conditions.

Group 3: Incremental Emergency Resources. Incremental and emergency load-flexibility programs are intended to increase resource availability during extreme events that are difficult to plan for. In the past few years, California has experienced increased intensity, frequency, and duration of extreme climate-driven weather events such as coincidental heat waves and wildfires. These emergencies are not fully accounted for in traditional planning standards. Two programs have been developed to help provide additional resources in an emergency. These programs are exclusively or primarily load flex programs: the Emergency Load Reduction Program (ELRP)[121] and the Demand Side Grid Support Program (DSGS). These programs serve as an insurance policy during unpredictable and volatile climate-driven extreme events. Flex Alerts provide an additional relief through unquantified voluntary energy conservation.

The 2024 Resource Stack and 2030 Projections

CEC staff, in collaboration with staff from the CPUC and California ISO, developed a framework for measuring how much load flexibility California has, which is used to determine if additional efforts are needed to meet the 7 GW by 2030 goal. This framework requires collecting information from load flexibility programs and then compiling the data into a bar chart to provide a visual "resource stack" that measures progress toward that goal. LSEs, third-party DR providers, and the CEC's DSGS Program provide data in various reports and proceedings. These data include information on load flexibility program enrollments, as well as actual or estimated load impacts.

CEC staff generated a resource stack by using the list of reports and data provided in Appendix C, along with the customer storage adoption and load impact estimates from the *2023 IEPR* forecast. The key assumptions to generate the resource stack for each year are provided in Appendix C.

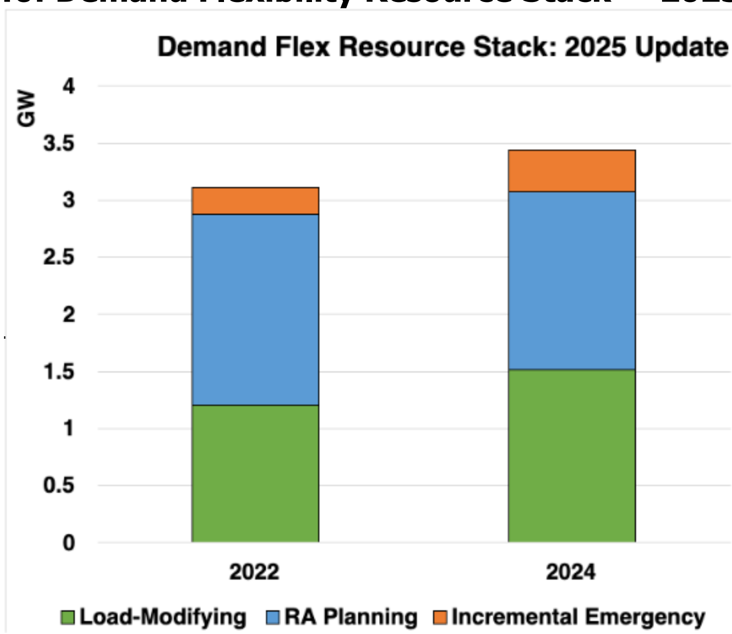
The CEC estimates roughly 3.4 GW of load-shift capabilities in California as of the end of 2024. Figure 40 compares how this capability has changed since the first SB 846 report was

121 The ELRP is a 5-year pilot program designed to pay electricity consumers for reducing energy consumption or electricity supply during periods of electrical grid emergencies to reduce the risk of electricity outages. The ELRP started in 2021 and is managed by the state's three large investor-owned utilities (IOUs).

published in 2023. These results correspond to a modest 10 percent growth since 2022. Table 14 provides a detailed breakdown of the resource stack estimates.

Staff used the *2023 IEPR* forecast to separately estimate the impacts of customer storage discharge. Customer storage adoptions have expanded significantly since 2022, while IOU reporting of TOU impacts mostly showed incremental EV rate enrollments since then. While the CEC's energy storage impact estimates may include slight overlaps with the impacts from EV-TOU rates offered by IOUs, these estimates are generated for a much broader customer segment including POU customers. The CEC's estimates for customer storage include only behind-the-meter resources. Front-of-the-meter storage, including the community solar+storage projects under LSE contracts, is not accounted for as a load-flexibility resource in this analysis.

Figure 40: Demand Flexibility Resource Stack — 2025 Update



Source: CEC

Table 14: 2022–2024 Load Flexibility Resource Estimates Breakdown (in Megawatts [MW])

Load-Modifying	2022	2023	2024	2-year Change
TOU & EV-TOU rates	1,000	1,078	1,122	12%
Customer storage discharge impacts (IEPR 2023 estimates)	173	266	358	107%
IOU Critical Peak Pricing (CPP)	30	21	31	3%

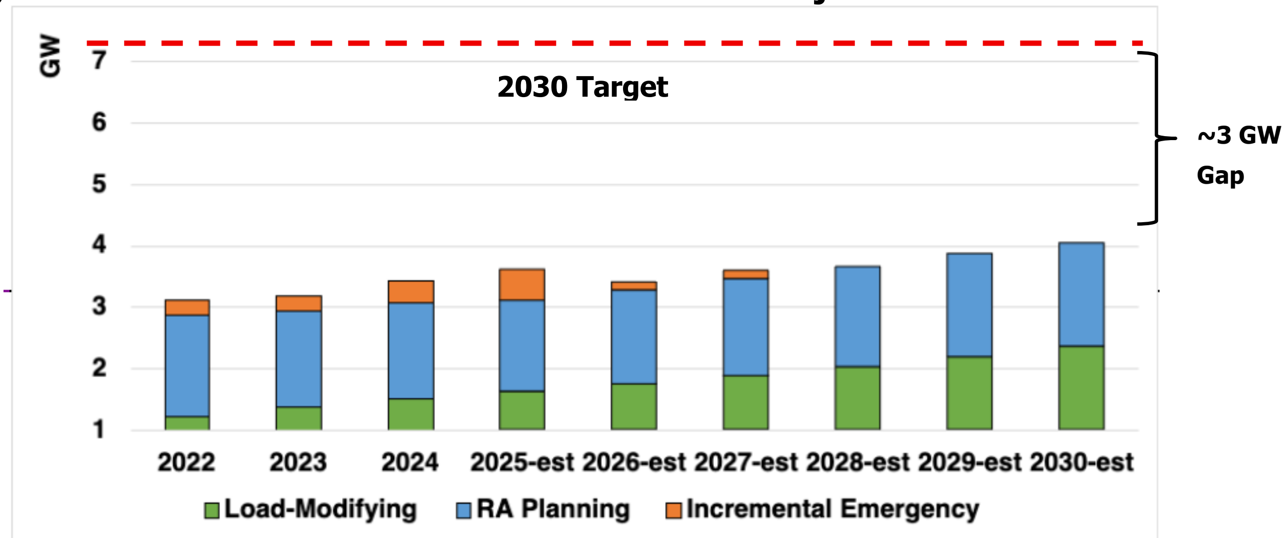
Load-Modifying	2022	2023	2024	2-year Change
Community Choice Aggregation (CCA) customer programs	7	3	3	-57%
RA Planning				
Emergency DR (IOUs)	784	763	760	-3%
Economic DR (IOUs & CCAs)	676	579	494	-27%
POU DR Programs and Contracts	210	233	304	45%
Incremental Emergency				
ELRP	190	190	209	10%
DSGS	46	46	161	250%
Grand Total	**3,116**	**3,179**	**3,442**	**10%**

Source: CEC

The 2022–2024 resource stack results show that the non-RA DR (load-modifying and incremental emergency) has increased by about 32 percent (or 438 MW). This growth is driven largely by EVs, batteries, and DSGS contributions. On the other hand, the total RA-eligible resources (non-POU) have decreased by about 14 percent (or 206 MW). As discussed in the *SB 846 Load Shift Goal Report*, the potential for increased RA resources has been limited by several factors, including challenges related to measurement and verification of load impacts, historical underperformance, and customer enrollment in supply-side DR. These factors must be considered when assessing the scope and scale of reliable supply-side solutions that are appropriate for meeting RA obligations.

CEC staff has also estimated projected growth through 2030 under the business-as-usual (BAU) market and policy conditions, using the resources and assumptions provided in Appendix C. Figure 41 shows that the resource totals would reach 4 GW by 2030, which results in a 3 GW gap toward the load-shift goal of 7 GW. These estimates assume that DSGS and ELRP are not extended beyond the scheduled or projected end of program funding.

Figure 41: California Demand Flex Resource 2030 Projections — BAU Scenario



Source: CEC

The 2030 projections show that California may not reach the 7 GW target under the BAU market conditions, indicating that the state likely needs additional near-term strategies that are cost-effective and support reliability and decarbonization efforts. New IOU initiatives, such as hourly dynamic rates, along with bidirectional charging (or vehicle-to-everything or V2X) and data center load flexibility applications, may improve the outlook.

Two technologies projected to have the largest growth are EVs and customer batteries. The *2023 IEPR* forecast estimated a 120 percent increase for the energy capacity of customer batteries by 2030. On the other hand, the incremental peak load impacts from EV charging (compared to the 2022 baseline) are projected to increase from 84 MW in 2025 to 431 MW in 2030. Any reductions in federal and state funding toward electrification incentives may adversely impact EV and energy storage adoptions, resulting in an additional reduction in the state's projected load-shifting capabilities. These developments will be closely monitored and incorporated into the staff analysis in future *IEPRs*.

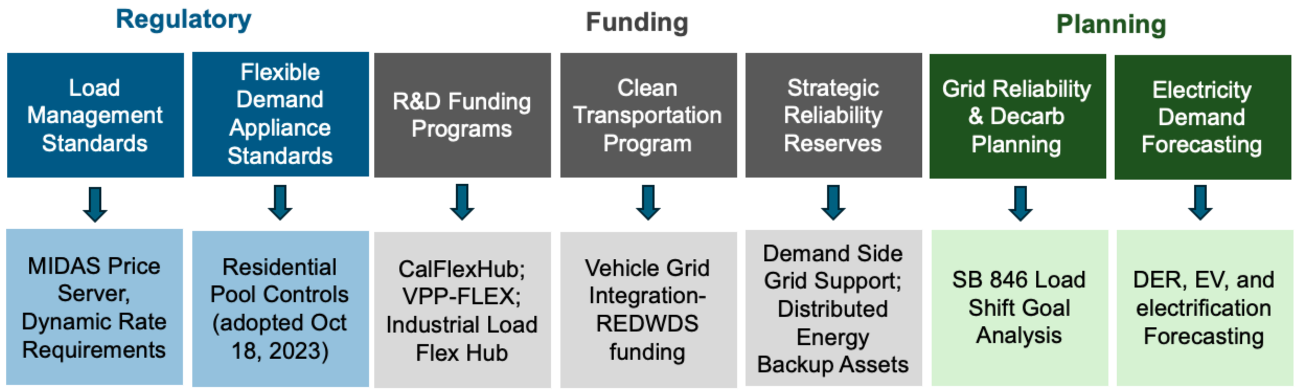
The CEC's progress tracking framework for the load-shift goal is an evolving effort and is not a definitive determination of the progress. CEC staff acknowledges the need for a more consistent way to measure statewide load flexibility uniformly across RA and load-modifying resources. CEC staff will continue to refine its tracking framework and improve tracking mechanisms based on stakeholder input and newly available data.

California's Load Flexibility Policy Initiatives

The *SB 846 Load-Shift Goal Report* discussed how the policy landscape has evolved in California since the CPUC's bifurcation decision in 2014, which required IOUs to integrate event-based DR into the wholesale market. Policy initiatives have continued to evolve in the last two years. Appendix C provides a list of regulatory and funding programs.

Figure 42 shows examples of how the CEC's regulatory, funding, and planning programs have been shaping load flexibility in California. These programs continue to grow in impact.

Figure 42: CEC Load Flexibility Program Highlights



Source: CEC

The CEC, CPUC, and California ISO continue to collaborate on their separate proceedings and initiatives. In September 2025, CPUC staff released a staff proposal to update the CPUC's guiding principles for advancing demand response in California.[122] The newly proposed guiding principles align with the market barriers discussed below and include:

- Predictability and reliability.
- Standardization and consistency.
- Cost-effectiveness.
- Environmental alignment.

While CPUC continues to establish dynamic rate alternatives and streamline the Load Impact Protocol (LIP)s, the California ISO has started its Demand and Distributed Energy Market Integration Initiative (DDEMI).[123] DDEMI is exploring enhancements or development of participation models and market rules promoting the representation of demand and distributed

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122 CPUC. Order Instituting Rulemaking to Enhance DR in California, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M582/K072/582072320.PDF.

123 California ISO DDEMI web page, https://stakeholdercenter.caiso.com/StakeholderInitiatives/Demand-Distributed-Energy-Market-Integration.

Load impact protocols are the CPUC's set of protocols required for demand response providers to evaluate the load impact of their programs.

energy, independently or managed in aggregation, in the day-ahead and real-time California ISO markets. The proposed timeline for DDEMI includes policy development in the fourth quarter (October–December) of 2025 and a decision in the first quarter of 2026.

Load Flexibility Stakeholder Outreach Results

Stakeholder input is critical for understanding the barriers, solutions, and strategies to achieving California's load shift goal of 7 GW by 2030. To gather this input, CEC staff used two sources: a load flexibility stakeholder survey conducted by CEC staff and the 2025 Demand Flexibility Summit held in May 2025 at UC Davis.[124]

CEC staff initiated the stakeholder survey in December 2024, directly emailing the survey to 39 stakeholders who had previously participated in the CEC's load flexibility-related proceedings and initiatives. These stakeholders broadly represent four groups: aggregators and technology providers, LSEs and utilities, consultants and research groups, and industry associations and consumer advocacy groups. The survey covered four topic areas:

- Policy barriers affecting the full usage of load flexibility
- Alternative market or regulatory models and approaches
- Emerging trends in California's market
- Other conceptual ideas to scale load flexibility

By mid-January, CEC staff received 27 sets of stakeholder responses to the email survey and consolidated that information for this analysis.[125]

A second source of stakeholder input was the 2025 California Demand Flexibility Summit held May 22, 2025, at UC Davis.[126] The summit sought to discuss the progress and challenges to achieving California's load-shift goal of 7 GW by 2030. This event was convened by a collaboration among the CEC, UC Davis Energy & Efficiency Institute, and Lawrence Berkeley National Laboratory and brought together more than 400 attendees from a wide spectrum of

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124 2025 California Demand Flexibility Summit web page, https://event.fourwaves.com/california2025demandflexsummit/pages.

125 Written responses were received from Renew Home, LEAP, Voltus, Olivine, WeaveGrid, Generac, Nostromo, Tesla, Cal Solar Storage Alliance, Cal Energy Storage Aliance, PG&E, SCE, SDG&E, SMUD, LADWP, MCE, SCPA, PCE, San Diego, Gridworks, LBNL, CEDMC, EPRI, Brattle, VGIC, Advanced Energy United, CLECA.

126 2025 California Demand Flexibility Summit web page, https://event.fourwaves.com/california2025demandflexsummit/pages.

stakeholders, as well as legislators and state agency representatives, to discuss load flexibility potential in California. The agenda addressed a broad range of topic areas:

- Fireside Chat: The road to 2030: Unlocking California's demand flexibility potential
  - Keynote Address : Powering the future: How demand flexibility can advance California's clean energy leadership
- Plenary 1: Updates and lessons from existing programs and incentives
- Plenary 2: Demand side load flexibility
- Plenary 3: Scaling demand flexibility — Breakthrough technologies and market solutions
- Plenary 4: Adopting demand flexibility innovations for California

CEC staff analyzed the stakeholder input provided by both sources. In summarizing the sentiments expressed by stakeholders, CEC staff generally tried to preserve stakeholders' words by avoiding making unnecessary edits or passing judgment on the views expressed. For the survey, staff committed to stakeholder respondents that staff would not ascribe a comment to any stakeholder to preserve their anonymity. Stakeholder perspectives expressed in survey responses and at the summit represent a broad spectrum of business interests and perspectives; thus, not all stakeholders may agree with all the sentiments expressed and that there may be perspectives not captured.

Based on the review and synthesis of survey responses and the panel discussions from the summit, CEC staff identified several common themes.

Stakeholders Perspectives: Program Requirements Can Limit Flexibility

Baselines

Stakeholders said a well-functioning market requires the development of baselines on which performance can be evaluated. However, load flexibility resources do not all operate in the same way, so a single approach to developing baselines can impede program potential. Newer resources, such as energy storage and EVs, can have very different use profiles. Stakeholders commented that the current requirements of consistent baselines may limit the dispatch of energy storage resources. Developing new approaches to measure the load-reduction performance of energy storage resources, such as EVs, deserves further consideration.

Dispatch Durations

Resource adequacy rules in the market generally require dispatches of four or more hours; however, some stakeholders commented that some customer resources may struggle to deliver reliable and predictable load drop for that duration. These stakeholders commented that certain DERs, such as batteries or smart thermostats, could potentially sustain large reductions for shorter periods. Stakeholders point to the shorter dispatch durations of the DSGS program as an example that could be replicated or expanded. Stakeholders further express that expanding this feature statewide could unlock some undefined amount of load flexibility. Developing appropriate frameworks to value shorter duration resources may deserve further consideration.

Dual Participation

The ability for customer resources to participate in several load-flexibility programs could have the benefit of increasing value to providers and customers while enabling the realization of multiple grid benefits from a single customer. Stakeholders commented that existing rules may restrict the ability of DERs to participate simultaneously in multiple load flexibility programs. These stakeholders believe that restrictions on dual enrollment may hinder participation when multiple technologies available for dispatch are installed at a single location (such as a meter). At the same time, it would be critical to avoid paying more for these resources than they provide to the grid to support affordability. This idea would require further investigation.

DER Exports

Stakeholders said current rules may restrict the ability of customer resources to export to the grid. Specifically, stakeholders commented that BTM energy storage capacity may be stranded due to the absence of a framework recognizing the RA capacity value of exporting BTM energy storage. Developing appropriate frameworks to enable export of BTM energy storage may deserve further consideration.

Device-Level Data Versus Meter Data

Under current rules, measurement of customer energy reductions is typically made at the customer's utility meter rather than at the device. As the suite of resources expands behind each meter (such as an EV, a controllable thermostat, or a controllable residential battery), it may be more effective to make measurements at the device level. However, challenges include the limited availability of such data (which makes it difficult to design and operate programs), the settlement quality of such data, and the need to retain customer confidentiality.

Stakeholders Perspectives: Differing Program Rules and Frequent Program Changes Result in Market Uncertainty

California has made great strides in developing and deploying many approaches to bring load flexibility to scale. While this progress involves continuous improvement and refinement, some stakeholders comment that programs, rules, and funding related to load flexibility seem to undergo constant change. A multitude of programs with different rules can inadvertently lead to inefficiencies in aggregating load-flexible resources. Although California has a wide array of programs designed to promote load shift, these stakeholders believe that the state has not yet achieved the ideal solution. The solution should be simple for customers to understand, easy to administer, consistent across utility territories, and provide sufficient value to promote customer participation through incentives. The solution should not be limited in budget and duration. To address this, some stakeholders suggest that state regulators and policymakers could convey a clear vision and policies through a California load-shift goal roadmap.

Stakeholder Perspectives: Ensuring Affordability, Equity, and Seamless Customer Engagement

Lack of Incentives

Providing financial incentives can increase customer and provider participation in load-flexibility programs and technologies. Some stakeholders comment that there is a lack of financial incentives for customers to participate in load flexibility programs and that this represents a barrier to full resource use of demand flexibility. Lack of incentives refers to programs that provide no financial incentives as well as programs that do not provide a sufficient level of incentives. An examination of the potential for additional financial incentives to support expanded use of demand flexibility deserves further consideration.

Consumer Experience

As mentioned previously, California has been developing and implementing many approaches to bring load flexibility to scale. One implication of this dogged pursuit is that California's utility customers and load-flexibility providers may be confronted with many programs with different eligibility requirements and incentives that may create confusion and poor customer engagement. Some stakeholders (from a customer perspective and a provider perspective) express that the load flexibility program environment is too fragmented and that there are too many competing program models operating in the same load flexibility space. These stakeholders believe that an examination of the potential for more unified and simplified utility programs deserves further consideration. Some stakeholders shared the Connected Solutions program[127] by National Grid in Massachusetts as a model. This program was intended to create a central platform for customers with DERs to sign-up for demand response.

Equity and Affordability

There is broad concern about the ability of all customers to access load-flexibility technologies and participate in load-flexibility programs and broad support for ensuring that the growth of load flexibility be equitable and affordable. However, there is concern among stakeholders that lower-income residents may have difficulty accessing or affording load-flexibility programs and technologies. To help ensure equitable access to grid-smart technologies and programs, an examination of stronger incentives for low- and moderate-income customers and those who live in low-income or disadvantaged communities deserve further consideration.

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127 MA Connected Solutions Program, https://www.nationalgridus.com/MA-Home/Energy-Saving-Programs/ConnectedSolutions.

Data Access

The existing customer data access framework is a barrier to third-party providers enrolling customers and managing their participation. Some stakeholders suggest the creation of a centralized data repository or a statewide load-flexibility hub where customers can review all programs and participation options, share or withdraw data access, and review performance and settlements. Some stakeholders shared Smart Meter Texas[128] as a successful model; it is a central platform that enables third parties to access smart meter data with customer consent.

Lack of Communication Standards and Limited Interoperability

There is a lack of consistent communication protocols across all load-flexibility resources, creating a complex and challenging environment for providers and aggregators, in which incompatible and proprietary tools and protocols inhibit the scaling required to reach California's load shift goal. Open-source standards may be key to the scalability of load flexibility. This view holds that increasing the adoption of open-source DER communication protocols and standards would reduce deployment costs, facilitate aggregation, and help ensure customers are not left unsupported if an original equipment manufacturer exits the market. Policies and practices that encourage standardization deserve further consideration.

Focusing Load Flexibility at Strategic Locations on the Distribution Grid

Deploying load-shifting resources at strategic locations can benefit the electrical grid, including by reducing the need for peak generation capacity and investments in transmission or distribution infrastructure. There is broad agreement that load flexibility efforts should be focused where they can have the greatest impact in terms of both reliability and cost management — that is, assisting grid managers in moments of tight supply, while also supporting customer growth and increased electrification, avoiding building new supply infrastructure, and lowering bills over the longer term. More work is needed to understand how to deploy load flexibility strategically, including identifying how best to locate and control resources. Some stakeholders suggest creating a strategy to encourage siting and controlling load flexibility at the distribution level. They suggest that this could enable cost-effective ways to accelerate support for new customers while getting the most value from electrical grid assets that ratepayers have already paid for and minimizing the need for new investments. Some stakeholders shared New York's Value Stack framework[129] as a promising approach.

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128 Smart Meter Texas webpage, https://www.smartmetertexas.com/home.

129 NYSERDA Value Stack Link, https://www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources.

Expanding Load Flexibility Opportunities for EVs, Especially Bidirectional Charging

There may be a lack of load-flexibility programs for EVs that garner the full value of charging optimization. Some stakeholders believe that the growing fleet of EV batteries and bidirectional charging (or V2X) represents a significant potential load flexibility resource, if challenges around compensation, interconnection, and metering and telemetry are addressed. An examination of potential barriers and enabling solutions to the full use of vehicle-grid integration with bidirectional charging may deserve further consideration.

Conclusions and Future Work

Many of the same challenges identified in the *2023 Load-Shift Goal* report remain. While some progress has been made, there is still significant progress needed to meet the state's load flexibility goal. The overall analysis in this report shows that agencies should continue to work together to address the policy issues identified in 2023. See Table C-3 in Appendix C for the full list of policy recommendations. The CEC should also further evaluate the successful models from out-of-state markets identified in this report for applicability in California.

CEC staff will continue to investigate topics related to load flexibility-potential, market-integrated DR performance, and emerging strategies under its Order Instituting Informational Proceeding on DERs in California's Energy Future. These topics include developing an updated load flexibility potential analysis incorporating the *2025 IEPR* forecast that is in development.

CEC staff recommends no adjustments to the 7 GW load-shift goal by 2030 in the *2025 Integrated Energy Policy Report* (*IEPR*), acknowledging the need for new market and policy strategies for the state to effectively double its load-shifting capabilities over the next five years.

CHAPTER 4:
Advancing Clean and Renewable Hydrogen for Electricity and Transportation

California's policies are moving the state to economy-wide decarbonization, including key energy-intensive sectors such as electricity generation and transportation. For the electric sector, the state is rapidly scaling up deployment of clean energy resources — particularly solar, wind, and energy storage — and analysis has shown that a diverse portfolio of resources is valuable to achieving the state's goals.[130] The state is also advancing low-carbon transportation such as transportation electrification. Some forms of transportation, such as aviation, off-road transportation, and long-haul trucking, however, may be challenging to electrify in many cases. Hydrogen is often cited as a fuel capable of meeting some of these transportation decarbonization goals.

Because the state needs to consider all options to meet its clean energy goals, Senate Bill 1075 (Skinner, Chapter 363, Statutes of 2022) calls for the CEC to study and model potential growth for hydrogen in decarbonizing the electricity and transportation sectors in the 2023 and 2025 IEPRs. SB 1075 did not limit the scope of the types of hydrogen to be considered by CEC; however, the CEC focused on hydrogen production pathways with low greenhouse gas (GHG) emissions, referred to in this report as clean and renewable hydrogen. The CEC conducted a preliminary analysis in the *2023 IEPR* and committed to a more detailed analysis in a forthcoming supplemental report. The objective is to provide deeper understanding of potential hydrogen production pathways and of a broader set of end uses in the electricity and transportation sectors.

