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2023 Demand Scenarios Project

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ABSTRACT

This report presents the results of the second cycle of the California Energy Commission’s Demand Scenarios Project. The Demand Scenarios Project assesses long-term statewide energy consumption and associated greenhouse gas emissions through 2050. Traditional demand forecasting focuses on a 10-to-15-year horizon. Meeting California’s climate goals, however, requires a longer-term planning approach that looks forward to 2050. To support this, the Demand Scenarios Project explores how energy usage might change through 2050 under different policy assumptions. The three primary scenarios — Reference, Policy, and Enhanced Policy — provide energy demand projections to assess the impact of current regulations, emerging policies, and fuel substitution on energy consumption and greenhouse gas emissions. Using a combination of in-house tools and the EnergyPATHWAYS model, `the project analyzes energy demand across all major sectors and fuel types.

The results show a consistent decline in fossil fuel use, particularly gasoline, diesel, and natural gas, and a steady rise in electricity and hydrogen demand, driven by building and transportation electrification. Notably, electricity loads shift toward the winter season, reflecting increased space heating demand. While these demand side scenarios help identify where progress is being made, they also reveal policy insights between potential emissions and reduction targets for 2045 and 2050. The report underscores the need for better data, coordination, and modeling to guide the state’s transition to a low-carbon energy future.

Keywords: Energy efficiency, electrification, decarbonization, long-term demand projections

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EXECUTIVE SUMMARY

For nearly 20 years, key electricity planning processes at the California Public Utilities Commission and the California Independent System Operator have used the California Energy Commission's (CEC) 10-year demand forecast to base most firm resource commitments and contractual procurement. In 2022 this time horizon was extended to 15 years as codified by Senate Bill 887 (Becker, Chapter 358, Statutes of 2022). However, numerous state legislative goals enacted to reduce greenhouse gas emissions focus on 2045 or 2050 time horizons. Establishing greenhouse gas reduction goals for these more distant points in time is necessary to enable energy users to implement the adaptation required to achieve these goals without serious disruption to California's economy and the lives of its residents.

Because time horizons further out than 10 to 15 years necessarily involve increased uncertainty, CEC staff has been reluctant to extend the official "demand forecast" to describe possible energy demand to 2050. As a result, staff has reserved the term "demand forecast" for the existing 15-year time horizon that the California Public Utilities Commission (CPUC) and the California Independent System Operator (California ISO) use to make commitments for new generating resource development or new transmission lines. Establishing an assessment time horizon out to 2050 more effectively frames longer-term consequences of the statutory economywide goals and individual control measures proposed for adapting energy use.

Staff now uses the term "demand scenarios" to describe a set of longer-term, multifuel projections to inform thinking about the implications of trying to achieve long-term goals.

Consequently, CEC staff developed the Demand Scenarios Project to address many of those uncertainties by creating multiple sets of projections and expanding scope to include all fuel types. No single set of energy demand projections will provide the needed clarity to base major long-term commitments or investment decisions.

One of the goals of the demand scenarios project was to develop more accurate projections of the impacts of numerous GHG emission reduction measures incorporated within the 2022 Scoping Plan developed by CARB in satisfaction of legislative direction. Using the same demand modeling techniques, to the extent appropriate, as have been used by the CEC for the demand forecasts accepted by the CPUC and California ISO in their resource planning and market studies makes more clear what the incremental change in demand for various energy types results from GHG control measures similar to those in the Scoping Plan.

Most of the broad results of this cycle of demand scenarios confirm the direction of change in the Scoping Plan. Electrification from fuel substitution can have a major impact on energy consumption for electricity (increase) and pipeline gas (decrease), reducing aggregate greenhouse gas emissions. However, the demand scenarios results are assessed by regions in the state giving insights about geographic variations in annual energy impacts. The hourly pattern of electric load changes substantially between the base year and 2050. Peak load increases and in most electric planning areas shift to the winter season. Minimum load drops drastically because of the rooftop solar assumptions in the Enhanced Policy Scenario. These nuances of hourly electric load impacts are beyond the scope of what was reported in the

Scoping Plan, yet crucial starting points for the supply-side assessments required to develop resources needed to maintain electric system reliability.

Approach

The CEC's Demand Scenarios Project aims to quantify the long-term energy consumption impacts of existing rules, regulations, and policies, with some limited incorporation of additional achievable energy efficiency and fuel substitution concepts that have not yet achieved funding or regulatory approval. To understand the contribution to state decarbonization goals, these energy consumption impacts are translated into greenhouse gas (GHG) emission projections. Decarbonization is the general term for specific actions that can be taken to reduce GHG emissions, while generally allowing the purpose to continue to be accomplished. Any gaps between demand scenario GHG projections and state GHG emission goals highlight the need for further policy development, new program designs, or additional incentives within existing programs to meet California's ambitious climate change goals. By analyzing demand scenarios, potential gaps and opportunities for policy actions to accelerate decarbonization can be identified.

Following the approach used in the 2021 Demand Scenarios assessment cycle, staff and a contractor team developed a demand scenarios model that integrates projections from internal CEC demand forecast and load-modifier tools with the EnergyPATHWAYS model. This model augments the CEC's modeling capabilities with other sectors/fuels not addressed in current CEC modeling tools. The CEC tools produce results for electricity and pipeline gas for the customer sectors (residential and commercial buildings, industry, agriculture, and other nontransportation end users, plus all the fuels used in transportation). The economic, demographic, and other inputs driving energy demand projections, consistent with Energy Commission modeling assumptions, are used in the EnergyPATHWAYS model. The results from Energy Commission models and the complementary results from the EnergyPATHWAYS model are integrated into the new demand scenarios model to provide complete coverage of all sectors/fuels for seven planning areas comprising nearly all the state. The energy outputs are then fed into the greenhouse gas emission tool, which calculates the annual emissions by sector and fuel type for each scenario.

To satisfy analysis for reporting required by Senate Bill 100 (De León, Chapter 312, Statutes of 2018), staff and the contractor team developed 8760 hourly electric load projections from 2023 through 2050 for each of seven electric planning areas. These load projections were accomplished by using the same *2023 Integrated Energy Policy Report* hourly load forecasting techniques and virtually the same set of hourly load profiles to translate annual electric energy at a disaggregated, or broken down, level into 8760 hourly load projections for each planning area.

Scenario Characteristics

As part of developing the long-term demand scenarios, staff collaborated with Verdant and their subcontractors Evolved Energy Research (EER) and Jai J Mitchell Analytics to develop three primary types of scenarios for this project: a Reference Scenario, Policy Scenario, and Enhanced Policy Scenario.

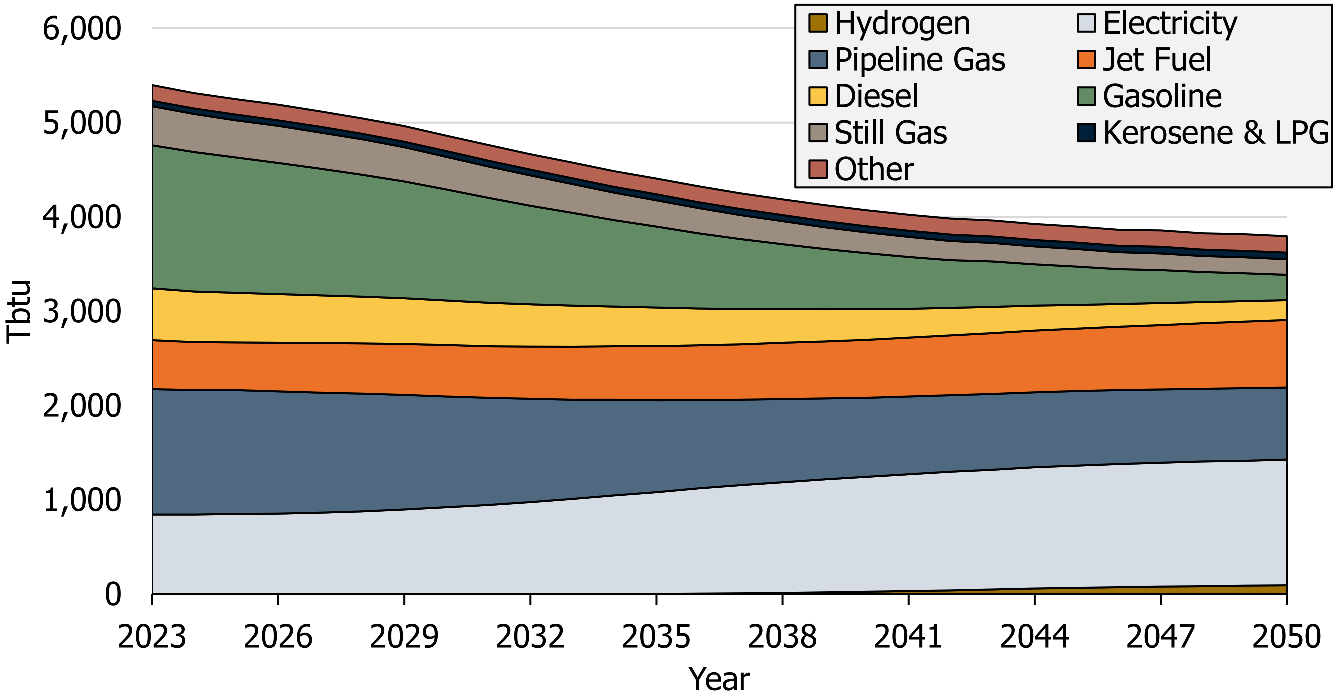
In addition, staff developed a high hydrogen transportation sensitivity to the Policy Scenario, which was provided to the Senate Bill 100 project for its use. This sensitivity altered the Policy Scenario split between electric (decreased) and hydrogen-fueled (increased) truck transportation. Staff additionally worked with the Energy Commission's Efficiency Division and the contractor Energy and Environmental Economics to develop a sensitivity to the Policy Scenario for managed charging of light-duty electric vehicles. Staff also developed a hydrogen pipeline sensitivity as a variant to the Enhanced Policy Scenario. This sensitivity explored the consequences of a "hydrogen economy" featuring industrial decarbonization hydrogen substitution for pipeline gas and its supply via pipelines in contrast to the focus on electric power generation and transportation use of hydrogen as described in Chapter 2 of the *2023 IEPR* in satisfaction of Senate Bill 1075 (Skinner, Chapter 363, Statutes of 2022).

Results

In each of the three primary demand scenarios (Reference, Policy, and Enhanced Policy), total statewide primary energy demand declines from 2023 to 2050. As shown in Figures ES-1 through ES-3 below, demand for pipeline gas, gases emitted during the separation of crude oil into various specific chemicals (still gas), diesel, and gasoline decline in all scenarios, largely due to the electrification of the building, industrial, and transportation sectors. Jet fuel demand for all flights refueled in California increases, reflecting the current uncertainty of the electrification or hydrogen substitution pathways to work at scale for the presumably growing aviation sector. Electricity demand grows in all scenarios, though the total increase in electricity consumption is reduced by energy efficiency measures and the inherent efficiency advantage of electric end-use technologies over pipeline fuel-burning technologies.

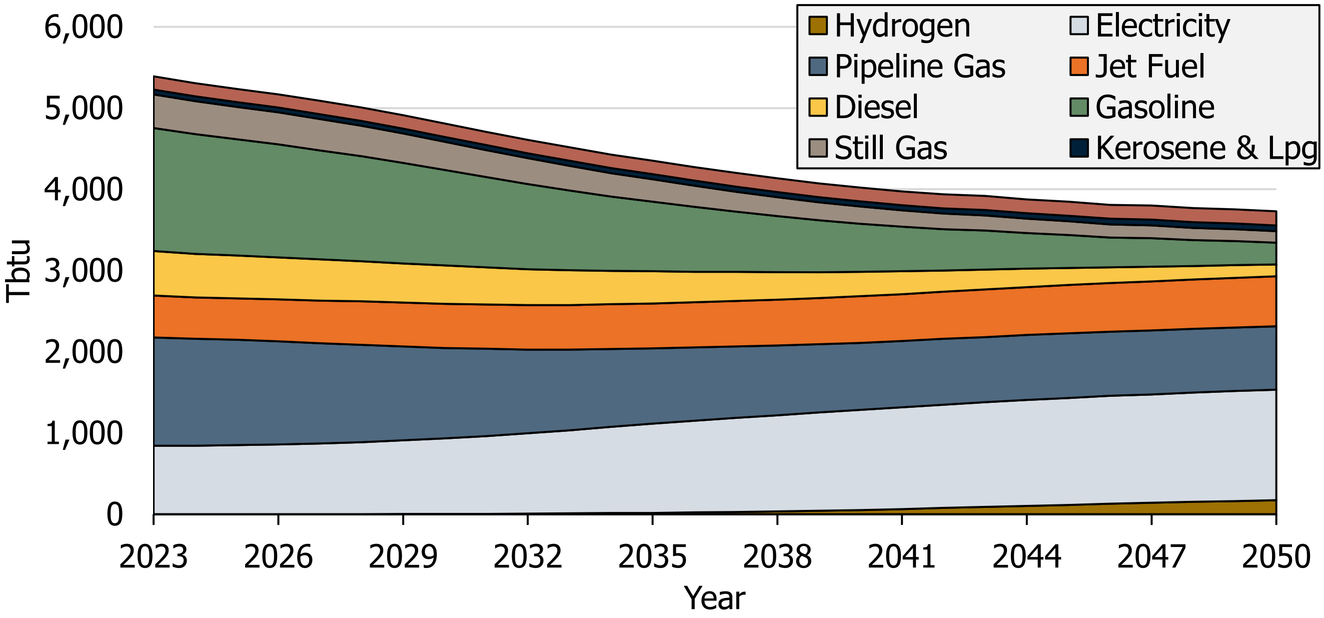
All scenarios show an increase in hydrogen fuel demand, with the total quantity of hydrogen consumption increasing from the Reference Scenario to the Policy Scenario and increasing again from the Policy Scenario to the Enhanced Policy Scenario. Demand for kerosene, liquified petroleum gas, and other fuels (other includes biomass, wood, coal, and steam in the figure below) remains flat through 2050 across all scenarios.

Figure ES-1: Reference Scenario Statewide Energy Demand by Fuel Type



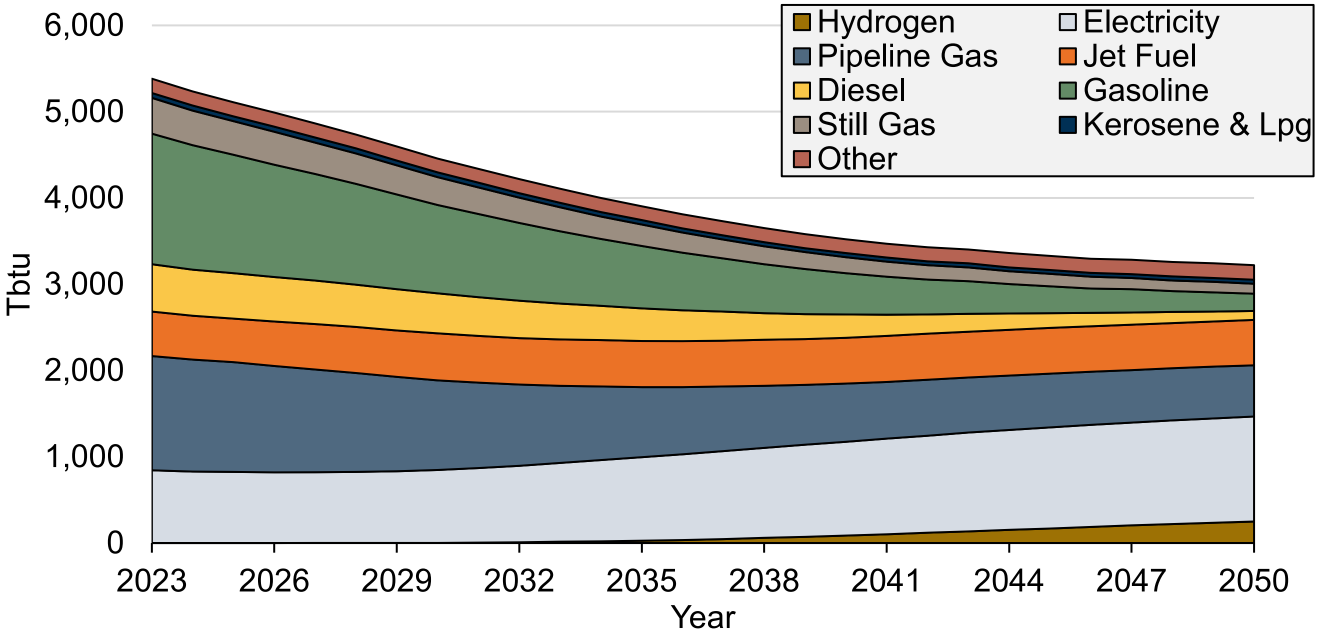
Source: CEC staff/EER

Figure ES-2: Policy Scenario Statewide Energy Demand by Fuel Type



Source: CEC staff/EER

Figure ES-3: Enhanced Policy Scenario Statewide Energy Demand by Fuel Type



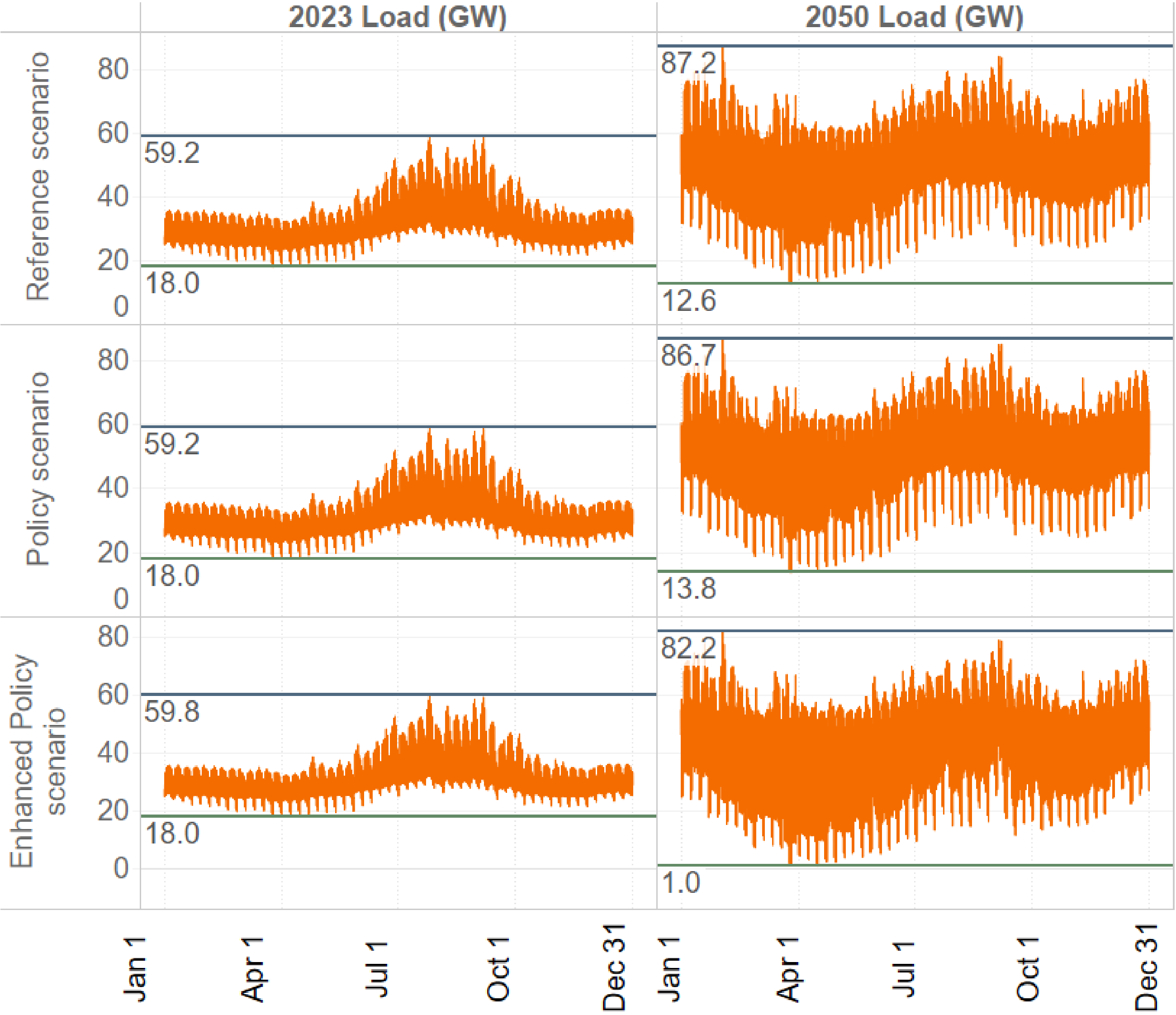
Source: CEC staff/EER

Comparing total statewide demand for electricity and nonelectric fuels illustrates the variation between scenarios. The Reference and Policy Scenarios result in similar statewide energy demand, with higher electricity demand and lower nonelectric fuel demand in the Policy Scenario relative to the Reference Scenario. In both scenarios, electricity demand increases by about 160 percent, and nonelectric fuel demand declines by about 50 percent from 2023 to 2050. The Enhanced Policy Scenario (along with related Enhanced Policy Hydrogen Pipeline Sensitivity) results in significantly lower demand for electricity and nonelectric fuels relative to the Reference and Policy Scenarios.