SB 1075 also requires CARB), in consultation with the CEC and CPUC to produce a comprehensive report on hydrogen. The CARB report will cover the development, deployment, and use of hydrogen across all sectors as a key part of achieving the state's climate, air

130 The term *clean and renewable* broadly refers to production pathways that produce low greenhouse gas (GHG) emissions and include production pathways that use renewable energy sources.

Analysis in the *2021 SB 100 Joint Agency Report* (developed in response to Senate Bill 100 [De León, Chapter 312, Statutes of 2018]) and the *2022 Scoping Plan for Achieving Carbon Neutrality* (*2022 Scoping Plan Update*) identify the need for a diverse portfolio of clean energy resources.

quality, and energy goals. CARB will also prepare a life-cycle analysis of GHG emissions from various forms of hydrogen. That report is anticipated to be published in 2026.

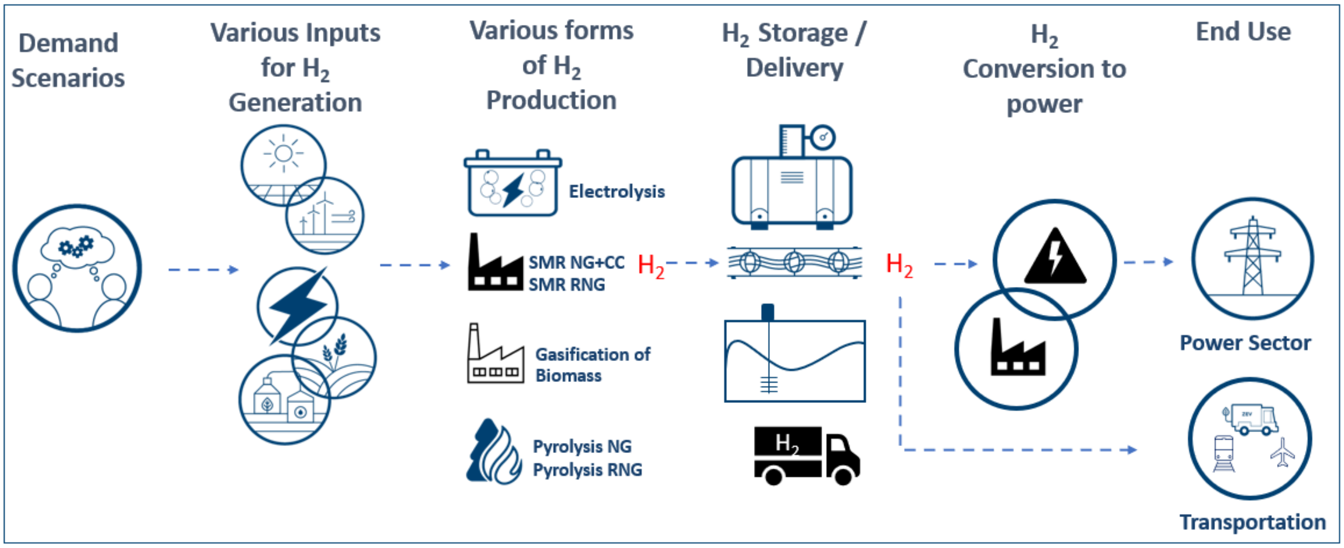
Hydrogen has historically been produced using fossil gas in key industrial sectors, including in the oil and gas industry, generating carbon dioxide (a GHG) as a by-product. For this analysis, the CEC considered hydrogen with lower GHG emissions. This included production from water using eligible renewable energy resources or produced directly from eligible renewable energy resources, including biogenic resources (biomass and gas generated from renewables). Carbon-emitting production processes using fossil gas, when combined with carbon capture, are also evaluated production pathways.

There are no explicit statewide policy goals for the use of hydrogen in the electric or transportation sectors in California, but as noted above, it is a candidate for the state to achieve its broader policy objectives. Additionally, federal actions have altered the market dynamics for hydrogen. Loss of federal funding has led the Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES) to pause its hydrogen hub activities, with the Governor's Office of Business and Economic Development and the University of California assuming administrative oversight during the transition. Under this new structure, the state will continue pursuing opportunities to advance clean hydrogen deployment, even without a dedicated federal hub funding. Separately, the federal tax credit landscape remains an important factor in future hydrogen development, as incentives can significantly influence project economics and market uptake.

With no clear guidelines to bound the analysis of demand, the CEC used illustrative demand scenarios for both the electricity and transportation sectors, as was done in 2023. For each scenario, the CEC evaluated the implications for feedstocks, production technologies, storage, transport, and end uses. This analysis uses information from SB 100 and Scoping Plan work.[131] The approach uses a mix of production pathways (Figure 43) that could be used to supply the hydrogen that meets the demand of the end-use scenarios.

131 For more information on the SB 100 Joint Agency Report, see https://www.energy.ca.gov/sb100. For more information on CARB's Scoping Plan work, see https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan.

Figure 43: 2025 Analysis of Hydrogen (H2) Pathways



Source: CEC (2025)

Hydrogen Demand Scenarios

Consistent with the *2023 IEPR* analysis, the CEC used two demand scenarios each for the assessment of the electric and transportation sectors. Scenarios were chosen to clearly determine what large differences in hydrogen demand might mean for infrastructure needs in the state. None of the scenarios are intended to be a prediction of or recommendation for the future demand for California. The scenarios define an annual quantity of hydrogen consumed and the specific applications (sectors and end uses) that would use the hydrogen.

Electric Power End-Use Demand Scenarios

The electric power generation scenarios are the same as they were in the *2023 IEPR:*

- **Fossil Gas Replacement (FGR)**: This scenario (upper) assumes hydrogen is used to replace all the fossil gas that CARB's *2022 Scoping Plan Update* estimated would be used to produce electricity in 2045. This amounts to 1.59 million tonnes of hydrogen fuel per year.[132]

132 This amount differs from the 1.88 million tonnes specified in the *2023 IEPR* because that analysis used a different thermodynamic basis for hydrogen — lower heating value —versus the current basis of higher heating value. This number is not based on the total hydrogen used across all sectors (1.6 million tonnes) in the CARB Scoping Plan but happens to be close.

- **Resource Diversification (RD):** This scenario (lower) assumes hydrogen is derived to diversify the portfolio of low carbon resources. This included replacing half of the long-duration energy storage energy and half of the grid power from geothermal resources, from the CPUC's 2018 RESOLVE resource planning model. This scenario is based on a 2020 report developed for the CEC by the University of California at Irvine (UCI).[133] It amounts to 0.35 million tonnes of hydrogen per year in 2045.

Transportation End-Use Demand Scenarios

The transportation hydrogen scenarios are similar to those in the *2023 IEPR*. Both hydrogen demand scenarios involve greater use of hydrogen than previously considered and are derived from the energy demand scenarios in the SB 100 analysis.

- **High Hydrogen Use Transportation Demand Scenario (HHU)**: Hydrogen demand in this scenario is 1.4 million tonnes per year in 2045, which is roughly the amount that CARB attributes to transportation applications in the *2022 Scoping Plan*.
- **Policy Scenario Transportation Hydrogen Demand (PS):** Hydrogen demand in this scenario is 0.81 million tonnes/year in 2045.

Hydrogen Production Portfolios

The CEC evaluated four main hydrogen technology pathways: electrolysis, reforming, gasification, and pyrolysis.[134] Each of these requires energy inputs and various material feedstocks (raw materials converted into hydrogen and by-products), leading to a total of nine production pathways that uniquely combine production technology with a feedstock and energy supply:

1. Electrolysis
    a. Proton exchange membrane water electrolysis with renewable electricity (PEM)
    b. Alkaline water electrolysis with renewable electricity (ALK)

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133 Reed, Jeffrey et al. University of California, Irvine, Advanced Power and Energy Program. June 2020. *Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California*. California Energy Commission. Publication Number: CEC-600-2020-002, https://efiling.energy.ca.gov/getdocument.aspx?tn=233292.

134 *Electrolysis* uses electricity to split water into oxygen and hydrogen. Steam methane reforming — or *reforming* — converts methane into hydrogen. *Gasification* is a thermochemical process that converts biomass into hydrogen. *Pyrolysis* is a thermochemical process that converts biomass into hydrogen in the absence of oxygen.

2. Steam methane reforming
    a. Fossil gas and carbon capture (SMR NG CC)
    b. Renewable gas, with or without carbon capture (SMR RNG)
3. Biomass gasification
    a. Forest residue feedstock (Biomass FR)
    b. Urban waste feedstock (Biomass UW)[135]
    c. Crop residue feedstock (Biomass CR)
4. Pyrolysis
    a. Fossil gas (Pyrolysis NG)
    b. Renewable natural gas (Pyrolysis RNG)[136]

Because there are many ways in which the hydrogen production landscape can develop, analysis required narrowing down the options evaluated for each scenario. Staff evaluated three hypothetical portfolios — electrolytic-heavy, balanced, and biogenic full. The nature of the three portfolios and the factors involved in the design are described below.

- **Electrolytic-heavy portfolio:** Electrolysis makes up most of this mix. Fossil gas pathways are deemphasized, biomass resources are at 10 to 35 percent of the statewide potential, and 65 to 100 percent of available RNG is employed to produce hydrogen.
- **Balanced portfolio:** All major pathways, fuels, and feedstocks will contribute to hydrogen production. There are equal and larger proportions on (1) electrolysis and (2) a combination of SMR with carbon capture and pyrolysis. Biomass and RNG resources provide limited hydrogen production.
- **Biogenic full portfolio:** Biogenic feedstocks are deployed 100 percent of the estimated statewide potential. While this portfolio makes maximal use of biogenic feedstocks, their limited availability still results in a high dependence on the other pathways in the upper scenarios. Electrolysis assumes a large portion of the remaining hydrogen supply, with pathways involving fossil gas providing moderate support.

135 Biomass which includes agricultural residue, forest waste, and urban waste.

136 Renewable Natural Gas (RNG) derived from livestock, landfill gas, municipal solid waste, and wastewater treatment.

Producing Renewable Electrolytic Hydrogen from Curtailed Power

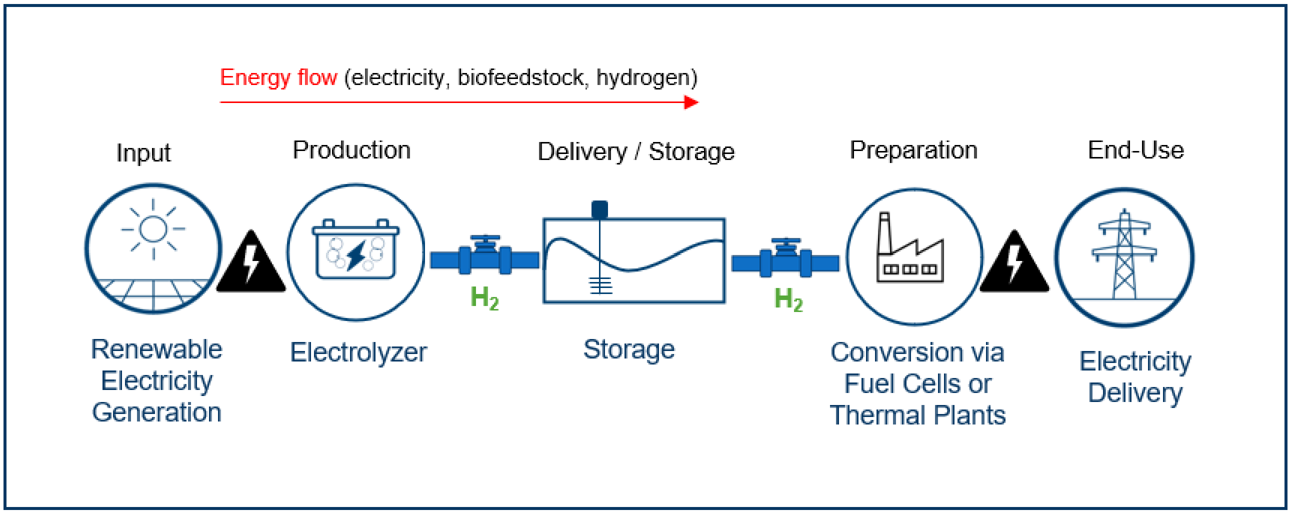
When electricity generation exceeds demand or is constrained by grid congestion, there is an opportunity to use the excess electricity that would otherwise be curtailed to produce hydrogen from an electrolyzer. However, the intermittent nature of curtailed electricity can result in limited and irregular quantities of hydrogen. Relying on the availability of excess electricity would also result in potentially long periods of time when an electrolyzer would be idle or at low utilization (operational) levels.

The production schedule for any hydrogen plant that focuses on curtailed power is going to be intermittent and unpredictable. Even during periods when curtailment is most likely to occur, the amount of electric power that would be available is variable. Right-sizing the equipment can be challenging. If electrolyzer capacity is sized to take advantage of curtailed power, a large amount of production capacity will be underutilized on times and days when power is not curtailed. Conversely, if electrolyzers are sized to achieve higher use levels, large curtailment may still be necessary. The most natural scenario for using curtailed energy is to have an electrolyzer located on-site of a renewable power asset and designed to run off the regular output of the renewable generator. This would support the economics of the renewable generator and improve the overall utilization of the power grid. However, this would mean the renewable generator is foregoing the opportunity to earn revenue from non-curtailed electricity.

Scenario Analysis

Hydrogen demand in any future scenario is likely to vary seasonally, daily, and hourly to meet diverse energy services in 2045. Matching supply and demand efficiently is challenging. For hydrogen to meet such variability, there must be an appropriate balance of production, storage, and delivery capacity to allow its use to scale. To evaluate different futures and assess infrastructure and economics, Guidehouse developed a modeling tool, the Integrated Value Chain Analysis (IVCA), to analyze infrastructure that would be needed to ensure supply meets potential demand. The IVCA model uses load profiles for different applications from CEC's production cost modeling to project production facilities and hydrogen storage to meet end-use demand. Road transport is assumed to be the only mode of delivery in the IVCA. Pipelines could be a cost-effective and efficient method of transporting hydrogen; however, pipelines were not evaluated in the IVCA because of the added complexity of assessing pipeline locations and costs. Figure 44 shows the full value chain for the electric power scenarios, including the three core components (production, storage, distribution). The figure illustrates hydrogen production from electrolysis using renewable energy, but all nine production pathways were evaluated in the resource assessment portion of this analysis that was completed after the IVCA.

Figure 44: Value Chain Configuration for Electric Power Scenarios, Using Electrolysis as the Production Pathway

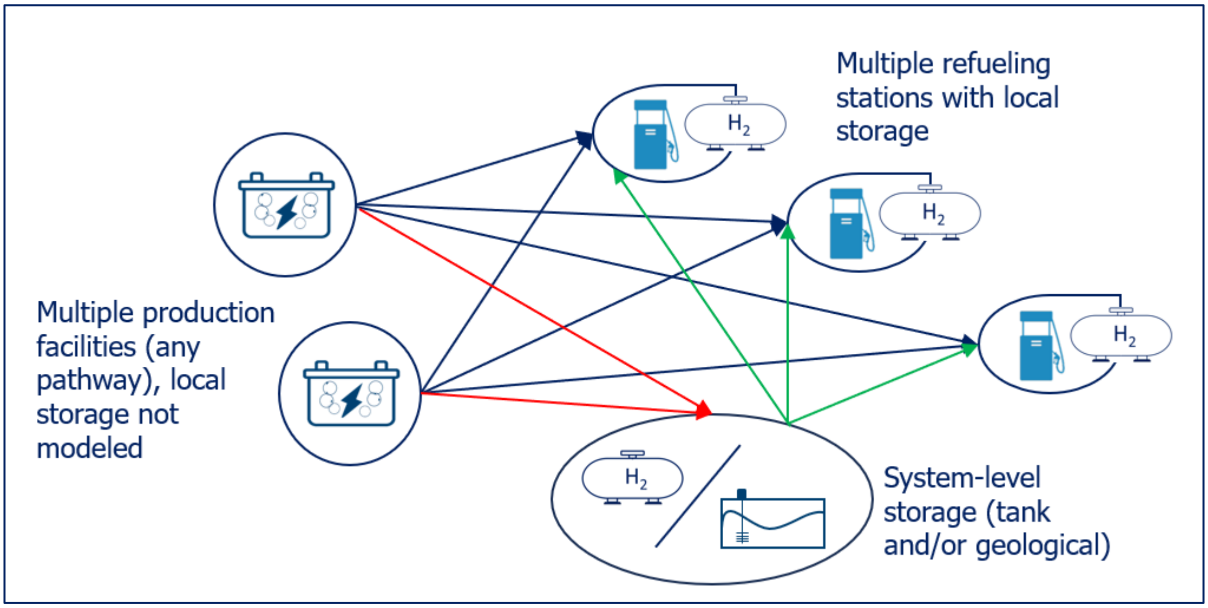


IVCA focuses on the steps of production through preparation for end use.

Source: Guidehouse Inc., 2025; CEC, 2025.

Figure 45 illustrates the three core components of the hydrogen value chain for medium-duty and heavy-duty (MDHD) transportation, along with the assumed connectivity. The figure applies to both transportation IVCA scenarios. The key difference from the IVCA for electric power is that the different producers and end users are considered separately rather than collectively. The IVCA tool covers more production nodes (five) and more refueling stations (55 to 75) than are illustrated in the figure. Instead of aggregating or bundling the production and end use into a single component each, the model computes the production and delivery of every facility in the ecosystem.

Figure 45: IVCA Value Chain Architecture for the Transportation (MDHD) Scenarios



Feedstocks and energy sources of production, as well as the end-use vehicles, are not shown.

Source: Guidehouse Inc., 2025; CEC, 2025

Three important high-level simplifying assumptions were made in the IVCA analyses:

- All the transportation hydrogen is assumed to be delivered to refueling facilities in quantities similar to those expected for refueling stations for MDHD vehicles (about 5 tonnes per day).
- Different sources of hydrogen will have complementary production profiles across the year, so that the total capacity for producing hydrogen is constant on a day-to-day basis. Thus, when one type of asset (such as an electrolyzer facility) is experiencing low production, another asset (for example, a biomass gasification plant) is assumed to have an excess that makes up the difference.
- The hydrogen markets for electric power and transportation are initially analyzed independently. The analyses did not quantitatively address the fact that hydrogen production and storage facilities for one sector can be made available to the other sector. Therefore, some *post facto* semiquantitative analysis was performed to preliminarily explore a combined market.

After defining the feasible combinations of production capacity and storage using IVCA, the results from the electric power and transportation analyses were combined to calculate the resources and infrastructure needed to deploy hydrogen for the scenarios. For this analysis, CEC combined the results for the upper (high hydrogen capacity) electric system and transportation scenarios and separately combined the results from the lower case (low hydrogen capacity) scenarios.

Resources Required to Meet Hydrogen Needs of the Scenarios

The charts and tables in this section show the results of the resource analysis, as applied to the three production portfolios, electrolytic-heavy, balanced, and biogenic full, for both combined scenarios. For each of the two scenarios, the shares of each type of feedstock assumed for the three production portfolios are summarized in Table 15. The mixes are different for the combined scenarios because the amount of demand in the combined upper (higher capacity) scenario is so large that the portfolio ideals are more difficult to meet. For example, in the combined upper scenario portfolio, available biomass is insufficient to enable an even apportionment between water-based, fossil-based, and biogenic-based feedstocks, without creating a mix that is similar to biogenic full.

Table 15: Production Portfolio Mixes in 2045 for the Two Combined Upper and Lower Scenarios for Electric Power and Transportation

Combined Upper Scenario:

Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Water (electrolysis)	72%	40%	44%
Fossil Gas (SMR+CC and pyrolysis)	12%	40%	22%
Biomass (gasification)	9%	14%	28%
RNG (SMR and pyrolysis)	6%	6%	6%

Combined Lower Scenario:

Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Water (electrolysis)	75%	34%	6%
Fossil Gas (SMR+CC and pyrolysis)	5%	33%	5%
Biomass (gasification)	10%	18%	74%
RNG (SMR and pyrolysis)	10%	15%	15%

Source: Guidehouse Inc., 2025

Within the analysis of each scenario, the limiting cases of no storage and full storage (as much storage as needed to allow the production capacity to be equal to the average demand) were computed. In the no-storage case, production capacity needs to be overbuilt, leading to the following resources needing to be higher than they would be for full storage: production capacity, numbers of plants, CAPEX investments, and — for electrolysis only — renewable electricity sources. The huge demand profile variability of the upper electric power scenario leads to a much greater difference between full versus no storage for the combined upper scenarios than the combined lower scenarios.

An important point is that the amount of hydrogen produced per year in any given scenario is the same, regardless of the production capacity and amount of hydrogen storage installed.

Thus, the non-capacity-related resources — the electricity, water, and feedstocks used — are the same for the no-storage and full-storage limits.

Hydrogen Production Capacity

Table 16 shows the amount of production capacity that would be needed for each feedstock type of each production portfolio under full storage and no storage conditions. The allocation of capacity among the four feedstock groups is the same for the full-storage and no-storage limits; the no-storage limit values are just a scaled version of the full-storage values.

Table 16: Production Capacity Requirements (Million Tonnes per Year) by Feedstock and Portfolio, Full-storage Case; No-storage is 4.5x for Combined Upper and 1.5x for Combined Lower Scenarios

Combined Upper Scenario

Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Water (electrolysis)	2.2	1.2	1.3
Fossil Gas (SMR+CC, pyrolysis)	0.37	1.2	0.64
Biomass Gasification (FR, UW, CR)	0.28	0.42	0.86
RNG (SMR, pyrolysis)	0.18	0.18	0.17

Combined Lower Scenario

Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Water (electrolysis)	0.87	0.39	0.072
Fossil Gas (SMR+CC, pyrolysis)	0.058	0.38	0.058
Biomass Gasification (FR, UW, CR)	0.12	0.21	0.86
RNG (SMR, pyrolysis)	0.12	0.17	0.17

Source: Guidehouse Inc., 2025

For the combined upper scenarios, the total production capacity required in the event of having no storage would be 4.5 times that of the case of having full storage. Most of the unused or excess capacity derives from the high scenario supply to the electric power sector.

The outlook is better for the combined lower scenarios; however, a lack of storage would still lead to a need for 50 percent more production capacity than what would be delivered. Having a smaller total demand for hydrogen means that the contribution of biomass in the biogenic full portfolio is much more dominant than it would for combined upper scenarios.

Numbers of Production Plants and Associated CAPEX Investment

Closely related to the required production capacity are the numbers of plants of each type needed and the CAPEX cost of purchasing and installing those plants. The analysis presumed hypothetical implementation trajectories for each production pathway, starting from the present time with almost all current hydrogen being from fossil SMR, which is assumed would install carbon capture shortly. Electrolysis and biogenic pathways ramp up quickly in the next five years and then sustain moderate growth through 2045. The proportion of hydrogen using fossil SMR (with carbon capture) steadily ramps down as more alternatives are included in the portfolio, potentially biogenic and electrolysis-heavy contributions. There is no usage of fossil gas in SMR plants in the combined lower scenarios biogenic portfolio implementation, only in pyrolysis plants that comprise 5 percent of the total production of hydrogen.

The number of plants deployed are shown in Table 17 for the case of full hydrogen storage availability. Without storage, there would have to be 4.0 to 4.5 times and 1.1 to 1.8 times as many production plants for the combined upper and combined lower scenarios, respectively. Except for the biogenic full portfolio in the combined lower resource scenario, electrolysis plants are the largest component of the mix, and associated CAPEX, regardless of storage level or resource scenario.

The electrolytic-heavy portfolio would require the most production plants and most CAPEX (summarized in Table 18): for full storage, 202 and 472 production plants at $26.0 billion and $64.5 billion, combined lower scenarios and combined upper scenarios, respectively. This is due to the assumed capacity factor of electrolyzer plants being one-half that of all other types of plants, as well as the small size of each plant. On the other hand, the biogenic full portfolio would require the least, at 119 and 368 plants and $9.5 billion and $46.2 billion for full storage combined lower and combined upper scenario cases, respectively. Gasification plants are assumed to be relatively large and are among the least expensive on a per-tonne hydrogen per-day production capacity basis.

Table 17: Number of Production Plants Required for Each Portfolio

Combined Upper Scenario:

Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Water (electrolysis)	381	213	231
Fossil Gas (SMR+CC, pyrolysis)	34	88	47
Biomass Gasification (FR, UW, CR)	20	27	54
RNG (SMR, pyrolysis)	37	36	36

Combined Lower Scenario:

Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Water (electrolysis)	155	70	13
Fossil Gas (SMR+CC, pyrolysis)	17	31	22
Biomass Gasification (FR, UW, CR)	9	14	54
RNG (SMR, pyrolysis)	21	42	30

Source: Guidehouse Inc., 2025

The CAPEX costs shown in Table 18 are total overnight cost (TOC), which includes equipment, installation, engineering procurement costs (EPC), and project and process contingencies. The

2025 costs were calculated from various literature sources, after which learning curve cost reductions were applied for 2026 through 2045.[137]

The capital cost per kW ($/kW) is expected to decrease between 2025 and 2045 as follows:[138]

- For electrolytic hydrogen (4.2 to 20.8 tonnes of hydrogen per day): from 5,080 to 3,700 $/(kg/day) (or 2,342 to 1,709 $/kW$_e$).
- For SMR with carbon capture (100 tonnes of hydrogen per day): from 5,710 to 4,680 $/(kg/day) (or 42,500 to 34,800 $/(MMBtu/day)).
- For SMR with no carbon capture (RNG plants, 15 tonnes of hydrogen per day): from 7,140 to 5,840 $/(kg/day) (or 53,100 to 43,500 $/(MMBtu/day)).
- For gasification (50 tonnes of hydrogen per day): from 2,590 to 1,950 $/(kg/day) (or 19,300 to 14,500 $/(MMBtu/day)).
- For pyrolysis (15 tonnes of hydrogen per day): from 2,700 to 1,840 $/(kg/day) (or 20,100 to 13,700 $/(MMBtu/day)).

Table 18: CAPEX in Billion Dollars Required for Each Portfolio[139]

Combined Upper Scenario:

Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Water (electrolysis)	58	29	35
Fossil Gas (SMR+CC, pyrolysis)	3.5	16	4.5
Biomass Gasification (FR, UW, CR)	1.8	2.7	5.4
RNG (SMR, pyrolysis)	1	2.4	1
Total	**64.3**	**50.1**	**45.9**

137 Electrolyzer costs: "Electrolysis Techno-Economic Analysis – CAPEX Rates," EPRI/LCRI, https://apps.epri.com/lcri-electrolysis-tea/en/capex-rates.html.

Biomass gasification, SMR, and SMR+CC costs: "H2A-Lite: Hydrogen Analysis Lite Production Model", NREL, https://www.nrel.gov/hydrogen/h2a-lite.

Pyrolysis costs: Guidehouse analysis of data from "Methane Pyrolysis for Hydrogen Production: Navigating the Path to a Net Zero Future," Energy and Environmental Science, https://pubs.rsc.org/en/content/articlelanding/2025/ee/d4ee06191h, and "High-Throughput Methane Pyrolysis for Low-Cost, Emissions-Free Hydrogen," PARC, https://web.archive.org/web/20240509090123/https:/arpa-e.energy.gov/sites/default/files/2021-01/07%20OK%20-%2020210112-ARAPE%20Methane%20Pyrolysis%20Meeting-PARC.pdf.

138 A full summary of CAPEX findings and methodology will be published in a forthcoming hydrogen staff paper.

139 CAPEX in 2023 billion Dollars, Total Overnight Cost (TOC).

Combined Lower Scenario:

Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Water (electrolysis)	23	9.6	1.9
Fossil Gas (SMR+CC, pyrolysis)	1.1	5.1	1.1
Biomass Gasification (FR, UW, CR)	0.74	1.4	5.4
RNG (SMR, pyrolysis)	0.68	2.4	1
Total	**25.5**	**18.5**	**9.4**

Without storage, the CAPEX cost is 4.5 times higher (combined upper scenario) and 1.5 times higher (combined lower scenario) than when assuming storage availability.

Source: Guidehouse Inc., 2025

Renewable Energy Land Requirements for Electrolysis

The land required for renewable energy to power electrolysis can be substantial. Because the cost and feasibility of producing hydrogen depends on the availability of electricity from renewable energy, incorporating land requirements and addressing electrolyzer capacity needs become an important part of the analysis. Analysis showed that a reasonably economical capacity factor of 45 percent for an electrolyzer production facility colocated with a wind or solar facility is only possible if the renewable energy facility is about six times as large as the electrolyzer rating,[140] so that relative sizing was assumed.

Renewable power needs for the combined resource analysis scenarios are shown in Table 19. Except for the biogenic full portfolio in the combined lower scenario, the amount of renewable power that would need to be available to support electrolytic hydrogen would be several times the current total existing installed capacity of wind and solar power assets.

The land area required for this renewable energy is shown in Table 20. As in the *2023 IEPR*, this assumes that all the power comes from solar PV and assumes the same value of 7 acres per MW_e.

140 Analysis of data from CEC's Energy Assessment Division, shows that realized solar and wind capacity factors (accounting for curtailment) in 2023 were 22.6 percent and 25.3 percent, respectively. Capturing curtailed energy should add about 1.2 percent to the capacity factor, which still results in only 23.8 percent to 26.5 percent. Unless very low-carbon grid power is available to supplement the renewable energy or a large battery is present, only undersizing of the electrolyzer with respect to the wind or solar farm will lead to a high enough capacity factor.

Table 19: Renewable Power Capacity in GW Required for Electrolysis

Scenario	Storage	Electrolytic-Heavy	Balanced	Biogenic Full
Combined Upper	Full Storage	171	95	104
Combined Upper	No Storage	764	425	463
Combined Lower	Full Storage	69	31	5.7
Combined Lower	No Storage	104	47	8.6

Source: Guidehouse Inc., 2025

Table 20: Land Area in Acres Required for Renewable Energy (Assuming Solar PV)[141]

Scenario	Storage	Electrolytic-Heavy	Balanced	Biogenic Full
Combined Upper	Full Storage	1,199,000	667,000	728,000
Combined Upper	No Storage	5,350,000	2,970,000	3,240,000
Combined Lower	Full Storage	483,000	218,000	40,000
Combined Lower	No Storage	728,000	329,000	60,000

Source: Guidehouse Inc., 2025

Electricity

Table 21 summarizes the amounts of electricity used to produce hydrogen for the various production portfolios and feedstock types. Fossil gas uses more electricity than RNG or biomass because that feedstock is mostly deployed via SMR with carbon capture, and the capture process uses a significant amount of electricity. The use of electricity for pyrolysis depends on how much each of the three technologies — plasma, thermal, and catalytic — is adopted. The present analysis assumes an equal split among the three, but if the plasma method is predominant, then the pyrolysis electricity use will be higher than shown here.

141 For reference, 7 acres of solar PV yields about 140 kg of hydrogen per day.

Table 21: Electric Energy Supply Required in GWh/year, by Feedstock and Portfolio

Combined Upper Scenario:

Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Water (electrolysis)	112,548	62,571	68,281
Fossil Gas (SMR+CC, pyrolysis)	1,427	4,617	2,315
Biomass Gasification (FR, UW, CR)	342	519	1,040
RNG (SMR, pyrolysis)	994	723	844

Combined Lower Scenario:

Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Water (electrolysis)	45,342	20,482	3,738
Fossil Gas (SMR+CC, pyrolysis)	382	1,802	555
Biomass Gasification (FR, UW, CR)	142	260	1,041
RNG (SMR, pyrolysis)	607	720	884

Source: Guidehouse Inc., 2025

Water Requirements

Water requirements are given in billions of gallons per year in Table 22. For comparison, average residential water consumption in California was 81 gallons in 2024 and one billion gallons of water serves about 33,800 homes per year.[142] As expected, electrolysis is a major consumer of water. However, SMR — with and without carbon capture — uses more water per kilogram of hydrogen produced than electrolysis.[143] This usage stems primarily from the cooling water requirement for SMR, but also to its use for the steam feedstock. As noted earlier, there is no SMR usage in the biogenic full portfolio in the combined lower scenarios; however, there is still a small amount of water use for fossil gas, attributable to pyrolysis (0.23

142 Average residential water use is based on data from the State Water Resources Control Board for all months in 2024 statewide. For more information, see https://www.waterboards.ca.gov/water_issues/programs/conservation_portal/conservation_reporting.html.

143 NREL. "H2A-Lite: Hydrogen Analysis Lite Production Model," https://www.nrel.gov/hydrogen/h2a-lite.

Note that H2A values for water consumption for SMR derive from NETL techno-economic analyses; for example, NETL. "Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies." https://netl.doe.gov/projects/files/ComparisonofCommercialStateofArtFossilBasedHydrogenProductionTechnologies_041222.pdf.

billion–0.50 billion gallons per year). Fossil gas is also de-emphasized in the electrolysis-heavy portfolio under combined lower scenarios conditions.

Table 22: Water Supply Required (in billion gallons/year), by Feedstock and Portfolio

Combined Upper Scenario:

Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Water (electrolysis)	8.20	4.50	5.00
Fossil Gas (SMR+CC, pyrolysis)	2.30	7.40	4.20
Biomass Gasification (FR, UW, CR)	1.00	1.50	3.00
RNG (SMR, pyrolysis)	0.37	0.49	0.43

Combined Lower Scenario:

Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Water (electrolysis)	3.30	1.50	0.27
Fossil Gas (SMR+CC, pyrolysis)	0.20	2	0.02
Biomass Gasification (FR, UW, CR)	0.40	0.74	3.00
RNG (SMR, pyrolysis)	0.27	0.49	0.42

Source: Guidehouse Inc., 2025

Non-water Feedstock

The final inputs to be accounted for are the non-water feedstocks, which include materials inputs used to provide process heat. These are listed in Table 23. The feedstock requirements for biomass gasification and methane pyrolysis are less well-determined than those for SMR and electrolysis, as the former technologies are less mature and have several significantly different variations (such as plasma, thermal, and catalytic pyrolysis) within the same overall category.

Table 23: Non-water Feedstock Required, by Feedstock and Portfolio

Combined Upper Scenario:

Feedstock Type	Electrolytic-Heavy	Balanced	Biogenic Full
RNG (SMR, pyrolysis) (million MMBtu)	33	31	32
Biomass Gasification (FR, UW, CR) (million bone dry tonnes) [BDT]	2.8	4.3	8.6
Fossil Gas (SMR+CC, pyrolysis) (million MMBtu)	66	211	114

Combined Lower Scenario:

Feedstock Type	Electrolytic-Heavy	Balanced	Biogenic Full
RNG (SMR, pyrolysis) (million MMBtu)	22	31	32
Biomass Gasification (FR, UW, CR) (million bone dry tonnes) [BDT]	1.2	2.1	8.6
Fossil Gas (SMR+CC, pyrolysis) (million MMBtu)	11	70	12

Source: Guidehouse Inc., 2025

Key Takeaways

- **Scale Drives Infrastructure Needs and Hydrogen Cost:** The demand for hydrogen in the power and transportation sectors is a key factor in driving investments for infrastructure buildout. The amount of hydrogen that can be produced and its availability affect the cost of hydrogen. This is why an economy of scale, with larger plants and storage (or pipelines) would reduce the CAPEX of production assets by almost 80 percent (from an average of $241 billion with no storage to $54 billion with storage).
- **Anticipated Seasonal Variation in Electricity Needs Drive Infrastructure Strategy in Power Sector:** If hydrogen is used to replace existing fossil gas-fired generation (such as meeting daily and seasonal demand when renewable electricity generation is not sufficient), there would be large variations in seasonal demand for hydrogen. Unless the delivery had inherent flexibility, as could be the case with pipelines, the variations could lead to overbuilding production capacity. Depending on how much large-scale storage is available, production capacity may be as high as 7.4 times the demand of 1.59 million tonnes per year. If ample hydrogen storage is

available, the dedicated hydrogen production capacity for the electric power sector could be the minimum value of 0.35 million tonnes per year.

- **Potential to More Easily Balance Infrastructure Build for Transportation Sector:** Demand profiles are regular and do not have dramatic changes, but there are some seasonal variations. Potential excess capacity is only about 15 percent for both scenarios studied (baseline demands of 1.4 and 0.81 million tonnes per year for upper and lower scenarios, respectively). When combining hydrogen production for transportation and electric power, the combined upper (higher capacity) scenarios have a maximum production capacity of 4.5 times demand, and the combined lower scenarios could reach about 1.5 times demand.
- **High Demand Would Require Pipelines and Potentially Large Storage Options:** The supply/demand analysis shows that the magnitude of storage required in many cases is so large (for example, hundreds to thousands of tonnes of hydrogen) that tank storage is clearly impractical and pipelines would be needed. California's geology creates opportunities and poses challenges for implementing geologic storage of hydrogen at the strategic quantities needed to meet the energy needs of the state for extended periods. While depleted oil and gas reservoirs offer potential for geological storage, and lined rock caverns are available, the suitability for hydrogen storage for either of these is not yet proven. Significant research and development efforts are needed and the CEC initiated a $3 million grant with Lawrence Berkeley National Laboratory this year to assess the potential benefits, costs, technical feasibility, and operational risks of storing hydrogen in natural gas underground storage facilities at two California sites.[144]
- **Offgrid Electrolysis** offers advantages in terms of lower emissions compared to combustion technologies, however, the limitations related to the land required for solar energy supply and intermittent nature of electricity supply makes electrolysis a challenging technology to implement in terms of cost and reliability. Onsite hydrogen production by electrolysis is limited to applications with modest needs; 7 acres of solar PV yield only about 140 kilograms of hydrogen per day.
- **Challenges Remain for Large Scale Biogenic Production:** Biomass and biogas could permit a significant amount of hydrogen production (up to 1.03 million tonnes per year, using the *2022 CARB Scoping Plan* estimate of availability in 2045). However, these feedstocks are produced in relatively small quantities and in widely

144 California Energy Commission, February 12, 2025, Business Meeting, Backup Materials for DOE-Lawrence Berkeley National Laboratory. https://www.energy.ca.gov/filebrowser/download/6994?fid=6994.

distributed locations across the state, which can create challenges with collecting, stockpiling, and processing biogenic feedstocks. Further, large scale hydrogen production from biogenic resources faces high levelized cost because of the limited feedstock supply — particularly RNG — and significant capital requirements. Commenters also note concerns with emissions, which were not evaluated as part of this analysis.

GLOSSARY

Additional achievable energy efficiency (AAEE) is the incremental energy savings from market potential that is not included in the baseline demand forecast but is reasonably expected to occur. AAEE includes many future updates of building standards, appliance regulations, and new or expanded energy efficiency programs.

Additional achievable fuel substitution (AAFS) refers to the substitution of one end-use fuel type for another that is reasonably expected to occur, such as changing out gas appliances in buildings for cleaner, more efficient electric end uses.

The **additional achievable framework** is applied to energy efficiency, fuel substitution, and transportation electrification for the *2023 IEPR* forecast. The additional achievable scenarios capture a range of incremental market potential impacts beyond what are included in the baseline demand forecast but are reasonably expected to occur.

Additional achievable transportation electrification is additional transportation electrification beyond the baseline demand forecast that is informed by a range of policy and market conditions that are reasonably expected to occur but do not lend themselves to the traditional demand-side modeling framework of the baseline forecast.

Alternating current refers to an electric current that sometimes reverses direction and changes magnitude.

Ancillary services are essential functions beyond the sale of electricity that maintain power grid stability, reliability, and quality by balancing supply and demand, controlling voltage, and simplifying system restoration after an outage.

An **attenuator** is a single surface-floating body or multiple connected bodies that rise and fall with wave motion and generate electricity through mechanical turbine rotation or hydraulic pumps that are driven by the flexing motion of the device.

A **balancing authority** is responsible for the planning and operation of a transmission control area. It matches generation with load and maintains consistent electric frequency of the grid, even during extreme conditions. In California, there are eight balancing authorities including Balancing Authority of Northern California, the California Independent System Operator, Los Angeles Department of Water and Power, Imperial Irrigation District, and others.

Behind-the-meter refers to energy activities on the consumer’s side of the grid. These activities would include, for example, energy consumed by a home or business, as well as energy generated by a rooftop photovoltaic system.

The **California Environmental Quality Act (CEQA)** requires that state and local government agencies disclose and evaluate potential environmental impacts of proposed projects and adopt feasible mitigation measures to reduce or eliminate those impacts.

The **California Independent System Operator (California ISO)** manages the flow of electricity across high-voltage, long-distance power lines that serve 80 percent of California’s electricity needs. The California ISO also operates a competitive wholesale energy market and studies and identifies investments in new transmission infrastructure though an annual transmission planning process.

Capacity factor is the ratio of the actual energy produced to the amount of maximum energy that could have been produced in the same period.

Consumer choice aggregation lets local governments buy electricity in bulk on behalf of their residents and businesses, giving local communities control over their energy supply.

Cooling degree days (CDD) refers to days in which the average temperature is above 65°F. The CDD space cooling requirements are quantified by how many degrees above 65°F the daily average temperature is.

Direct current refers to an electric current that flows only in one direction.

Distributed energy resources (DER) refers to typically smaller generation units that are located on the consumer's side of the meter or providing generation to serve nearby load.

Distributed generation (DG) refers to generation units that provide generation to serve onsite or nearby load. Rooftop PV is a type of distributed generation.

An **end user** refers to the person or entity that purchases and consumes energy. An end user differs from a user or consumer in that the end user is both the purchaser and final user of the product or service.

A **load profile** describes the changes in electricity demand over a particular interval, such as a 24-hour day or an 8760-hour year.

Level 2 chargers typically provide about 35 miles per hour of charging but can range from 12 to 70 miles, depending on the vehicle and charger. **DC fast charging** also varies by vehicle and charger, with most chargers able to restore a passenger PEV to 80 percent of full range within 30 minutes.

A **gigawatt** is equal to 1 billion watts.

A **gigawatt electric** is a unit of power equivalent to 1 billion watts.

Grid hardening is the process of making the electrical grid more resilient to extreme weather and other potential threats. One example is moving power lines underground to reduce the possibility of downed lines starting wildfires. Another example is switching out wooden utility poles for ones made of steel or concrete; these materials better withstand high winds and are more resistant to fire.

Heating degree days (HDD) refers to days in which the average temperature is below 65°F. The associated space heating requirements are quantified by how many degrees below 65°F the daily average is.

A **hyperscaler** is a large-scale cloud service provider that allows for massive computing power and storage capacity.

Integrated resource planning refers to planning for a safe, reliable, and cost-effective electricity supply.

A **kilometer** is the equivalent of 0.62 miles.

A **load-serving entity** provides or sells electricity to customers.

A **load modifier** technology is on the demand side (for example, behind the meter) and has a load profile that is different from the system load profile and therefore, with large adoption, would change the system load profile. To be considered load modifying, a program or tariff should modify load on a predictable, consistent basis. Programs that modify load only during certain system conditions and/or are integrated into the wholesale market are not included in the demand forecast. For example, BTM technologies dispatched by system operators in response to system conditions, such as those used in some demand response programs, are not considered load modifiers.

A **load shape** is the hourly profile of electricity demand as a percentage of the total demand.

Levelized cost of energy (LCOE) is the average total cost of an energy generation project per unit of total electricity generated. Also referred to as the levelized cost of electricity, LCOE is a measurement to assess and compare alternative methods of energy production.

Light-duty vehicles are vehicles that have a gross vehicle weight rating of less than or equal to 10,000 pounds, such as cars, pickup trucks, and smaller vans.

The National Environmental Policy Act (NEPA) requires federal agencies to assess the environmental effects of their proposed actions before making decisions.

The CPUC's **net billing tariff (NBT)** sets electricity rates and other charges for investor-owned utility customers in California who submit an interconnection application for eligible renewable customer-sited distributed generation (such as behind the meter PV or storage) on or after April 15, 2023. The tariff is effective once customers receive permission to operate eligible customer-sited resources.

Medium- and heavy-duty vehicles are vehicles that have a gross vehicle weight rating of more than 10,000 pounds, including larger vans, trucks, and buses.

Resource adequacy is the requirement that the electrical grid has sufficient resources to operate safely and reliably at all times. Resource adequacy programs focus on ensuring that demand can be met in the short term, typically the next 3 years or less.

Right sizing electrification matches electric equipment and infrastructure to specific customer load needs to help prevent overbuilding and ensure efficiency needs.

A **terawatt** is equal to 1,000,000,000,000 (1 trillion) watts.

A **therm** is a unit of heat energy equal to 100,000 BTU or 1.06×10^8 Joules. One hundred cubic feet (2.83 cubic meters) of gas at standard temperature and pressure contains approximately one therm of energy.

A **tonne** is a metric unit of mass equal to 1000 kilograms.

Transportation electrification refers to the process of moving away from fossil-fuel powered internal combustion engines and toward cleaner fuel cell and battery-electric vehicles.

ACRONYMS

AAEE	additional achievable energy efficiency
AAFS	additional achievable fuel substitution
AATE	additional achievable transportation electrification
AB	Assembly Bill
AC	alternating current
AHRI	Air-Conditioning, Heating, and Refrigeration Institute
ALK	alkaline water electrolysis with renewable electricity
ASP	automation service provider
BAAQMD	Bay Area Air Quality Management District
BAU	business as usual
Biomass CR	biomass gasification using crop residue
Biomass FR	biomass gasification using forest residue
Biomass UN	biomass gasification using urban waste feedstock
BTM	behind-the-meter
BUILD	Building Initiative for Low-Emissions Development
CALeVIP	California Electric Vehicle Infrastructure Project
CalFUSE	California Flexible Load Unified Signal for Energy
California ISO	California Independent System Operator
CAPEX	capital expenditures
CARB	California Air Resources Board
CDD	cooling degree days
CEC	California Energy Commission
CED	California Energy Demand Forecast
CEDU	California Energy Demand Update
CEQA	California Environmental Quality Act
CMUA	California Municipal Utility Association
CPCN	certificate of public convenience and necessity
CPP	critical peak pricing
CPUC	California Public Utilities Commission
CUTR	California Utilities' Transportation Rate
DACAG	Disadvantaged Communities Advisory Group
DAWG	Demand Analysis Working Group
DCFC	direct current fast charger

DDEMI	Demand and Distributed Energy Market Integration Initiative
DER	distributed energy resources
DG	distributed generation
DSGS	Demand Side Grid Support Program
DGStats	California Distributed Generation Statistics
dGen	Distributed Generation Market Demand
DMV	California Department of Motor Vehicles
DOF	California Department of Finance
EBDP	Equitable Building Decarbonization Program
EGEUR	Electric Generator End-Use Rates
EGS	enhanced geothermal systems
EIR	environmental impact report
ELRP	Emergency Load Reduction Program
EPC	engineering procurement costs
EV	electric vehicle
FCEV	fuel cell electric vehicle
FERC	Federal Energy Regulatory Commission
FGCP	fossil gas commodity price
FSC	flexible service connection
FSSAT	Fuel Substitution Scenario Analysis Tool
FTM	front-of-the-meter
GCM	Global Climate Model
GHG	greenhouse gas
GIDAP	Generator Interconnection Deliverability Allocation Procedures
GO-Biz	Governor's Office of Business and Economic Development
GW	gigawatt
GW_e	gigawatt electric
GWh	gigawatt-hour
HDD	heating degree days
HVAC	heating, ventilation, and air conditioning
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
IOU	investor-owned utility
IPCC	Intergovernmental Panel on Climate Change

IPE	Interconnection Process Enhancements
IRP	Integrated Resources Plan
ITC	Investment Tax Credit
IVCA	Integrated Value Chain Analysis
JEDI	Jobs and Economic Development Impact
JPA	joint powers authority
km	kilometer
kW	kilowatt
kWh	kilowatt-hour
LCFS	Low Carbon Fuel Standard
LD	light-duty
LDES	long-duration energy storage
LIP	load impact protocol
LNG	liquefied natural gas
LSE	load-serving entity
LTPP	Long Term Procurement Plan
MDHD	medium- and heavy-duty
MND	mitigated negative declaration
MOU	Memorandum of Understanding
MW	megawatt
MWh	megawatt hour
NBT	Net Billing Tariff
ND	negative declaration
NEM	net energy metering
NEPA	National Environmental Policy Act
NGCC	natural gas combined cycle
NGI	natural gas intelligence data
NOAA	National Oceanic and Atmospheric Administration
NOPA	notice of proposed award
NOx	oxides of nitrogen
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
PAR	Proposed Amended Rules
PARMM	Passenger, Air, Rail, Microtransit, and Marine Model

PEM	proton exchange membrane
PG&E	Pacific Gas and Electric Company
PiCS	programs and incremental codes and standards
PM2.5	fine particulate matter
POU	publicly owned utility
PRM	planning reserve margin
PS	policy scenario
PSH	pumped storage hydropower
PTC	permit-to-construct
PV	photovoltaic
Pyrolysis NG	pyrolysis with fossil gas
Pyrolysis RNG	pyrolysis with renewable gas
QFER	Quarterly Fuel and Energy Reports
REACH	Reliable, Equitable, and Accessible Charging for Multifamily Housing
REDWDS	Reducing Emissions, Deploying Wide-Scale, and Demonstrating Standards
REV	rural electric vehicle
ROB	replace-on-burnout
RPS	Renewables Portfolio Standard
RR	revenue requirement
SB	Senate Bill
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric Company
SIP	State Implementation Plan
SMR	small modular reactor
SMR NG CC	steam methane reforming with fossil gas and carbon capture
SMR RNG	steam reforming with renewable gas
SMUD	Sacramento Municipal Utility District
SSP	shared socioeconomic pathway
TBD	to be determined
TDF	Transmission Development Forum
TECH	Technology and Equipment for Clean Heating
TEDF	transportation energy demand forecast

TOC	total overnight cost
TOU	time of use
TPP	Transmission Planning Process
TPR	transmission project review
TWh	terawatt-hour
UCI	University of California at Irvine
U.S.	United States
U.S. DOE	United States Department of Energy
U.S. EIA	United States Energy Information Administration
V2X	bidirectional charging
VMT	vehicle miles traveled
WDAT	wholesale distribution access tariff
WECC	Western Electricity Coordinating Council
ZE	zero emission
ZEV	zero-emission vehicle

APPENDIX A: Assessing the Benefits and Contributions of the Clean Transportation Program

The California Energy Commission's (CEC) Clean Transportation Program provides funding to support innovation and accelerate the development and deployment of zero-emission transportation and fuel technologies.[145] This appendix highlights some of the recent projects under the Clean Transportation Program and provides an evaluation of the program as required biennially in the *Integrated Energy Policy Report (IEPR).* The Clean Transportation Program benefits assessment includes projects funded between July 1, 2023, and June 30, 2025, adding to the benefits reported in the *2023 IEPR*. The total cumulative greenhouse gas (GHG) emission reductions, Oxides of Nitrogen (NOx) reductions, and PM2.5 (fine particulate matter) reductions from projects included in this assessment are estimated at 5,400 thousand metric tons, 6,800 metric tons, and 120 metric tons, respectively.