A signal outcome for hourly electric loads is the growing difference between highs and lows of the day for all seasons of the year, as shown in Figure ES-4. Winter load increases dramatically, while summer load increases only marginally. Electrification of buildings and charging electric vehicles, with the load profiles that were assumed, induce this result. Building electrification increases winter space heating loads to the point that nearly all regions of the state shift to winter peaking by the 2040s.

The differences among scenarios are muted by the inclusion of various zero-emission appliance standards in the Reference Scenario. In the Enhanced Policy Scenario, reduction in minimum loads is caused by an optimistic penetration of rooftop photovoltaic systems with only an average increase in behind-the-meter storage. Absent a major increase in storage capacity to spread usage of solar production to a broader set of hours, the midday output of rooftop solar essentially satisfies all other electric loads in some days of the year.

Figure ES-4: Comparing Statewide Hourly Electric Load Variability Across Scenarios for the 8760 Hour of 2023 and 2050



Source: EER

Greenhouse Gas Emission Projections

The emissions calculations performed for the Demand Scenarios Project use a different emissions accounting method from those used by California Air Resources Board (CARB) emissions reporting and California's gross emissions targets. For those emission sources in common between the board and the demand scenario analyses, the CEC uses emission factors that are defined using the board's emissions inventory methods. The key differences between emissions calculation methods are as follows:

1. The demand scenarios account for all aviation emissions from refueling flights either originating or terminating in California. In contrast, CARB's inventory accounts only for flights within the state. As a result, Demand Scenarios aviation emissions exceed the board's aviation emissions in all years due to this accounting difference.

2. CARB’s inventory includes process emissions and land-use emissions, which are out of scope for the demand scenarios as the Demand Scenarios Project accounts only for emissions related to energy demand.

In addition to these important differences in method, the demand scenarios emissions also cannot be compared directly to California’s emissions reductions targets because the demand scenarios do not consider supply-side emissions reduction measures, such as the following:

- decarbonized fuel blending beyond 2023 levels
- electric generation resource mix changes to satisfy Senate Bill 100 reporting,
- point-source carbon capture and
- sequestration in the electricity generation and industrial sectors, and direct air capture.

These supply-side strategies, among others, can be deployed in California to reduce emissions beyond what is captured in these demand scenarios.

Relation to Senate Bill 100

In this second cycle of the Demand Scenarios Project, the timing was right for the demand scenario results to feed into the second cycle of the SB 100 reporting. SB 100 requires that all electric generation supplying retail sales in California be 100 percent renewable or non-carbon-emitting by 2045. In designing the package of input assumptions for SB 100 supply-side capacity expansion and production simulation modeling, the interagency advisory team recommended use of the Policy Scenario as the “base” demand projection, along with two sensitivities relative to that “base” set of assumptions. These were a demand flexibility sensitivity and high hydrogen usage sensitivity.

The load flexibility inputs into the supply-side resource mix must be rooted in the fundamental mix of hourly load patterns at a highly disaggregated level. In satisfying one of the Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) requirements to develop a 2030 goal for demand response programs, the CEC developed a model to assess annual demand capacity potentials. Demand response is a set of programs that incentivize electricity consumers to modify their short-term use of electricity to assist in maintaining the necessary balance of aggregate supply and demand. Several modifications to the model allowed for additional capabilities for the Senate Bill 100 report. These capabilities include extending projection potentials beyond 2030, improving links to fundamental hourly load patterns, improving links to various end-user customer sectors, and improving program enlisting probabilities.

In the high hydrogen use sensitivity, following direction from the interagency SB 100 management team, CEC staff reduced the mix of medium- and heavy-duty zero-emission vehicles that were electric and replaced them with hydrogen zero-emission vehicles compared to the base policy scenario. This more closely matches the zero-emission vehicle mix in CARB’s *2022 Scoping Plan*. However, the production of hydrogen necessarily leads to a large increase in electricity to produce hydrogen. Staff developed a special analysis that constructed a hypothetical fleet of electrolyzer types with monthly statewide hydrogen consumption requirements. An electrolyzer is a device that uses electricity to separate water into hydrogen and oxygen by breaking the bonds between these two elements that comprise water. This package was provided to the SB 100 supply assessment team for use in enhancing the operating profile that would satisfy a "grid-friendly" constraint. "Grid-friendly" is a term developed by CARB to mean operating a fleet of electrolyzers in a manner to minimize impacts on the overall electrical grid, while still satisfying the production of the desired amount of hydrogen.

These two sensitivity cases are not described in detail in this report. They will appear in the upcoming SB 100 report, along with the results.

Conclusions

Most of the broad results of this cycle of demand scenarios confirm expectations. Electrification from fuel substitution can have a major impact on energy consumption for electricity (increase) and pipeline gas (decrease), reducing aggregate greenhouse gas emissions. The hourly pattern of electric load changes substantially between the base year and 2050. Peak load increases and in most electric planning areas shift to the winter season, but minimum load drops drastically because of the rooftop solar assumptions in the Enhanced Policy Scenario.

By design, a demand-side only analysis cannot capture the impact of the broader set of control measures in the 2022 Scoping Plan (for example, carbon capture, direct air capture, and natural and working lands are excluded). Thus, the scenario inputs are largely demand-side policies and programs, and these sets of assumptions mean that the scenarios collectively fall short of statutory greenhouse gas emission reduction goals. They do, however, show that energy consumption policies can play a major role in meeting greenhouse gas targets.

Although the role of hydrogen is not yet settled at either the state or federal level, sensitivities that explore higher levels of hydrogen consumption at the end-user level have revealed interesting, albeit preliminary outcomes, deserving of further assessment. Further, reliance upon hydrogen has massive electricity (and water) consumption consequences that are not counted in these electric planning area results. Although the Enhanced Policy Scenario Pipeline Hydrogen Sensitivity explored the development of hydrogen pipelines to enable industrial consumption, the results revealed the challenges in creating a pipeline routing system that connects expected consumers with hydrogen production technologies and their locations.

Modeling the impacts of various policies and control measures has revealed numerous uncertainties not adequately addressed in existing data collection systems. Better data sharing among state agencies and associated public-private partnerships would help, but the state needs to invest in expanded data collection efforts to reduce uncertainties and enable future assessments to be more accurate.

The assessments underlying this report were completed circa November 2024. During the preparation of this report summarizing those assessments, there have been major changes in federal energy policies that reduce federal incentives and attempt to undermine California's ability to independently implement an economywide decarbonization strategy that are at the heart of the design of the policy scenarios described herein. California continues to pursue innovative policy solutions to build toward decarbonization.

CHAPTER 1:
Background and Current Work

Energy demand forecasting has been a core agency activity since the establishment of the California Energy Commission (CEC) 50 years ago. With some exceptions, the focus was on electricity and natural gas, not other fuels. By the early 2000s, the CEC was forecasting transportation energy demand but only when the transportation sector started to use electricity and natural gas did transportation energy demand become integrated with electricity and natural gas demand for buildings, industries, agriculture, water pumping, and other traditional uses.

For nearly 20 years, the demand forecast had referred to the next 10 years. This is the forward time horizon that balanced reasonable levels of demand certainty with the lead time for procuring and constructing supply-side infrastructure (primarily generation and transmission). Key electricity planning processes at the California Public Utilities Commission (CPUC) and the California Independent System Operator (California ISO) use the CEC's 10-year forecast and base most firm commitments and contractual procurement on this time horizon. Numerous state legislative goals enacted to reduce greenhouse gas (GHG) emissions focus on the 2045 or 2050 time horizons. Establishing GHG reduction goals for these more distant points in time is necessary to enable energy users to implement the adaptation required to achieve these goals without serious disruption to California's economy and the lives of its residents.

Because longer time horizons necessarily increase uncertainty, CEC staff has been reluctant to use the term "forecast" to describe possible energy demand to 2050. The Demand Scenarios Project can address many uncertainties by creating multiple sets of projections. No set of energy demand projections will provide the needed clarity to support major long-term commitments or investment decisions. As a result, staff has chosen to reserve the term "demand forecast" for the existing 15-year time horizon that the CPUC and ISO use to make commitments for new generating resource development or new transmission lines. Staff adopted the term "demand scenarios" to describe a set of longer-term projections to inform thinking about the implications of achieving long-term goals.

The CEC formally began a Demand Scenarios Project as part of the *2021 Integrated Energy Policy Report (IEPR)* cycle. The analysis, scenarios, and results were finalized and presented publicly at a workshop April 7, 2022. Planning for a second cycle of demand scenarios work was launched in fall 2022. By summer 2023, a team of staff and contractors was assembled with the objective of covering all sector/fuel combinations for several scenarios and some key sensitivities. Two public workshops were held to provide results and receive comments about the completed assessments. This report is the culmination of the second demand scenarios cycle.

Purpose

Over the decades, CEC products have evolved to meet internal needs, the needs of partner agencies, and the needs of policy makers. The recent increasing policy and planning focus on GHG reductions to address climate change has accentuated the need for developing longer-term demand projections and supply-side consequences for all energy types. Although developing a set of demand scenarios has intrinsic value, this value is enhanced when demand scenarios are assessed for supply-side and GHG consequences. For example, using the official demand forecast time horizon of 10 or 15 years leaves unknown what lies beyond. Establishing an assessment time horizon out to 2050 was explicitly designed to understand longer-term consequences of the statutory economywide goals and individual control measures proposed for adapting energy use.

Preliminary projections in the Demand Scenarios Project confirmed informed but qualitative estimates that the electrification of building loads would lead to shifts from traditional system electrical hourly load peaks in the summer to the winter season. In the results for this cycle, hourly load projections show that this shift happens to nearly all planning areas and all scenarios by the early to middle 2040s. This shift has large implications for the mix of generating resources and the reliance on imports needed to serve electric load reliably in the winter season.

Building electrification is commonly characterized as a shift from pipeline gas to electricity, neglecting the role that propane plays in much of rural California without pipeline gas service. Residential propane energy usage is only about 10 percent as large as pipeline gas in annual energy terms, and commercial usage is an even smaller proportion compared to pipeline gas usage. However, propane has qualities that differ from pipeline gas. Propane is distributed by hundreds of small businesses across California, and there are no industry protections for these distributors like those that exist for the pipeline gas utilities under the CPUC's jurisdiction.

Propane also has reliability qualities that will be hard for electricity to match given the inherent vulnerability of the electric distribution system, especially in forested, sparsely populated regions of the state. Including propane in the demand scenarios scope directs attention to the unique issues surrounding this fuel type, which is a relatively small contributor to statewide GHG emissions but vital to hundreds of thousands of end users.

Demand scenario specifications and their quantitative assessments, which provide objective, independent information, are vital inputs into setting or periodically reassessing California's energy and GHG emission reduction goals or the need for incentives or programs that target customers and industries that may not adapt through market forces alone.

Relations to SB 100 and Interagency Collaboration

Senate Bill 100 (De León, Chapter 312, Statutes of 2018) requires that retail electric sales in California be 100 percent renewable or otherwise from non-carbon-emitting generating facilities by 2045. Electric generation supply-side studies require demand projections to determine the quantity of generating resources and the capabilities of the system to match the growth and variability of future demand. The first round of the periodic SB 100 assessments was initiated in advance of the launch of the CEC staff Demand Scenarios Project, so the demand projections and the supply-side assessments were conducted using the modeling capabilities of the firm Energy and Environmental Economics. In this cycle of SB 100 assessments, demand scenarios projections were used. Linking demand scenarios projections to the SB 100 project required methodological extensions and interagency coordination beyond what had been anticipated.

Senate Bill 100 Needs

During the extended phase of developing supply-side scenarios to be assessed within SB 100 reporting, it became clear that developing one or more scenarios featuring high levels of demand response and load flexibility would also be required. These demand-side capabilities were to be assessed for the ability to displace the quick-ramping capabilities of some existing gas-fired generating facilities. Satisfying the electricity resource planning requirements of SB 100 meant that several improvements in demand scenarios capabilities were required.

The first improvement addresses the need for the Demand Scenarios Project to develop hourly loads out to at least 2045. The basic framework for hourly electric load projections had been developed by CEC forecasting staff, so the baseline hourly load projection method and hourly load impacts of load modifiers were available. However, resource constraints and less extensive historical data meant that hourly load had only been developed for the three investor-owned utilities (IOUs) transmission access regions within the California ISO area and not for the four publicly owned utility (POU) planning areas. To satisfy SB 100 supply-side modeling needs, hourly load projection capabilities had to be extended to these POU planning areas for the first time.

The second improvement develops the load flexibility inputs into the supply-side resource mix, rooting them in the fundamental mix of hourly load patterns at a highly disaggregated level. In satisfying one of the Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) requirements to develop a 2030 goal for demand response programs, the CEC had developed the projection capability to make annual demand response capacity potential projections. Extending these projection capabilities to at least 2045 and improving links to hourly load patterns of the various customer end use sectors came under the wing of the Demand Scenarios Project. The project also focused on adapting existing knowledge of what proportion of such loads would be willing to enlist in load flexibility programs, and at what cost.

This increase in scope for electricity-only topics for SB 100 was accomplished, and projections were delivered to the supply assessment team of the SB 100 project. At the time of writing this report, the SB 100 assessment is still underway. Staff expects results to be included in the final SB 100 report.

Interagency Coordination

In the initial demand scenario cycle, the SB 100 management team designed and conducted analysis largely through internal CEC processes. During this second cycle, it became apparent that the choice by the SB 100 management team to use demand scenario projections as a key input into the SB 100 modeling would require increased communication and collaboration with CPUC and CARB.

Demand scenarios and sensitivity assessments can uncover consequences of current policies that could create unexpected consequences if left unchanged for extended periods. As an example, there has been a vigorous debate within CPUC proceedings about the specifics of net metering and the pricing of exports to the grid for behind-the-meter (BTM) solar photovoltaic (PV) installations on end-use customer rooftops. Advocates for more favorable rate treatment tout the reliability advantages and bill reduction benefits relative to IOU rates.

Detractors point to the cost shift from PV systems owners to nonparticipating customers and the inefficiency of small BTM PV systems compared to large utility-scale solar PV projects. In this cycle, creating a scenario with reduced costs and extension of the existing federal investment tax credit beyond the current expiration date was found to create so much electric generation that output during the hours of maximum production exceeded the total load on the entire California ISO system on several spring days when air-conditioning and space-heating needs are low. Whether this outcome is a problem depends upon the electric resource mix and the flexibility of system operators to accommodate a drastic reduction in traditional minimum load levels. This finding adds a dimension to the ongoing rooftop PV debate.

These scenarios provide a sense of how easy or difficult it may be to achieve various goals and provide insights motivating development of new analytic capabilities. For example, in this cycle CARB staff requested a sensitivity to the original Policy Scenario that shifted the mix of ZEV fuel more toward hydrogen and less toward electricity than the Policy Scenario originally selected for SB 100. The SB 100 management team agreed with CARB’s request, and it directed that the electrolysis electric load to produce this hydrogen be “grid-friendly,” meaning that it should be flexible enough to limit stress during peak load hours on the electric grid. Staff implemented this constraint to mean that electrolyzer capacity should largely operate when electric generating capacity was not required to satisfy traditional end-user loads.

Since the results of demand scenario hourly electric load projections had been found to shift from summer to winter peaking, these results meant that a historical pattern of usage as typically used in production simulation modeling wasn’t appropriate. Staff developed a new tool that created a mix of various electrolyzer types with time-varying output capabilities, combined with monthly end-user hydrogen usage requirements. This tool allowed for integration into supply-side production simulation models to determine the optimal hourly load impacts of hydrogen production consistent with underlying assumptions of electric generation and storage resource mixes in specific SB 100 scenario assessments.

Although the coordination discussions were critical for successful analysis, tackling these specific SB 100 interests in specific energy demand topics slowed down the intended schedule and resulted in some reductions in scope of the original range of scenario assessments.

A word about terminology is in order. This report uses a convention adopted by the CPUC in the 1980s to distinguish between fuel substitution (changing between two CPUC-regulated fuels), versus fuel switching (changes involving one CPUC-regulated fuel and one or more non-regulated fuels). This means changes from pipeline gas to electricity is fuel substitution, and changes from pipeline gas to hydrogen is fuel switching.

CHAPTER 2: Scenario Design

Overview of Demand Scenarios

This chapter provides an overview of the scenarios designed and assessed in the second cycle of the Demand Scenarios Project. Detailed input assumptions and modeling tools are discussed in later chapters. Demand scenarios are projections of energy consumption for various fuels that quantify the impact of some of the energy policies and programs that are needed to decarbonize California's economy. These scenarios focus on the long-term planning horizon of 2050. Three demand scenario types with multiple sensitivities were developed. These projections are a critical component of the analyses required by SB 100, which assesses the decarbonization of the electric generation sector.

The CEC demand scenarios aim to measure the long-term energy consumption impacts of existing rules, regulations, and policies, with some limited incorporation of additional energy efficiency, fuel substitution, and transportation electrification concepts not yet through the funding or regulatory approval processes. To understand the contribution to state decarbonization goals, these energy consumption impacts are translated into GHG emission projections. Any gaps (differences) between demand scenario projections and state GHG emission goals highlight the need for supply-side emissions reductions, further policy development, new demand-side program designs, or additional incentives within existing programs to meet California's climate change goals. By analyzing demand scenarios, potential gaps, and opportunities for policy actions to accelerate decarbonization can be identified.

The outputs for each demand scenario or any sensitivity based on that scenario include annual energy demand for all fuel types and annual GHG emissions by fuel type for all major sectors. Following the approach used in the 2021 Demand Scenarios assessment cycle, staff and Evolved Energy Research (EER, a part the contractor team supporting this project) developed the Demand Scenarios Model (DSM) that integrates projections from internal CEC demand forecast and load modifier tools with EER's EnergyPATHWAYS (EP) modeling tool. The EER model augments CEC modeling capabilities with other sectors/fuels not addressed in current CEC modeling tools. The CEC tools produce results for electricity and pipeline gas for all major customer sectors (residential and commercial buildings, industry, agriculture, and other nontransportation end users, plus all the fuels used in transportation).[1]

The economic, demographic, and other inputs driving energy demand projections, consistent with CEC modeling assumptions, are used in the EP model. The results from CEC models and the complementary results from the EP model are integrated into the new DSM to provide complete coverage of all sectors/fuels for seven electric planning areas comprising nearly all

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[1] The Demand Scenarios project replaces the older term natural gas with pipeline gas - a term that is encompassing of more constituents such as methane whether natural or artificial, digester gas, hydrogen, or synthetic methane.

the state.[2] The energy outputs are fed into the GHG emissions tool, which calculates the annual emissions by sector and fuel type for each scenario.

In contrast to the 2021 Demand Scenarios modeling cycle, hourly electric load projections were developed from 2023 to 2050 for each of the seven electric planning areas. As is the case in the CEC demand forecasting practice, annual electricity consumption at an end-use level is coupled with unitized 8760 load profiles to produce hourly projections by numerous sector/end-use combinations. The profiles are summed hour by hour across all categories of consumption to create a system total by planning area. Finally, the demand for the system is scaled up for transmission and distribution losses to produce an hourly "managed net load" comparable to adopted CEC electric demand forecasts. This scaling enables the annual electricity consumption and hourly electric load of each scenario to be used in electricity resource planning studies employing capacity expansion and production simulation models.

Scenario Types Definitions

As part of developing the long-term demand scenarios, staff collaborated with the contract team (Verdant and its subcontractors EER and Jai J Mitchell Analytics [JJMA]) to develop the detailed specifications of the demand scenarios. Staff envisioned three types of scenarios for this project.

1. Reference Scenario

- This is a business-as-usual scenario starting from a CEC-adopted, managed electricity and pipeline gas demand forecast extrapolated to 2050. The Reference Scenario uses the same assumptions as the 2023 IEPR-adopted electricity planning forecast and the complementary pipeline gas forecast, extended through 2050. All other sector/fuel projections, whether developed through CEC staff transportation forecasts or contractors modeling tools (EnergyPATHWAYS), use consistent input assumptions, where applicable.
- This scenario assumes continuation of the same set of standards, programs, and policies reflected in the CEC-adopted managed demand forecast with the same degree of policy alignment.

2. Policy Scenario

- The second scenario type includes the same standards, programs and policies that are in the Reference Scenario but includes a higher level of compliance, as well as a few policies well advanced in the regulatory approval process. Some other technologies are included where forecasting staff finds a sufficient case for adoption in later years based on sufficient technology readiness levels and other climate goals.

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[2] Two areas of California served by electric utilities headquartered outside of California are excluded from the assessments. Several Northern California areas are served by PacifiCorp, and portions of the Lake Tahoe region are served by Nevada Power. Generally, these areas are not served by pipeline gas, and the principal alternative to electricity is propane, provided by independent distributors.

- New policies such as federal efforts to encourage decarbonization, for example, the industrial subsidies for fuel switching in the Inflation Reduction Act, are included in this scenario.

3. Enhanced Policy Scenario

- The third scenario type includes additional programs, policies, and assumptions added onto those already included in the Policy Scenario.
- The Enhanced Policy Scenario is aspirational and designed to show the need for further demand-side policy development, new program designs, additional incentives within existing programs, or additional approaches not yet robustly quantified that could contribute substantial GHG emission reductions.
- Although this scenario is expected to make further progress toward California GHG emission reduction goals, further policies and implementing programs will be needed.