Role of the Clean Transportation Program

The state has been a leader in recognizing the need to rapidly reduce GHG emissions and other pollutants from its transportation system. Transportation is the largest source of GHG emissions in California when accounting for emissions from fuel production. In addition to GHGs, the transportation sector is a major emitter of criteria pollutants, with mobile sources responsible for nearly 80 percent of nitrogen oxide emissions and more than 90 percent of diesel particulate matter emissions statewide. Protecting and improving public health in the state will require substantial emissions reductions from the transportation sector.

To help address these problems, improve public health, and reach clean air goals, Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007) created the Clean Transportation Program to be administered by the CEC. The statute authorizes the CEC to develop and deploy alternative and renewable fuels and advanced transportation technologies to help attain the state's climate change and clean air goals. Assembly Bill 126 (Reyes, Chapter 319, Statutes of 2023) reauthorized the funding program through July 1, 2035, and focused the program on zero-emission transportation.

145 CEC. "Clean Transportation Program," https://www.energy.ca.gov/programs-and-topics/programs/clean-transportation-program.

The Clean Transportation Program has an annual budget of about $100 million and provides financial support for projects that:

- Develop and deploy zero-emission technology and fuels in the marketplace.
- Produce alternative and renewable low-carbon fuels in California.
- Deploy zero-emission fueling infrastructure, fueling stations, and equipment.
- Establish workforce-training programs and conduct public outreach on the benefits of alternative transportation fuels and vehicle technologies.

The Clean Transportation Program does not operate in a vacuum, but within a context of several laws, executive orders, regulations, and other funding programs to reduce GHG emissions, petroleum dependence, and criteria pollution for all Californians. California's bold policies are spurring a market transformation to zero-emission vehicles (ZEVs). Table A-1 summarizes several policies and transformational goals related to clean transportation.

Table A-1: California's Clean Transportation Related Goals

Target	Goal	Policy
Carbon Neutrality	By 2045	Executive Order B-55-18
GHG Emissions Reduction	40 percent below 1990 levels by 2030	Senate Bill 32 (Pavley, Chapter 249, Statutes of 2016)
Light-Duty ZEV Sales	100 percent by 2035	Executive Order N-79-20 and N-27-25
Medium- and Heavy-Duty ZEVs	100 percent operating by 2045 (where feasible)	Executive Order N-79-20 and N-27-25
ZEV Infrastructure Deployment	250,000 chargers by 2025; 200 hydrogen stations	Executive Order B-48-18
NOxReduction	80 percent reduction by 2031	Clean Air Act; California State Implementation Plans

Source: CEC

There is strong collaboration among the state agencies on clean transportation policy implementation and through the ZEV Market Development Strategy, spearheaded by the

Governor's Office of Business and Economic Development (GO-Biz).[146] These efforts include vehicle incentives developed by the California Air Resources Board (CARB), the Low Carbon Fuel Standard (LCFS) developed by CARB, infrastructure investments by investor-owned utilities (IOUs) overseen by the California Public Utilities Commission (CPUC), and broader business coordination with GO-Biz. The CEC and CARB have complementary responsibilities, with CARB serving as the lead agency on zero-emission vehicle deployment and the CEC as the lead agency on ZEV fueling infrastructure. The projects supported by the Clean Transportation Program interact with and are informed by the broader ecosystem of efforts.

The CEC Is the State's Primary ZEV Infrastructure Planning Agency

The Clean Transportation Program benefits from and is informed by the CEC's leadership in ZEV infrastructure analyses directed through statute.

Assembly Bill 2127 (Ting, Chapter 365, Statutes of 2018) requires the CEC to prepare and update a statewide assessment of electric vehicle (EV) charging infrastructure. The assessment focuses on the number and types of charging infrastructure needed to support California's ZEVs in 2030 and 2035. In February 2024, the CEC adopted the *Assembly Bill 2127 Second Electric Vehicle Charging Infrastructure Assessment*.[147] For passenger vehicles, the report projects that California will need 1 million public and shared-private chargers by 2030 and 2.1 million chargers by 2035.

The report also highlighted an alternative scenario for light-duty vehicles that assumed drivers would rely more heavily on fast charging. Under this alternative scenario, the total number of chargers would fall from 1 million to 660,000 chargers in 2030. For medium- and heavy-duty plug-in electric vehicles, the report finds that California will need 114,500 chargers by 2030 and 264,000 chargers by 2035.

Senate Bill 1000 (Lara, Chapter 368, Statutes of 2018) directs the CEC to assess disproportionate deployment of EV charging infrastructure. The latest assessment will update the per-capita charger and drive-time results from the first two assessments (2020 and 2022)

146 GO-Biz. "ZEV Market Development Strategy," https://business.ca.gov/industries/zero-emission-vehicles/zev-strategy-2/.

147 Davis, Adam, Tiffany Hoang, Thanh Lopez, Jeffrey Lu, Taylor Nguyen, Bob Nolty, Larry Rillera, Dustin Schell, and Micah Wofford. 2023. *Assembly Bill 2127 Second Electric Vehicle Charging Infrastructure Assessment: Assessing Charging Needs to Support Zero-Emission Vehicles in 2030 and 2035.* California Energy Commission. Publication Number: CEC-600-2024-003-CMR, https://www.energy.ca.gov/publications/2024/assembly-bill-2127-second-electric-vehicle-charging-infrastructure-assessment.

and provides new results on at-home charging and near-home public charging potential.[148] Draft findings show that low-income and disadvantaged communities continue to have fewer public chargers per capita, though drive times to fast chargers have improved overall, particularly in rural disadvantaged areas. In a full-EV future, multifamily households, renters, and residents of disadvantaged or urban communities are estimated to have lower access to home charging.

The CEC also analyzes hydrogen fuel cell electric vehicle (FCEV) infrastructure needs. Recent analyses include the *Joint Agency Staff Report on Assembly Bill 126: 2024 Annual Assessment of the Hydrogen Refueling Network in California*[149] and the *2023 Staff Report on Senate Bill 643*.[150] These reports assess the existing and planned refueling infrastructure for light-, medium-, and heavy-duty FCEVs in California.

Requirements for Assessing the Clean Transportation Program

California Health and Safety Code Section 44273 requires the CEC to include an evaluation of Clean Transportation Program efforts as part of each biennial *IEPR,* including:

- A list of projects funded by the Clean Transportation Program.
- The expected benefits of the projects in terms of air quality, petroleum use reduction, GHG emissions reduction, technology advancement, benefit-cost assessment, and progress toward achieving these benefits.
- The overall contribution of the funded project toward promoting a transition to a diverse portfolio of clean, alternative transportation fuels and reduced petroleum dependency in California.
- Key obstacles and challenges to meeting these goals identified through funded projects.
- Recommendations for future actions.

148 Senate Bill 1000 Staff Workshop, https://www.energy.ca.gov/event/workshop/2024-12/senate-bill-1000-staff-workshop

149 Crowell, Miki, and Tri Dev Acharya. 2025*. Joint Agency Staff Report on Assembly Bill 126: 2024 Annual Assessment of the Hydrogen Refueling Network in California.* California Energy Commission and California Air Resources Board. Publication Number: CEC-600-2025-025, https://www.energy.ca.gov/publications/2025/joint-agency-staff-report-assembly-bill-126-2024-annual-assessment-hydrogen.

150 Villareal, Kristi. 2024. *2023 Final Staff Report on Senate Bill 643: Clean Hydrogen Fuel Production and Refueling Infrastructure to Support Medium- and Heavy-Duty Fuel Cell Electric Vehicles and Off-Road Applications.* California Energy Commission. Publication Number: CEC-600-2023-053-SF.

Funding Summary and Highlights of the Clean Transportation Program

The Clean Transportation Program has provided more than $2.7 billion in funding through the program since 2009. These project awards are summarized in Table A-2.

Table A-2: Clean Transportation Program Investments Through June 2025

Funded Activity	Cumulative Awards to Date (in Millions)*	# of Projects or Units
Alternative Fuel Production		
Low-Carbon Fuel Production	$187	75 Projects
Alternative Fuel Infrastructure		
Light-Duty Electric Vehicle Charging Infrastructure	$721	35,000 chargers
Light-Duty Hydrogen Fueling Infrastructure (Including Operations and Maintenance)	$184	89 Public Fueling Stations
Medium- and Heavy-Duty ZEV Infrastructure	$940	611 Projects
Other Alternative Fuel Infrastructure	$34	98 Stations or Sites
Alternative Fuel and Advanced Technology Vehicles		
Alternative fuel vehicle and ZEV demonstration and deployment	$245	14,516+ Natural Gas, Propane, Hybrid and ZEVs and 54 Demonstrations
Related Needs and Opportunities		
Manufacturing	$294	42 Projects
Workforce Training and Development	$45	30 Projects
Regional Alternative Fuel Readiness	$22	93 Regional Plans
Supporting Projects	$30	13 Projects or Sites
Total	**$2.7 Billion**	**-**

*** Includes all agreements that have been approved at a CEC business meeting or are expected for business meeting approval following a notice of proposed award. For canceled and completed projects, includes only funding received.**

Source: CEC

Contributions of the Clean Transportation Program to a Clean Transportation Future

With a legislative mandate to fund clean transportation alternatives and contribute to state climate policy objectives, the Clean Transportation Program serves a key role in supporting zero-emission transportation. As policies, technologies, and market forces have evolved over the life of the Clean Transportation Program, the program has increasingly focused resources into zero-emission technologies, with a special focus on ZEV infrastructure. However, if there are segments where zero-emission technology is not feasible, the program will also support near-zero-emission technologies.

Light-Duty Plug-In Electric Vehicle Charging

The CEC has supported the rollout of light-duty EVs by awarding more than $721 million in Clean Transportation Program funding for EV charging infrastructure. Investments have funded EV charging stations at many types of locations and various power levels. Partly because of these investments, California has the largest network of publicly accessible EV chargers in the nation. Table A-3 shows recent examples of targeted solicitations and block grants for light-duty charging infrastructure.

Table A-3: Recent Targeted Solicitations and Block Grants for Light-Duty Charging

Title	Goal	Status
Reliable, Equitable, and Accessible Charging for Multifamily Housing (REACH)	Fund charger installation projects that will benefit and be used by multifamily housing residents within disadvantaged communities, low-income communities, and affordable housing	REACH 2.0 notice of proposed award (NOPA) released December 2023 with $41 million for 11 projects; REACH 3.0 NOPA released April 28, 2025, with $38 million for 9 projects
Rural Electric Vehicle (REV) Charging	Increase charging access in rural areas that are not adequately served by charging stations, especially in low-income and disadvantaged communities	REV 2.0 NOPA released November 12, 2025, with $13 million for 6 projects
Fast and Available Charging for All Californians (FAST & FAST 2.0)	Fund fast-charging projects that are open to the public but focused on high-mileage vehicles	FAST NOPA released August 2023 with $10.5 million for 3 projects; FAST 2.0 NOPA released July 2025 with $35 million for 22 projects
Tribal Electric Vehicle Infrastructure, Planning and Workforce Training and Development	Acceleration of ZEV adoption among California Native American tribes by funding charging infrastructure, infrastructure planning, and workforce training and development	NOPA released November 2024 with $15 million for 9 projects
California Electric Vehicle Infrastructure Project (CALeVIP)	Provide streamlined incentives for light-duty EV charging infrastructure at publicly accessible sites	Up to $138 million paid or reserved for payment; closed to new applications
CALeVIP 2.0	Fund DC fast charger installations at publicly accessible sites, especially within disadvantaged or low-income communities	Up to $250 million in total funding; most recent funding opportunity closed January 2026, with up to $55 million available
Communities in Charge	Improve EV accessibility by swiftly deploying L2 EV charging stations, with priority given to disadvantaged and low-income communities, including tribal lands	Up to $250 million in total funding; the fourth funding wave closed January 2026, with up to $56 million available

Source: CEC

Medium- and Heavy-Duty Charging Infrastructure

State policy toward improving public health and addressing the impacts of local air pollution has resulted in a greater focus on medium- and heavy-duty fleets, which is why recent investments of the Clean Transportation Program reflect a long-term focus on ZEV infrastructure for trucks and buses. As previously mentioned, the AB 2127 Second Electric Vehicle Charging Infrastructure Assessment identified a potential need for 114,500 chargers to support 157,000 medium- and heavy-duty ZEVs in the state by 2030. The CEC has supported medium- and heavy-duty ZEVs by awarding more than $940 million in Clean Transportation

Program funding for charging infrastructure for these segments. Table A-4 shows recent examples of targeted solicitations and block grants for medium- and heavy-duty charging infrastructure to support this need.

Table A-4: Recent Targeted Solicitations and Block Grants for Medium- and Heavy-Duty Infrastructure

Title	Goal	Status
Implementation of Medium- and Heavy-Duty Zero-Emission Vehicle Infrastructure Blueprints	Offer funding to prior Medium- and Heavy-Duty Blueprint Planning grant recipients to implement charging or hydrogen refueling infrastructure projects	Original NOPA released February 2024 with $25.0 million for 5 projects. Second solicitation closes March 2026, with up to $40 million available
Depot Charging and Hydrogen Refueling Infrastructure for Medium- and Heavy-Duty On-Road Zero-Emission Vehicles	Fund the deployment of depot ZEV infrastructure for on-road vehicles	Solicitation will close March 2026, with up to $20 million available
ZEV Port Infrastructure	Fund the deployment of medium- and heavy-duty charging or hydrogen refueling infrastructure for California ports	Solicitation closes March 2026, with up to $60 million available
Charging and Refueling Infrastructure for Transport in California Provided Along Targeted Highway Segments	Fund projects that support medium- and heavy-duty charging or hydrogen refueling infrastructure or both along designated corridors	Original NOPA released February 2024 with $34.2 million for 3 projects. Second NOPA released March 2025 with $40 million for 4 projects
Electric School Bus Bi-Directional Infrastructure	Fund projects that help enable managed charging and bidirectional power flow for electric school buses.	NOPA released September 2023 with $10.8 million in funding for 4 projects
Innovative Charging Solutions for Medium- and Heavy-Duty Electric Vehicles	Fund innovative charging technologies and/or business models that highlight the unique needs of medium- and heavy-duty vehicles and fleets	NOPA released January 2024 with $25.1 million for 3 projects
EnergIIZE Commercial Vehicles	Provide funding for charging and hydrogen refueling projects to support trucks and buses.	Transit and drayage set-aside funding lanes closed in October 2025; consolidated funding lane, Fast Track, closed in July 2025; MegaWatt Charging Standard (Pilot) closed February 2026, with up to $10 million available
Zero-Emission School Bus and Infrastructure	Offer incentives to help local education agencies transition to a zero-emission school bus fleet.	Second application window closed November 2024

Source: CEC

Hydrogen Refueling Infrastructure

The Clean Transportation Program has invested in producing renewable hydrogen and building the infrastructure needed to refuel fuel cell electric vehicles. The CEC is required to allocate 15 percent of the Clean Transportation Program funds to deploy hydrogen fueling stations until there is a sufficient network to support FCEVs. FCEVs using hydrogen offer another zero-emission transportation option, and the further development and deployment of medium- and heavy-duty FCEVs will help accelerate the growth of hydrogen production and reach economies of scale earlier than with light-duty vehicles alone.

Through the Clean Transportation Program, the CEC has awarded more than $180 million to support 89 publicly available hydrogen stations focused on light- and medium-duty vehicle fueling, including associated operations and maintenance. The CEC has also awarded nearly $120 million for hydrogen stations for public and private medium- and heavy-duty vehicles.

The CEC issued a new hydrogen refueling infrastructure solicitation in September 2024 to develop light-duty or mixed-use hydrogen refueling stations in San Francisco County and Sacramento County. The solicitation also supported construction, operations and maintenance, or both for planned and operational stations where progress had stalled because of cost constraints. The solicitation included up to $15 million in funding and closed in January 2025. The solicitation resulted in a $1.5 million operation and maintenance grant for three hydrogen refueling stations. Meanwhile, many of the CEC's funding solicitations for medium- and heavy-duty ZEV infrastructure have blended charging and hydrogen refueling projects as described in Table A-4.

The CEC will continue exploring strategies to support existing stations, improve customer refueling experience, and expand the network to meet ZEV transportation needs.

Manufacturing

The CEC is committed to California's goals of zero-emission transportation while growing high-quality manufacturing jobs in the state. The CEC has awarded more than $290 million in manufacturing funds to increase in-state manufacturing of ZEVs, ZEV components, and ZEV charging or refueling equipment. This funding has helped California lead the nation in ZEV manufacturing jobs with 55 ZEV-related manufacturers in the state.[151]

Under the Zero-Emission Transportation Manufacturing solicitation, more than $170 million in awards were made that enabled more than $250 million in private match funding from the awardees. Projects like the "Zero-Emission Bus Manufacturing Ramp-Up in the State of California" with the bus manufacturer GILLIG are supporting battery-electric bus manufacturing operations in Livermore (Alameda County). With state support, the company has multiplied its throughput of electric buses while growing and retaining good paying union-represented manufacturing jobs in California. These manufacturing awards, along with the other projects, are expected to directly create about 1,200 jobs and result in other co-benefits, many of which are within or near disadvantaged and low-income communities.

151 CEC. 2025. "California Zero-Emission Vehicle-Related Manufacturing Web Application." Accessed November 20, 2025. Data last updated March 2025, https://experience.arcgis.com/experience/95583f19bded4bf0bdd0fbdd4dd77c85/?draft=true.

In August 2022, the ZEV Battery Manufacturing Block Grant solicitation (GFO-21-606) was released for a third-party implementor to award grant funds for projects that will increase in-state manufacturing of ZEV batteries.[152] With oversight from the CEC, CALSTART[153] launched the PowerForward ZEV Battery Manufacturing Grant project and released a NOPA revised in August 2025, proposing $64.2 million in funding for six projects.[154]

Workforce Training and Development

Workforce training and development are critical to the Clean Transportation Program, helping California meet its clean transportation, climate, and equity goals. Through targeted investments, the Clean Transportation Program supports the creation of high-road jobs,[155] expands access to career pathways in ZEV and infrastructure sectors and strengthens workforce development in disadvantaged and underserved communities. The Zero-Emission Vehicle Workforce Training and Development Strategy guides these efforts and defines the CEC's role in coordinating training, partnerships, and support services.

Recent completed projects include the Advanced Transportation and Logistics Initiative, which launched new ZEV training programs at community colleges across the state, and the IDEAL Transportation Electrification Training project, which provided hands-on energy and EV installation experience for more than 500 youth in the California Conservation Corps. Thirteen workforce pilot projects from the IDEAL ZEV Workforce solicitation are also developing curriculum, apprenticeships, and support services for diverse populations, including high school students, veterans, and tribal communities.

152 CEC. "GFO-21-606 — Zero-Emission Vehicle Battery Manufacturing Block Grant." Accessed January 22, 2025, https://web.archive.org/web/20230923084200/https://www.energy.ca.gov/solicitations/2022-08/gfo-21-606-zero-emission-vehicle-battery-manufacturing-block-grant.

153 CALSTART is a nonprofit organization focused on developing and accelerating the adoption of clean, efficient transportation technologies.

154 PowerForward. 2025. "PowerForward: ZEV Battery Manufacturing Grant Program." Accessed November 3, 2025, https://powerforwardgrant.org/index.html. See also "Notice of Proposed Awards: PowerForward Grant Solicitation Zero-Emission Vehicle Battery Manufacturing." Accessed November 3, 2025, https://powerforwardgrant.org/documents/PowerForward_Updated_NOPA%202.pdf

155 High-road jobs meet certain standards including for job quality; see California Workforce Development Board. "High Road Training Partnerships." Accessed January 22, 2025. Available at https://cwdb.ca.gov/initiatives/high-road-training-partnerships/. See also Section 14005 of the California Unemployment Insurance Code. Available at https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=UIC&division=7.&title=&part=&chapter=2.&article=.

The CEC has launched specialized solicitations and partnerships to expand training for tribal members, certify more electricians through the Electric Vehicle Infrastructure Training Program, and fund workforce development for zero-emission school bus infrastructure. In addition, the CEC has embedded workforce development as a reimbursable activity across major block grants for EV infrastructure deployment.

To ensure workforce investments are data-driven, the CEC is working with the UC Labor Center to assess labor and workforce training gaps in electric vehicle supply equipment-related occupations. Through this multipronged approach, the Clean Transportation Program continues to engage employers, educators, and community organizations to build a skilled, diverse, and job-ready workforce to support California’s clean transportation transition.

Benefits of the Clean Transportation Program

Section 44273 of the Health and Safety Code requires the CEC to evaluate: petroleum use reduction, air quality benefits, GHG emissions reductions, benefits to costs, and technology advancement for the Clean Transportation Program. This report estimates outcomes associated with the Clean Transportation Program projects funded between July 2023 and June 2025, totaling $316 million in program funding for 1542 projects.

The benefits assessed reflect the benefits from projects that the Clean Transportation Program has at least partially funded. However, project developers, investors, and other public programs may contribute varying levels of funding to a project supported by the Clean Transportation Program. Thus, this assessment can present a big picture view of the total benefits that the Clean Transportation Program has supported, but it does not claim attribution of those benefits to the program itself.

Progress Toward the State’s ZEV Infrastructure Goals

To demonstrate the significant progress California has made in installation of publicly accessible ZEV infrastructure, ZEV charging and hydrogen refueling counts are published on the CEC’s Zero-Emission Vehicles and Infrastructure Statistics online dashboards. As of September 2025, California has deployed more than 200,000 public and shared-private Level 2 and DC fast charging ports serving light-duty vehicles, along with nearly 20,000 planned or operational charging ports and 192 hydrogen fueling nozzles for medium- and heavy-duty vehicles. The state’s hydrogen network includes 61 open retail stations for light-duty fuel cell vehicles. These deployments reflect steady progress toward California’s zero-emission vehicle infrastructure goals and provide critical support for expanding ZEV adoption across all vehicle classes.

Table A-5: Progress Toward ZEV Infrastructure Goals

Category	Light-Duty Chargers	Light- and Medium-Duty Hydrogen	Medium- and Heavy-Duty Chargers and Hydrogen
Estimated Current Chargers/ Hydrogen Refueling Nozzles*	201,180	116	20,093**
Anticipated Additional Future Chargers/Nozzles***	162,620	142	22,000
Total	363,800	258	42,093

*** Existing charging ports estimated based on available data from U.S. Department of Energy's Alternative Fuels Data Center, PlugShare, grant recipient reporting, and surveys to electric vehicle network service providers, utilities, and public agencies in California.**

** **Includes charging/refueling positions that are under development.**

*****Estimates are derived from public presentations and statements by utilities, CPUC, CARB, and other entities. Includes an estimate of chargers resulting from CALGreen code, funding from the State budget acts, and federal funding. Estimates may change as solicitations are released.**

Source: CEC

The deployment of charging and hydrogen infrastructure represents one key outcome of Clean Transportation Program investments. This infrastructure buildout also generates measurable environmental and health benefits by reducing petroleum consumption, GHG emissions, and harmful air pollutants.

Expected benefits represent the outcomes directly supported by Clean Transportation Program funding. These benefits are based on the calculated displacement of petroleum-derived fuels. Air quality calculations consider baseline petroleum-based pollution emissions against the reduced pollutant profile of a replacement fuel. For example, fuel cell electric vehicles have no NO_x or tailpipe particulate matter emissions compared to the petroleum it displaces. To estimate GHG reductions, additional calculations consider the carbon intensity of the fuel, such as the resource mix of the electricity grid for charging. Estimates are based on input data derived from the CEC's *AB 2127 Second Electric Vehicle Charging Infrastructure Assessment*, CARB's Low Carbon Fuel Standard, and CARB's vehicle stock models (EMission FACtor [EMFAC]).

The following tables summarize estimates of petroleum reduction, air quality benefits, and GHG emissions reductions associated with the Clean Transportation Program projects funded from July 2023 through June 2025. The amount of petroleum displaced rises steadily through 2030 as more projects come online, then falls through 2035 as more projects reach the end of their assumed lifespan of ten years. Similarly, GHG, NO_x, and $PM_{2.5}$ emissions reductions from these projects all rise significantly from 2025 through 2030 before falling through 2035.

Table A-6 provides the estimated petroleum displacement in 2025, 2030, and 2035 by project type.

Table A-6: Petroleum Fuel Reductions (million gallons of gasoline equivalent)

Project Type	Petroleum Reductions in 2025	Petroleum Reductions in 2030	Petroleum Reductions in 2035
Light-Duty Charging Infrastructure	9.47	19.31	16.94
Medium- and Heavy-Duty Charging Infrastructure	1.89	24.02	24.02
Hydrogen Refueling Infrastructure	0.71	29.15	29.15
Total	12.07	72.48	70.11

Source: CEC

Table A-7 provides the estimated NO_x and $PM_{2.5}$ emissions reductions in 2025, 2030, and 2035 by project type. Funded projects are estimated to reduce NO_x emissions by 680.19 metric tons per year in 2030 and $PM_{2.5}$ emissions by 12.24 metric tons per year in 2030.

Table A-7: Criteria Air Pollutant Reductions (Metric Tons Per Year)

Project Type	NO_x Reductions in 2025	NO_x Reductions in 2030	NO_x Reductions in 2035	$PM_{2.5}$ Reductions in 2025	$PM_{2.5}$ Reductions in 2030	$PM_{2.5}$ Reductions in 2035
Light-Duty Charging Infrastructure	12.74	23.95	20.54	0.64	1.31	1.15
Medium- and Heavy-Duty Charging Infrastructure	14.8	252.06	252.06	0.40	4.27	4.27
Hydrogen Refueling Infrastructure	21.2	404.18	404.18	0.17	6.66	6.66
Total	48.74	680.19	676.78	1.85	12.24	12.08

Source: CEC

Table A-8 provides the estimated GHG emissions reductions in 2025, 2030, and 2035 by project type.

Table A-8: GHG Reductions (in Thousand Tons Carbon Dioxide Equivalent)

Project Type	GHG Reductions in 2025	GHG Reductions in 2030	GHG Reductions in 2035
Light-Duty Charging Infrastructure	81.71	165.41	144.93
Medium- and Heavy-Duty Charging Infrastructure	18.0	249.83	249.83
Hydrogen Refueling Infrastructure	3.18	128.17	128.17
Total	102.89	543.41	522.93

Source: CEC

Benefit-Cost Assessment

The CEC has awarded nearly $320 million toward Clean Transportation Program infrastructure projects between July 1, 2023, and June 30, 2025, with cumulative GHG emission reductions of 5.4 million metric tons of carbon dioxide equivalent (assuming an equipment lifespan of ten years). This results in 0.017 metric tons of carbon dioxide-equivalent reduced for every $1 invested by the Clean Transportation Program, or a cost-effectiveness of $58 per metric ton.

Advancing ZEV Technologies and Novel Applications

The Clean Transportation Program continues to play a key role in supporting zero-emission technologies in nontraditional and hard-to-electrify sectors. These investments not only showcase the potential of new applications but also create real-world case studies that help derisk future deployments for other fleets and industries.

One such example is a $504,650 grant to the Center for Transportation and the Environment,[156] in partnership with the City of Glendale, to pilot a zero-emission construction green zone work crew. This project will deploy a suite of four electric construction vehicles — including a dump truck, excavator, pickup truck, and wheel loader — supported by the installation of three dual-port 19 kW chargers and one 60 kW charger. The demonstration aims to reduce emissions from traditionally diesel-powered construction operations and explore fleet integration in a municipal context.

Another grant, totaling $1.1 million, was awarded to the Foundation for California Community Colleges to demonstrate zero-emission, autonomous electric aircraft for agricultural chemical application. This innovative project includes five FAA-approved drones powered by off-grid solar mobile charging systems, along with two zero-emission pickup trucks for repositioning the aircraft across the farm. The solar systems — comprising 25 kW of solar panels and 200 kWh of energy storage — enable fully off-grid, emissions-free operation. The project is being implemented in partnership with Pyka Inc. and Ogive Technology, with Victoria Island Farms serving as the end user. This project represents a novel integration of electric aviation and sustainable agriculture.

A third project highlights innovation in municipal fleet operations. The Western Riverside Council of Governments received $598,279 to establish a commercial green zone fleet across multiple jurisdictions. The project includes a diverse mix of zero-emission vehicles — such as a transit van, street sweeper, dump truck, pickup truck, sport utility vehicle, and other urban

156 The Center for Transportation and the Environment is a nonprofit organization that works to advance sustainable transportation technologies.

vehicles — along with the deployment of eight Level 2 chargers, one DC fast charger, and one solar charger. The collaboration spans the City of Banning, City of Moreno Valley, and Riverside County agencies, enabling shared learning and accelerating adoption across local governments.

In addition to vehicle and infrastructure demonstrations, the Clean Transportation Program is also advancing vehicle-grid integration (VGI) through the Reducing Emissions, Deploying Wide-Scale, and Demonstrating Standards (REDWDS) initiative. Released in March 2023, REDWDS is a seminal $21 million grant program funding unidirectional and bidirectional charging projects across all vehicle classes and segments. All funded projects are required to use hourly dynamic rates to enable more advanced VGI functionality. The program awarded 10 applicants with agreements executed in 2024 and sets the stage for a potential Phase II investment of $188 million — with the capacity to support more than 400,000 VGI-enabled deployments.

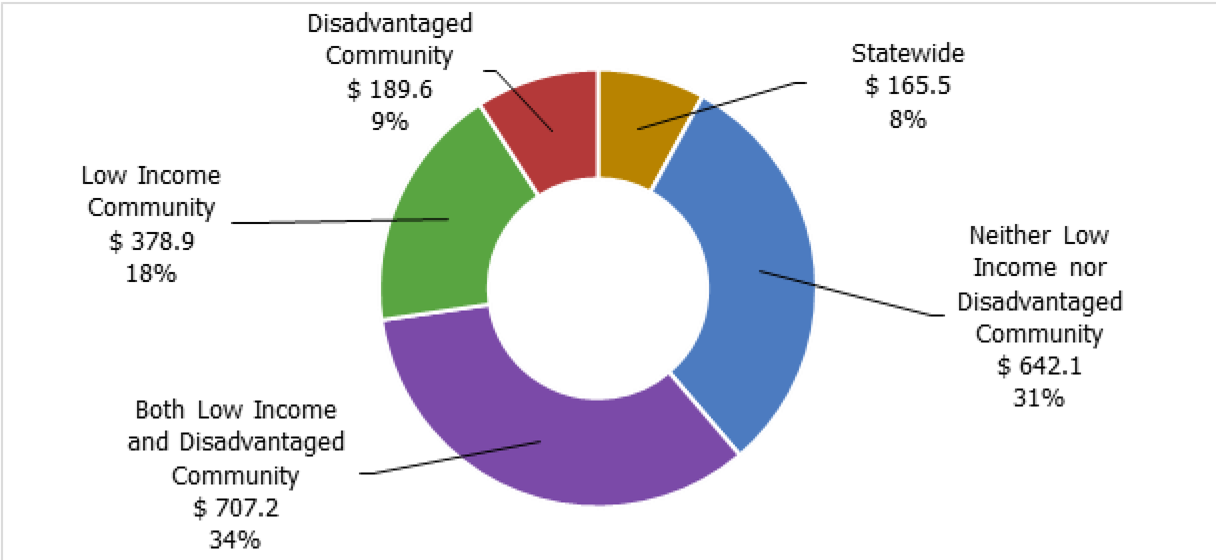
The REDWDS portfolio supports a broad range of vehicle use cases — from personal vehicles to public and private fleets — and aligns closely with the state’s long-term grid integration and decarbonization goals. By requiring adherence to open standards and prioritizing interoperability, REDWDS helps accelerate the path toward a more intelligent, flexible charging network. Demonstrating scalable, standards based VGI solutions will strengthen California’s ability to optimize charging patterns, enhance grid resilience, and unlock new value streams for drivers and fleets alike.

Together, these projects demonstrate how Clean Transportation Program investments foster innovation, test emerging solutions, and push the boundaries of zero-emission transportation in the public and private sectors. By supporting advancement in construction, agriculture, aviation, municipal operations, and grid integration, the program continues to lay the groundwork for scalable, standards-based, and equitable clean transportation technologies across California.

Equity and Community Benefits

The CEC is committed to ensuring that all Californians have an opportunity to participate in and directly benefit from Clean Transportation Program supported programs and services and seeks particularly to increase benefits to disadvantaged and underrepresented communities in implementing the Clean Transportation Program. Assembly Bill 126 requires that on and after January 1, 2025, at least 50 percent of Clean Transportation Program funds go toward projects that benefit low-income and disadvantaged communities. As shown in Figure A-1, as of June 2025, more than 61 percent of funds have gone to projects in disadvantaged or low-income communities or both.

Figure A-1: Clean Transportation Program Funding in Disadvantaged and Low-Income Communities (in Millions)



Totals may not match due to rounding. Includes investments from the beginning of the Clean Transportation Program through June 2025. "Statewide" projects are not considered to be in disadvantaged or low-income communities.

Source: CEC

The CEC also seeks to effectively engage communities disproportionately burdened by pollution and improve economic resiliency, including by supporting in-state employment, manufacturing, and local economic development. The CEC will continue to work with the Clean Transportation Program Advisory Committee, Disadvantaged Communities Advisory Group, and other interested and affected groups to enhance program benefits.

Clean Transportation Program — Looking Ahead

In September 2023, the Legislature passed AB 126, allocating $1 billion to the CEC to deploy ZEV infrastructure over the next decade. This historic investment will enable the Clean Transportation Program to continue supporting a wide range of infrastructure projects through 2035.

AB 126 updates key statutory requirements for infrastructure funding. It revises the hydrogen fueling station funding allocation from a maximum of 20 percent for light-duty stations to a minimum of 15 percent for light, medium, and heavy-duty hydrogen fueling stations until July 1, 2030. It also mandates that at least 50 percent of hydrogen stations and electric vehicle chargers be in or directly benefit disadvantaged communities.

ZEV infrastructure remains a cornerstone of California's clean transportation transition supporting GHG emissions reduction, improved air quality, pollution mitigation, and the creation of high-quality instate jobs. With more than 2 million light-duty ZEVs sold to date, California is also intensifying efforts to electrify medium- and heavy-duty fleets.

Looking ahead, the CEC will maintain a strong focus on infrastructure deployment. For the light-duty vehicle segment, program priorities include the expansion of direct current fast chargers in communities, increased Level 2 charger access in multifamily dwellings, especially in underserved areas and continued investment in infrastructure that complements corridor buildout. These efforts will be supported by improvements to building codes and growing private sector investment.

In the medium- and heavy-duty sector, the CEC will prioritize funding for depot charging for fleet-based operations and en-route, high-powered charging along key freight corridors. These investments will be especially important for enabling long-distance travel and meeting the earliest regulatory adoption timelines.

Hydrogen infrastructure investments will continue to support the FCEV market to ensure drivers have stable access to a reliable network. At the same time, the CEC will direct additional funding toward new medium- and heavy-duty hydrogen fueling stations, with an emphasis on depot-based and publicly accessible refueling to support scalable adoption in sectors such as freight, transit, and drayage.

APPENDIX B: Firm Zero-Carbon Resources

Introduction

California's commitment to achieving 100 percent clean electricity by 2045, as outlined in Senate Bill 100 (De León, Chapter 312, Statutes of 2018), requires a transformation of the electric grid that balances reliability with the state's clean energy goals. With the expansion in use of variable renewable resources and the retirement of fossil gas plants, the state needs increased amounts of firm, zero-carbon resources capable of delivering reliable, dispatchable, zero-emission power on demand. These resources are essential to ensuring grid reliability during multiday extreme or atypical weather events, including periods of low renewable energy generation, by delivering zero-carbon electricity with high availability and promoting the integration of eligible renewable energy resources into the electrical grid.

Under Senate Bill 423 (Stern, Chapter 243, Statutes of 2021), the California Energy Commission (CEC), in consultation with the California Public Utilities Commission (CPUC), California Independent System Operator (California ISO), and California Air Resources Board (CARB), has assessed the potential of firm zero-carbon technologies to support a resilient and clean grid.

The first SB 423 report,[157] published March 21, 2025, evaluated emerging firm zero-carbon resources: geothermal, hydropower, long-duration storage, bioenergy, hydrogen, small modular reactors, fusion, and carbon capture. The report addressed the role of each technology in system and local reliability, multiday weather events, key barriers, and recommendations. This appendix presents updated findings from the CEC's ongoing evaluation of firm zero-carbon resources, focusing on technological maturity, recent innovations, policy support, challenges, and opportunities. As shown in Figure B-1, this update includes geothermal, hydropower, long-duration energy storage (LDES), carbon capture, hydrogen, small modular fission reactors (SMR), and bioenergy. Fusion is not included since there were no significant updates to report.

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157 Yee Yang, Chie Hong and Kristen Widdifield. December 2024. *SB 423 Firm Zero-Carbon Resources Report*. California Energy Commission. Publication Number: CEC-200-2024-012, https://efiling.energy.ca.gov/GetDocument.aspx?tn=262264&DocumentContentId=98778.

Figure B-1: Firm Zero-Carbon Resources

Resources	Role			Technology Readiness	2025 Avg. CAPEX $/kW
Long Duration Energy Storage (LDES)	Local Reliability / Resiliency	System Reliability	Zero Emissions	5-9	1,280-7,000
Hydropower	Local Reliability	System Reliability	Zero Emissions	9	8,000 – 10,000
Geothermal	Local Reliability	System Reliability	Zero / Low Emissions	7-9	6,800 - 16,000
Bioenergy	Local Reliability / Resiliency	System Reliability	Zero / Low Emissions	9	5,000
Hydrogen	Local Reliability / Resiliency	System Reliability	Zero / Low Emissions	5-9	1,500 – 2,500
Modular Fission Reactors	Local Reliability / Resiliency	System Reliability	Zero Emissions	6	8,500 – 9,400
Generation with Carbon Capture	Local Reliability	System Reliability	Zero / Low Emissions	4-9	2,700 - 3,400

Local Reliability
Resiliency
System Reliability
Zero Emissions
Low Emissions

Note: Technology readiness is based on technology readiness levels (TRL).

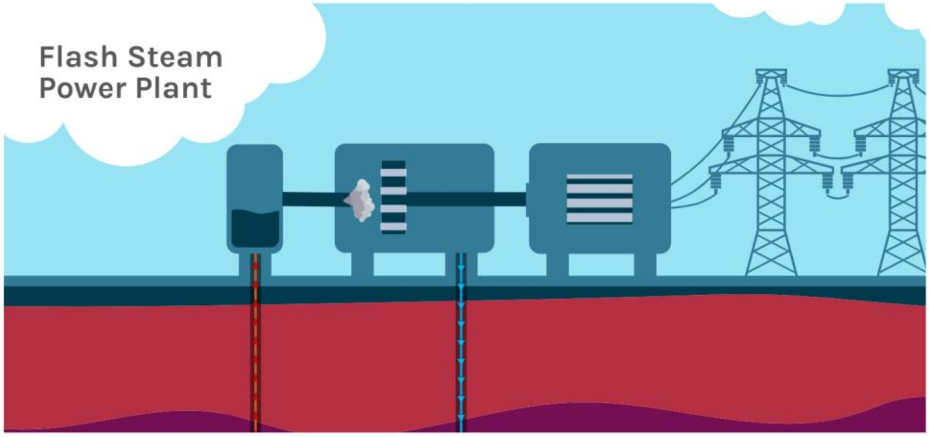
Source: CEC staff with 2024 NREL ATB/SB 423 Final Report data

Geothermal Resources

Geothermal power provides steady baseload zero-carbon electricity, using heat from the subsurface. The consistent output and high-capacity factor of geothermal power make it a valuable firm resource.

Geothermal power plants can be divided into two categories: conventional geothermal plants and enhanced geothermal systems (EGS) plants. Conventional geothermal power relies on hot fluids underground, which are turned into steam. The steam spins a turbine, generating electricity. Figure B-2 illustrates a “flash steam” power plant, one of several variants of a conventional geothermal power plant.

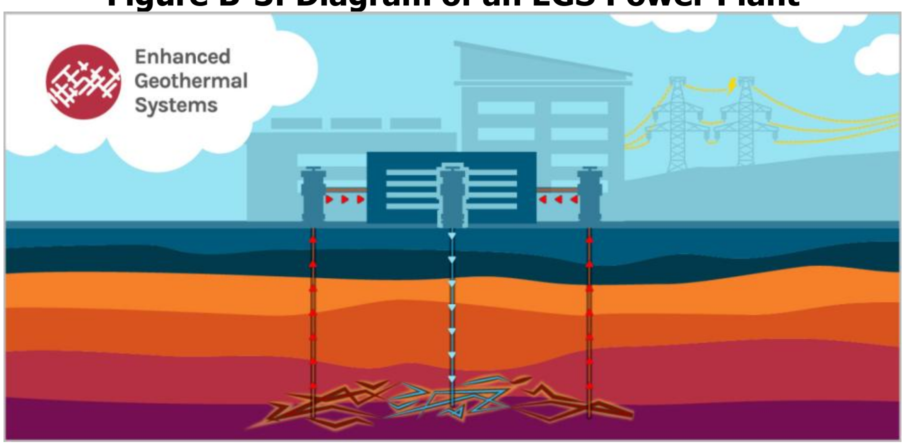
Figure B-2: Diagram of a "Flash Steam" Conventional Geothermal Power Plant



Source: U.S. Department of Energy.[158]

EGS inject cool water into hot dry rock formations. The water absorbs heat from the rock, and the newly heated water is extracted and turned into steam to spin a turbine. Figure B-3 illustrates an EGS power plant.

Figure B-3: Diagram of an EGS Power Plant



Source: U.S. Department of Energy.[159]

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158 United States Department of Energy staff. N.d. "Electricity Generation." United States Department of Energy, https://www.energy.gov/eere/geothermal/electricity-generation.

159 United States Department of Energy staff. N.d. "Enhanced Geothermal Systems." United States Department of Energy, https://www.energy.gov/eere/geothermal/enhanced-geothermal-systems.

Conventional geothermal power plants are a mature technology. California operates 2.715 GW of electrical capacity from conventional geothermal plants — roughly two-thirds of all operational geothermal capacity in the United States —located primarily in the Geysers and in Imperial Valley.[160]

California policies, such as the CPUC procurement requirements and POU decarbonization targets could encourage new geothermal investment. For example, as part of the CPUC's Integrated Resource Planning (IRP) proceeding, the CPUC has ordered jurisdictional LSEs to procure at least 1,000 MW (net qualifying capacity) of "clean firm resources," for which geothermal power qualifies.[161] Also, the CPUC has directed the Department of Water Resources to consider procuring up to 1,000 MW of geothermal power by 2037.[162]

Recent developments in the industry may potentially expand geothermal development. Demonstration projects across Utah, including the U.S. Department of Energy–sponsored Frontier Observatory for Research in Geothermal Energy (FORGE) and commercial developer Fervo Energy, are testing the viability of enhanced geothermal systems (EGS). In addition, an EGS demonstration project was completed in California in 2019, the Northwest Geysers Enhanced Geothermal System Demonstration Project,[163] which successfully confirmed the technical feasibility of stimulating and sustaining geothermal production in non-traditional systems. Because of the vast subsurface resource, if EGS proves commercially viable, EGS could provide a large amount of geothermal power. NREL estimates that if successful, EGS could add over 100 GW of geothermal capacity nationally, as depicted in Figure B-4. The Clean Air Task Force estimates that using 1 percent of California's superhot rock geothermal resource potential, at depths of 5.0 to 7.5 kilometers, could add 35 GW of electricity generation capacity (Figure B-5).

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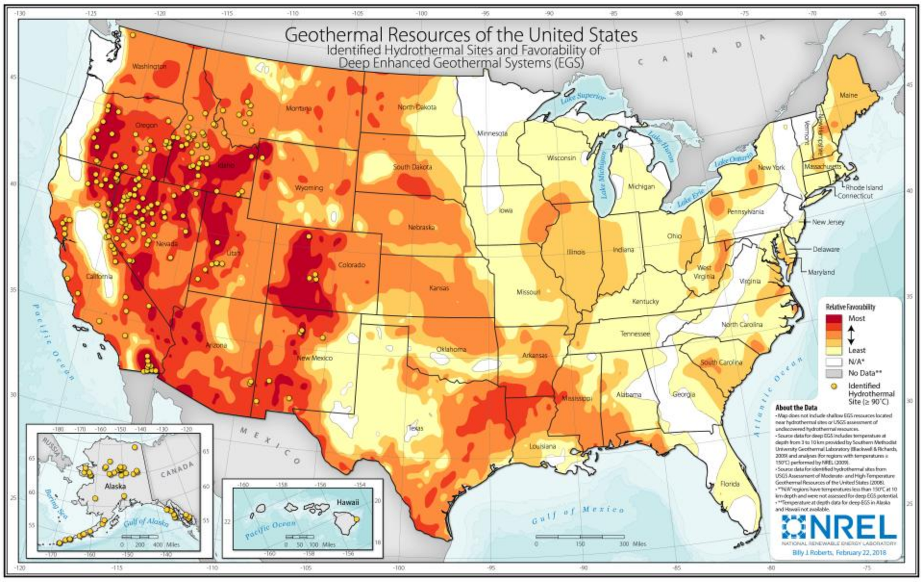
160 United States Department of Energy staff. N.d. "Geothermal: Electricity Generation." United States Department of Energy, https://www.energy.gov/eere/geothermal/electricity-generation.

161 CPUC staff. 2021. *Fact Sheet: Decision Requiring Clean Energy Procurement for Mid-Term Reliability*. California Public Utilities Commission, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/d2106035-mtr-decision-factsheet--07-01-2021.pdf.

162 CPUC staff. 2024. *Fact Sheet: Decision Determining Need for Centralized Procurement of Long Lead-Time Resources (R.20-05-003)*. CPUC, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/ab1373/final_decision_-ab1373_factsheet_pdf.pdf.

163 Hartline, Craig, Mark Walters, Melinda Wright, Chakra Rawal, Julio Garcia, and John Farison. 2019. *The Northwest Geysers Enhanced Geothermal System Demonstration Project, The Geysers, California (Final Report)*. https://www.osti.gov/biblio/1523288.

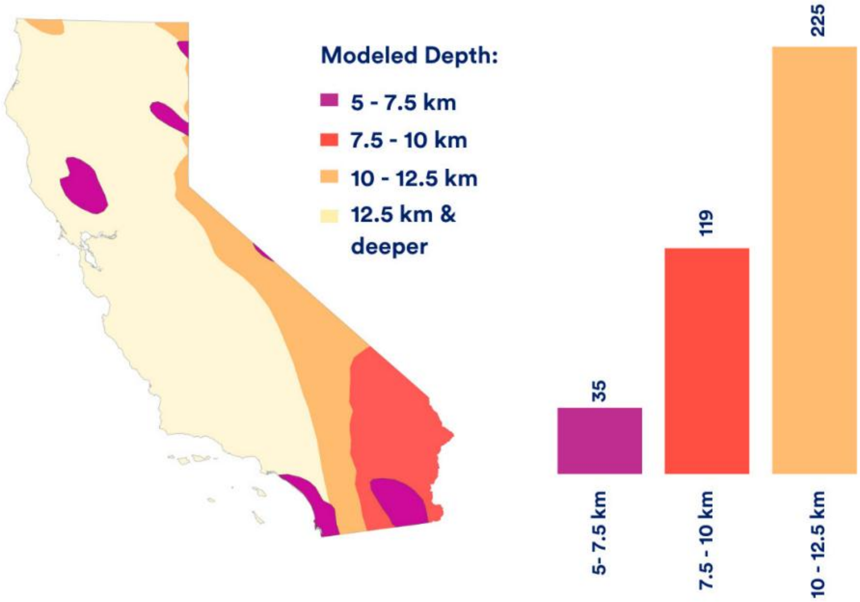
Figure B-4: Map of Identified Hydrothermal Sites and Favorability of Deep EGS in the United States



Source: NREL ATB 2024[164]

164 National Renewable Energy Laboratory (NREL), "Geothermal – 2024 Annual Technology Baseline," https://atb.nrel.gov/electricity/2024/geothermal.

Figure B-5: The Potential of 1 Percent of California's Superhot Rock Geothermal Resource (GW)



Source: Clean Air Task Force 2025[165]

Hydropower Resources

Hydropower[166] has long served as a cornerstone of California's electricity supply, offering dispatchable zero-carbon power and water management benefits. The state hosts more than 12 GW of conventional hydroelectric capacity, including large dam-based systems and run-of-river facilities that generate electricity directly from the natural flow or stored volume of rivers and reservoirs. These systems provide flexible generation that can ramp up or down to match demand. While most conventional hydro sites are already developed, modernization of existing infrastructure and technological innovation offer opportunities for enhanced performance and reliability.

As well as conventional hydropower, California has more than 3.9 GW of pumped storage hydropower (PSH). Unlike traditional hydropower that relies on the river inflows, pumped storage functions like a large energy storage system. It uses electricity, often during off-peak

165 Rogers, Terra, Ann Garth, and Ashley Arax. June 2025. *Unlocking California's Geothermal Potential: A Strategic Opportunity for Clean, Firm Power*. Clean Air Task Force. Clean Air Task Force, https://cdn.catf.us/wp-content/uploads/2025/06/23162128/california-geothermal-report.pdf.

166 Hydropower is electricity made from moving water. Dams, rivers, or pumped storage systems send water through turbines, which spin to produce power.

periods, to pump water from a lower reservoir to an upper one. During periods of high demand, stored water is released through turbines to generate electricity, allowing PSH to deliver firm, reliable power to the grid.