Table 1 lists the three main scenarios and several sensitivities that were assessed within the Demand Scenarios Project.

Table 1: Demand Scenarios

Scenario Number	Demand Scenario Types	Demand Scenario/Sensitivity
1	Reference Scenario	Reference Scenario
2	Policy Scenario	High Electrification (HE)
3	Policy Scenario (Sensitivity)	High DER & DF
4	Policy Scenario (Sensitivity)	High Hydrogen Use
5	Policy Scenario (Sensitivity)	Managed Light-Duty Charging
6	Enhanced Policy Scenario	High Electrification (HE)
7	Enhanced Policy Scenario (Sensitivity)	Pipeline Hydrogen

Source: CEC staff

Scenario Modeling Framework

CEC staff’s scenario development process included developing a framework to identify sectors/fuels projections that could be developed by CEC staff using work already completed as part of the 2023 IEPR cycle or could be assessed using the CEC’s existing modeling tools. The detailed specifications for the remaining fuel projections were developed by the contractor in consultation with CEC staff. The modeling framework in Table 2 has been used in developing the various scenarios.

The first column shows the various sectors, followed by the inputs developed for each sector and the various models used. For all the sector models, the process involved extending existing CEC demand analysis tools to 2050 such as stationary sector demand forecast models, programmatic tools for Additional Achievable Energy Efficiency (AAEE) and Additional Achievable Fuel Substitution (AAFS), other AAFS using Fuel Substitution Scenario Analysis Tool

(FSSAT), BTM PV and battery storage tools, and transportation demand forecasting models and tools.

The baseline forecast that is used as a starting point for the demand scenarios was prepared for the *2023 IEPR*. Across all sectors, the baseline forecast process is driven by economic and demographic projections.

For efficiency and fuel substitution, a wide range of committed or reasonably expected to occur efficiency program- and standards-induced savings and fuel substitution impacts could be devised. Developing a scenario requires adjusting the baseline projections for the incremental impacts of AAEE and AAFS programs. The Demand Scenarios Project chose to select from among the AAEE and AAFS scenarios developed for the *2023 IEPR* in formulating demand scenario specifications. These will be discussed in the subsequent chapters.

BTM PV and PV paired with storage retrofits were forecasted using the CEC's California-specific version of National Renewable Energy Laboratory (NREL's) Distributed Generation Market Demand Model (dGen™). Stand-alone BTM storage retrofits and distributed generation additions resulting from Title 24 energy standards are forecasted in separate models.

As noted in the far-right column, there are instances in which some niche energy consumption end-user types have not been modeled by the CEC staff. In this cycle, the EP model was used to develop these projections. In addition, there were instances in which CEC transportation modeling of some end-user/fuel types was assessed only on a statewide basis, requiring a new effort to disaggregate projections to electric planning areas. Finally, there were a few instances in which assessment of the *CARB 2022 Scoping Plan* control measures required supplemental analyses on an ad hoc basis outside the formal models. The goal of Table 2 is to provide a reasonably comprehensive overview of the various tools used to assess the full scope of customer sector/fuel type combinations as part of this effort. Many of the entities following CEC demand forecasting or load modifier assessments will be familiar with these tools.

Table 2: Modeling Framework

Sectors	Inputs	Electricity	Pipeline Gas	Additional Fuels in Transportation	Additional Fuels Outside Transportation
Res/Com/Ind	Baseline Forecast	Res/Com/Ind Models	Res/Com/Ind Models	N/A	EP
Res/Com/Ind	Energy Efficiency Impacts	AAEE/AAFS Programmatic Tool	AAEE/AAFS Programmatic Tool	N/A	EP
Res/Com/Ind	Fuel Substitution Programmatic Impacts	AAEE/AAFS Programmatic Tool	AAEE/AAFS Programmatic Tool	N/A	EP
Res/Com/Ind	Other Fuel Substitution	FSSAT	FSSAT	N/A	FSSAT & EP
Transportation	Baseline Forecast	Transportation Models	Transportation Models	Transportation Models & EP Model	N/A
Ag & Water Pumping	Baseline Forecast	Ag Model	Ag Model	N/A	EP
Ag & Water Pumping	Energy Efficiency Impacts	AAEE/AAFS Programmatic Tool	AAEE/AAFS Programmatic Tool	N/A	EP
TCU	Baseline Forecast	TCU Model	TCU Model	N/A	EP
PV/Storage	Baseline Forecast	dGen, Title 24, Standalone Storage Models	N/A	N/A	N/A

Note: EP refers to the EER's EnergyPATHWAYS model. Res/Com/Ind refers to Residential, Commercial, Industrial, respectively.

Source: CEC staff

Table 3, Table 4, and Table 5 summarize the input assumptions at a high level for each of the three scenarios using terminology and abbreviations used in the demand forecasting process. Generally, the nonpolicy assumptions for each sector (such as economic and demographic projections, retail energy prices, and so forth) remain the same in all scenarios. The policy-based assumptions (building and appliance standards, utility-funded programs, compliance with prospective policies, and so forth) become more aggressive from reference to policy and from policy to enhanced policy. A "baseline" projection is generated with the nonpolicy assumptions of the *2023 IEPR* that is common across scenarios, while the aggregate energy impacts of policy assumptions and adjustments for each scenario are quantified using various supplemental tools, with increasingly large impacts through time. The details of these scenario-specific policy assumptions and the ways that related energy impacts are quantified will be covered in subsequent chapters.

Table 3: Reference Scenario Framework

Sectors	Inputs	Electricity	Pipeline Gas	Additional Fuels in Transportation	Additional Fuels Outside Transportation
Res/Com	Baseline Forecast	*2023 IEPR* Baseline Forecast Extended To 2050	*2023 IEPR* Baseline Forecast Extended To 2050	N/A	EP
Res/Com/Ind	AAEE Impacts	BAU (Scenario 3)	BAU (Scenario 3)	N/A	EP
Res/Com/Ind	AAFS Programmatic	BAU (Scenario 3)	BAU (Scenario 3)	N/A	EP
Res/Com	AAFS FSSAT	Scenario 3	Scenario 3	N/A	FSSAT & EP
Industrial	Baseline Forecast	*2023 IEPR* Baseline Forecast Extended To 2050 Modified by Refinery Adjustments	*2023 IEPR* Baseline Forecast Extended To 2050 Modified by Refinery Adjustments	N/A	EP
Transportation	Baseline Forecast	*2023 IEPR* Baseline Consumption Forecast Extended To 2050+ AATE Scenario 3	*2023 IEPR* Baseline Consumption Forecast Extended To 2050+ AATE Scenario 3	Transportation Models & EER Model	N/A
Ag & Water Pumping	Baseline Forecast	*2023 IEPR* Baseline Forecast Extended To 2050	*2023 IEPR* Baseline Forecast Extended To 2050	N/A	EP
Ag & Water Pumping	AAEE Impacts	BAU (Scenario 3)	BAU (Scenario 3)	N/A	EP
TCU	Baseline Forecast	*2023 IEPR* Baseline Forecast Extended To 2050	*2023 IEPR* Baseline Forecast Extended To 2050	N/A	EP
PV/Storage	Baseline Forecast	*2023 IEPR* PV/Storage Forecast Extended To 2050	N/A	N/A	N/A

Note: EP refers to EER's EnergyPATHWAYS model. Res/Com/Ind refers to Residential, Commercial, Industrial, respectively. "2050 Extension" refers to the 2023 IEPR forecast extended to 2050.

Source: CEC staff

Table 4: Policy Scenario (PS) Framework

Sectors	Inputs	Electricity	Pipeline Gas	Additional Fuels in Transportation	Additional Fuels Outside Transportation
Res/Com	Baseline Forecast	*2023 IEPR* Baseline Forecast Extended To 2050	*2023 IEPR* Baseline Forecast Extended To 2050	N/A	EP
Res/Com/Ind	AAEE Impacts	BAU (Scenario 3)	BAU (Scenario 3)	N/A	EP
Res/Com/Ind	AAFS Programmatic Impacts	Scenario 4	Scenario 4	N/A	EP
Res/Com	FSSAT	Scenario 4	Scenario 4	N/A	FSSAT & EP
Industrial	Baseline Forecast	*2023 IEPR* Baseline Forecast Extended To 2050 Modified by Refinery Adjustments	*2023 IEPR* Baseline Forecast Extended To 2050 Modified by Refinery Adjustments	N/A	EP
Industrial	FSSAT	PS Specifications	PS Specifications	N/A	FSSAT & EP
Transportation	Baseline Forecast	PS Specifications	PS Specifications	Transportation Models & EP	N/A
Ag & Water Pumping	Baseline Forecast	*2023 IEPR* Baseline Forecast Extended To 2050	*2023 IEPR* Baseline Forecast Extended To 2050	N/A	EP
Ag & Water Pumping	AAEE Impacts	BAU (Scenario 3)	BAU (Scenario 3)	N/A	EP
Ag & Water Pumping	FSSAT	PS Specifications	PS Specifications	N/A	FSSAT & EP
TCU	Baseline Forecast	*2023 IEPR* Baseline Forecast Extended To 2050	*2023 IEPR* Baseline Forecast Extended To 2050	N/A	EP
PV/Storage	Baseline Forecast	*2023 IEPR* PV/Storage Forecast Extended To 2050	N/A	N/A	N/A

Note: EP refers to EER EnergyPATHWAYS model. Res/Com/Ind refers to Residential, Commercial, Industrial, respectively, and PS refers to Policy Scenario specifications described in Chapter 3. "2050 Extension" refers to the 2023 IEPR forecast extended to 2050.

Source: CEC staff

Table 5: Enhanced Policy Scenario (EPS) Framework

Sectors	Inputs	Electricity	Pipeline Gas	Additional Fuels in Transportation	Additional Fuels Outside Transportation
Res/Com	Baseline Forecast	2050 Extension	2050 Extension	N/A	EP
Res/Com/Ind	AAEE Impacts	Scenario 6	BAU (Scenario 3)	N/A	EP
Res/Com/Ind	AAFS Programmatic Impacts	Scenario 5	Scenario 5	N/A	EP
Res/Com	FSSAT Impacts	Scenario 5	Scenario 5	N/A	FSSAT & EP
Ind	Baseline Forecast	2050 Extension Modified by Refinery & Oil Extraction Adjustments	2050 Extension 2050 Modified by Refinery & Oil Extraction Adjustments	N/A	EP
Ind	Other Fuel Substitution	EPS Specifications	EPS Specifications	N/A	EP
Transportation	Baseline Forecast	EPS Specifications	EPS Specifications	Transportation Models & EP	N/A
Ag & Water Pumping	Baseline Forecast	2050 Extension	2050 Extension	N/A	EP
Ag & Water Pumping	AAEE Impacts	Scenario 6	Scenario 3	N/A	EP
Ag & Water Pumping	Other Fuel Substitution	EPS Specifications	EPS Specifications	N/A	FSSAT & EP
TCU	Baseline Forecast	2050 Extension	2050 Extension	N/A	EP
PV/Storage	Baseline Forecast	2050 Extension	N/A	N/A	N/A
PV/Storage	Baseline Forecast with Additional Incentives	EPS Specifications	N/A	N/A	N/A

Note: EP refers to EER EnergyPATHWAYS model. Res/Com/Ind refers to Residential, Commercial, Industrial, respectively, and EPS refers to Enhanced Policy Scenario specifications described in Chapter 3. “2050 Extension” refers to the 2023 IEPR forecast extended to 2050.

Source: CEC staff

CHAPTER 3:
Method, Inputs, and Assumptions

This chapter provides details of the assessments of the scenarios and sensitivities described in Chapter 2. For each of the major customer sectors, the method used to assess the scenario is described. In cases where the method simply involves using different inputs for a sector's CEC demand forecasting model or an alternative variant of a load modifier tool, explanations are brief with references to more in-depth documentation. In cases where new modeling tools are used, more in-depth methodological descriptions are included.

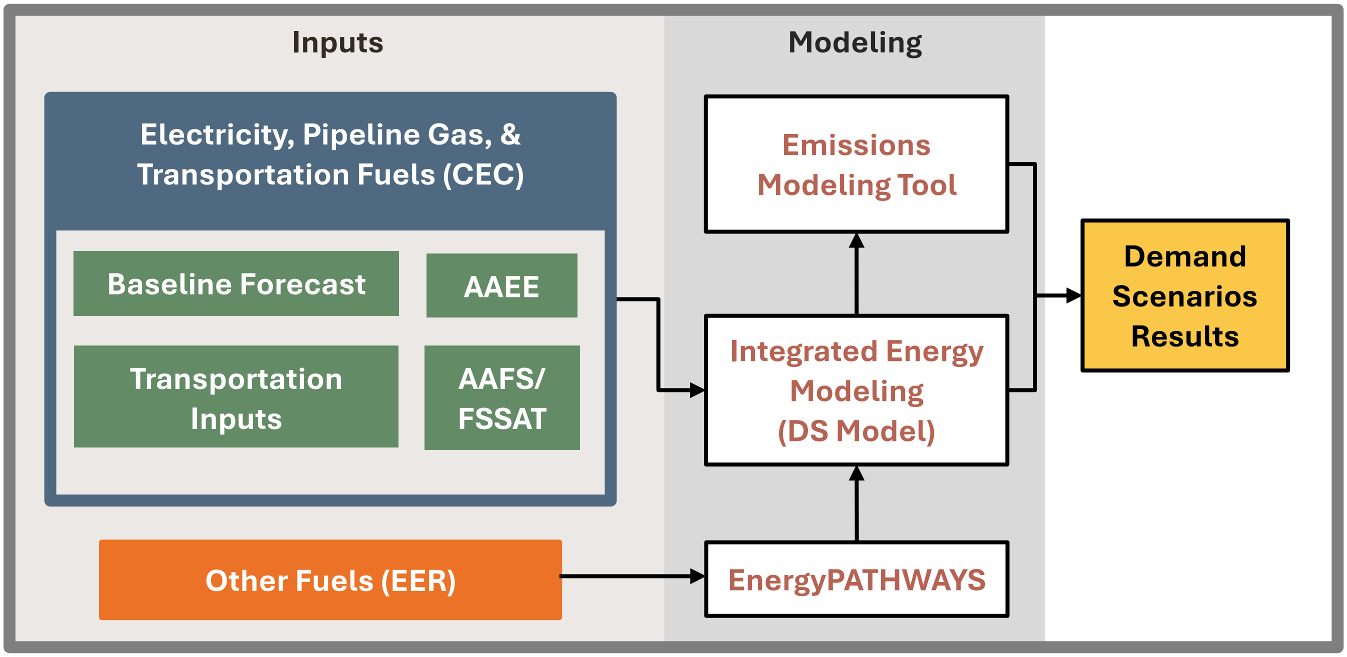
Similarly, when a scenario relies upon an assessment of a particular program or policy that has already been documented as part of the *2023 IEPR*, such as AAEE Scenario 3, then this chapter will direct the reader to documentation prepared as part of that demand forecasting process of that proceeding. When new policies, programs, or variants of CARB 2022 Scoping Plan control measures are part of a scenario design, the inputs and assumptions will be documented in greater depth.

Overview of the Assessment Approach

Where data are available, the scenario assessment uses results from the CEC demand forecasting model and load modifier tools, including electricity and pipeline gas projections in buildings, agriculture and industry, and transportation demand forecasting models for all fuels. All fuel consumption projections for other sector/fuel type combinations are assessed using EER's EP model. Projections from these two sources are integrated to form a composite projection for each fuel type, in each sector, in each electric planning area, for each year 2023 through 2050 for each scenario or sensitivity.

For electricity, these annual energy projection results at various levels of granularity are disaggregated into 8760 hourly results by allocating annual electric sales using unitized hourly load profiles, scaled up for transmission and distribution losses. Then all sources for each hour are summed hour by hour to provide coincident hourly planning area load projections. These results are conceptually compatible with the CEC hourly demand forecast "managed net load" projections. Figure 1 depicts this flow.

Figure 1: Integrated Modeling Flow Chart



Electricity, pipeline gas, and transportation fuels datasets from the CEC and datasets on other fuels (from EER) are aggregated and fed into the Integrated Energy Model (DS Model). The resulting outputs are then used to run the Emissions Modeling Tool.

Source: CEC staff

Table 6 provides a detailed identification for each sector/fuel type combination whether the source is CEC or EER models and tools. For Table 6, the rows are fuel types, and the columns are the familiar customer sectors. In CEC forecasting practice, industrial typically includes oil and gas extraction and petroleum refining, but these are shown separately to be clear about sector/fuel combinations where the EER model plays an important role.

Table 6: Source and Fuel Type and Sector

Fuel	Agriculture	Commercial	Industrial	Oil & Gas Extraction	Petroleum Refining	Residential	TCU	Transportation
Electricity	CEC*	CEC	CEC	CEC	CEC	CEC	CEC	CEC
Natural Gas	CEC	CEC	CEC	CEC	CEC	CEC	CEC	CEC
Diesel	EP	EP	N/A	EP	N/A	EP	N/A	CEC*
Gasoline	EP	EP	EP	N/A	N/A	N/A	N/A	CEC
Steam	EP	EP	EP	EP	EP	N/A	EP	N/A
Biomass/ Wood	N/A	EP	N/A	N/A	N/A	CEC	N/A	N/A
LPG	N/A	EP	EP	EP	N/A	CEC	N/A	N/A
Coal	N/A	N/A	EP	N/A	N/A	N/A	N/A	N/A
Hydrogen	CEC**	N/A	CEC**	CEC**	CEC**	N/A	N/A	CEC*
Still gas	N/A	N/A	N/A	N/A	EP	N/A	N/A	N/A

***CEC data are supplemented by EP.**
****CEC assessment includes only incremental use of hydrogen based on scenario specifications.**

Source: CEC staff

Building Electrification

CEC staff based the building electrification scenarios on the *2022 CARB Scoping Plan* and the AAEE and AAFS load modifier scenario assumptions of the 2023 IEPR demand forecast. All the building scenarios used the Fuel Substitution Scenario Analysis Tool (FSSAT), which accounts for the impacts from combustion control measures such as the California Air Resources Board's (CARB's) zero-emission GHG appliance standards (ZEAS) for space and water heating above the impacts assumed from existing programmatic and incremental codes and standards AAFS and AAEE efforts enumerated in the *2023 IEPR*.[3] The Reference, Policy, and Enhanced Policy Scenarios adapt the *2022 CARB Scoping Plan* assumptions for buildings where appropriate. These additional achievable assumptions included in the demand scenarios capture a range of incremental market potential impacts beyond what is included in the baseline demand forecast but are within the range of what is reasonably expected to occur.

Table 7 summarizes the input assumptions used for the Reference, Policy, and Enhanced Policy Scenarios. The assumptions are broken down by additional achievable programmatic scenarios, and the supplementary modeling of the zero-emission appliance standards impacts above the programmatic impacts (referred to as "FSSAT-ZEAS AAFS").[4] The higher-numbered scenarios assume more aggressive, optimistic, and speculative energy impacts. All the scenarios have the same programmatic AAEE gas scenario assumptions but vary on the programmatic AAEE electric and programmatic AAFS assumptions.[5]

This scope of input assumptions in Table 7 captures reasonably expected to occur decarbonization policy mechanisms. For example, the FSSAT-ZEAS-AAFS assumptions for the Reference and Policy Scenarios reported reflect the assumptions used for the AAFS scenarios adopted in the *2023 IEPR*. Both demand scenarios model GHG control measures included in the 2022 State Strategy of the State Implementation Plan (SIP), which establishes that 100 percent of the sales of space- and water-heating devices by 2030 must comply with CARB's concept of a GHG emission standard for new or existing residential and commercial buildings.[6] CARB began public engagement for the zero-GHG emission space and water heater measure in 2023. The demand scenarios characterize CARB's concept of a zero-GHG emission appliance standard going into effect in 2030. Separate from CARB's proposed standards, air quality

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[3] See pp. 115–121 in Bailey, Stephanie, Jennifer Campagna, Mathew Cooper, Quentin Gee, Heidi Javanbakht, and Ben Wender. 2023. *2023 Integrated Energy Policy Report.* California Energy Commission. Publication Number: CEC-100-2023-001-CMF, https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2023-integrated-energy-policy-report.

[4] See Appendix A, Table A-1, which provides detailed zero-emission appliance assumptions used for the FSSAT-ZEAS-AAFS scenarios.

[5] For example, programmatic AAEE and AAFS scenario 3 includes IOU energy efficiency and low-income and fuel substitution programs as well as POU programs, Codes and Standards impacts from Title 24 Building Standards and Title 20 California and federal appliance standards, beyond utility programs such as the Technology and Equipment for Clean Heating (TECH) program and the Buildings Initiative for Low-Emissions Development (BUILD) program, and the Equitable Building Decarbonization program.

[6] CARB. September 2022. *2022 State Strategy for the State Implementation Plan*. Pages 101–103, https://ww2.arb.ca.gov/sites/default/files/2022-08/2022_State_SIP_Strategy.pdf.

management districts (AQMDs), such as the Bay Area and South Coast AQMDs, have adopted (or plan to adopt) zero-nitrogen oxides (NOx) emission appliance standards for specific classes of combustion devices. On March 15, 2023, the Bay Area AQMD Board of Directors adopted zero-emission NOx standards that go into effect for small water heaters in 2027 and space heating in 2029.[7] The South Coast AQMD adopted its zero-NOx emission appliance standards June 7, 2024,[8] for large water heaters, small boilers, and process heaters and intends to adopt space and water heater zero-NOx emission appliance standards in June 2025.[9]

All building scenarios employ some of the building decarbonization assumptions used in the *2022 CARB Scoping Plan* (Scoping Plan).[10] The Scoping Plan assumes new residential and commercial buildings will be all-electric in 2026 and 2029, respectively. For existing buildings, 80 percent of *all* appliance sales (that is, when appliances are replaced at the end of life) will be electric by 2030, and appliance sales will be 100 percent electric for the residential sector in 2035 and 2045 for the commercial sector.

The Scoping Plan assumes more comprehensive building electrification than the assumptions reported in Table 7. In demand scenarios, only the EP Scenario models fuel substitution for end uses other than space and water heating. The Reference and Policy Scenarios assume the same new construction assumptions but strictly for space and water heaters. The Enhanced Policy Scenario incrementally adds the impacts from electrifying other end uses such as cooking, clothes drying, and residential propane end uses. As such, it is only residential propane end uses and end uses other than space and water heating where the Enhanced Policy scenario assumptions match those assumed in the *CARB 2022 Scoping Plan*.

The contributions from programs and incremental codes and standards (referred to as "programmatic") to the building assumptions of the demand scenarios are enumerated in the 2023 IEPR Demand Forecast.[11] They include impacts from future updates of non-emissions-based building standards, non-emissions-based appliance regulations, and new or expanded energy efficiency and fuel substitution programs. The 2023 programmatic AAEE and AAFS scenarios help capture a range of incremental market potential impacts beyond what are

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[7] Bay Area AQMD press release. March 15, 2023. "Air District Strengthens Building Appliance Rules to Reduce Harmful NOx Emissions, Protect Air Quality and Public Health," https://www.baaqmd.gov/~/media/files/communications-and-outreach/publications/news-releases/2023/barules_230315_2023_003-pdf.pdf?la=en&rev=73fdaf7bb91b475b9b7913c133c31737.

[8] South Coast AQMD press release. June 7, 2024. "South Coast AQMD Approves Rule to Accelerate the Transition to Zero-Emission for Building Water Heaters" http://www.aqmd.gov/docs/default-source/news-archive/2024/1146-2-June-7-2024.pdf?sfvrsn=9.

[9] The scheduled June 6 Public Hearing date is subject to change. South Coast AQMD. Proposed Amended Rules (PAR) 1111 and 1121. https://www.aqmd.gov/home/rules-compliance/rules/scaqmd-rule-book/proposed-rules/rule-1111-and-rule-1121 (Accessed May 6, 2025).

[10] California Air Resources Board. December 2022. *Final 2022 Scoping Plan*: Appendix C: AB 197 Measure Analysis. (pp. 15–16) https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-appendix-c-ab-197-measure-analysis.pdf.

[11] California Energy Planning Library: CED 2023 Demand Side Modeling. See "Additional Achievable Energy Efficiency and Additional Achievable Fuel Substitution Forecast," https://www.energy.ca.gov/data-reports/california-energy-planning-library/forecasts-and-system-planning/demand-side-1.

included in the baseline demand forecast but are within the range of what is reasonably expected to occur.

Although not reported in Table 7, all scenarios assume the same final version of the 2023 IEPR baseline forecast and incorporate the zero-NOx emission appliance standards adopted by the South Coast AQMD (Amendments to Rule 1146.2) and Bay Area AQMDs (Amendments to Rules 9-4 and 9-6).[12] All scenarios reflect CEC staff's updated technology characterization assumptions used in the Energy Commission's Fuel Substitution Scenario Analysis Tool (FSSAT), which reflects data from the 2019 Residential Appliance Saturation Survey (RASS)[13] and the 2023 Potential and Goals Study.[14] CEC staff made these updates to reflect the best available data for the demand scenarios project. Incorporating these updates creates different impacts than the scenarios reported in the 2023 IEPR forecast despite using similar adoption assumptions.

Table 7: Summary of Building Scenario Assumptions

Scenario	AAEE Gas	AAEE Electric	AAFS	FSSAT-ZEAS AAFS
	Programmatic	**Programmatic**	**Programmatic**	**Modeling of combustion control measures**
Reference	Scenario 3	Scenario 3	Scenario 3	Scenario 3 (Space and water heating ZEAS in 2030)
Policy	Scenario 3	Scenario 3[a]	Scenario 4	Scenario 4 (Space and water heating ZEAS in 2030 with a slightly faster ramp rate)
Enhanced Policy	Scenario 3	Scenario 6	Scenario 5	Scenario 5 (includes fuel substitution of propane and all modeled end uses)

[a] The High DER/DF sensitivity of the Policy Scenario assumes programmatic electric AAEE Scenario 4, not Scenario 3.

Source: CEC staff

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[12] The 2023 IEPR Additional Achievable Fuel Substitution scenarios were based on the draft version of the 2023 IEPR forecast.

[13] The CEC periodically conducts surveys of residential customers to develop current statistics of end-use fuel share or specific technologies for a single fuel for most end-uses consuming electricity, pipeline gas or other fuels.

[14] The CPUC biennially conducts a Potential and Goals study to identify opportunities for energy efficiency measures that are cost effective from several perspectives – the customer, the utility, or societal. In recent studies, the CPUC has begun assessing the potential for fuel substitution measures in addition to energy efficiency measures.

Industrial Decarbonization

In this cycle of the demand scenarios project, CEC staff guided the development of an expanded version of the Agricultural and Industrial Module (Ag-Ind Fuel Substitution Module) in the Fuel Substitution Scenario Analysis Tool (FSSAT). The previous version simply provided a mechanism to modify the aggregate industrial and agricultural forecast results for AAEE and AAFS programmatic impacts. This early version had no industry-specific fuel substitution logic to shift specific end uses of pipeline gas to electricity or hydrogen in response to "what if" scenario inputs. This description is at a greater level of detail than other sectors in Chapter 3 because the Ag-Ind Fuel Substitution Module has not previously been used in CEC demand assessments nor documented in any other report.

The version used for this project quantifies fuel substitution from pipeline gas consumption to electricity and hydrogen consumption. Such fuel substitution covers the largest of the pipeline gas end uses, including process heat — both high and low temperature — and water heat. Several scenarios and sensitivities were constructed following the general design of the fuel substitution scenarios in other customer sectors. These assumptions use many of the control measures addressed in CARB's 2022 Scoping Plan but usually at a lower level of penetration.

This documentation contains five broad topic areas:

- A review of the basic features of the CEC staff industrial demand forecasting model and how the Ag-Ind Fuel Substitution Module coordinates with the baseline forecast
- An overview of the features of the Ag-Ind Fuel Substitution Module
- The design and assumptions for the inputs for the fuel substitution scenarios
- Use of the Ag-Ind Fuel Substitution Module and supplemental analysis to assess the impacts of a hydrogen pipeline sensitivity based on the Enhanced Policy Scenario
- Overview of results

Linkage to the CEC Industrial Demand Forecast

As with other economic sectors assessed in FSSAT modules, the Ag-Ind Fuel Substitution Module starts from the same industry disaggregation documented in the North American Industrial Classification System (NAICS) code,[15] energy type, end-use disaggregation, and planning area geography as used for the 2023 IEPR demand forecast.

Table 8 compares the baseline agriculture and industrial forecast granularity with that of the Ag-Ind Fuel Substitution Module.

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[15] *The North American Industrial Classification System* (NAICS) is a system that classifies non-residential economic activity. It follows the principle that producing units that use similar production processes should be grouped together.

Table 8: Comparison of Industrial Demand Forecast With Ag-Ind FSSAT Module

Variable	Baseline Forecast	Ag-Ind Fuel Substitution Module
Sector/industries	Agriculture and 46 Industries defined by NAICS codes	Same
Energy types	Electricity and pipeline gas	Electricity, pipeline gas, and hydrogen
Fuel substitution logic	None	Direct shift in end-use shares by fuel type as a user input
End uses	Seven including thermal	Nine, 6 of the 7 original end uses with thermal split into process heat-high, process heat-low, and water heat
Geographic disaggregation	Seven electric planning areas plus MKRP	Same
Forecast horizon	2040	2050

Source: CEC staff

The CEC agriculture and industrial models produce outputs at the CEC electric forecast zones (20) and hence CEC electric planning areas (8). All electric utilities above a basic size level report, on a quarterly time frame, monthly electricity sales by NAICS code to the CEC. All pipeline gas utilities report quarterly their monthly pipeline gas deliveries by NAICS code as well. Other pipeline gas marketers also report sales. Historical pipeline gas deliveries are allocated to electric forecast zones and planning areas as part of baseline forecasting. Formulating the baseline forecast model for pipeline gas for each of the electric planning areas is useful in assessing fuel substitution from pipeline gas to electricity because this additional electricity consumption must be provided on an electricity planning area basis to enable proper electric resource planning.

Although neither the Ag-Ind Fuel Substitution Module or the baseline CEC industrial models cover combustion of other fuels, such as petroleum coke, fuel oil, hydrogen, wood waste, and so forth, pipeline gas is the largest share of purchased energy. It is also the exclusive nonelectric fuel used in many industries.[16] Since neither the CEC industrial demand forecast nor the FSSAT Ag-Ind Fuel Substitution Module addresses these other fuels, EER's EP model is used to cover other fuels.

Parameters and Inputs Unique to the Ag-Ind Fuel Substitution Module

There are several parameters and input assumptions unique to the Ag-Ind Fuel Substitution Module. These are:

- The number and scope of end uses.
- The addition of hydrogen as a fuel choice displacing pipeline gas for some end uses.

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[16] CARB Emission Inventory data show that petroleum refining and cement production are the only industries with large consumption of nonelectric energy forms besides pipeline gas.

- The potential through time for end-use fuel substitution by NAICS-defined industries by planning area.
- The adoption rate through time of potential fuel substitution from pipeline gas to either electricity or hydrogen.
- The methods of production and distribution of hydrogen from point of production to point of use.

End-Use Scope

Table 8 indicates that the Ag-Ind Fuel Substitution module has nine end uses as opposed to seven in the underlying pipeline gas industrial forecast model. The thermal end use is partitioned into three more specific end uses essentially defining three specific purposes to replace the broad aggregate of "thermal." This more specific set of pipeline gas end uses is critical in determining what replacement fuels are most appropriate in displacing pipeline gas. APPENDIX B provides a detailed explanation of the data sources and processes in going from seven end uses to nine. In short, three "thermal" end uses called Process Heat-High, Process Heat-Low, and Water Heat are used in the Ag-Ind Fuel Substitution Module. Further, the shift from pipeline gas for these three end uses can be replaced only as follows:

Pipeline gas Process Heat-High to hydrogen

Pipeline gas Process Heat-Low to electricity

Pipeline gas Water Heat to electricity

Electric heat pumps are capable of generating hot water and steam under pressure up to about 150°C and are likely to be capable of higher temperatures in the future.[17] Hydrogen is more feasible for those process heat applications that require higher temperatures. These high-temperature applications using pipeline gas combustion would be far above the capabilities of any industrial heat pump. Research and development and subsequent commercialization of electric, non-heat-pump technologies might create more options in the future.

Fuel Substitution and Adoption Rate Inputs

The Ag-Ind Fuel Substitution module has input structures that allow each of the ag sector and the 46 industries to have their own unique pattern of fuel substitution potential and adoption rate through time. Due to data limitations, this capability is not fully implemented in this cycle of demand scenarios. Some industries that have greater baseline pipeline gas consumption have been characterized with specific potential and adoption rate inputs, but many smaller industries use generic growth assumptions for potential and adoption patterns.

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[17] de Boer, Robert et al. 2020. *Strengthening Industrial Heat Pump Innovation: Decarbonizing Industrial Heat.* https://orbit.dtu.dk/en/publications/strengthening-industrial-heat-pump-innovation-decarbonizing-indus

Computational Process

Fuel Substitution

Fuel substitution is computed for each one of the Ag and 46 NAICS code industries individually. The focus is on pipeline gas shifting to electricity or hydrogen, but refineries, oil extraction, and cement industries consume other fuels. For these industries, the capabilities come from EP.

The generic structure of the Ag-Ind Fuel Substitution Module is straightforward, although repeated several hundred times (47 industries, three end uses, eight planning areas). Direct fuel substitution from pipeline gas to electricity or hydrogen is computed for each one of the Ag and 46-NAICS code industries. Equation 1 defines the incremental electricity that is added by the displacement of pipeline gas. Similarly, Equation 2 described the incremental hydrogen that is added by the displacement of pipeline gas. Equation 3 shows how the baseline pipeline gas consumption is converted into the pipeline gas consumption following fuel substitution by the subtraction of these two sources of pipeline gas displacement.

Equation 1

$$Elec\ Added_i^j(t) = PG_i(t) \times Eu_i^j \times Adopt_{Ei}(t) \times EffConv_{Ei}$$

Equation 2

$$Hydrogen\ Added_i^j(t) = PG_i\ (t) \times Eu_i^j \times Adopt_{Hi}(t) \times Pot_{Hi}(t) \times EffConv_{Hi}$$

Equation 3

$$\begin{aligned} PG_i^{FS}(t) = PG_i^B(t) - PG_i^B(t) \times Eu_i^j \times Adopt_{Ei}(t) \times Pot_{Ei}(t) \\ - PG_i^B(t) \times Eu_i^j \times Adopt_{Hi}(t) \times Pot_{Hi}(t) \end{aligned}$$

Variables are as follows:

$PG_i^B(t)$ = Baseline pipeline gas forecast for industry i in year t, out to 2050

$PG_i^{FS}(t)$ = Baseline PG after FS for industry i in year t, out to 2050

Eu_i^j = end-use j fuel share for each industry i

$Pot_{Ei}(t)$ or $Pot_{Ei}(t)$ = Potential in year t for fuel substitution in end-use j for either fuel

$Adopt_{Ei}(t)$ or $Adopt_{Hi}(t)$ = Adoption in year t of potential by end-use j industry

$EffConv_{Ei}$ or $EffConv_{Hi}$ = KWh of electricity per therm of PG or KG H2 per therm of PG

Any hydrogen that is consumed must be produced, and all production methods require energy. For hydrogen produced using methods requiring electricity, in whole or in part, **Equation 4** defines the additional incremental electricity required when electricity is used to produce the hydrogen that is consumed.

Equation 4

$$ElecHydro_i^H(t) = Hydrogen\ Added_i^j(t) \times \sum EProd_i^k\ (t) \times ProdShare_i^k(t)$$

Variables:

$ElecHydro_i^H(t)$ = electricity consumed in the production of hydrogen in industry i year t

$Hydrogen\ Added_i^j(t)$ = Hydrogen added in industry i, end-use j, and year t

$EProd_i^k(t)$ = electricity usage per unit of hydrogen in industry i, production method k, in year t

$ProdShare_i^k(t)$ = production method share for industry i, method k, in year t

Hydrogen Production and Distribution

How hydrogen is produced and distributed is a critical component of the Ag-Ind Fuel Substitution Module for several reasons, including the following:

- Producing hydrogen requires a large amount of input energy.
- Alternative technologies for producing hydrogen can result in large or minimal GHG emissions.
- All commercially available methods of producing **green** hydrogen use electrolysis, which requires high levels of electric load.
- Getting hydrogen from the point of production to the point of use requires either onsite production, pipelines, trucking, or some combination of the three.

Boiled down to the essence, there are three practical methods for generating hydrogen. The first, steam methane reforming, strips hydrogen atoms from methane, producing gaseous hydrogen and carbon dioxide. The second is electrolysis of water, which produces gaseous hydrogen and oxygen. The third is pyrolysis of organic matter to produce hydrogen. However, where hydrogen is produced and how it gets from point of production to point of use introduce a complex set of options. Each set has unique electricity production costs and associated emissions (or other waste) from the production and distribution processes. Table 9 provides a list of options that can be examined within the Ag-Ind Fuel Substitution Module.

There is lack of agreement among state agencies about how hydrogen is going to be produced and distributed, so this is a key uncertainty in assessments. Later in this section of Chapter 3, staff will describe a sensitivity that is based on the Enhanced Policy Scenario. it assumes a substantial shift to the pipeline distribution method rather than the onsite production method for all industrial plants assumed in both the Policy and Enhanced Policy Scenarios. In the long term (5 to 25 years), the sensitivity explores some of the ramifications of reliance upon hydrogen production by renewable electrolysis. However, in the near term (one to five years), the steam methane reforming method continues to serve current and new end users as a pipeline delivery system is developed and eventually interconnects with the preferrable renewable electrolysis production plants.

Table 9: Hydrogen Production and Distribution Options in Ag-Ind Fuel Substitution Module

Production Method	Direct Electricity Use (kWh/kg H2)	Indirect Electricity Use (kWh/kg H2)	Direct CO2 Emissions (kg CO2e/kg H2)	Sources/Notes
Steam Methane Reforming With No Carbon Capture and Storage	0	0	8.5	https://www.sciencedirect.com/science/article/pii/S2666790822001574
Steam Methane Reforming With Carbon Capture and Storage	0	0	1.2	https://www.sciencedirect.com/science/article/pii/S2666790822001574
Electrolysis Using Grid Electricity — Standard	52.5	5	0	Assume 75% efficiency in hydrogen production (141,803 kJ/kg H2) / (3,600 kJ/kWh) / 0.75 = 52.5 kWh/kg H2
Electrolysis Using Grid Electricity — Efficient	41.5	5	0	Assume 95% efficiency in hydrogen production (141,803 kJ/kg H2) / (3,600 kJ/kWh) / 0.95 = 41.5 kWh/kg H2
Electrolysis Using Remotely Co-Located Renewable Generation	0	52.5	0	Assumes mix of electrolyzer units with baseload being efficient, and cycling units less efficient, collectively delivering hydrogen via pipeline to end-users

Source: Guidehouse and CEC staff

Annual Energy Projections

Once the annual energy impacts for electricity and pipeline gas are projected by the Ag-Ind Fuel Substitution Module, they and the baseline industrial demand forecast (extended to 2050) are used as inputs to the annual integration tool developed by EER. Unlike a similar process for the building sector, which wholly replaces all energy types in the EP model, the industrial sector has substantial amounts of consumption of other energy types. Thus, the integration tool that EER developed to combine sector inputs (baseline projections and incremental changes due to fuel substitution) is more selective in combining inputs from CEC models and the EP model to provide annual energy projections for each energy type.

Projecting Hourly Electric Loads by Planning Area

Once annual energy consumption for each energy type has been projected for a specific scenario in each of the eight planning areas, hourly 8760 electricity electric load can be projected at this same level of geography. As is the case in other FSSAT modules, the annual consumption of electric energy is allocated to the 8760 hours of each future year using a fixed hourly load profile for each industry in each planning area. Where load profiles were not available by a planning area or an industry, the Ag-Ind Fuel Substitution Module uses the closest match from another electric planning area. The hourly load profiles in this round of demand scenario assessments stem from the HELM 2.0 project conducted by ADM Associates.[18] A replacement set of hourly load profiles specific to the three IOUs, LADWP, and SMUD is in development and will be used once they are available.

The hourly loads by industry, year, and planning area are forwarded to the hourly integration tool developed by EER, which produces consolidated, coincident hourly load projections in a virtually identical format to that prepared by CEC demand forecasting staff for the official electric load forecasts each IEPR cycle.

Rationale for and Design of Demand Scenarios

Chapter 2 of this report provides a high-level description of the assumptions used for each of the Policy and Enhanced Policy Scenarios. For the industrial sector, there is less of a precedent to guide how assumptions might be designed since, until recently, most industrial programs sponsored by California utilities have emphasized energy efficiency rather than fuel substitution. Scenarios should be grounded in as much real-world data and factors inducing industries to decarbonize as much as possible.

Legislative or Regulatory Requirements

Various California laws have been enacted through time assigning specific goals for decarbonization of sectors of the economy, some specific to individual industries. These statutes do not, however, specify how to accomplish the goal. The Cap-and-Trade Program devised and administered by CARB provides general inducements to decarbonize but is not technologically specific. That is, compliance can be satisfied either by technology changes,

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[18] California Energy Commission staff. 2019. CEC-500-2019-046, California Investor-owned Utility Electricity Load Shapes

including fuel substitution, or by emission credits created outside any specific industry. Neither of these two statutory approaches to decarbonization helps guide actual fuel substitution input assumptions.

Federal legislation in the 2020 Infrastructure Investment and Jobs Act and the 2022 Inflation Reduction Act provides various tax incentive and grant opportunities for a wide range of industrial technologies explicitly designed to induce decarbonization of the industrial sector through energy efficiency or fuel substitution or both. The Inflation Reduction Act includes two programs:

- Section 13501 authorizes $10 billion for the 48C Manufacturing Tax Credit.
- Section 50161 authorizes $5.8 billion for the Advanced Industrial Facilities Deployment Program.