Closed-loop pumped storage, a subtype of PSH, is gaining traction as a long-duration energy storage solution. Unlike conventional hydropower and PSH, which interact with existing river or lakes, closed-loop systems operate independently of natural waterways. This design helps reduce environmental impacts and provides opportunities for projects in areas without large rivers or lakes. Projects such as San Vicente (San Diego County), Haiwee PS (Inyo County), and Lake Elsinore (Riverside County) represent key closed-loop PSH developments in California. The 500 MW San Vicente project, led by the City of San Diego and the San Diego County Water Authority, is advancing through design and permitting with support from state funding. The 1,600 MW Haiwee project, proposed by Premium Energy Holdings, is in the early planning stages. The Lake Elsinore project remains stalled due to regulatory setbacks and lacks an active FERC license.

Support for hydropower includes a combination of federal- and state-level funding alongside supportive policy measures. Federal support includes the Infrastructure Investment and Jobs Act,[167] administered through the DOE's Water Power Technologies Office, which funds research, development, and planning for hydropower technologies. At the state level, California offers financing through programs such as the Clean Energy Financing Programs.[168] However, aging infrastructure, environmental constraints, and regulatory complexity continue to limit new development. Modernization, improved coordination, and interagency planning offer pathways to sustain the role of hydropower in California's energy transition.

Long-Duration Energy Storage

LDES technologies provide the capability to store electricity for discharge durations exceeding eight hours, enabling deeper integration of intermittent renewables. While lithium-ion batteries dominate current deployments, there are limitations to the expansion, including short discharge durations and supply chain availability of critical components, including lithium. A more diverse pipeline of LDES technologies is valuable to help California achieve its carbon reduction goals.

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167 U.S. Department of Energy. "Funding Notice: Infrastructure Investment and Jobs Act — Pumped Storage Hydropower, Wind, and Other Projects," https://www.energy.gov/eere/water/funding-notice-infrastructure-investment-and-jobs-act-pumped-storage-hydropower-wind-and.

168 CEC. "DOE Title 17 Clean Energy Financing Program," https://www.energy.ca.gov/programs-and-topics/programs/doe-title-17-clean-energy-financing-program.

One key challenge to commercializing LDES technologies is that there is limited market demand in the United States. Most electricity markets in the United States have summer peaking electricity demand, and it is more profitable for utilities to deploy batteries that can store energy for four hours or less than to deploy longer-duration batteries.[169] Furthermore, capital costs for LDES technologies that can store energy for four hours or more are typically higher than lithium-ion batteries that have four-hour or less storage durations.[170] Together, these factors result in limited demand for LDES technologies.

Factors advancing LDES include the CEC's Electric Program Investment Charge R&D and LDES programs to support the development and demonstration of multiple nonlithium ion LDES technologies, which may reduce LDES technology costs. The CEC LDES program provides grant funding for 10 demonstration projects, sized 1.5 to 10 MW, demonstrating vanadium redux, zinc air, zinc hybrid, and iron-air technologies.

Also, CPUC procurement orders are creating some near-term market demand for LDES technologies. As part of the CPUC's IRP proceeding, the CPUC has ordered jurisdictional LSEs to procure at least 1,000 MW (net qualifying capacity) of "long-duration storage resources (eight hours or greater)."[171] The CPUC has also directed the Department of Water Resources to consider procuring up to 2,000 MW of LDES by 2037 — up to 1,000 MW of LDES that can store electricity for 12 or more hours, and up to 1,000 MW of LDES technologies capable of multiday storage.[172] These efforts reflect that CPUC modeling has shown that these resources could be needed in a future system if they are cost-effective,

169 Denholm, Paul, Wesley Cole, and Nate Blair. September 2023. *Moving Beyond 4-Hour Li-Ion Batteries: Challenges and Opportunities for Long(er)-Duration Energy Storage*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-85878, https://www.nrel.gov/docs/fy23osti/85878.pdf.

170 For example, Pacific Northwest National Laboratory estimates that in 2023, 100 MW lithium-ion batteries with durations of four hours have lower total installed costs, in $/kW, than lead acid battery, vanadium redux flow, or thermal LDES technologies but higher total installed costs than CAES technologies. See Pacific Northwest National Laboratory staff. N.d. "Cost and Performance Estimates." Pacific Northwest National Laboratory, https://www.pnnl.gov/projects/esgc-cost-performance/estimates.

171 CPUC staff. 2021. *Fact Sheet: Decision Requiring Clean Energy Procurement for Mid-Term Reliability*. California Public Utilities Commission. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/d2106035-mtr-decision-factsheet--07-01-2021.pdf.

172 CPUC staff. August 26, 2024. "CPUC Advances Clean Energy With Centralized Procurement Strategy." California Public Utilities Commission, https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-advances-clean-energy-with-centralized-procurement-strategy.

Generation With Carbon Capture Technologies

Carbon capture can reduce GHG emissions from a range of facilities, including fossil gas combined-cycle (NGCC) plants, which is the most common application of carbon capture, and from industrial sources. Post combustion absorption systems using amine solvents[173] to remove carbon dioxide are the most mature, achieving capture efficiencies of 90 to 97 percent.[174] Other pathways, such as swing adsorption, membrane separation, and cryogenic capture have achieved a range of technology readiness levels. Alternatively, some facilities are able to process flue containing carbon dioxide without pre-separation, permanently storing carbon dioxide in building materials and other durable products. Sequestration typically involves injecting carbon dioxide into deep geologic formations like saline aquifers or depleted oil and gas reservoirs, a process known as *geological carbon sequestration*.

Federal financial support, including the expanded 45Q tax credit, is a key driver of carbon capture development. The 45Q credit provides up to $85 per metric ton of carbon dioxide permanently stored and other qualified uses and recent federal updates, including the extension of begin-construction deadline and new timing requirements have made it one of the most important incentives enabling many projects to move forward. In addition to tax incentives, the Infrastructure Investment and Jobs Act initially included funding to support demonstration and commercial deployment of carbon capture projects.

However, in 2025, the U.S. Department of Energy under the current administration canceled more than $3.7 billion in planned awards for carbon capture and related clean energy projects. One of the rescinded grants affected the planned retrofit of the Sutter Energy Center, a gas power plant in Sutter County owned and operated by Calpine.[175] The project aimed to demonstrate postcombustion carbon capture with nearby geologic sequestration. Despite the setback, Calpine is continuing development of the project, which is now in the front-end engineering and design phase. The ION Clean Energy CO_2 Capture Project[176] demonstrated

173 Pancione, Esther, Alessandro Erto, Francesco Di Natale, Amedeo Lancia, and Marco Balsamo. November 2024. "A Comprehensive Review of Post-Combustion CO_2 Capture Technologies for Applications in the Maritime Sector: A Focus on Adsorbent Materials." *Journal of CO_2 Utilization*, Volume 89. https://www.sciencedirect.com/science/article/pii/S2212982024002907?.

174 U.S. Environmental Protection Agency Office of Air and Radiation. May 23, 2023. *Greenhouse Gas Mitigation Measures: Carbon Capture and Storage for Combustion Turbines*. https://www.epa.gov/system/files/documents/2023-05/TSD%20-%20GHG%20Mitigation%20Measures%20for%20Combustion%20Turbines.pdf?.

175 Calpine Corporation. "Carbon Capture and Sequestration (CCS)," https://www.calpine.com/carbon-capture-and-sequestration-ccs/.

176 For more information, see the National Energy Technology Laboratory project landing page at https://netl.doe.gov/project-information?p=FE0031950.

ION's third-generation IICE-31 solvent technology for post-combustion carbon capture at engineering scale (1 Mwe) using flue gas from Calpine's Los Medanos Energy Center. The project, in partnership with Koch Modular, Sargent & Lundy, Calpine, and Hellman & Associates, will capture 10 tonnes of CO_2 per day with over 95 percent purity and was completed in April 2025.

At the state level, support for carbon capture comes through regulation and market incentives. Additional statutes have expanded California's carbon capture policy framework: Senate Bill 905 (Caballero, Chapter 359, Statutes of 2022) directs the development of a comprehensive regulatory program for carbon capture, transport, and geologic storage, including requirements for risk assessment, environmental justice consultation, and unified permitting. Assembly Bill 1279 (Muratsuchi, Chapter 337, Statutes of 2022) establishes statewide greenhouse gas targets and identifies carbon removal and sequestration as part of the portfolio needed to meet carbon neutrality by 2045.

Carbon capture remains a potentially important tool for decarbonizing firm generation assets, offering a pathway for reducing emissions from gas-fired power plants that play a critical role in grid reliability. At the same time, several implementation issues must be resolved to enable responsible and scalable projects. Carbon capture facilities typically require approval from multiple state and federal agencies, creating complex and potentially lengthy permitting processes. Community concerns, particularly in areas with histories of environmental injustice, have led to increased scrutiny of project siting and safety. In addition, questions regarding long-term monitoring responsibilities and liability for stored CO_2 remain under discussion at both the state and federal levels. Clarifying this governance, permitting, and community-engagement frameworks will be essential to advance CCUS deployment in a manner consistent with California's climate, environmental, and equity objectives.

Clean and Renewable Hydrogen for Electricity Generation

Hydrogen can be made in different ways with a variety of feedstocks, and how it is made affects fuel cost, how much can be produced, and whether it is zero carbon. The main value of hydrogen for the grid is that it can store large amounts of energy for long periods, effectively creating a long-duration energy system, and then be used when it is needed most.[177] Hydrogen as a storage resource makes it a potentially useful partner to solar and wind, which vary with the availability of wind and sunshine, especially during long stretches when those

177 U.S. Department of Energy. August 2024. *Achieving the Promise of Low-Cost Long Duration Energy Storage: An Overview of 10 R&D Pathways from the Long Duration Storage Shot Technology Strategy Assessments*. https://www.energy.gov/sites/default/files/2024-08/Achieving%20the%20Promise%20of%20Low-Cost%20Long%20Duration%20Energy%20Storage_FINAL_08052024.pdf.

resources are not producing much power. More details about the role of hydrogen in power generation, including the ways it is made, the technology updates, and the challenges that remain, are discussed in Chapter 4.

Small Modular Fission Reactors

Small modular reactors (SMRs) are a class of advanced nuclear fission technology in development that aim to provide safer, more flexible, and scalable nuclear power solutions. Most SMR designs are still in the demonstration phase, with only two designs having received U.S. Nuclear Regulatory Commission approval. They typically generate up to 300 MW of electricity per unit and are factory-fabricated for modular deployment, which could reduce construction timelines and costs if commercialized. The compact size of these reactors could allow for siting in remote or constrained locations and integration with industrial or district heating applications. However, SMRs are not yet deployed at scale, face regulatory and supply chain challenges, and cannot be built in California because of the state's moratorium on new fission reactors.

Two SMR designs have received U.S. Nuclear Regulatory Commission (NRC) approval. TerraPower's Natrium reactor, a sodium-cooled fast reactor coupled with a molten salt-based energy storage system, is one of the most prominent projects based in the United States. The only Natrium demonstration project[178] in Kemmerer, Wyoming, began construction in 2024, with nuclear operations anticipated to start in 2026.

California enacted a statewide moratorium in 1976 that prohibits new fission plants from being built and operated in the state until the federal government establishes a long-term solution for high-level radioactive waste. As such, all commercial high-level nuclear waste and spent nuclear fuel generated at nuclear power plants in California are stored on site. Without a repeal of the moratorium or the establishment of a federally sanctioned disposal pathway, which has not occurred since the federal government halted development of the Yucca Mountain nuclear waste repository, SMRs cannot be installed in California.[179] However, California utilities continue to explore long-term procurement opportunities for SMR-based capacity outside the state.[180] Federal policies have recently been implemented to bolster limited uranium supply chain, such as processing and fuel fabrication, in the United States. If

178 Terrapower Wyoming web page, https://www.terrapower.com/wyoming/.

179 Legislative Analyst's Office. February 26, 2015. A.G. File No. 2015-001, https://lao.ca.gov/BallotAnalysis/Initiative/2015-001.

180 Samra, Mandip. City of Burbank Water and Power. Presentation. "2024 Integrated Resource Plan (IRP) & the Role of Clean Firm Resources." July 29, 2025, IEPR workshop on Firm Zero-Carbon Resources and Hydrogen, https://efiling.energy.ca.gov/GetDocument.aspx?tn=265057.

regulatory and supply challenges are resolved, proposed applications for SMRs include providing zero-carbon, dispatchable electricity at high-capacity factors.

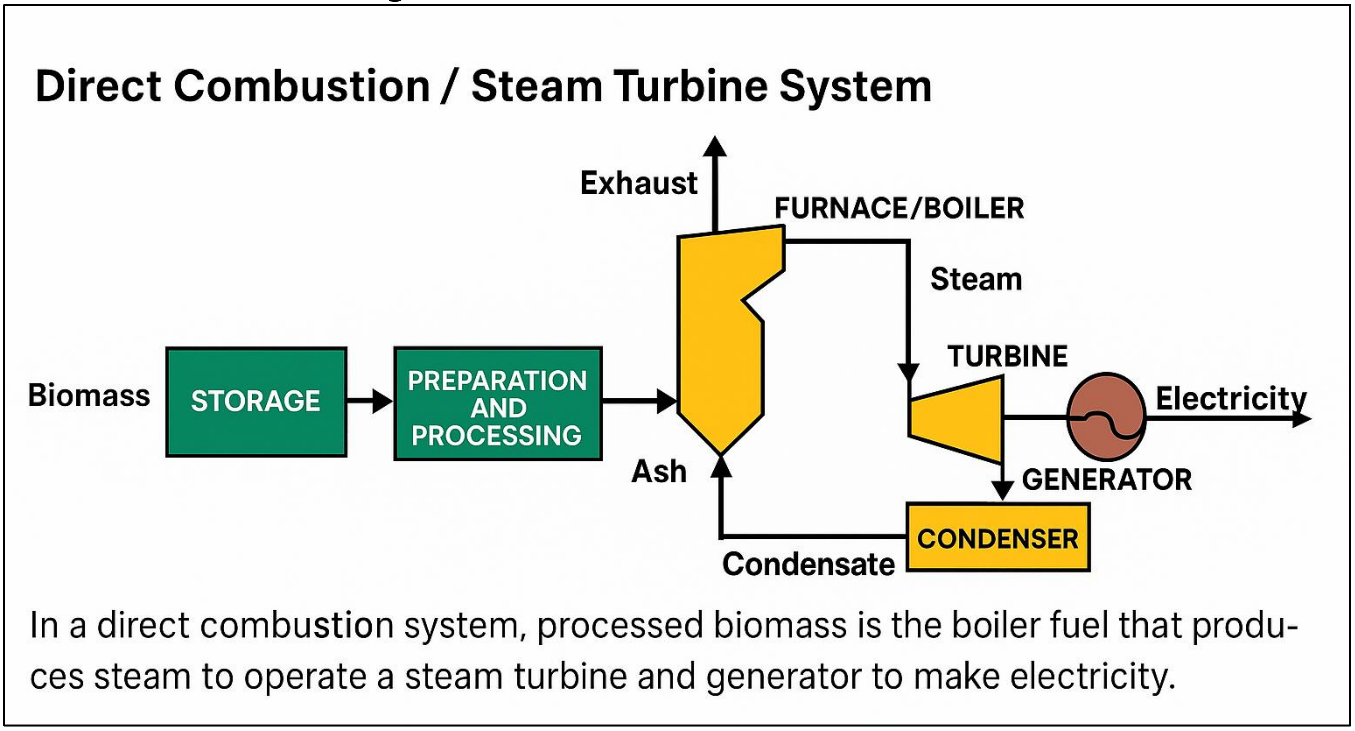
Bioenergy

Bioenergy technologies generate electricity by converting organic feedstocks, including biomass and waste-derived methane, through direct combustion and thermochemical processes. Direct combustion of biomass (Figure B-6), such as wood waste or agricultural residue, is the most established method and produces heat to drive steam turbines, but it also emits criteria pollutants and greenhouse gases unless paired with carbon capture systems to create a carbon-negative system.

Alternatively, thermochemical conversion pathways (Figure B-7) such as gasification and pyrolysis produce intermediate fuels like hydrogen or syngas,[181] which can then be combusted in turbines or used in fuel cells for electricity generation.

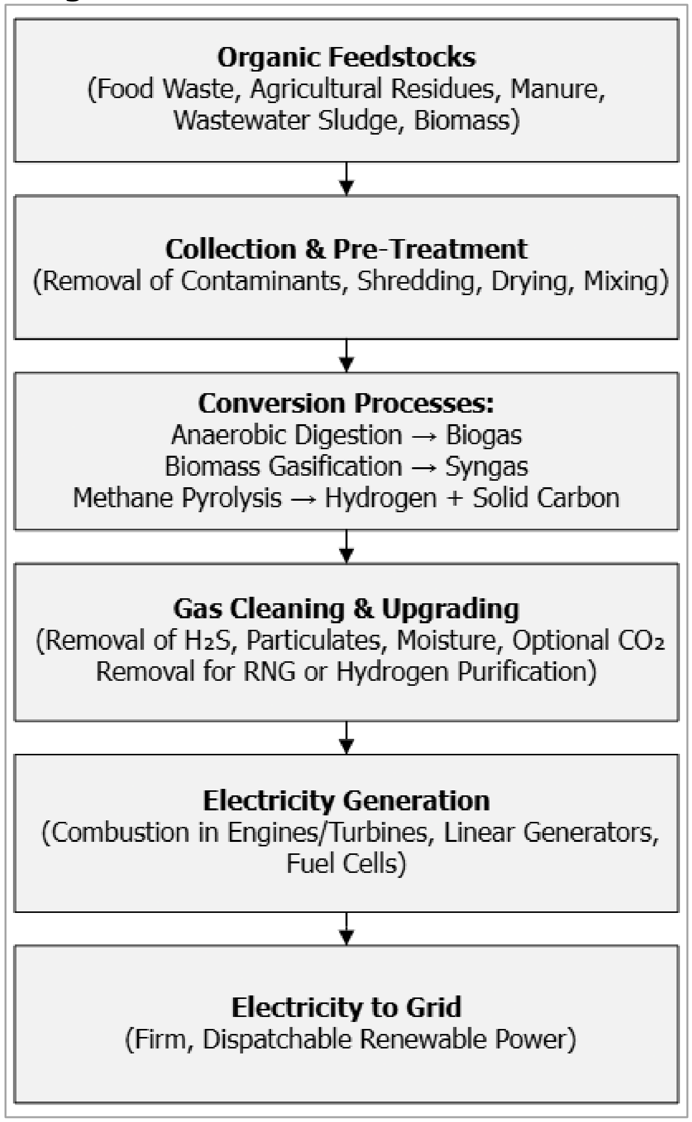
181 *Syngas* is the short name for a gasification product, mostly from waste biomasses, known as "synthesis gas," consisting of a mixture of H_2, CO, and CO_2 that could be used as a potential intermediate in the conversion of biomass into fuel. For more information, see https://www.sciencedirect.com/topics/earth-and-planetary-sciences/synthesis-gas.

Figure B-6: Biomass Direct Combustion



Source: Whole Building Design Guide, https://www.wbdg.org/resources/biomass-electricity-generation.

Figure B-7: Thermochemical Processes



Source: CEC staff

Policy incentives such as California’s Low Carbon Fuel Standard and federal production tax credits can improve the economics of bioenergy projects. When combined with carbon capture, bioenergy can serve as a carbon removal strategy while providing firm electricity.

California’s bioenergy development relies on diverse organic feedstocks, including dairy and landfill methane, wastewater biogas, and woody biomass drawn from wildfire-prone areas. The Department of Conservation supports this transition through programs like the *Forest*

Biomass to Carbon-Negative Biofuels Pilot Program[182] (funded with a $50 million appropriation in 2022). This program awarded grants of $500,000 to several applicants within the Sierra Nevada region with projects that demonstrate technologies and plans for the creation of energy from Sierra Nevada-sourced forest biomass to help offset the use of fossil fuel, improve forest and community resilience, and create regional economic opportunities.

Key challenges for bioenergy include securing a consistent supply of fuel, managing variability in emissions, and remaining cost-competitive with other forms of electricity generation. The U.S. Department of Energy notes that transporting low-energy-density biomass over long distances can increase costs and associated greenhouse gas emissions, making proximity to reliable feedstock sources a critical factor in project planning.[183] Strategically deployed, bioenergy facilities can also enhance rural economic development, reduce waste, and contribute to California's clean electricity goals.

Conclusion

California's transition to a clean and reliable electric grid requires a diverse portfolio of renewable and zero-carbon resources, particularly those capable of providing firm and dispatchable capacity. Geothermal, hydropower, long-duration energy storage, carbon capture, hydrogen, small modular reactors, fusion, and bioenergy are technologies that have promise but are at various technology readiness levels and face technology-specific barriers to deployment.

While each technology faces unique barriers, they also offer specific strengths that can complement variable renewable energy resources and help meet systemwide and local reliability needs. Continued innovation, investment, and regulatory coordination will be essential to scale these technologies and reduce deployment risks. As California pursues its SB 100 goals, firm zero-carbon resources are essential to maintaining grid stability, supporting decarbonization, and ensuring equitable outcomes across communities. These technologies vary in commercial readiness, cost, and grid application but together offer a pathway to achieving California's clean energy and reliability goals.

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182 California Department of Conservation. April 18, 2023. News release. "State Invests $3 Million to Convert Forest Waste into Carbon-Negative Fuel Development," https://www.conservation.ca.gov/index/Pages/News/State-Invests-3-Million-Convert-Forest-Waste-into-Carbon-Negative-Fuel.aspx?.

183 United States Department of Energy. *Quadrennial Technology Review 2015 Biomass Feedstocks and Logistics Chapter 7: Technology Assessments*, https://www.energy.gov/sites/prod/files/2016/01/f28/QTR2015-7B-Biomass-Feedstocks-and-Logistics.pdf.

Findings

Based on the market analysis and research presented, the following findings are offered to support the expanded consideration and adoption of firm zero-carbon resources in California.

- **Align market and contracting mechanisms with reliability attributes**: Support efforts to develop market mechanisms such as central procurement, or long-term contracting structures that value the unique operational characteristics of firm zero-carbon resources, including the respective contributions to system adequacy, flexibility, and resilience.
- **Continue public investment in demonstration and early deployment**: Continue to support current state-funded programs that support demonstration, pilot, and early-stage deployment of firm zero-carbon technologies, including LDES, hydrogen, carbon capture, fusion energy, and advanced geothermal systems. Funding may include support for emerging technologies to overcome the innovation valley of death.[184]
- **Continue to improve permitting coordination for emerging technologies**: Continue to identify opportunities to improve coordination, increase permitting transparency, and reduce process-related uncertainty for projects involving firm zero-carbon infrastructure.

184 Idea to Value. May 21, 2021. "The Innovation Valley of Death," https://www.ideatovalue.com/inno/nickskillicorn/2021/05/the-innovation-valley-of-death/.

APPENDIX C: Load-Shift Goal Report Supplemental Information

Load-Shift Goal Progress Tracking Framework Assumptions and Data Sources

In generating the load-shift goal progress estimates, CEC staff used many reports and data from various proceedings and programs, including the resources below.

Table C-1: The List of Load Flexibility Resources and Data Points Used for Reference

Resource	Load-Shift Metric	Reference
2022 TOU portfolio	Annual utility peak demand impacts	SB 846 report estimate (2023)
New TOU enrollments (2023-2030)	Annual utility peak demand impacts	IOU DR Net Qualifying Capacity reports (2024)[185]
Customer storage discharge (non-event based)	Annual statewide peak demand impacts	2023 IEPR customer energy storage adoption and hourly load forecast[186]
IOU Critical Peak Pricing (CPP) impacts	Annual utility peak demand impacts	IOU DR Net Qualifying Capacity reports (2024)
CCA Customer Programs	Annual utility peak demand impacts	2025 IEPR Demand Forms[187]

185 CPUC. Resource Adequacy Compliance Materials web page, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials. Accessed December 23, 2025.

186 CEC. Self-Generation Planning Library spreadsheet, https://www.energy.ca.gov/media/9535.

187 2025 IEPR Demand Forms, available on the docket web page for 25-IEPR-02, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=25-IEPR-02.

Resource	Load-Shift Metric	Reference
Market-integrated Emergency DR	CPUC RA Awards	California ISO DR Performance reports (2023-2025)[188] & DR provider LIP reports (2023)[189]
Market-integrated Economic DR	CPUC RA Awards	California ISO DR Performance reports (2023-2025) & DR provider LIP reports (2023)
POU DR Programs	Annual utility peak demand impacts	POU Integrated Resource Plans (submitted to CEC in 2023-2024)[190]
ELRP	Annual highest load impact (/hr)	LIP modeling results (1-in-10 conditions) (2023-2025)[191]
DSGS	Highest load impact (/hr) during grid events	2022-2024 grid emergency and testing event performance results; Option#4's grid emergency commitments for 2025

Source: CEC

Key assumptions for 2022–2024 resource stack:

1. The load impact estimate of 1 GW for time-of-use (TOU) rates from the SB 846 (2023) report is considered as the baseline estimate for 2022.
2. The *2023 IEPR* incremental customer battery resource estimate is scaled to reflect the entire battery population for 2024.
3. Potential overlap between EV-TOU rate impacts and the tariff-based customer battery impacts is ignored.