The U.S. Department of Energy has demonstration programs to educate various industries about technology options (both commercially available today and emerging ones in the near term or midterm). The Better Buildings series is one example of educational efforts, but facilities selected for demonstrations may not be sufficiently representative even of their industry to be a major impetus for decarbonization technology adoption.[19]

Scenario Design

Table 10 provides a more specific summary of the approach that was developed given the legislative or regulatory basis that existed at the time of this project.

Reference Scenario: There is no incremental fuel substitution from the Ag-Ind Fuel Substitution Module since this scenario is essentially the same as the 2023 IEPR industrial forecast. However, AAEE Scenario 3 and AAFS Scenario 3 do include modest levels of respective energy efficiency and fuel substitution impacts for the ag and industrial sectors.

Policy Scenario: Induced largely by federal incentives and tax credits, there are moderate levels of pipeline gas displaced by electricity for many industries and lower levels of pipeline gas displaced by H2 in an even more limited set of industries. The potential grows and then plateaus in the early 2030s as federal incentive funds phase out. AAEE Scenario 3 and AAFS Scenario 3 do include slightly increased amounts of respective energy efficiency and fuel substitution impacts relative to the Policy Scenario.[20]

Enhanced Policy Scenario: The assumptions essentially mimic the Policy Scenario up to the early 2030s but thereafter continue to grow at a slower rate. This growth presumes that sufficient demonstrations funded in the early years and substantial expansion of commercially available technologies matching the process needs of many industries have convinced more

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[19] Better Buildings Initiative of U.S. DOE staff. Accessed 2025. "Decarbonization | Better Buildings Initiative." U.S. Department of Energy, https://betterbuildingssolutioncenter.energy.gov/efficiency.

[20] AAEE and AAFS programmatic impacts are applied to the baseline industrial demand forecast just as is the case in the FSSAT buildings sector module before the Ag-Ind FS module computes potential to reduce double counting of programmatic versus "what if" fuel substitution scenario impacts.

industrial decision-makers that fuel substitution is a viable option for decarbonization. In the end, staff made significantly informed but somewhat uncertain judgments to devise specific potential and adoption rate assumptions.

Table 10: Scenario-Specific Fuel Substitution Guidance

Scenario	Rationale for Scenario Design
Reference	No fuel substitution except through AAFS programmatic efforts
Policy	▪ Moderate levels of pipeline gas to electric fuel substitution for water heat and process heat-low using industrial-scale heat pumps ▪ More limited fuel substitution of pipeline gas to hydrogen for the process heat-high end-use where high temperatures cannot be achieved by heat pumps ▪ Potential expands through time as heat pumps and hydrogen combustion prove themselves through federal demonstration projects and the incentives adopted in the federal Inflation Reduction Act and other legislation ▪ Facilities that adopt hydrogen as a replacement for pipeline gas are assumed to use of onsite electrolysis and storage
Enhanced Policy	▪ Increased adoption rates after early 2030s as decarbonization technologies become more common and they become part of the conventional set of choices for industrial facilities ▪ Growing potential after early 2030s as manufacturing capacity for these products expands, but at a slower pace than earlier forecast years when stimulated by federal incentives

Source: CEC staff

In the Ag-Ind fuel substitution module, there are two independent factors used to specify a scenario. Fuel substitution potential references the technical possibilities of shifting from pipeline gas to electricity or hydrogen. This reflects engineering realities of substitution for the various production processes in each industry, capabilities of equipment manufacturers to deliver alternative fuel equipment to markets at scale, and so forth.

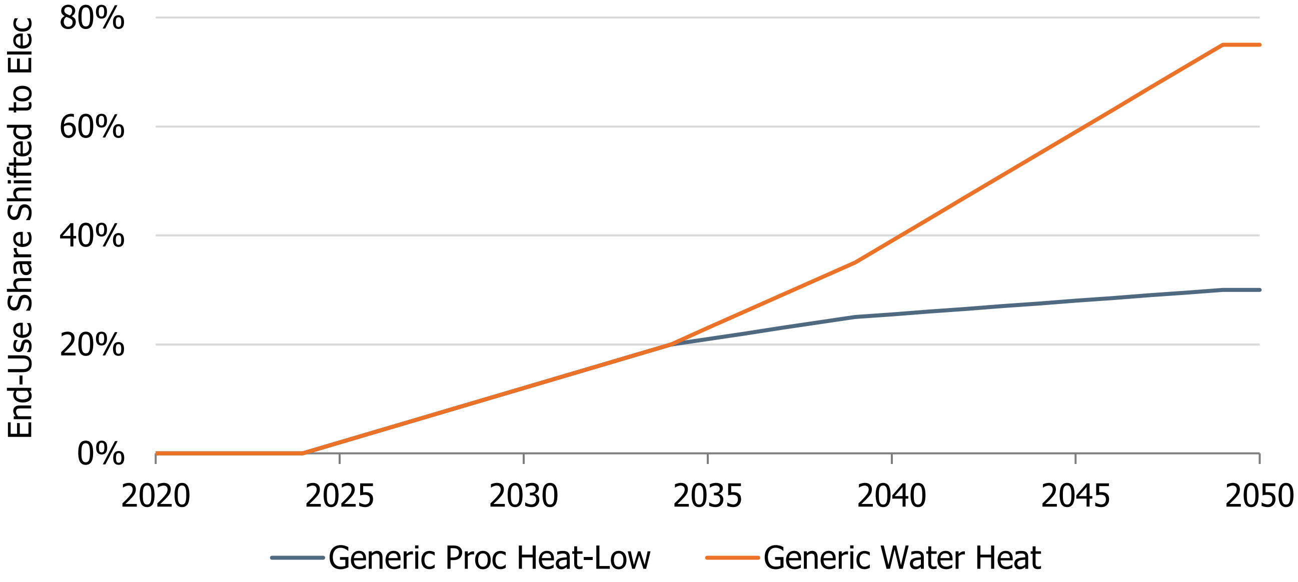
Adoption rates reflect the willingness of industrial decision makers to adopt new, unfamiliar technologies, retraining of plant personnel, capital costs of alternative fuel equipment, relative operating costs of processes designed for pipeline gas versus alternative fuels, and so forth. Potential is expressed as percentages of an underlying end use that can potentially shift, while adoption rate is the percentage of that potential which is achieved in any future year. Generally, both are expected to grow through time but could plateau if incentives and other inducements cease. Each of these two factors will be discussed for the Policy and Enhanced Policy Scenarios.

Fuel Substitution Potential

Figure 2 through Figure 5 depict the Policy and Enhanced Policy assumptions that define the growth in potential for fuel substitution through time.

Figure 2 shows Policy Scenario fuel substitution potential for pipeline gas displaced by electricity for Water Heat and Process Heat-Low. The potential for replacing boilers to heat water with industrial scale heat pumps grows steadily and plateaus at 75 percent. Heating water is a common industrial process, so a generic potential covering all industries was assumed. The potential for substituting diverse Process Heat-Low applications grows with federal incentive schedules and then slows dramatically to plateau at 30 percent. There is nothing comparable to a heat pump that is so universally applicable across low temperature process heat applications, so the markets for electricity equivalents to current gas-fired equipment will be smaller and more fragmented.

Figure 2: Policy Scenario Fuel Substitution Potential for Process Heat-Low and Water Heat: Pipeline Gas to Electricity



Source: CEC staff

Figure 3 uses the same format as Figure 2 to show Enhanced Policy Scenario fuel substitution potential for pipeline gas being displaced by electricity for Water Heat and Process Heat-Low. In the Enhanced Policy Scenario, the assumptions are essentially identical to the Policy Scenario up through the early 2030s. After the middle 2030s, the growth in potential continues to increase, achieving somewhat higher levels of potential than in the Policy Scenario. The authors emphasize that the feasibility and practicality of using an industrial heat pump depends upon the temperature differential between the source and output of the equipment.[21] In a factory setting, those waste heat sources that can be efficiently concentrated to affect the source temperature for a heat pump can be important to reducing the temperature differential. Not all waste heat sources can be concentrated efficiently; as a result, the

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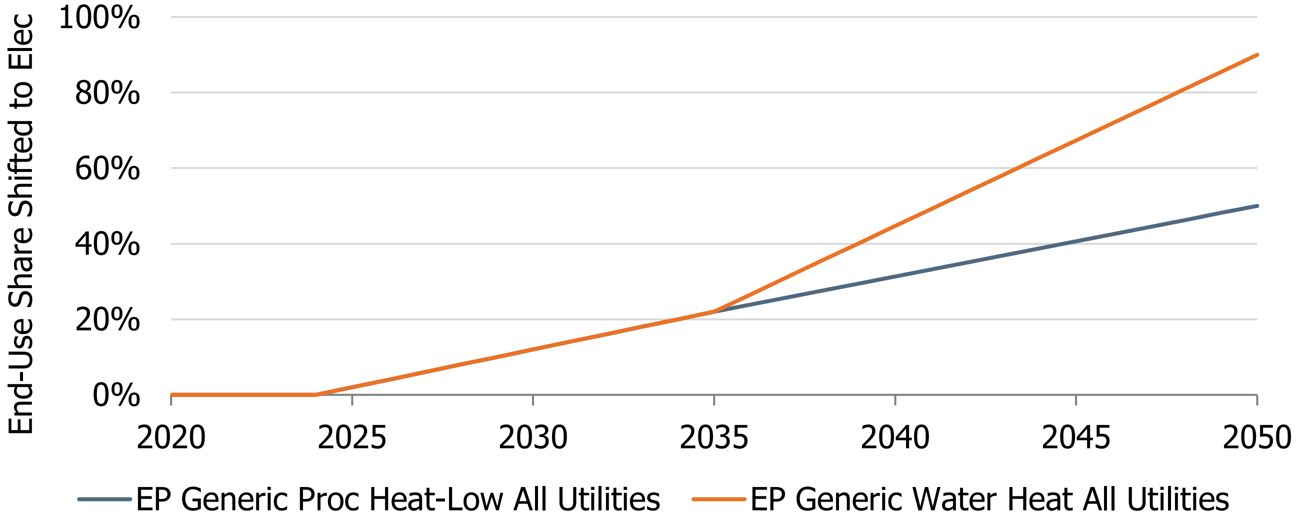
[21] St. John, Jeff. June 27, 2023. "Steam Made by Heat Pumps Can Help Clean up Industry and Manufacturing." Canary Media, https://www.canarymedia.com/articles/heat-pumps/steam-made-by-heat-pumps-can-help-clean-up-industry-and-manufacturing.

potential for neither the water heat nor low temperature process heat end uses is likely to ever get to 100 percent.

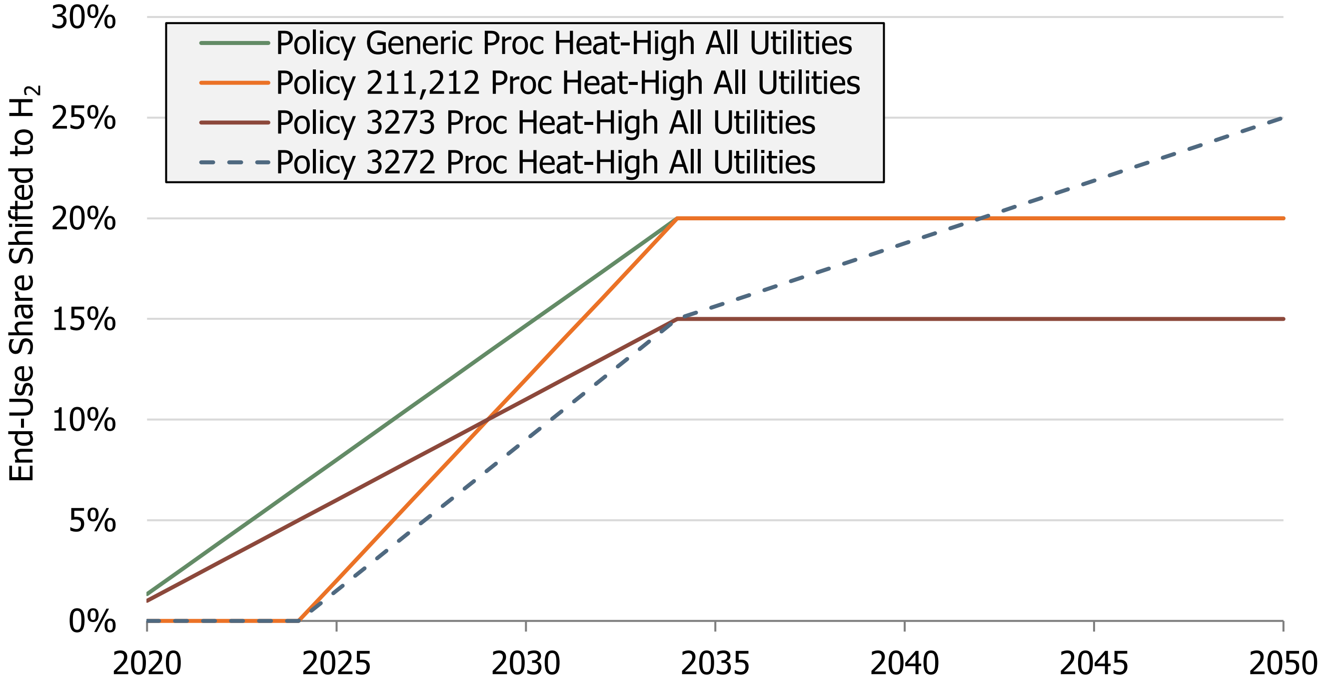
Figure 3: Enhanced Policy Scenario Fuel Substitution Potential for Process Heat-Low and Water Heat: Pipeline Gas to Electricity



Source: CEC staff

Figure 4 and Figure 5 provide the assumptions used to characterize the potential to displace pipeline gas with hydrogen for the high-temperature process heat end use. In contrast to Figure 2 and Figure 3, these figures show only a single end use, but there is not as much commonality among industries, so more industries have their own patterns for growth in potential rather than assuming a generic pattern as was the case for water heat and low-temperature process heat. In Figure 4, the Policy Scenario exhibits a pattern driven by federal incentives to expand potential up until the early 2030s, with a subsequent plateau. The green line is a generic pattern that starts early and plateaus about 2035. The purple line (3273 – Cement) and the red line (211,212 — Oil and Gas Extraction) have different early patterns but also plateau. The dashed blue line (3272 – Glass) is the only industry that shows steady growth through time.

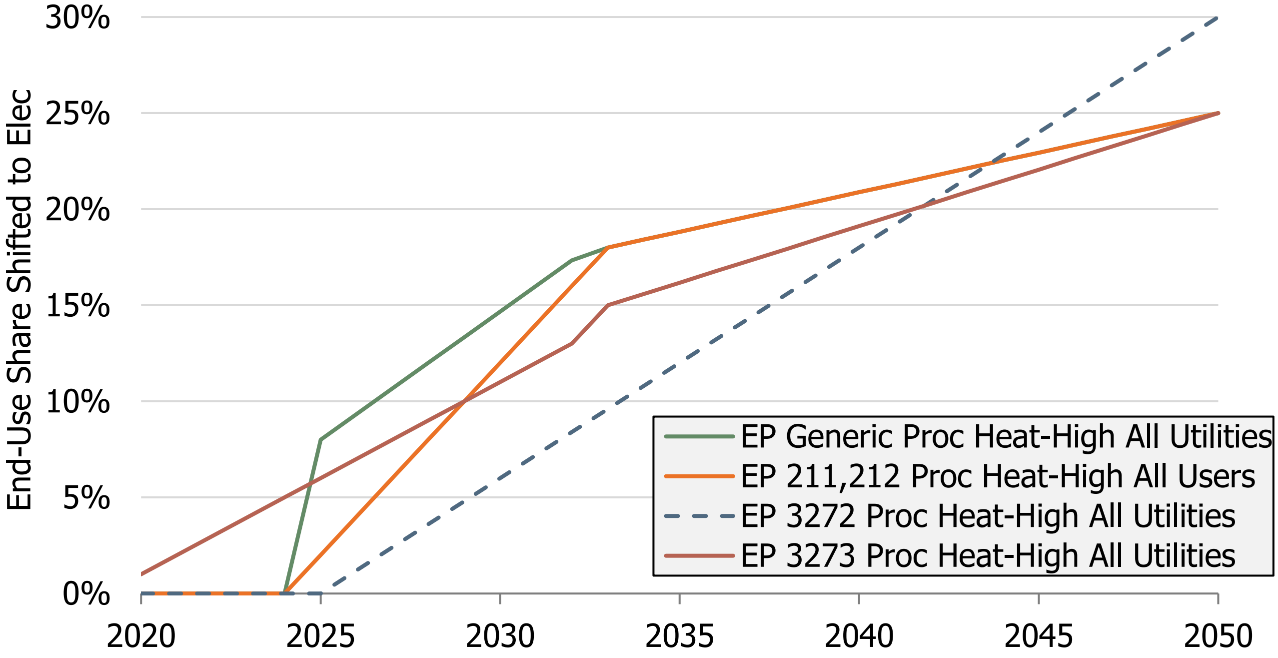
Figure 4: Policy Scenario Fuel Substitution Potential for Process Heat-High: Pipeline Gas to Hydrogen



Source: CEC staff

Figure 5 uses the same format to show the pattern of growth in potential for the Enhanced Policy scenario. Two things are different for this scenario. First, the potential is somewhat higher in the earlier years for some industries and continues to grow, albeit more slowly, after the early 2030s. In addition, in this scenario, the oil extraction facilities using pipeline gas from the interstate Mojave and Kern River Pipelines (MKRP) are included in the fuel substitution computations while they were excluded in the Policy Scenario. The tremendous consumption of pipeline gas for thermally enhanced oil recovery in the Bakersfield area nearly doubles the potential for use of hydrogen in the overall statewide oil extraction industry.

Figure 5: Enhanced Policy Scenario Fuel Substitution Potential for Process Heat-High: Pipeline Gas to Hydrogen



Source: CEC staff

Figure 2 through **Figure 5** depict a higher potential for electricity fuel substitution into the low-temperature process heat and water heating end uses than there is for hydrogen in the high-temperature process heat share of overall pipeline gas consumption. There is more diversity across the 46 industries in how pipeline gas is used for Process-Heat-High than for use of Water Heat or Process Heat-Low. Recalling Equation 2, while the shares of potential are uniform, the aggregate quantity of total pipeline gas consumption in each industry capable of being shifted to either electricity or hydrogen is not nearly as uniform. This lack of uniformity is due to variations in industry consumption in the baseline forecast, the thermal share in the baseline forecast, and the allocation of that thermal share to the Process Heat-High end use.

The previous figures are good for showing change through time but hard to see actual numeric values. Table 11 provides a summary for the 2050 endpoints for the line graphs.

Table 11: Summary of 2050 Potential for End-Use Fuel Substitution to Electricity or Hydrogen

Industry Applicability (NAICS)	End-Uses for Fuel Substitution	Type of Fuel Substitution	Policy	Enhanced Policy	Special Notes
Generic	Process Heat-Low	PG>>E	0.3	0.5	
Generic	Water Heat	PG>>E	0.75	0.9	
Generic	Process Heat-High	PG>>H2	0.2	0.25	
211, 212 (Oil & Gas Extraction)	Process Heat-High	PG>>H2	0.2	0.25	The portion of pipeline gas supplied by utilities
211, 212 (Oil & Gas Extraction)	Process Heat-High	PG>>H2	0	0.25	The portion of pipeline gas supplied by MKRP pipelines
3272 Glass (revised)	Process Heat-High	PG>>H2	0.20 *	0.25	Policy penetration rate revised downward with slower growth than generic
3273 Cement	Process Heat-High	PG>>H2	0.25	0.30	Slower growth than generic
3274 Lime	Process Heat-High	PG>>H2	0.15	0.25	
3279 Minerals	Process Heat-High	PG>>H2	0.15	0.25	

***Glass industry potential revised downward from the value used in the original Policy Scenario provided to the SB 100 process.**

Source: CEC staff

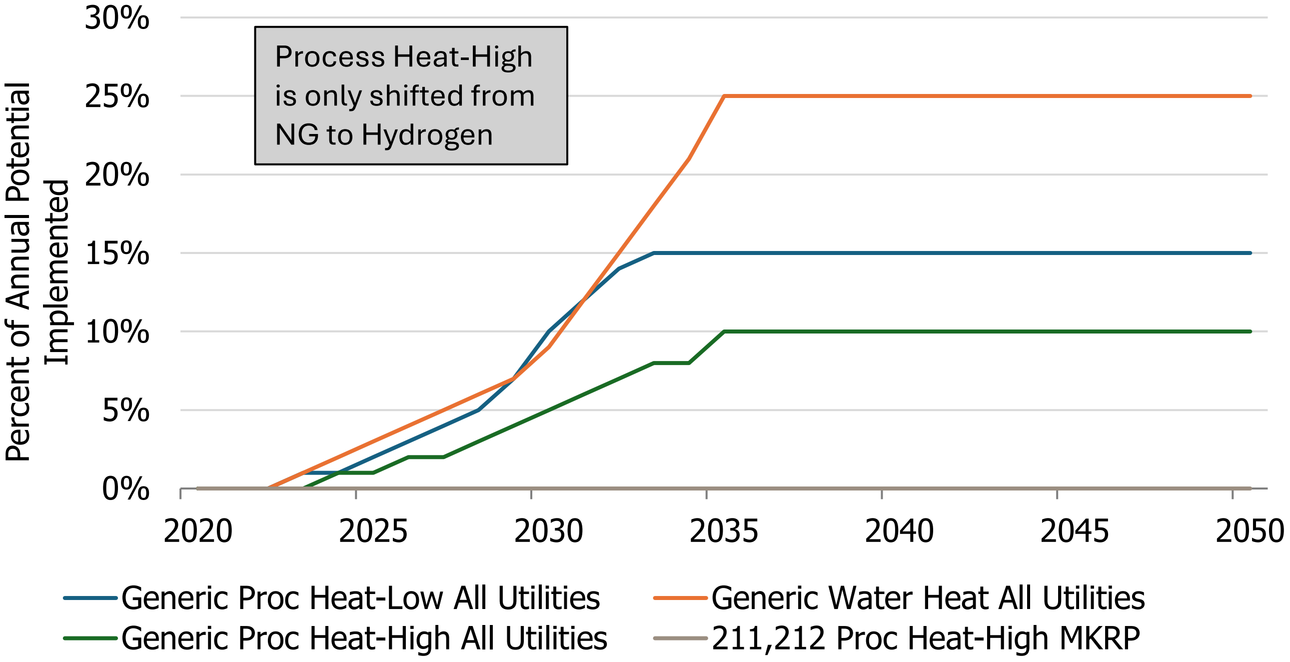
Adoption Rates for Potential

A second set of critical assumptions affecting the actual scenario results is the adoption rate. The adoption rate reflects the influence of end-user behavior on the "technical potential" represented by the potential as shown in Figure 6 through Figure 8. This representation of "behavior" includes a wide range of phenomenon (cost of switching, impact of production downtime for equipment replacement, competitive position among production facilities outside California, availability of capital, and so forth) that are even less well understood than potential. The Ag-Ind Fuel Substitution Module does not model any of these specific factors influencing adoption; rather, the adoption rates are judgmental assumptions. In the Ag-Ind Fuel Substitution Module, adoption rates can be industry and end-use specific, although data reflecting differences among industries are scant.

Figure 6 depicts the adoption rates for the Policy Scenario, while Figure 7 depict the higher adoption rates assumed for the Enhanced Policy Scenario. The assumed adoption rates for the Enhanced Policy Scenario are generally double those of the Policy Scenario because the

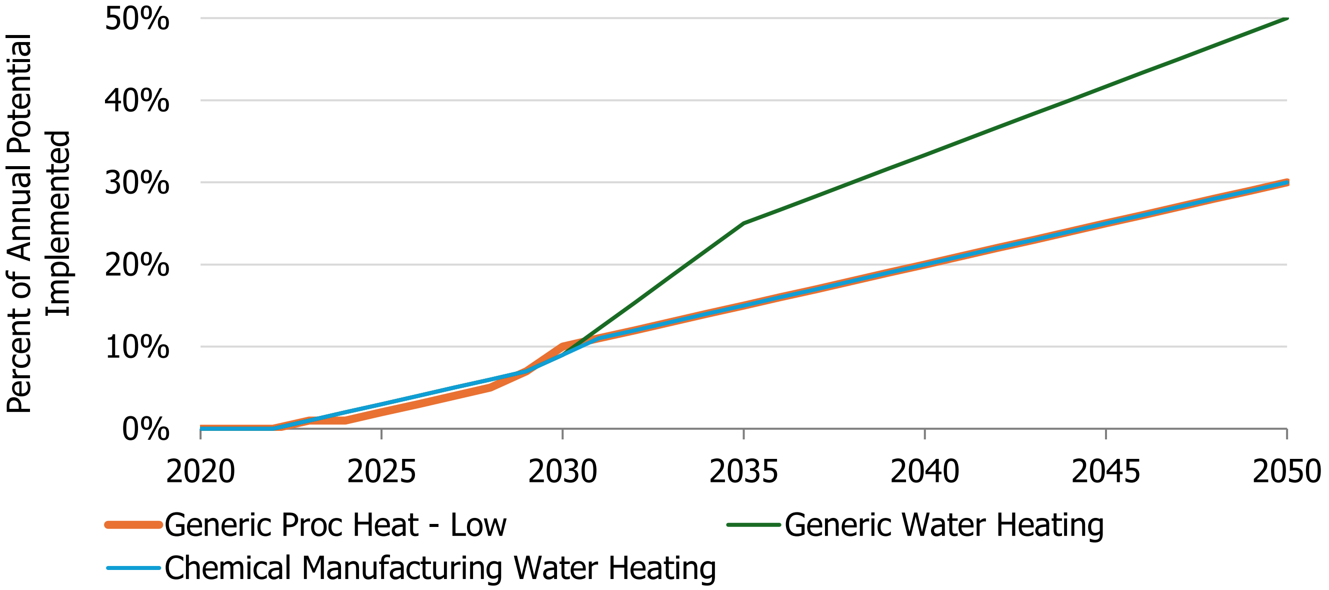
Enhanced Policy Scenario assumes greater industry acceptable of decarbonization technologies.

Figure 6: Adoption Rates for Pipeline Gas to Electricity or Hydrogen for the Policy Scenario



Source: CEC staff

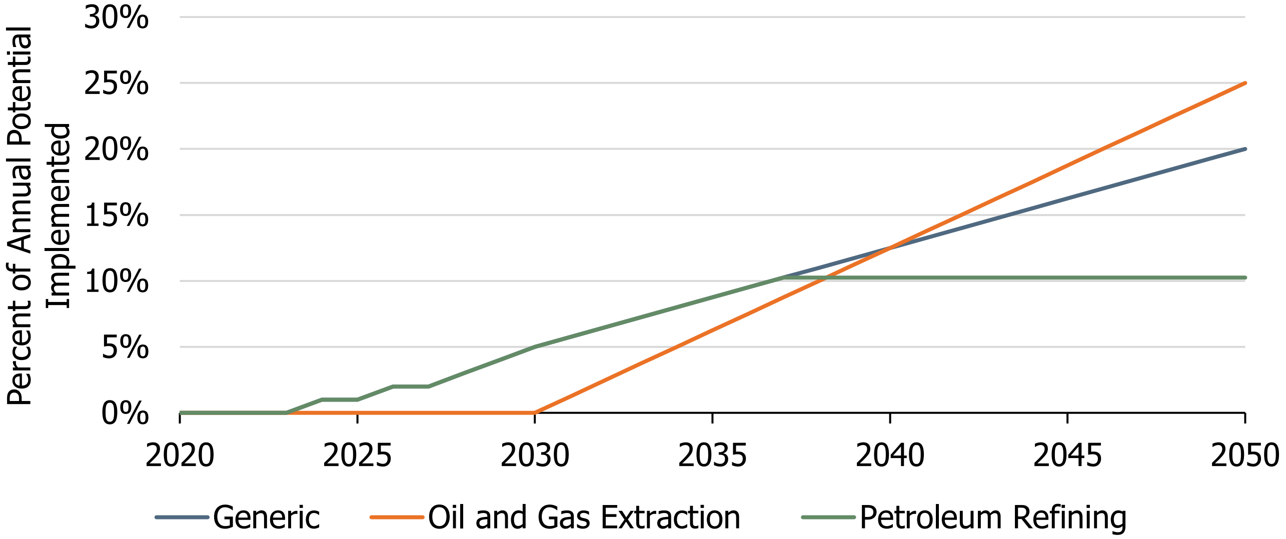
Figure 7: Adoption Rates for Water Heat and Process Heat-Low to Electricity for the Enhanced Policy Scenario



Source: CEC staff

Figure 8 provides similar adoption patterns but in this case for Process Heat-High shifting from pipeline gas to hydrogen. The great majority of industries follow a generic pattern through time, but oil and gas extraction and petroleum refining have their unique patterns.

Figure 8: Adoption Rate for Process Heat-High Pipeline Gas to Hydrogen for the Enhanced Policy Scenario



Source: CEC staff

Table 12 provides a summary of 2050 Adoption Rates for the Policy and Enhanced Policy Scenarios that were depicted through time in Figure 6 to Figure 8. As a reminder, the basic equation implementing fuel substitution is the product of three key factors multiplied against the total industry-specific pipeline gas projection in each planning area each year:

- the time-invariant end-use share,
- the fuel substitution potential in each year, and
- the adoption rate in each year.

The data limitations that require use of judgment for all these factors mean that there is more uncertainty in the results, and many alternative scenario designs are equally plausible.

Table 12: Summary of 2050 Adoption Rates for End-Use Fuel Substitution to Electricity or Hydrogen

Industry Applicability (NAICS)	End-Uses for Fuel Substitution	Type of Fuel Substitution	Policy	Enhanced Policy	Special Notes
Generic	Process Heat-Low	PG>>E	0.15	0.3	
Generic	Water Heat	PG>>E	0.25	0.5	
Generic	Process Heat-High	PG>>H2	0.1	0.20	
211, 212 (Oil & Gas Extraction)	Process Heat-High	PG>>H2	0.1	0.25	Supplied by Utilities
211, 212 (Oil & Gas Extraction)	Process Heat-High	PG>>H2	0	0.25	Supplied by MKRP pipelines
324 (Refining)	Process Heat-High	PG>>H2	0.1	0.1	
3272 Glass (revised)	Process Heat-High	PG>>H2	0.1	0.2	Adoption rate revised downward for final projections
3273 Cement	Process Heat-High	PG>>H2	0.1	0.2	

Source: CEC staff

Despite the capability of the Ag-Ind Fuel Substitution Module to incorporate assumptions for each NAICS code industry in each of the eight planning areas, data limitations suggest using generic assumptions until better information is available. Oil and gas extraction, petroleum refining, glass, cement, and chemicals sometimes have specific assumptions. More refined assumptions require more comprehensive data about industrial preferences among direct fuel substitution, CARB's emission trading program, and carbon capture and sequestration, among others.

Pipeline Hydrogen Sensitivity to Enhanced Policy Scenario

As mentioned earlier in this section, the subject of a "hydrogen ecosystem" has become more visible in the past several years among California and federal policy makers. The Biden administration established a competition to fund eight regional hydrogen hubs. The federal government has awarded the Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES) application $1.2 billion to create a hydrogen hub in Southern California. The ARCHES partnership views this funding as capable of developing about one-tenth of the scale of hydrogen production, distribution, and consumption that they imagine through time. Senate Bill 1075 (Skinner, Chapter 363, Statutes of 2022) required CARB, in consultation with the CEC and CPUC, to assess and make recommendations concerning many facets of the usage of green hydrogen to contribute to achieving California's GHG emission reduction goals. It further required the CEC to develop an assessment of hydrogen growth potential for electric power generation and transportation in both the 2023 and 2025 IEPRs.[22] In the *2023 IEPR* discussion, the CEC also identified a set of topics requiring further research and assessment for industrial decarbonization through fuel substitution from pipeline gas to hydrogen.[23]

The industrial sector has generally used hydrogen as input to chemical processing steps rather than as source of heat through combustion. Faced with the challenge to decarbonize, the industrial sector has lagged behind others because of numerous distinct processes within the overall industrial sector, the reliance on specialized high-temperature processes, critical investment into the existing long lifespan infrastructure, and the sheer scale of energy consumption. Even hydrogen advocacy groups like Energy Independence Now (EIN) have focused on transportation sector users and production of hydrogen rather than industrial-scale usage involving pipelines.[24]

The impetus of the federal Inflation Reduction Act and other federal legislation is broadening the scope of hydrogen as a viable replacement for carbon-based fuel sources, and a few industrial conversion projects are being developed to displace pipeline gas consumption within the industrial sector.

There are several ways to produce hydrogen and deliver it to end users. The FSSAT Ag-Ind module can incorporate inputs that can accept any of these combinations. Listed below are the most prominent combinations of hydrogen production methods and associated delivery methods.

- Steam methane reforming onsite
- Steam methane reforming using existing/augmented hydrogen pipelines
- Electrolysis onsite using grid supplied electricity
- Electrolysis offsite using renewable generation to produce hydrogen delivered by a much more extensive hydrogen pipeline network
- Combinations of these

In the Reference Scenario, no fuel switching to hydrogen was assumed, but in the Policy and Enhanced Policy Scenarios, Staff assumed onsite electrolysis with grid electricity as the universal mechanism for all industries.

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[22] SB 1075 added Section 25307 to the Public Resources Code.

[23] California Energy Commission staff. 2023. 2023 Integrated Energy Policy Report, Chapter 2, page 62.

[24] Energy Independence Now staff. Accessed 2025. "What We Do," https://einow.org/what-we-do.

Staff also designed a sensitivity based on the Enhanced Policy Scenario to explore the consequences of a partial shift to hydrogen pipeline-based delivery (EPS with pipeline hydrogen). A significant portion of the hydrogen produced in California is used in refineries and other industries requiring hydrogen as a chemical input. Refineries are heavily connected to pipeline infrastructure to receive crude oil to refine.

In addition, refineries are connected to refined petroleum product pipelines as one leg of distributing gasoline, diesel, and other products throughout the state. Some of this hydrogen is produced within the fence line of refineries themselves, while other hydrogen production comes from independent companies serving multiple customers. Since refineries function as concentrated locations of high hydrogen demand, even independent hydrogen producers establish operations near refineries or other facilities requiring hydrogen as an input to their production processes.

Table 13 provides the production capacities of independent hydrogen producers throughout California and what is publicly known about the consumers of their hydrogen production. To help promote the partnership between hydrogen producers and refineries, a few production facilities have built out dedicated hydrogen pipelines to their corresponding partners. These existing hydrogen pipelines can form the first branch of a localized hydrogen hub.

Table 13: California Industrial Gas Companies Hydrogen Production Facilities

Producer	City	Technology	Capacity (tons/year)	Industry
Air Products	Sacramento	SMR	2,023	Multiple
Praxair	Ontario	SMR	7,276	Multiple
Air Liquide	El Segundo	SMR	75,643	Oil Refining
Air Products	Rodeo	SMR	105,547	Oil Refining
Air Products	Carson	SMR	87,956	Oil Refining
Air Products	Martinez	SMR	77,402	Oil Refining
Air Products	Martinez	SMR	30,785	Oil Refining
Air Products	Sacramento	SMR	unknown	Food
Air Products	Wilmington	Refinery Fuel Gas SMR	140,730	Oil Refining
Praxair	Ontario	SMR	10,555	Multiple
Praxair	Ontario	SMR	228,687	Oil Refining
Total			**766,604**	

Source: EIN 2020[25]

For the EPS Pipeline Hydrogen sensitivity, these hydrogen production facilities (with a few short pipelines) are used as nodes to extend hydrogen distribution to new industrial customers

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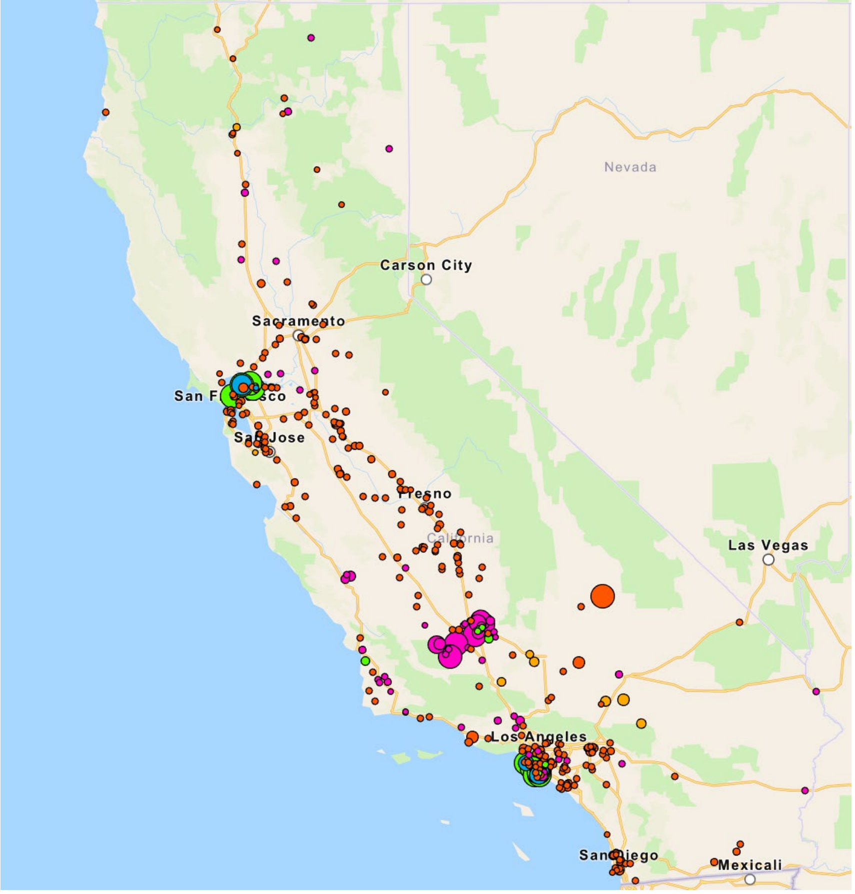
[25] U.S. Department of Energy cited in the EIN Renewable Hydrogen Roadmap: https://einow.org/rh2roadmap

as hydrogen production expands through time. The location of nearly all larger industrial facilities is known through energy consumption and emission reporting requirements of CARB. To minimize infrastructure costs of expanding the hydrogen network, pipelines within the proximity of the existing hydrogen production facilities were considered for repurposing to serve nearby large industrial facilities.

If the pipelines themselves are not usable for hydrogen, the pipeline right-of-way can be reused for the expansion. In either situation, these potential hydrogen pipeline extensions enable local industrial customers to use a cleaner fuel source and offset emissions. With these layers of geographic filtering, several industrial customers who report emission data to the California Air Resources Board, were selected as potential candidates for hydrogen fuel switching. The original set of industrial facilities before any filtering are depicted in **Figure 9** below.

Figure 9: Distribution of Industrial Facilities Across California



Each dot corresponds to the location of an industrial facility that reports emission data to the California Air Resources Board. The size of the dot is proportioned using the estimated natural gas consumption that occurs onsite. The colors of the industrial facilities vary to represent the subsector the facility belongs to.

Source: CEC analysis using the 2021 emission data from the CARB Pollution Mapping Tool[26]

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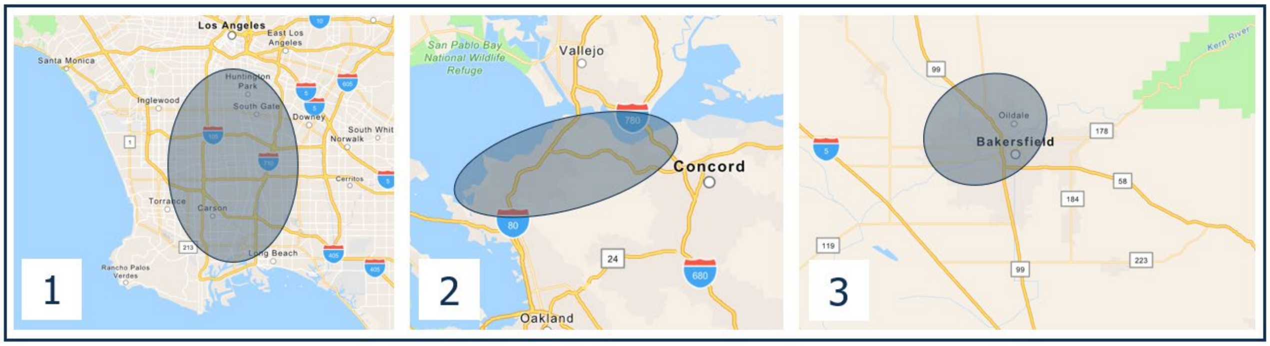
[26] CARB. "CARB Pollution Mapping Tool," https://ww2.arb.ca.gov/resources/carb-pollution-mapping-tool.

The existing hydrogen infrastructure narrows down the expansion of a hydrogen network to three core regions: (1) Los Angeles metro area, (2) San Pablo and Suisun Bays in Northern California, and (3) the San Joaquin Valley oil fields.

Figure 10: Prospective Hydrogen Network Hubs



Each highlighted region references the plausible expansion of a hydrogen network based on underlying federal pipeline geospatial data from the Pipeline and Hazardous Materials Safety Administration.[27] The regions represent the areas previously outlined: 1) Los Angeles Metro area, 2) San Pablo and Suisun Bays, 3) San Joaquin Valley oil fields.

Source: CEC staff

For the analysis within the EPS Pipeline Hydrogen sensitivity, only the portion of pipeline gas consumption that is classified as Process-Heat High is considered as a candidate for hydrogen fuel switching. As discussed earlier, the cost and properties of hydrogen combustion are ill-suited to Process Heat-Low and Water Heat applications, which can be served better by industrial-scale electric heat pumps.

The product of the thermal share of the original baseline pipeline gas forecast in Appendix B, Table B-1, multiplied by the portion of thermal designated as Process Heat-High in Appendix B, Table B-3 provides the average portion of the total usage of each industry that is assumed available for displacement by pipeline-delivered hydrogen in a limited hydrogen pipeline network. This portion is multiplied against the imputed pipeline gas consumption for 2021 for each facility in CARB's Major Industrial Facility database to obtain a facility-specific Process Heat-High consumption value.[28]

The Process Heat-High consumption of a limited number of industrial facilities within these regions are prospectively organized in a timeline to adopt hydrogen at a pace that matches an assumed growth rate for production capacity from the nearby hydrogen production plants. These time series projections then help quantify the millions of therms of pipeline gas that can

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[27] Pipeline and Hazardous Materials Safety Administration. "[National Pipeline Mapping System](https://www.npms.phmsa.dot.gov/)," https://www.npms.phmsa.dot.gov/.