188 California ISO. Reports and Presentations web page, https://www.caiso.com/market-operations/market-monitoring/reports-and-presentations.

189 CPUC. Demand Response Workshops web page, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-workshops.

190 POU IRPs, available on the docket web page for 18-IRP-01, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=18-IRP-01.

191 CPUC. Emergency Load Reduction Program web page, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/emergency-load-reduction-program.

Key assumptions for 2025–2030 resource projections:

1. IOUs' market-integrated DR portfolio is assumed to stay flat based on IOU projections.
2. IOU's 2024 DR NQC reports provide estimates through 2026. The load impacts from EV-TOU rates are assumed to grow linearly through 2030.
3. There are no extensions for ELRP and DSGS beyond current program end dates.
    a. Reflects the Governor's proposed budget for FY25/26 for DSGS.

California's Policy Landscape

Table C-2 provides an overview of California's load flexibility-related regulatory proceedings, planning efforts, and funding programs. These programs are largely administered by the CEC, CPUC, and the California ISO. Load flexibility-related proceedings and programs are organized into three groups considering the respective primary target area:

- Technology deployment programs to increase resource potential.
- Market integration efforts that generate market signals for resource utilization
- Grid integration efforts that target load flexibility integration into resource planning, including distribution planning and the DER interconnection process.

Table C-2: The List of Load Flexibility-Related Proceedings and Funding Programs in California

Focus Area	Proceeding or Initiative	Agency
Increase resource potential & develop technological capabilities	LMS & FDAS	CEC
Increase resource potential & develop technological capabilities	Clean Transportation Program	CEC
Increase resource potential & develop technological capabilities	EPIC R&D Demonstration Funding	CEC
Increase resource potential & develop technological capabilities	Transportation Electrification	CPUC
Increase resource potential & develop technological capabilities	Self-Generation Incentive Program (SGIP)	CPUC
Increase resource potential & develop technological capabilities	Electrification funding and regulatory programs (CEC, CPUC, and CARB)	State
Increase resource potential & develop technological capabilities	Electrification incentive and tax credit programs	Federal

Focus Area	Proceeding or Initiative	Agency
Determine market mechanism & resource utilization	DSGS	CEC
Determine market mechanism & resource utilization	DR proceeding (LIP simplification)	CPUC
Determine market mechanism & resource utilization	RA proceeding (QCC reform)	CPUC
Determine market mechanism & resource utilization	Demand Flexibility proceeding	CPUC
Determine market mechanism & resource utilization	Net Billing Tariff (NBT) implementation	CPUC
Determine market mechanism & resource utilization	Demand & Distributed Energy Market Integration (DDEMI) Initiative	California ISO
CPUC LSE customer programs	Programs offered by jurisdictional LSEs for their customers, including demand flex.	CPUC
Integrate load flexibility into grid planning	SB 846 Load Shift Goal Analysis	CEC
Integrate load flexibility into grid planning	High DER Proceeding	CPUC

Source: CEC

Table C-3: The List of Policy Recommendations Published in CEC's SB 846 Report

#	Load Modifying
1	Support hourly dynamic pricing frameworks.
2	Encourage rate and program designs that offer incentives for load shifting.
3	Provide incentives for load-shifting technologies paired with dynamic rates.
4	Deploy information infrastructure to support load shifting.
5	Adopt flexible demand appliance standards.
6	Complete deployment of metering infrastructure.
7	Reduce transaction costs associated with load-flexibility program and market development.
8	Promote load-modifying program development, measurement, and compensation protocols.

	Resource Planning and Procurement
9	Adopt an incentive-based capacity valuation approach for supply-side DR.
10	Explore a centralized, competitive DR marketplace.
11	Include an adder on wholesale market revenue for supply-side DR.
12	Reform availability rules and resource requirements for DR resources participating in RA.
13	Conduct an evaluation, measurement, and verification study of supply-side DR load impacts.
14	Explore modifications to DR participation pathways to support behind-the-meter storage.
	Incremental and Emergency
15	Pilot approaches to compensate DR providers for incremental capacity delivered under extreme heat or other critical conditions.
16	Pilot a pathway for behind-the-meter energy storage.
17	Pilot short-duration load-shifting resources in emergency and incremental load-flexibility programs.
18	Periodically reassess the role of emergency resources in forecasting, resource procurement, and emergency planning processes.

Source: CEC

APPENDIX D: Forecast of Fossil Gas Rates

Introduction

As part of the California Energy Commission’s (CEC) ongoing evaluations of the fossil gas system, staff conduct analysis of trends in fossil gas supply, demand, and prices. This appendix provides the CEC’s long-term forecasts of North American commodity fossil gas prices, Western Electricity Coordinating Council (WECC)-wide electric generator total customer rates, and California total customer rates by sector through 2050.

There are many market and system operational changes that can affect rates, and no analysis can predict future markets perfectly; however, an assessment of potential rate changes over time helps the reader understand potential trends. Rates are made up of the commodity price, which is the price for the fossil gas at specific locations in the system, and the additional cost of transporting that fossil gas from that location to the customer. The primary customers of fossil gas are state buildings, commercial and residential end users, electricity generators (such as gas-fired power plants), and industrial operations. This analysis provides rate forecasts for various customer types.

Modeling Method

Total customer rates represent the final price customers pay for fossil gas — what a customer would see on their gas bill. Staff models average total customer rates by sector and utility. Figure D-1 depicts how total customer rates are modeled. The total customer rate is a combination of the commodity price and transportation rate. The commodity price is for fossil gas at specific pricing hubs throughout North America such as Pacific Gas and Electric (PG&E) Citygate or Opal, Wyoming.

CEC staff includes western pricing hubs because the total customer rate for electric generators in the WECC is used in the CEC’s and the WECC’s production cost modeling. Commodity prices include costs to explore, develop, extract, and transport fossil gas to the specific pricing hub and accounts for about 25 percent of the total customer rate in long-term modeling. The commodity price is modeled using a regression model, Fossil Gas Commodity Price (Commodity Price Forecasting — Fossil Gas Commodity Price (FGCP) Model) model, leveraging the machine learning platform Prophet. In actuality, the commodity price is a free-market price set by buyers and sellers.

Figure D-1: Total Customer Rates Modeling Process

Source: CEC

Transportation rates represent the cost of delivering fossil gas from regional pricing hubs to end-use customers. These costs account for roughly 75 percent of the total customer rate in the long-term modeling framework. Because the regulatory structures, data sources, and rate designs differ between California and the rest of the WECC region, transportation rates are modeled using two approaches.

For areas outside California, staff models transportation rates only for electric generators within the WECC. These rates are estimated using the Electric Generator End-Use Rates (EGEUR) model, which captures interstate pipeline transportation costs between major pricing hubs and generation centers across the western United States.

For customers within California, staff uses the California Utilities' Transportation Rate (CUTR) model to estimate transportation rates for all major customer sectors — residential, commercial, industrial, and electric generation. The CUTR model is based on data from California's major gas utilities and reflects the cost structure and regulatory treatment unique to the state's intrastate gas system. The electric generator component of the CUTR model is also used to represent in-state generation transportation costs, ensuring consistency between the modeling of California and WECC-wide electric generation sectors.

Transportation rates from these models are combined with commodity prices from the FGCP model to produce total customer rates. For example, an electric generator located in western Washington would have a transportation rate derived from the EGEUR model added to the Sumas hub commodity price from the FGCP model to determine the total delivered cost. In contrast, a PG&E residential customer in California would have a transportation rate estimated using the CUTR model added to the PG&E Citygate (a virtual trading point in PG&E's gas service territory, see Figure D-2) commodity price from the FGCP model to produce the residential total customer rate.

Scenario Development

For the *2025 IEPR*, staff produced one commodity price forecast, one electric generator total customer rate for the WECC, and four California-specific total customer rate scenarios. These four scenarios are based on four demand cases from the demand forecast using one revenue requirement (RR). The following cases and scenarios are explored:

- Four demand cases[192]
    - One from *2023 CED Adopted Fossil Gas Forecast*
        - *Base Demand Case*
    - Three from *2024 CED Adopted Fossil Gas Forecast*
        - *Additional Achievable Fuel Substitution (AAFS) 2*
        - *AAFS 3*
        - *AAFS 4*

The naming convention of the scenarios is the demand case used followed by the RR case, which for this IEPR is only one RR — the constant growth RR, calculated as a simple average of the utilities' historical RRs. This constant growth RR projects a steady growth rate of RR that remains the same each year throughout the forecast period. Thus, the first scenario would be 2023 base demand case/constant growth RR, the next scenario would be 2024 AAFS 2/constant growth RR, and so on.

Staff chose the demand forecasts to provide perspective on the impacts of demand on total customer rates. The 2023 base demand case was used as this was the most recently available, while in 2024, the AAFS 2, AAFS 3, and AAFS 4 were used.

The base case for fossil gas demand represents the business-as-usual forecast based on midlevel assumptions about economic, demographic, and policy conditions without assuming significant fuel substitution or additional efficiency measures. This scenario serves as the reference case for comparison. AAFS is a demand-side forecasting modifier that represents additional shifts from fossil-fuel end uses to cleaner or more efficient alternatives, beyond what is captured in base-case assumptions and existing programs.

Regarding AAFS scenarios, California's climate goals have made building decarbonization a priority. Staff developed scenarios representing more conservative (AAFS 2) and more optimistic (AAFS 3 and 4) versions of the proposed zero-emission space and water heater

192 For the 2023 Demand Case, see https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2023-integrated-energy-policy-report.

For the 2024 Demand Cases, see https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2025-integrated-energy-policy-report.

regulations. AAFS 2 assumes a gradual, statewide adoption of zero-emission technologies, while AAFS 3 and 4 incorporate the California Air Resources Board's concepts for the Zero-Emission Space and Water Heater Standards with a staggered statewide compliance schedule.

The naming convention of the scenarios is the demand case used followed by the RR case, which for this IEPR is only one RR — the constant growth RR, calculated as a simple average of the utilities' historical RRs. This constant RR projects a steady growth rate of RR that remains the same each year throughout the forecast period. Thus, the first scenario would be 2023 base demand case/constant growth RR, the next scenario would be 2024 AAFS 2/constant growth RR, and so on.

Staff chose the demand forecasts to provide perspective on the impacts of demand on total customer rates. The 2023 base demand case was used as this was the most recently available. While in 2024, the AAFS 2, AAFS 3, and AAFS 4 were used.

As described above, each demand case is paired with a constant RR to produce five total customer rate scenarios, one for WECC electric generators outside of California, and four for residential, commercial, industrial, and electric generator customers within California. The RR includes operation and maintenance (O&M), capital investments, administration costs, taxes, interest, and profits and is reported to the California Public Utilities Commission (CPUC) annually.[193] Staff developed a constant growth RR based on the average of historical RR reported to the CPUC. The constant growth rate RR was chosen to give a baseline RR for the utilities. Future iterations could include pipeline decommissioning work that could possibly lower the RR utilities would need to operate their system.

Commodity Price Forecasting — Fossil Gas Commodity Price (FGCP) Model

To model this component, CEC staff developed the FGCP model using Prophet, a machine learning platform specifically designed for time series forecasting, to project monthly fossil gas commodity prices across various pricing hubs. The FGCP model has built-in mechanisms to accommodate missing data and reduce the impact of outliers, and it can handle various sources of uncertainty while incorporating both seasonal trends and irregular events.

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193 This data comes from the CPUC's *2023 California Electric and Gas Utility Costs Report: AB 67 Annual Report to the Governor and Legislature.* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2024/2023-ab-67-report.pdf.

Due to the incomplete disclosure and recording of historical commodity gas prices for certain hubs over the past two decades, particularly for the first decade, the historical data for these hubs remain partially unavailable. To address these data gaps, which concern the most critical input to the FGCP, staff developed and integrated a two-stage data imputation model within the FGCP framework. In the first stage, staff filled small gaps in recent price data by using similar nearby time points. In the second stage, larger gaps from earlier years were filled by learning from the benchmark hub (Henry Hub) and nearby hubs with complete data. After testing different configurations of the imputation model, the version that produced the most accurate estimates was chosen. The finalized imputed price series was validated for statistical consistency and integrated into the FGCP model. As more historical data become available, the FGCP model can operate with reduced dependence on imputation.

For the FGCP model, the primary input regressor — the variable used to explain and influence the prediction of commodity fossil gas prices — is the United States Energy Information Administration's (U.S. EIA) forecasted Henry Hub price, which provides a key indicator of the interconnected nature of the North American fossil gas market. Figure D-2 shows the fossil gas pricing hubs and their approximate locations for which prices are forecasted with the help of the FGCP model. Henry Hub, the national benchmark for fossil gas prices in North America, located in Erath, Louisiana, is not shown on this map.

Figure D-2: Western Fossil Gas Pricing Hubs

Source: CEC

In addition, staff incorporated a range of energy-related variables as input regressors to ensure that the model's commodity price predictions remain realistic and aligned with the evolving North American energy landscape. Pipeline infrastructure and liquefied natural gas (LNG) were not included in the analysis; however, staff plans to integrate both in future updates.

Key elements of the FGCP model include:

- Time-Series Forecasting: Staff used the model to leverage the historical monthly price data of fossil gas hubs to identify trends and forecast future prices over a 25-year horizon.

- Growth/Trend: The FGCP model helps to capture long-term growth trends in fossil gas prices, reflecting both upward and downward movements over time.
- Seasonality: Staff used Prophet's ability to handle seasonality to detect seasonal fluctuations in fossil gas prices which tend to vary based on demand during summer and winter seasons.
- Uncertainty: The model also allowed staff to account for uncertainty. This helps reflect inherent market volatility.

Forecasted data sets are used as inputs for producing the forecasted commodity prices using the FGCP model. Staff primarily used publicly available data from trusted sources. Natural Gas Intelligence (NGI) data is the only exception. Table D-1 presents major data sources used in the FGCP model. The historical data is used to train the FGCP model.

Table D-1: In-House FGCP Modeling Select Data

Data	Data Source	Description	Function in model
Henry Hub spot price	U.S. EIA	• National benchmark for fossil gas prices • Historical monthly data on prices, volumes, and deals • Yearly forecasted price data	The Henry Hub price serves as the benchmark for U.S. natural gas and is linked to multiple interstate and intrastate pipelines. The model uses it to constrain hub price predictions within a reasonable range.
Fossil Gas Pricing Hubs' monthly spot prices	NGI	• Historical spot prices	Historical prices are used to train the FGCP model and used to verify accuracy during back casting.
Fossil Gas Trading Volume	NGI	• Historical daily hub data	Volume reflects the 'hub' attribute, enabling the model to capture hub-specific traits, enhance prediction accuracy, and produce more representative forecasts.

Data	Data Source	Description	Function in model
Nationwide electricity retail price	U.S. EIA	• Historical state-level monthly data • National yearly forecasted price data	The model uses it to represent the 'state' attribute of various hubs, enabling differentiation of commodity price trends across states during prediction.
Electricity generation from NG	U.S. EIA	• Historical state-level yearly data	Serves the same function as the 'Nationwide Electricity Retail Price'.
Renewable energy consumption	U.S. EIA	• Historical national monthly data • National yearly forecasted data	Renewable energy consumption influences natural gas prices by affecting demand, helping the model generate more realistic price predictions.
Heating and cooling degree days	National Ocean and Atmospheric Administration	• Historical state-level yearly data	Functions similarly to the 'Nationwide Electricity Retail Price' and 'Renewable Energy Consumption' regressors.

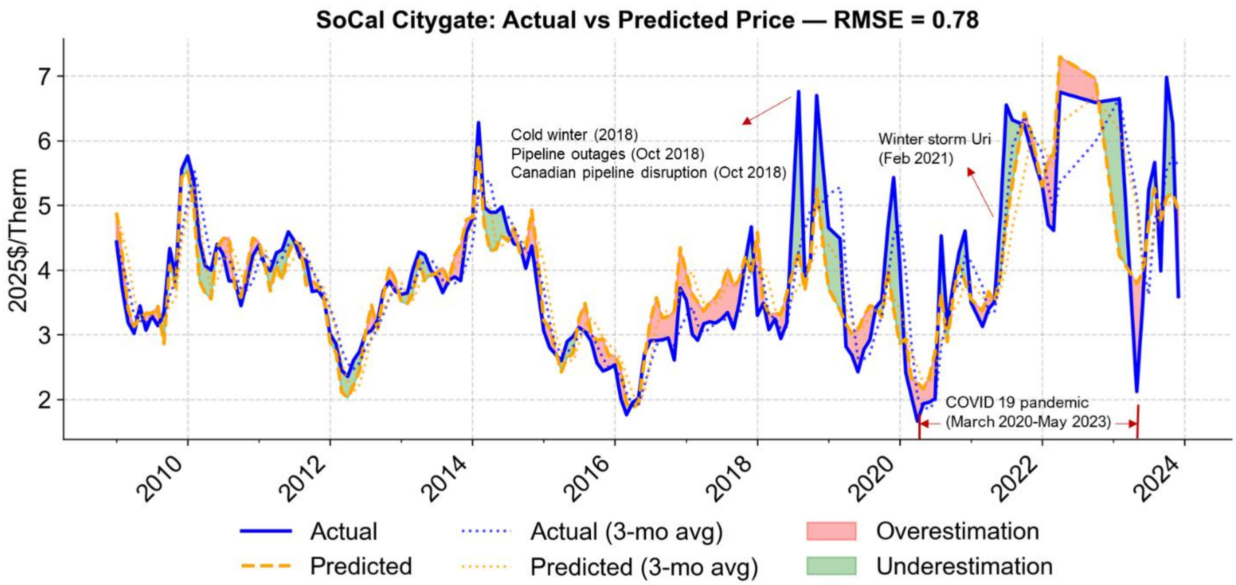
Source: CEC

Staff employed backcast training in the FGCP model to enhance prediction performance and optimize hyperparameters.[194] CEC staff evaluates accuracy by using Root Mean Square Error (RMSE) to select the best model configuration. Figure D-3 shows the backcasting verification

194 In this model, *hyperparameters* control the flexibility and behavior of key components: trend, seasonality, and holidays. They guide the model in determining whether changes in the trend are meaningful, how strong, and consistent seasonal patterns are, and the impact of holidays. Proper tuning helps the model strike a balance between capturing real patterns and filtering out random noise.

of the FGCP model, using the SoCal Citygate hub (a virtual trading point on the SoCal Gas system, see Figure D-2) as an example. Over the past 15 years, the model has closely followed actual price with small deviations (RMSE = 0.78 relative to the total data range 0–7), thereby demonstrating strong performance in predicting SoCal Citygate prices. The wide variations in gas prices are due to events that significantly influenced the fossil gas market, such as the COVID-19 pandemic lockdowns or extreme weather events such as winter storm Uri.[195]

Figure D-3: Verifying NGCP Model Accuracy



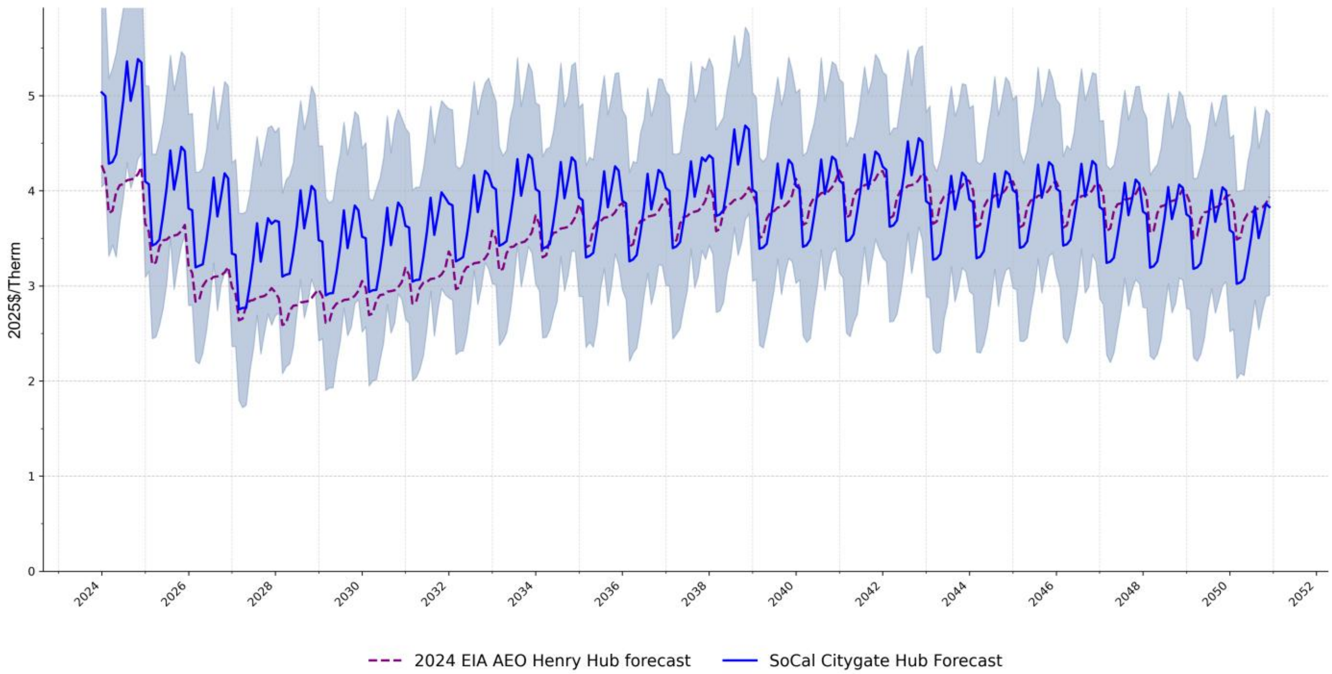
Source: CEC

FigureThe FGCP forecast for SoCal Citygate is depicted in Figure D-4. The FGCP predicted prices (dark blue line) generally align with the U.S. EIA's Henry Hub trends (red dotted line), maintaining the historical pattern in which SoCal Citygate prices are slightly higher than Henry

195 Winter Storm Uri was an intense cold snap in mid-February 2021 that brought unusually low temperatures to large regions of the United States, including the Northwest, Southwest, Central and Southern Plains, Great Lakes, Southeast, and Gulf Coast. The event was the fourth in the past decade to jeopardize gas and bulk-power system reliability, driving sharply higher prices. See Appendix D: Extreme Weather Events in the Final 2021 Integrated Energy Policy Report, Volume III for further details. https://www.energy.ca.gov/publications/2021/2021-integrated-energy-policy-report.

Hub prices. The forecast also includes an uncertainty area (light blue) based on 80 percent uncertainty intervals.

Figure D-4: In-House FGCP Modeling Select Data Sources

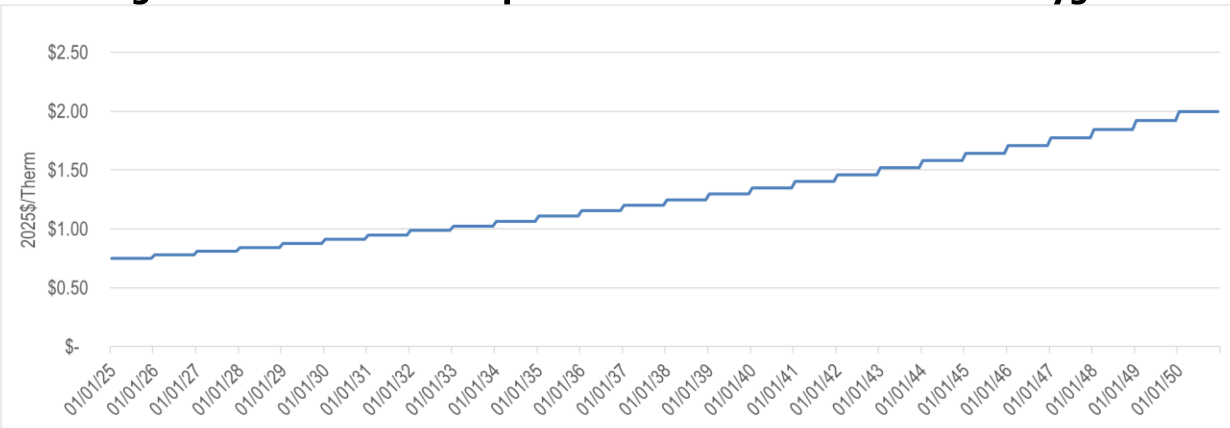


Source: CEC

Electric Generator Total Customer Rates Modeling

CEC staff developed the EGEUR model, which forecasts total customer rates for electric generators in the WECC. EGEUR uses transportation rates from interstate pipelines for electric generation outside California. Staff used January 2025 data from the tariff sheets of 15 pipeline companies obtained from their company websites and reported to Federal Energy Regulatory Commission (FERC) to update the 15 western North American pricing hubs (Figure D-2) for EGEUR's transportation rates. For pipelines inside California, staff used the CUTR model. (See next section for details about the CUTR model.) To the commodity prices, staff added these transportation rates to the commodity prices from the FGCP model to arrive at the electric generator total customer rates. Figure D-5 shows the resulting transportation rate for the SoCal Citygate from the EGEUR model.