[28] Although CARB collects consumption values for each major industrial facility by fuel type, these data are considered confidential. CARB reports the GHG emissions from the combustion of these fuels in two groups: biomass fuels and other fuels. The Other GHG emissions values for each facility are used to impute pipeline gas consumption assuming other fuels' GHG emissions are calculated using 100 percent pipeline gas combustion. With a few important exceptions, CARB official emission inventory data support the assumption that pipeline gas is the exclusive fuel combusted by California industry.

possibly be displaced by hydrogen across the industrial sector facilities near the expanded pipeline. As hydrogen supply grows, more industrial facilities can then join the expanding hydrogen network. Since the expansion of pipeline delivery capacity occurs in discrete steps, in any specific year the actual shift in pipeline gas to hydrogen is constrained by the minimum of the process heat consumption or the delivery capacity of the hydrogen production or the pipeline distribution infrastructure.

Absent facility-specific contractual agreements between existing hydrogen production facilities and industrial end users, this modeling approach ignores the amount and term of existing hydrogen supply/demand arrangements. The large size of facilities supplied by a hydrogen pipeline or the related expansion through time means that only a few planning area/industry combinations are included in this sensitivity.

Table 14 summarizes the shares of Process Heat-High pipeline gas consumption that are assumed to be replaced by hydrogen through time. Onsite production of hydrogen via grid-supplied electrolysis continues at the potential and adoption rate assumptions for that NAICS industry in the parent Enhanced Policy Scenario input assumptions for the remaining Process Heat-High consumption in a NAICS industry outside the large facilities receiving hydrogen via pipeline.

Table 14: Shares of Base Process Heat-High Projections in EPS Pipeline Hydrogen Sensitivity Converted to Pipeline Hydrogen Through Time by Planning Area and Industry

PA	NAICS	2020	2025	2030	2035	2040	2045	2050
LADWP	324	0	0	72.6%	72.7%	74.1%	68.6%	64.3%
MKRP	211	0	0	0.0%	0.0%	18.8%	19.2%	19.8%
NCNC	325	0	0	0.0%	0.0%	55.9%	55.4%	55.3%
PGE	211	0	0	86.2%	80.5%	74.1%	68.6%	64.3%
PGE	324	0	0	86.2%	80.5%	74.1%	68.6%	64.3%
PGE	325	0	0	5.0%	5.0%	5.0%	5.0%	5.0%
SCE	211	0	0	5.5%	5.6%	17.0%	29.5%	42.8%
SCE	3221	0	0	100.0%	100.0%	100.0%	100.0%	100.0%
SCE	324	0	0	86.2%	80.5%	74.1%	68.6%	64.3%
SCE	3272	0	0	100.0%	100.0%	100.0%	100.0%	100.0%
SCE	331	0	0	89.4%	88.1%	87.3%	86.7%	86.8%
SCE	332	0	0	100.0%	100.0%	100.0%	100.0%	100.0%

Source: CEC staff

For some regions, the existing hydrogen production capacity is not sufficient to support the expansion of hydrogen distribution to nearby customers. Thus, renewable generation, either onsite or from nearby generation projects, can be used to produce emission-free green hydrogen and support the gap. Renewables will be instrumental in helping decarbonize the San Joaquin Valley, as there are no hydrogen production plants in the region. Likewise, the

San Pablo and Suisun Bays have limited hydrogen production capacity, so capacity growth supported by renewable electric generating resources will allow the local high-demand industrial customers to reduce their pipeline gas consumption significantly. Of course, the long-term goal of decarbonization is for renewable production of hydrogen to replace carbon-intensive methods, but this is not feasible in the near term.

The EPS Pipeline Hydrogen sensitivity created explicit input assumptions about the transition from existing hydrogen production facilities using SMR methods toward a future dominated by a combination of renewable-supported electrolysis and onsite grid-supported electrolysis. Although onsite grid-supported electrolysis does not meet the standards for classification as green hydrogen, as California's electric generation sector becomes greener, eventually reaching zero GHG emissions in 2045 in compliance with SB 100, hydrogen production with grid electricity comes closer to meeting a green hydrogen standard. This sensitivity design implicitly accepts the initial use of hydrogen that does not meet standards for "green" hydrogen in early years to accelerate the initial expansion in the use of hydrogen.

The adoption timeline used within the analysis for the hydrogen sensitivity is organized by year, CEC electric planning areas, and the corresponding NAICS code for the facility. To simplify the organization, years are binned into decades, starting in 2030, so facilities have time to prepare for the transition to hydrogen. Most prospective facilities are captured during the first decade in 2030. The following years allow for growth in hydrogen production and pipeline delivery capacity before more facilities can connect. This final adoption table is then used in conjunction with the CEC's pipeline gas demand forecast for the industrial sector's Process Heat-High projections to model the projections of hydrogen consumption displacing pipeline gas out to 2050 by production method and delivery system. Appendix B, Table B-4, reports the evolution through time in the share of hydrogen developed by production technology and delivery mechanism.

Transportation Electrification

Framework for Transportation Energy Demand Scenarios

The transportation energy demand forecast developed by CEC staff includes all major transportation modes in the state (on-road, rail, aviation, and other off-road modes), including all on-road vehicle classes and the fuels consumed in each one. Although only the electricity demand for transportation is formally a component of the electricity demand forecast adopted by the CEC in each IEPR cycle, the projections for other fuels frequently are developed with the same modeling tools and use common driver variables, where appropriate.

The framework for transportation projections in the Demand Scenarios Project involves a series of postprocess modifications to the 2023 IEPR Planning Forecast designed to align with some existing policies, potential policies, and goals with clean technological or policy pathways informed by market analysis. Staff made these modifications for multiple transportation modes and the fuels they use that exist in the transportation energy demand forecast.

The transportation energy demand component of the 2023 IEPR Planning Forecast has a baseline forecast and a set of additional achievable transportation electrification (AATE) scenarios. The baseline forecast consists of a suite of models that incorporate consumer preferences, regulations, economic and demographic projections, projected improvements in technology, freight and passenger travel patterns, and other market factors to forecast transportation energy demand. The baseline forecast starts with current market conditions and forecasts transportation energy demand based on the projected inputs. For AATE scenarios, staff makes additional modifications to capture some policies, such as supply-side policies, that are otherwise difficult to integrate fully with the demand-side baseline forecast model suite.

By postprocessing the transportation energy demand forecast, various benefits of the forecast are maintained while allowing for a reasonable estimation of the energy demand effects of other policies. For example, to the extent that the forecast captures consumers' increasing preference for larger sport utility vehicles, demand scenarios may be able to capture increasing zero-emissions requirements or policies that could favor electric travel modes of such vehicles. The primary technological orientation for transportation demand scenarios is to electrify the energy demand outputs, although other fuels (for example, hydrogen and synthetic fuels) may be low-carbon options favored by policy or technology, as well as various forms of increased efficiency (for example, reduced vehicle miles traveled [VMT] with similar appropriate transportation service satisfaction).

The Reference Scenario extends the AATE 3 Scenario to 2050. Staff made no additional modifications. As a complete scenario, the AATE 3 Scenario does capture other fuel demand such as hydrogen and petroleum, although the primary preference for AATE 3 is electric modes of transportation.

Policy Scenario

The table below summarizes major modifications to the Reference Scenario that comprise the Policy Scenario. The changes are primarily postprocess modifications to energy demand with alignment to the same level of transportation service provided by the Reference Scenario energy. Where appropriate, staff used energy efficiency ratios (EERs) to inform enhanced efficiency associated with electrification or other fuel substitution. For example, staff used a conservative EER estimate of 2.0 for battery-electric aviation.[29]

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[29] Jayant Mukhopadhaya and Brandon Graver. 2022. Performance Analysis of Regional Electric Aircraft – International Council on Clean Transportation. Available at https://theicct.org/publication/global-aviation-performance-analysis-regional-electric-aircraft-jul22/.

Table 15: Major Policy Scenario Transportation Energy Demand Categories With Reference Scenario Modifications

Transportation Mode	Policy Scenario Changes (or none)
Light-Duty Vehicles	No policy changes above reference (e.g., CARB's Advanced Clean Cars II is in the reference scenario).
Aviation	ZE fuel substitution for jet fuel for in-state aviation starting 2030, 10 percent electricity and 10 percent H2 by 2045 (5 percent for Out-of-State Aviation).
Locomotives and Rail	In alignment with the recently adopted In-Use Locomotive Regulation, ZE fuel switching starting in 2027, diffusion to 100% by 2058.
Freight Trucks	Additional ZE freight truck adoption associated with CARB's ZE Truck Measure, a regulation in development.
Transit	No changes above reference (e.g., Innovative Clean Transit Regulation is in the reference scenario).
Off-Road Vehicles	Electrification sufficient to align with 100 percent ZE port operations by 2045. Post-process modification of the CEC's off-road transportation model to align with 80 percent electrification by 2050.
Oceangoing Vessels	OGV energy replacement of 5 percent hydrogen by 2045, with increased OGV efficiency of 10 percent.

Source: CEC staff

Policy Scenario With High Hydrogen Use Augmentation

The Policy Scenario with High Hydrogen Use involves two modifications to the original Policy Scenario. The first involves a postprocess modification to hydrogen fuel demand for freight trucks. Normally, the freight truck energy demand model goes from vehicle count to energy demand. However, several fuel cell truck categories do not exist in the freight model. Therefore, staff created modifications to the Reference Scenario using a fuel substitution method rather than a vehicle replacement method.

To inform the demand flexibility component of the High Hydrogen Use Augmentation, which requires stock values for battery-electric trucks, staff further postprocessed the battery-electric truck stock to align with the proportional reduction in electricity demand seen by the hydrogen substitution.

Policy Scenario With Managed Charging Sensitivity

In coordination with the Efficiency Division at the CEC, Demand Scenarios staff worked with the firm E3 to develop a managed charging sensitivity to the Policy Scenario. The framework conducts an increasing blend through time of an idealized hourly scenario for LD charging and the original Policy Scenario time-of-use (TOU)-informed hourly results.

E3 developed the idealized hourly scenario to optimize for "marginal-cost based retail rates" using the firm's RESHAPE-EV model. The RESHAPE-EV model uses two different perspectives on managed charging. The first perspective is EV driving and charging simulation, which takes the driver's perspective based on driving profiles and price signals. The second perspective is that of an electric load aggregator, with customer charging managed to minimize bills. The first perspective has priority. That is, customer demands must be met before an aggregator can engage in managed charging.

The result of the RESHAPE-EV model run for blending is a shape that emphasizes weekend charging and daytime charging. For example, the RESHAPE-EV model run assigns 42 percent of all vehicle charging to occur between the five hours between 10:00 a.m. and 3:00 p.m. It also assigns 47 percent of vehicle charging demand to be met on weekend days. By contrast, the Policy Scenario assigns 26 percent and 20 percent, respectively.

Blending of the Policy Scenario hourly results and the RESHAPE-EV results occurs with a linear weighting. Staff assigned a 1 percent weighting of RESHAPE-EV in 2027 and linearly grew the weighting to 30 percent RESHAPE-EV by 2050, with the original Policy Scenario representing the other portions.

Enhanced Policy Scenario

The Enhanced Policy Scenario for transportation energy demand is similar in approach to the Policy Scenario. Table 16 depicts the changes, if any, by transportation mode in creating the EPS scenario assumptions. The major modification is to the light-duty energy demand. Light-duty energy demand reduction results from a decrease in VMT and associated energy consequences. Other modifications to the enhanced policy scenario are informed by market analysis and broader policy goals.

Table 16: Enhanced Policy Scenario Transportation Modifications to the Policy Scenario

Transportation Mode	Enhanced Policy Scenario Changes (or none)
Light-Duty Vehicles	Reduction in VMT in the light-duty sector, 10 percent by 2030 and 15 percent by 2045, compared to per-capita VMT in 2045. Energy consequences across all fuel types.
Aviation	Same in-state aviation ZE fuel substitution as the Policy Scenario. For out of state aviation, 10 percent electricity and 10 percent H2 by 2045.
Locomotives and Rail	Same as Policy Scenario.
Freight Trucks	Same as Policy Scenario.
Transit	Same as Policy Scenario.
Off-Road Vehicles	Enhanced electrification sufficient to fully replace all off-road transportation by ZE technologies by 2045.
Oceangoing Vessels	OGV energy replacement of 45 percent hydrogen by 2045, with increased OGV efficiency of 10 percent.

Source: CEC staff

Staff designed the VMT reduction approach for the light-duty scenario to have no VMT reduction for light-duty vehicles that could be reasonably classified as "rural." Staff used U.S.

Census bureau rural and urban designation data and Department of Motor Vehicles registration data to approximate vehicle classes that are disproportionately rural. For example, about 15 percent of diesel-burning heavy pickup trucks are registered to rural ZIP codes, whereas only about 1.4 percent of electric compact cars are registered to rural ZIP codes. The result of the VMT approach is that the 15 percent of rural-designated diesel-burning heavy pickups had no VMT reduction, whereas nearly all electric compact cars were subject to VMT reductions. One outcome is that VMT reductions are seen slightly more by electric vehicles than combustion vehicles.

Other modifications for the Enhanced Policy Scenario were extensions of existing methods seen in the Policy Scenario.

Grid-Friendly Hydrogen Production

Hydrogen demand interfaces with electricity demand in an unconventional way compared to traditional demand analysis. For most low- or zero-carbon energy frameworks, hydrogen must be either sourced from electricity and water (electrolysis) or from biological sources (pyrolysis of biological material or biomethane reforming).

The biological sourcing of hydrogen is at an early stage in technological development, but there are indications that it can be a viable source. There are uncertainties with biological feedstocks. For the SB 100 demand scenarios, staff aligned the proportion of biological sourcing of hydrogen with the proportion in CARB’s 2022 Scoping Plan.

The leading expectation for sourcing hydrogen is electrolysis. This process uses water and electricity to separate the hydrogen and oxygen found in water. The hydrogen can then be used in zero-emission fuel cells (for example, fuel cell electric vehicles) or combusted, leaving water as a by-product.[30] Producing, storing, and distributing hydrogen result in demand for electricity. Many advocates of the production and use of hydrogen insist that hydrogen be produced using electrolysis facilities supplied by renewable generation that is decoupled from the grid to assure that no carbon was emitted in producing the electricity requirements — "green hydrogen.”

Hydrogen demand can theoretically be met by off-grid electricity production (for example, solar panels directly tied to electrolyzers), but the high capital cost of electrolyzers makes this approach challenging. Operating only with intermittent solar would underuse expensive electrolyzers and have likely efficiency reductions from operational ramping, reducing the economic viability of this strategy. The underutilization cost may be offset by the low levelized cost of off-grid solar. Infrastructure for hydrogen distribution on this model would be complicated as well. Ultimately, uncertainty remains as to whether this will be a viable approach.

Grid-integrated hydrogen production is another strategy that could manage some of the challenges with off-grid production. Electrolyzers operate most efficiently when they have a

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[30] In cases of hydrogen combustion, some nitrogen oxides, toxic pollutants with indirect greenhouse effects, may form from the high temperature of combustion and the oxygen and nitrogen present in the atmosphere.

steady source of electricity, but this preference can conflict with the needs of the rest of the grid. Assessing this type of production and optimizing it with the rest of the state's electricity demand require, at minimum, a more dynamic approach for the 8760 hours of a typical year. This approach is not feasible for a standard demand model.

Interagency discussions among the SB 100 team considered options and decided that for SB 100 purposes, electrolysis electricity should be grid-connected, but in a manner that was "grid-friendly." To develop a grid-friendly hydrogen production scenario, CEC staff designed a set of operational parameters for electricity supply in the production cost model, a part of the modeling efforts of SB 100. The production cost model assigns energy supply to meet demand. For the grid-friendly approach, staff developed a set of operational parameters and monthly production targets that interact with the model to optimize load instead of assigning a deterministic hourly demand profile to which the production cost model would assign energy sources. For additional information on these results, interested parties may refer to the SB 100 process and report, expected to be published in 2026.

The parameters for production cost model interaction are described by four paradigms: baseload time-of-use, flexible, and super-flexible. Each paradigm has three operational conditions: temporal operation, capacity factor, and ramping efficiency. The paradigms and operational conditions result in the following parameter characterization, described in Table 17 below.

Table 17: Grid-Friendly Hydrogen Electrolyzer Operation Parameter Characterization

Parameter	Temporal Operation Characterization	Capacity Factor Characterization	Efficiency From Ramping Characterization
Super-Flex	Can drop to zero load to maximize against price signals	Lowest capacity factor to capture maximum flexibility	Consistent ramping means lowest efficiency
Flexible	Can drop to very low levels to represent high flexibility	Lower capacity factor to capture some flexibility	Regular ramping causes relatively large reductions in efficiency
TOU	Regularly drops to low levels to approximate TOU optimization schedules	Moderate capacity factor to approximate likely TOU scheduling	Some ramping causes some reductions in efficiency
Baseload	Maintains high operational capacity	Near 100 percent capacity factor to prioritize production	Baseload operation maintains ideal efficiency

Source: CEC staff

The parameter characterization is quantitatively described by Table 18 below.

Table 18: Grid-Friendly Hydrogen Electrolyzer Operation Parameter Quantification

Parameter	Percentage Share of Electrolyzer System	Minimum Load Draw	Maximum Load Draw	Target Annual Capacity Factor	Multiplier for Ramping Efficiency
Super Flex	16.7%	0%	70%	40%	0.7
Flexible	16.7%	10%	77.5%	55%	0.8
TOU	16.7%	20%	87.5%	75%	0.9
Baseload	50%	92.5%	97.5%	95%	1.0

Source: CEC staff

Each paradigm has quantified operational parameters that interact with the production cost model to meet monthly hydrogen production targets at the lowest cost. Staff established monthly hydrogen production targets in each scenario year by the annual demand, with a seasonal adjustment identical to the proportions in medium- and heavy-duty seasonal electricity demand. Minimum and maximum load bounds are set to approximate the likely behavior of the different paradigms. For example, Super Flex can, at some hours, operate at zero load, so long as it maintains the monthly production targets and approximates an annual capacity factor of 40 percent. However, because Super Flex is subject to more ramping, staff assumed a ramping multiplier of 0.7.

In summary, although there is a large amount of electricity devoted to production of hydrogen by renewable generation-supported electrolysis, the Demand Scenarios Project, by itself, is unable to determine where the electrolyzers will be located. That uncertainty makes placement into a specific electric planning area impossible. Further, how the mix of electrolyzers will be operated on an hourly basis throughout a year with the rest of the electric generating resources, storage capabilities, and imports from outside California cannot be determined without seeing the results of the production cost modeling.

The evolving mix of electric generation resources required to satisfy SB 100 requirements will influence production cost model outcomes. These aspects prevent including electrolyzer load in electric planning area results of the Demand Scenarios project except for those projections that are explicitly industrial onsite production and usage as described earlier in this chapter.

BTM PV and Storage

Background

The demand scenarios adoption forecasts for behind-the-meter (BTM) distributed generation (DG) were based on the 2023 IEPR BTM DG forecast, which used a California-specific variant of NREL’s dGen model. This approach was thoroughly discussed during development of the

2023 IEPR demand forecast.[31] While the *2023 IEPR* serves as the baseline, some demand scenarios incorporate factors that increase BTM DG adoption beyond IEPR projections. Scenarios with greater BTM DG adoption were designed to increase the deployment of BTM energy storage, a flexible resource capable of responding to end-user and grid needs. The CEC Policy Scenario High DER aimed to increase cumulative BTM storage capacity by 5,000 MW by 2050, while the CEC Enhanced Policy scenario targeted a 10,000 MW increase by 2050, compared to the 2023 IEPR forecast.

For BTM PV generation, capacity factors align with the *2023 IEPR* in the Demand Scenarios Project. As a result, increases in self-generation forecasts are proportional to increases in BTM PV capacity.

Adoption Modeling Technique

The BTM DG demand scenarios were developed by modifying two inputs to the 2023 IEPR BTM DG adoption forecast. Depending on the demand scenario, the Investment Tax Credit (ITC) was extended, and capital expenditure (CapEx) costs for BTM storage were reduced. Furthermore, the modeling considered the impacts of adding storage to existing stand-alone PV interconnected under net energy metering (NEM) tariffs.

The ITC provides a 30 percent federal tax credit for CapEx on BTM PV and storage systems. This credit is set to expire in 2035 unless renewed by Congress. Without an ITC extension, the forecast effective costs for BTM DG technologies rise post-2035, leading to lower adoption forecasts. As shown in **Table 19**, the Enhanced Policy Scenario includes an ITC extension through 2050. Extending the ITC leads to ongoing CapEx reductions and supports greater adoption compared to other scenarios.