Figure D-5: EGEUR Transportation Results for the SoCal Citygate



Source: CEC

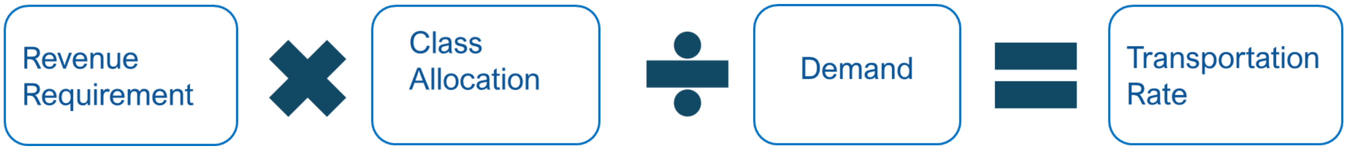
California Utilities' Transportation Rate Modeling

The CUTR model (developed by Aspen Environmental) forecasts transportation rates, the cost of moving gas from pricing hubs to end users, for the residential, commercial, industrial, and electric generation sectors across California's three major gas utilities (PG&E, Southern California Gas Company [SoCalGas], and San Diego Gas & Electric [SDG&E]). The CUTR model uses demand inputs from the CEC's demand forecasts for the residential, commercial, and industrial sectors, and the *2024 California Gas Report*[196] electric generation demand forecast as the demand inputs. Class allocations, the share of RR each sector pays, are held constant and are taken from the utilities' January 2025, advice letters. Staff set the base-year RR using utilities' January 2025, advice letters and then applied the constant RR growth trajectory for each utility.

The CUTR model process, depicted in Figure D-6, calculates transportation rates by multiplying the RR by the class allocations and dividing by demand, then adds the resulting transportation rate to the specific commodity price to produce total customer rates by sector and utility in California.

196 *2024 California Gas Report*. Prepared by the California Gas and Electric Utilities, average demand year forecast, https://www.socalgas.com/sites/default/files/2024-08/2024-California-Gas-Report-Final.pdf.

Figure D-6: CUTR Model Process

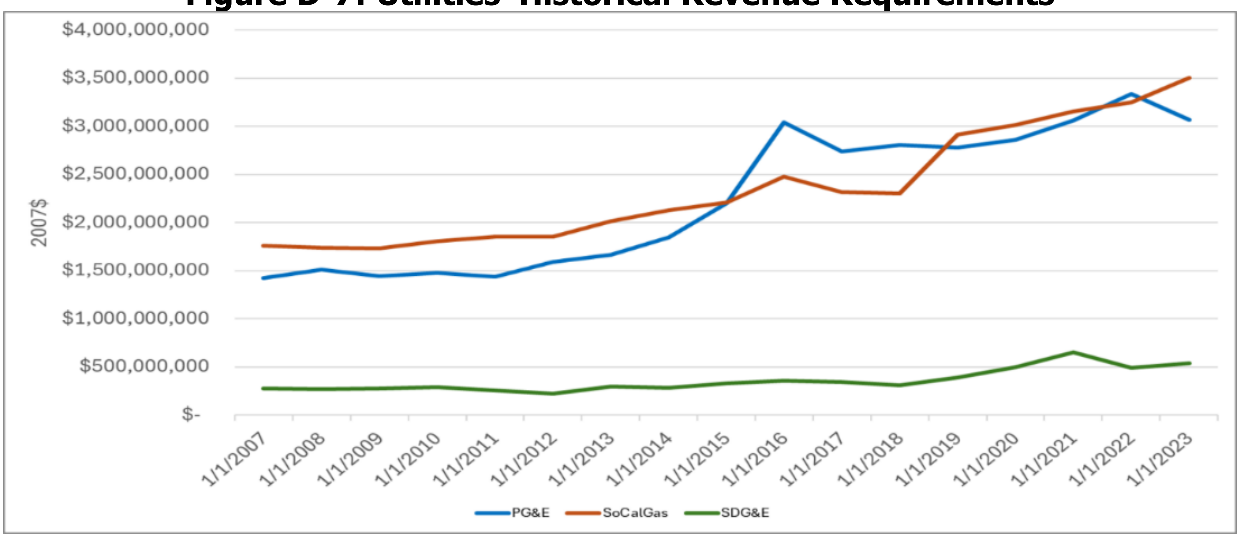


Source: CEC

Revenue Requirement

As explained earlier, RR is the amount of money a utility needs to operate its gas system. Along with demand, the RR is one of the two main drivers of transportation rates within California. The RR includes O&M, capital investments, administration costs, taxes, interest, and profits and is reported to the CPUC annually.[197] Figure D-7 shows historical RR for California's fossil gas utilities.

Figure D-7: Utilities' Historical Revenue Requirements



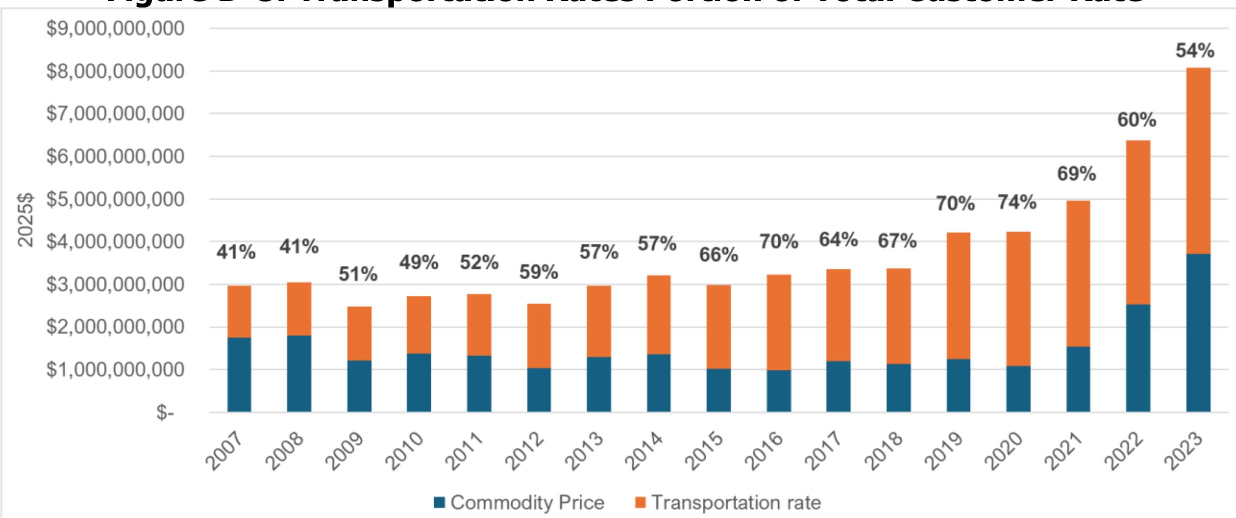
Source: CPUC's 2023 California Electric and Gas Utility Costs Report: AB 67 Annual Report to the Governor and Legislature, CEC

All utilities see an increased RR over time. PG&E RR increased 115 percent between 2007 to 2023 from a little more than $1 billion to about $3 billion, an average annual increase of 5.4

197 These data come from the CPUC's *2023 California Electric and Gas Utility Costs Report: AB 67 Annual Report to the Governor and Legislature*, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2024/2023-ab-67-report.pdf.

percent per year. Large RR increases from 2011 to 2016 were due to costs for pipeline safety work after the rupture of a PG&E transmission pipeline in San Bruno.[198] From 2007 through 2023, SoCalGas RR increased 95 percent (5.5 percent annual average increase), while SDG&E RR increased 99 percent (4.6 percent annual average increase). SDG&E's smaller increases are due to being a smaller system and is part of SoCalGas/Sempra. Much of the increase in RR over the last 15 years is due to pipeline safety work. Figure D-8 shows the historical commodity price and transportation rates' portion of total customer rate. The transportation rates' portion of total customer rates from 2007 to 2023 were between 41 percent and 74 percent.

Figure D-8: Transportation Rates Portion of Total Customer Rate

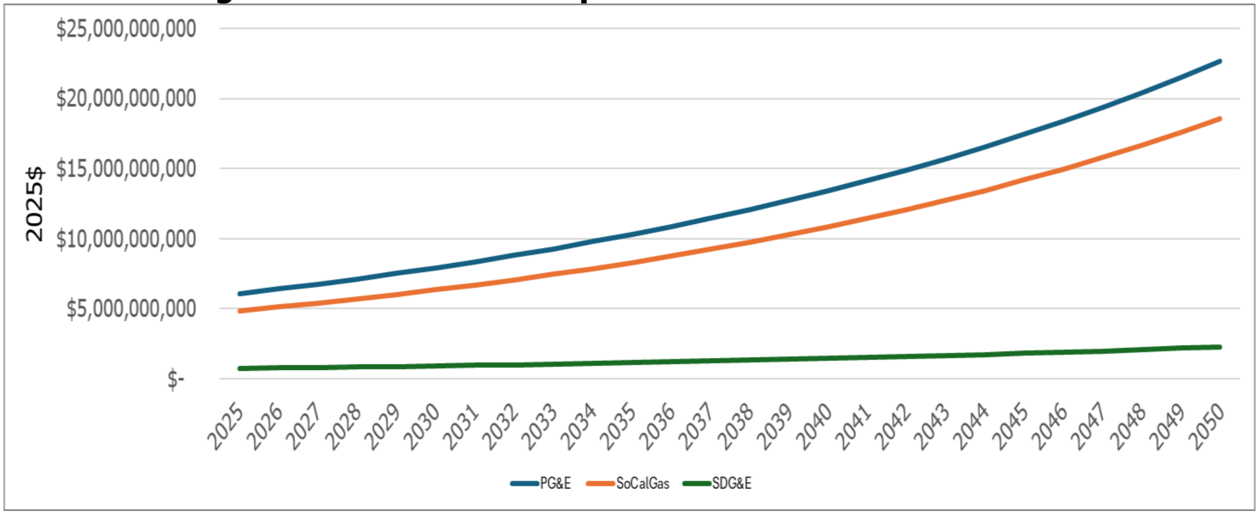


Source: CPUC's 2023 California Electric and Gas Utility Costs Report: AB 67 Annual Report to the Governor and Legislature, CEC

The constant RR case (Figure D-9) projects the same growth rate year to year throughout the forecast period (5.4 percent for PG&E, 5.5 percent for SoCalGas, and 4.6 percent for SDG&E). This percentage is a straight average of the utilities' historical RR (Figure D-7). Under this assumption, PG&E's RR would start at about $5 billion in 2025 and would increase to almost $24 billion in 2050.

198 On September 9, 2010, a 30-inch gas pipeline owned by PG&E exploded, killing eight people and destroying dozens of homes in the San Francisco suburb of San Bruno, California.

Figure D-9: Revenue Requirements — Constant Growth



Source: CEC

Select Total Customer Rates Results

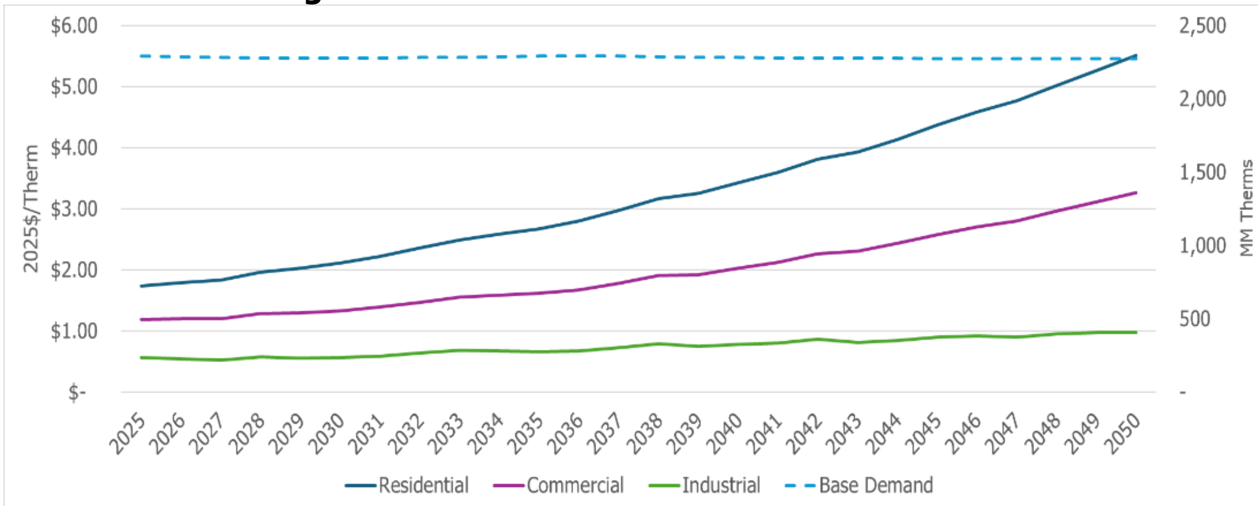
The projected rate outcomes are without state or utility intervention. In the absence of state or utility intervention, fossil gas total customer rates rise sharply in the later years due to increasing revenue requirements and declining demand. As the numerator (RR) increases and the denominator (demand) decreases, the resulting rates escalate significantly. A significant driver of decreasing demand is the expectation that fewer customers will elect to have gas service. Decreasing demand combined with increasing RR due to increased system costs will likely result in fewer fossil gas customers paying for infrastructure.

The most extreme rate increases occur in the residential sector under the AAFS demand case — which assume steep declines in demand — combined with the constant RR growth scenario, which assumes the highest RR path. In this case, the zero-emission adoption under AAFS reduce gas demand, leaving fewer gas ratepayers to cover system and transportation costs, thereby significantly raising unit rates. The following are forecasts of SoCalGas' residential total customer rates under various scenarios:

- Under the base demand case, total customer rates start at $1.74/Therm in 2025 and grow to $5.50/Therm in 2050.
- Under the AAFS 2 demand case, total customer rates rise to about $43.17/Therm by 2050.

Figure D-10 shows the results for SoCalGas by sector for the 2023 Base Demand Case and the constant growth RR.

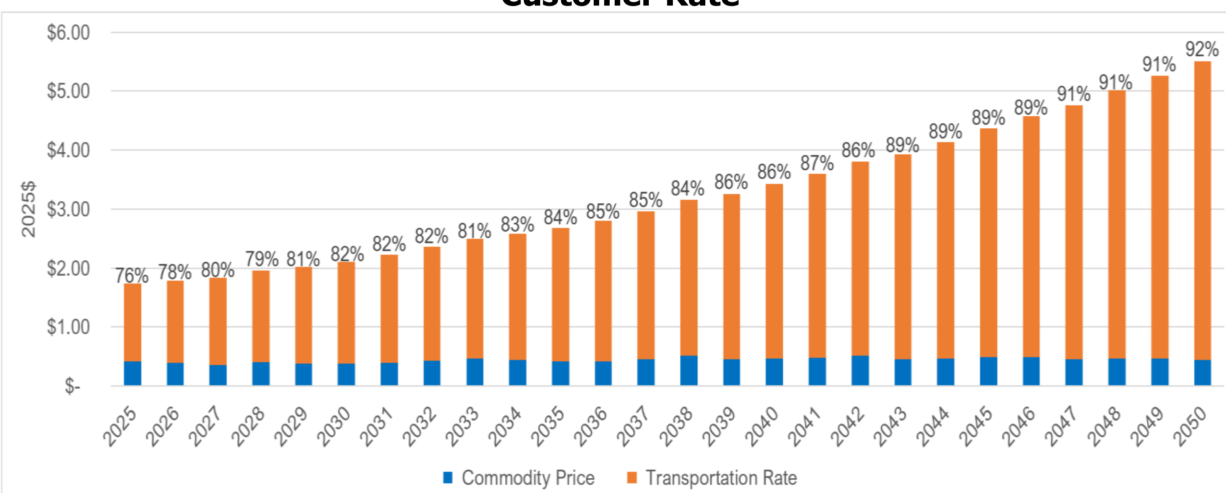
Figure D-10: SoCalGas' Total Customer Rates



Source: CEC

SoCalGas's transportation rate as a percentage of total customer rate grows from 76 percent in 2025 to 92 percent in 2050. This growth reflects the growing RR and declining demand over time. Figure D-11 shows SoCalGas' residential transportation rates' percentage of total customer rates for the base demand case and constant growth RR.

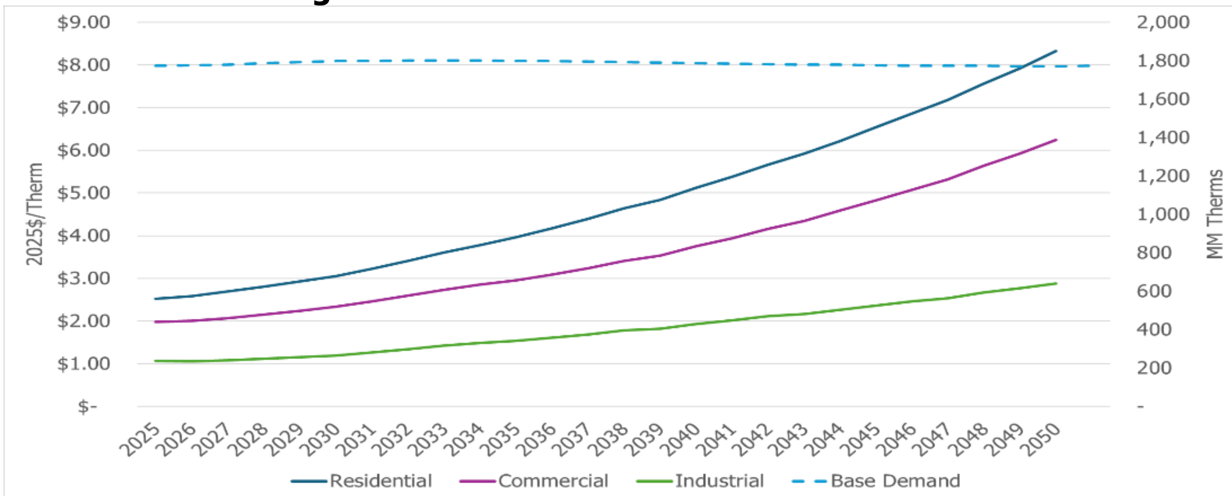
Figure D-11: SoCalGas' Residential Transportation Rates' Percentage of Total Customer Rate



Source: CEC

PG&E's residential rates increase from $2.52/Therm in 2025 to $8.32/Therm in 2050. Figure D-12 displays the results for PG&E by sector for the base demand case and the constant growth RR.

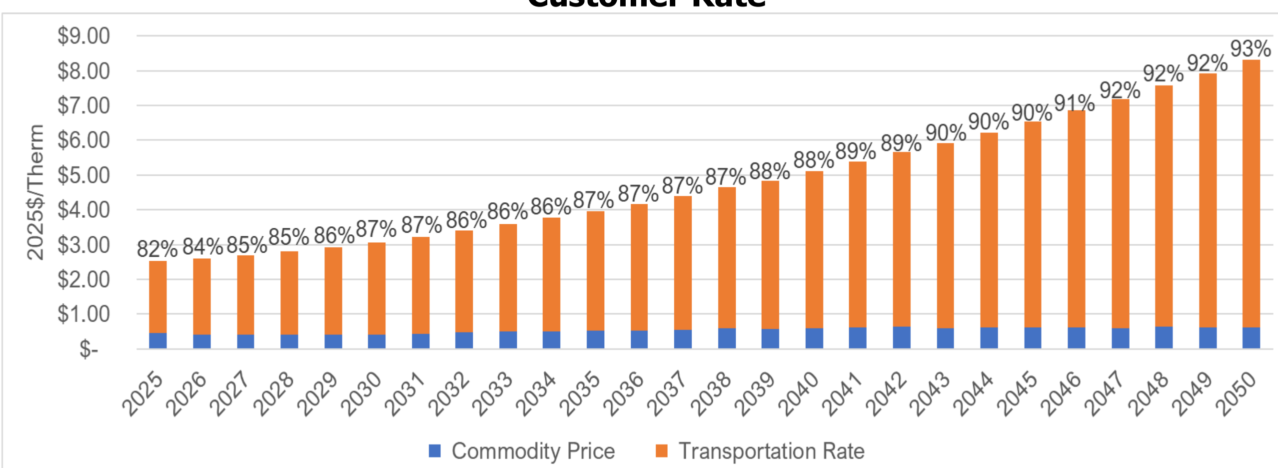
Figure D-12: PG&E's Total Customer Rates



Source: CEC

PG&E's transportation rate as a percentage of total customer rate grows from 82 percent in 2025 to 93 percent in 2050. Figure D-13 shows PG&E's' residential transportation rates' percentage of total customer rates for the base demand case and constant growth RR. The figure shows increasing RR and decreasing demand over time.

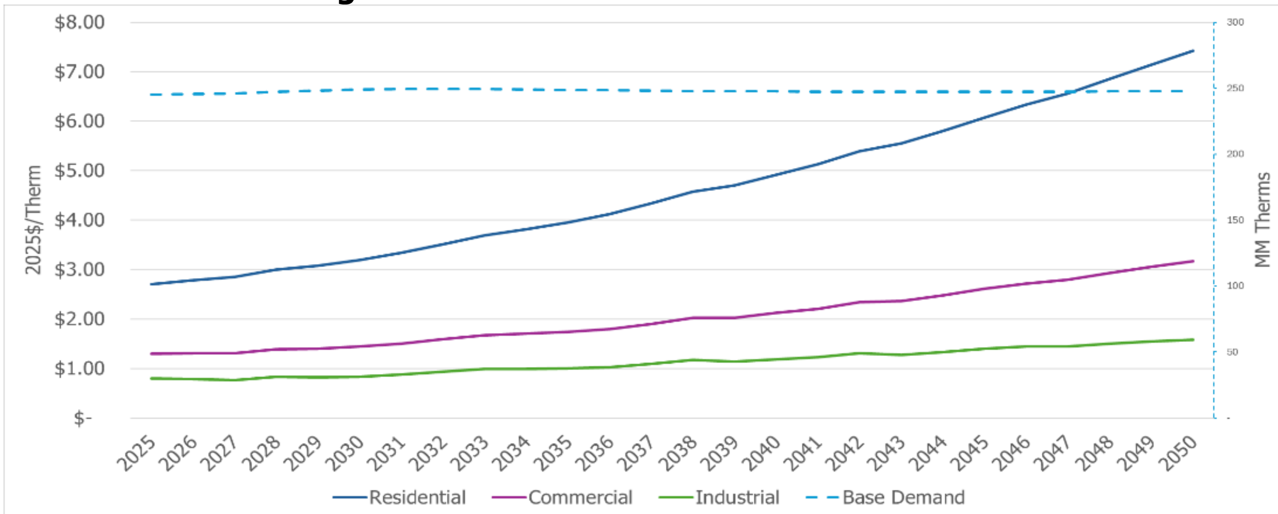
Figure D-13: PG&E's Residential Transportation Rates' Percentage of Total Customer Rate



Source: CEC

SDG&E'S residential rates grow from $2.70/Therm in 2025 to $7.43/Therm in 2050. Figure D-14 displays the results for SDG&E by sector for the Base Demand case and the constant growth RR.

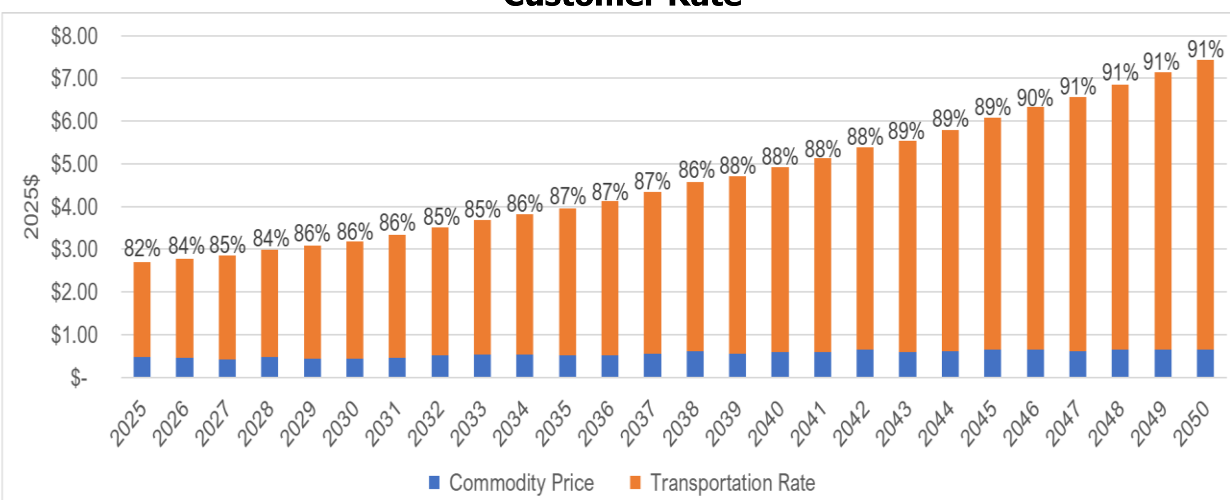
Figure D-14: SDG&E Total Customer Rates



Source: CEC

SDG&E's transportation rate as a percentage of total customer rate grows from 82 percent in 2025 to 91 percent in 2050. This growth reflects the growing RR and declining demand over time. Figure D-15 sFigurehows SDG&E's residential transportation rates as a percentage of total customer rates for the base demand case and constant growth RR.

Figure D-15: SDG&E's Residential Transportation Rates as a Percentage of Total Customer Rate



Source: CEC