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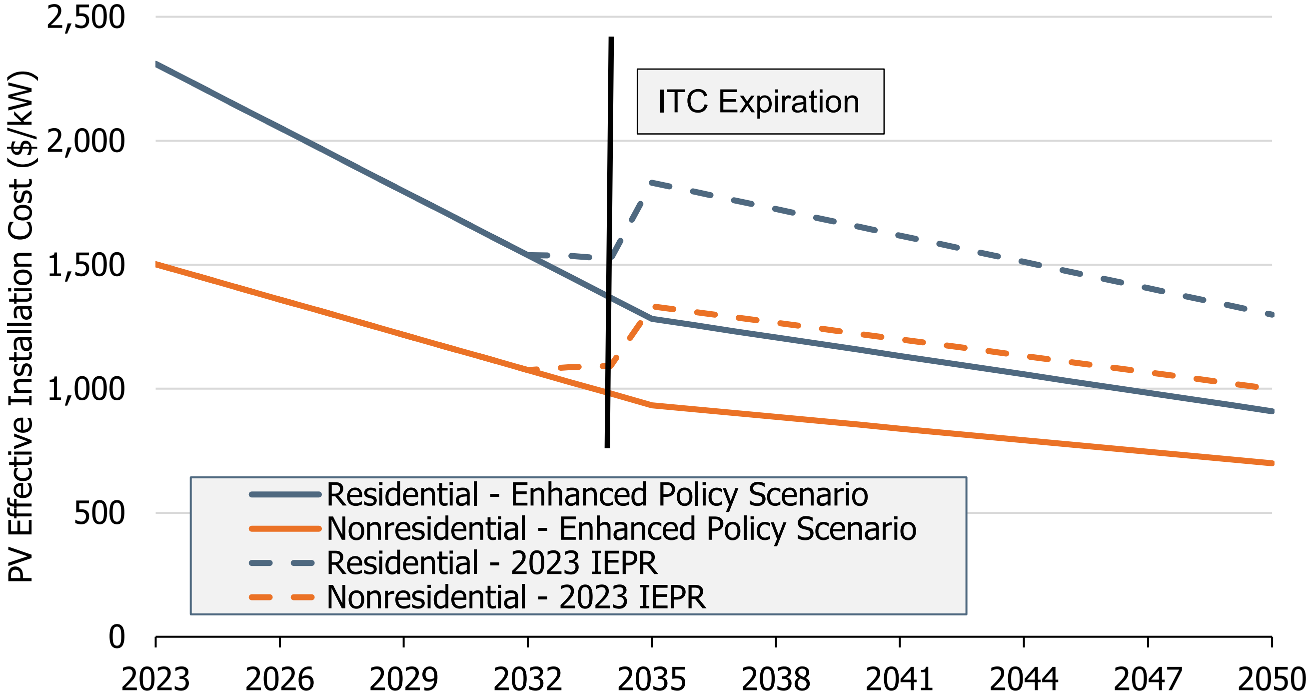
[31] NREL's presentation of the California-specific version of the dGen model from the August 8, 2023, Demand Analysis Working Group is available at (https://www.energy.ca.gov/media/8580).
Sekar, Ashok, Paritosh Das, Ashreeta Prasanna, Michael Sizemore, and Kevin McCabe (National Renewable Energy Laboratory). June 2024. *Modeling Distributed Generation in California.* California Energy Commission. Publication Number: CEC-200-2024-001, https://www.energy.ca.gov/publications/2024/modeling-distributed-generation-california.

Figure 11 illustrates the difference in effective PV costs with the ITC extension.

Figure 11: PV Net Installation Cost by Scenario



Source: CEC staff

In this context, CapEx includes all costs associated with purchasing and installing a BTM energy storage system, including dealer markups. The Enhanced Policy Scenario assumes a 50 percent CapEx reduction for installing BTM storage, making it the most aggressive scenario. This 50 percent reduction was chosen to align forecast results with the demand scenario objectives.

The net billing tariff (NBT) provides greater financial benefit to pair BTM PV with storage compared to NEM tariffs. Under NBT, hourly net energy exports are valued based on grid needs, rather than import electricity rates, as is the case with NEM tariffs. Electricity is most valuable to the grid during evening hours when PV generation is low. BTM energy storage allows customers to store excess PV generation in the afternoon and use it during the most grid-constrained and high-cost hours for electricity.

As a result, the NEM contractual turnover assumes a portion of utility customers with BTM PV under NEM agreements will adopt storage when their agreement expires, and they transition to the NBT. The forecasted number of storage additions from NEM contract turnover are based on the forecast attachment rate for new BTM DG installations in the same year.

These demand scenarios capture cost-effectiveness of BTM DG technologies from the adopter’s perspective, dependent upon policy and technology market conditions. Extension of the ITC is contingent on future federal policy. A 50 percent discount to BTM storage CapEx is likely unrealistic without expansion or introduction of additional state and federal incentives, although some cost reductions may occur through the maturation of the energy storage industry. BTM storage adoption from NEM contractual turnover doesn't require new policy considerations and is instead driven by consumer behavior.

Table 19: BTM Distributed Generation Demand Scenario Modeling Framework

Scenario Assumptions	Reference Scenario	Policy Scenario	Policy Scenario High DER	Enhanced Policy Scenario
Investment Tax Credit	2023 IEPR forecast	2023 IEPR forecast	2023 IEPR Forecast ITC expires 2034	ITC extended to 2050
Technology CapEx	2023 IEPR forecast	2023 IEPR forecast	2023 IEPR Forecast	50% reduction in forecast storage CapEx
NEM Contractual Turnover			Fraction of existing standalone PV adopters add storage when their NEM contract expires	Fraction of existing standalone PV adopters add storage when their NEM contract expires

Source: CEC staff

Hourly BTM PV Forecast Modeling Technique

To support POU planning area hourly load projections, Hourly BTM PV generation shapes were developed for POU planning areas. These shapes were not needed for the *2023 IEPR*, which includes only hourly demand forecasts for the California ISO region and its three member IOUs. The shapes were derived using a method consistent with the 2023 IEPR demand forecast and based on a large sample of historical metered BTM PV data procured by the CEC.

Historical metered data for each POU planning area were grouped by year, customer sector, month, week, and hour. These data were averaged across days within the same week of each month and then across years. The result is 96 distinct BTM PV hourly shapes — four per month, per sector, for each POU planning area. The data were normalized to reflect each hour as a percentage of total monthly BTM PV generation, maintaining the 2023 IEPR capacity factors. The result is hourly cumulative forecasts for BTM PV generation estimates in each POU planning area.

Hourly BTM Storage Forecast Modeling Technique

Hourly BTM storage shapes were developed for POU planning areas, like BTM PV. POU planning area shapes were based on IOU planning area shapes from the 2023 IEPR demand forecast. Residential BTM storage shapes were developed by CEC staff using NREL's System Advisor Model, while nonresidential storage shapes were based on data from the CPUC's 2021-2022 Self-Generation Impact Evaluation.[32] In both cases, the forecast shapes were normalized

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[32] More details on the 2023 IEPR hourly BTM Storage shapes, discussed at the October 26, 2023 Demand Analysis Working Group, are available at https://www.energy.ca.gov/event/meeting/2023-10/ca-energy-demand-forecast-updates-and-draft-results. The CPUC's *2021—2022 Self-Generation Impact Evaluation* is available at

so each hour represents the power charged or discharged per unit of nameplate BTM storage capacity. Once the shapes were finalized, CEC staff applied incremental BTM storage capacity to each hourly shape, reflecting the power dispatched by the forecasted adoption of new residential and nonresidential BTM storage in each POU planning area.

Energy Pathways

EER's EP model is a comprehensive energy analysis tool designed to project the consequences of user-defined economywide energy demand scenarios.[33] EP is highly adaptable to different data input structures and can be used in three approaches to integrate inputs and assumptions to project demand:

1. **Energy demand.** EP can accept existing energy demand forecasts and modify them to adapt to different economic drivers and geographies.
2. **Stock with service demand or energy demand.** EP can track the stock rollover of technology stocks and new sales, ensuring that the fleet of in-service appliances or vehicles can meet required service or energy demand in each modeled year.
3. **Service demand with energy demand or efficiency.** EP can calculate projected energy demand where service demand is available, but no data for stocks or technologies are available for a full rollover calculation. Instead, service efficiency terms are used to calculate energy demand from service demand.

In the Demand Scenarios Project, CEC staff directly developed nearly all the sector and fuel combination projections outside the EP model. For a subset of sectors and fuels, EER used the EP model to develop projections using Approach 1 described above, adapting existing energy demand forecasts to a specific geography and in some cases modifying them to align with CEC-provided drivers. In all instances where the EP model was used to produce projections, staff calibrated the related inputs to align with the previous iteration of the demand scenario analysis in the near term, then allowing the drivers or underlying energy projections to shape that specific projection. Table 20 lists the sector-fuel combinations developed by EER in the EP model.

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https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/self-generation-incentive-program/sgip-2021-2022-impact-evaluation.pdf.

[33] Detailed documentation of the EP model is available in the technical documentation for EER's 2023 Annual Decarbonization Perspective report, available by clicking the "Download Technical Documentation" option at https://www.evolved.energy/2023-us-adp.
Haley, Ben, Ryan Jones, Jim Williams, Gabe Kwok, Jamil Farbes, Darcie Bentz, Greg Schivley, and Jesse Jenkins. 2023. *Annual Decarbonization Perspective 2023: Carbon-Neutral Pathways for the United States.* Evolved Energy Research, https://www.evolved.energy/2023-us-adp.

Table 20: Sector/Fuel Type Outputs From EP Model

Sector	Fuel/s	Source of Projection	Driver Description
Agriculture	Electricity	Supplemental data from EP	CEC agriculture gross state product projection, modified from AEO 2022 projections
Agriculture	1. Diesel 2. Gasoline 3. Steam	EP	CEC agriculture gross state product projection, modified from AEO 2022 projections
Commercial	1. Diesel 2. Gasoline 3. Steam 4. Biomass/Wood	EP	Projected commercial square footage
Industrial	Gasoline	EP	CEC subsector-specific drivers, modified from AEO 2022 projections
Industrial	Steam	EP	
Oil & Gas Extraction	Diesel	EP	CEC provided projections, modified from AEO 2022 projections
Oil & Gas Extraction	Steam	EP	
Petroleum Refining	Steam	EP	CEC provided projections as driver, modified from AEO 2022 projections
Residential	Diesel	EP	Households and calibrated data from the EIA State Energy Data System
TCU	Steam	EP	Projected commercial square footage
Transportation	Diesel	Supplemental data from EP	AEO 2022 projections
Transportation	Hydrogen	Supplemental data from EP	

Source: EER

Carbon Capture and Sequestration

Inclusion of the energy and emission impacts of the deployment of carbon capture for technologies other than power generation was explored for this analysis. EP has several industrial carbon capture representations, which translate an assumed level of carbon capture over time into projected energy demand. The inputs supplied for this analysis are based on the same assumptions for industrial carbon capture as used in other EER analyses. They produce estimated incremental electricity and steam demand per additional unit of carbon capture based on literature sources.[34]

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[34] Kuramochi, Takeshi, Andrea Ramírez, Wim Turkenburg, and André Faaij. 2012. "Comparative Assessment of CO2 Capture Technologies for Carbon-Intensive Industrial Processes." *Progress in Energy and Combustion Science*. Volume 38, Issue 1, https://www.sciencedirect.com/science/article/abs/pii/S0360128511000293.

As with other subsectors modeled with EP, it is possible to develop these carbon capture projections on a planning-area basis. However, given that the scope of the Demand Scenarios Project does not extend to the disposition of captured carbon, staff elected not to include a carbon capture element within any scenario or sensitivity until it could be given a more robust treatment in future demand scenarios work.

Carbon utilization is a critical consideration for the emissions and potential energy impact of carbon capture technology deployment. Captured carbon could be stored geologically or potentially used in the production of e-fuels. The optimal utilization to meet emissions targets, however, is a complicated proposition, which depends heavily on cost dynamics that can only be captured in an energy supply optimization analysis. Factors impacting carbon utilization include the cost of carbon capture, competing uses for hydrogen (other than e-fuel production), and the cost of transportation from point of production to point of use and carbon storage costs.

Refinery Adjustments

The CEC's baseline electricity and pipeline gas demand forecasts for the refinery industry are not adjusted for the decline anticipated in use of petroleum-based fuels. In contrast, all scenarios examined in this analysis incorporate a feedback mechanism in which the energy demand of petroleum refineries decreases in response to declining demand for refined products within the state. This "refinery adjustment" uses baseline data from 2023 and assumes a fixed relationship between the demand for key refined products (diesel, gasoline, and jet fuel) and the overall energy input required by the petroleum refinery subsector. Staff assumed that this relationship is representative of broader refinery operations. As the annual demand for these refined products declines in each scenario, driven by different core assumptions for each scenario, the energy consumption of refineries is proportionately reduced.

Since transportation fuel demand is not uniform in all scenarios, the adjustments to refinery energy consumption differ in each scenario. The refinery adjustment significantly alters demand for the petroleum refining subsector in the later modeled years as large reductions in fuel demand driven by transportation electrification displace the use of conventional refined fuels. It is possible to modify the refinery adjustment based on user inputs, including expanding or shrinking the set of fuels that are used to estimate refinery output and changing assumptions about shares of fuels that are not produced by instate refining capacity. This feedback mechanism was incorporated to address a shortcoming of previous demand scenario work, where demand for refined products drops significantly but energy demand for refineries does not decline in response.

The annual refinery adjustment affects all fuels used within the petroleum refining subsector, ensuring a comprehensive approach to modeling changes in energy demand. The refinery adjustment is also translated into an hourly electricity impact by applying the specific hourly demand profile for refinery electricity consumption. The electricity impacts of the refinery adjustment are broken out as separate load modifiers in the annual and hourly scenario results.

Oil and Gas Production Adjustments

Oil and gas production is another subsector where energy demand can be adjusted based on changing demand for oil- and gas-derived fuels. While the state does not exclusively depend on oil and gas production from within California, there are possible futures where energy demand for oil and gas production could decrease as demand for fuels produced from oil and natural gas production decline. This analysis developed an oil and gas adjustment, which parallels the refinery adjustment mechanism, and used this adjustment functionality only for the Enhanced Policy Scenario and related sensitivities.

The oil and gas adjustment has a similar structure and purpose to the refinery adjustment but considers energy consumption associated with production rather than refining. This adjustment reflects changes in energy demand driven by shifts in oil and gas production activities. Like the refinery adjustment, it assumes a fixed relationship between demand for oil-derived fuels (diesel, gasoline, and jet fuel) and the operational demand for oil and gas production, using baseline data from 2023 as the reference point. As demand for refined products decreases over time, this adjustment scales down the associated energy demand for oil and gas production proportionately.

This adjustment is only included in the Enhanced Policy Scenario and associated sensitivity, as the scenario explores a possible future where in-state oil and gas production responds to declining in-state demand for refined products. By incorporating this additional layer of feedback, the Enhanced Policy Scenario considers how declining energy consumption patterns across the oil and gas subsector may impact the state’s energy and emission outcomes. The oil and gas adjustment shares the same set of user inputs as the refinery adjustment, and any changes to the refinery adjustment calculations are also reflected in the oil and gas adjustments. As with the refinery adjustment in the electricity results for the scenarios, the oil and gas adjustment is reported as a separate load modifier.

Assumptions for Other Loads

As noted in Table 6**,** CEC modeling efforts are extensive and capture nearly all sources of energy demand within California. One of the subsectors not addressed by CEC modeling is oceangoing vessels. The contractor team used EP to project energy demand for oceangoing vessels, including fuel switching to hydrogen in select scenarios. EP uses a downscaling of the Energy Information Administration’s Annual Energy Outlook to estimate projected California fuel demand for oceangoing vessels.

The reference scenario reflects the projected demand for diesel for the oceangoing vessel subsector. Based on assumptions from the demand scenarios team, all other scenarios assume some level of fuel switching away from diesel to hydrogen. The Policy Scenario assumes 5 percent hydrogen demand from oceangoing vessels in 2040, and the Enhanced Policy Scenario assumes 50 percent hydrogen by 2040 in addition to a 10 percent improvement in efficiency.

Developing an Integrated Tool

While EP was used to develop a very small portion of the projected total energy demand in each scenario (less than 10 percent of total energy demand), another custom tool developed by EER was used to integrate the many CEC projections, as well as the subset of sector and fuel combinations that were produced by the EP model. This is the new Demand Scenarios Model. The model consists of a set of scripts, all of which are developed in the Python programming language, which combine the range of inputs for a given scenario, adjusting to the planning area and applying potential modifications to a given file (for example, converting to standard units).

The final outputs of the tool are the annual and hourly results for each scenario. The integration tool is divided into two major portions: annual compilation and hourly compilation. The integration of the various annual files is completed first, followed by hourly compilation calculations.

The annual portions of the integration script combine the range of projections from several groups and models, ensuring consistent mapping of fuel names, planning area names, and sector names. The underlying projections from the CEC vary widely in naming conventions, data table structure, file format, units, and sign conventions. The annual integration script was designed to ease compilation of these highly heterogeneous files, depending on user inputs to identify the appropriate value, planning area, sector, and fuel columns, along with any necessary mapping to ensure consistent naming.

The script also adapts statewide transportation demand projections provided by the CEC into planning area level results based on an allocation of light-, medium-, and heavy-duty vehicles provided by the CEC. Where CEC data are unavailable to support allocating transportation energy demand planning area, other factors (for example, share of fuel sales by planning area or planned rail expansion) are used.

The annual script controls how the limited set of EP results are combined with CEC projections. It also implements the refinery demand and oil and gas production adjustments, which are discussed in following sections. Driven by user inputs, the annual integration tool produces several results files, which slice the data in different ways (for example, one file with all fuels in a common unit, another file with only electricity in GWh and with load modifiers broken out separately).

The annual script also supports developing emission projections within the script directly, based on a separate input file and controls that allow the direct calculations to be turned on and off. The script simply multiplies annual energy projections by fuel type with user-defined emission factors. Some fuel types have a constant value through time, while others vary through time according to user scenario assumptions. Alternatively, the annual energy results can be imported into the separate Excel®-based emissions tool, which is discussed below.

The hourly portions of the integration script combine the many hourly electricity projections, ensuring consistent mapping of hourly data to the format expected for electric generation supply-side modeling. The hourly integration maintains planning area granularity and adjusts demand for transmission and distribution losses based on CEC assumptions distinct to each planning area. Annual load projections that lack corresponding hourly load data (electric aviation loads, rail, cable car, trolleybus, off-road electrification, motor homes, vanpool, and ferryboats) are assumed to have flat hourly load profiles. The hourly portion of the script adapts the annual loads for these categories into flat hourly loads, also adjusting for losses in the process. Given the size of the files involved for hourly scenario results, the tool also gives users the latitude to divide the results into subgroupings and write those results to disk (for example, the current demand scenario analysis separates IOU and other planning areas into respective results files to keep file sizes manageable).

Baseline Hourly Electric Load Modeling

Verdant developed an hourly baseline electric load projection for the four POUs using an extension of the Hourly Load Model (HLM) method the CEC developed for the IOUs and California ISO. This baseline is essentially the projection of hourly load using historical relationships between annual electric energy and hourly load without any of the adjustments or formal load modifiers in future years that lead to changes in traditional hourly load shapes. Influences on hourly HLM load projections come from the hourly load projections from sector load modifiers described previously, which vary from scenario to scenario depending upon the amount and shape of electrification impacts.

Overview of Methods

The CEC relied on Verdant to produce the hourly baseline forecast of electricity load for the four primary publicly owned utility areas Burbank combined with Glendale (BUGL), Los Angeles Department of Water and Power(LADWP), Imperial Irrigation District (IID), and several Northern California POUs not part of the California ISO (NCNC) (collectively referred to as the POUs) for the 2023–2050 period. Hourly electric load forecasts for these POU areas have not been developed as part of the routine IEPR proceeding. For the POU hourly forecasts, Verdant followed the steps and scripts that were developed by the CEC staff for the creation of the IOU hourly forecasts. Verdant focused on developing the POUs' hourly baseline forecasts of electricity consumption, incorporating the impacts of climate change and then applying many of the electrification and efficiency load modifier impacts that were developed by CEC staff to develop the reference scenario. The following sections describe the steps Verdant followed to develop the POU hourly forecasts.

At a high level, the process for developing an hourly electric load forecast for each POU involves:

- Assembling historical annual energy consumption, hourly electric load measured at the system level, hourly weather data, and load impacts and duration for any specific incidents disrupting "normal" load patterns during the historical period.
- Organizing these historical data in chronological order with descriptive parameters of date, time, day of week, and so forth.
- Creating an econometric specification constrained to explanatory variables available throughout a long-term future time horizon.
- Making initial parameter estimates and iterating to reach a final specification and parameter estimates that maximizes fit.
- Developing a baseline hourly projection to 2050, without impacts from load modifiers, using projected annual baseline energy consumption, hourly weather variable projections

- Adding or subtracting impacts of scenario-specific load modifiers (scaled for losses) and other hourly adjustments, if any, to the baseline hourly projection to form a system-level, managed hourly forecast.

This overview will be elaborated upon below and further details are described in Appendix D.

Baseline Hourly Load for POUs

The starting point of the POU hourly load projections was a baseline annual consumption forecast. To estimate the baseline consumption, the California Energy Demand (CED) annual forecast, developed for the Integrated Energy Policy Report (from 2023 extended to 2050), was used along with historical 8760 load data (from 2016 to 2022). These data sources were provided by the CEC for each of the POUs referenced above.

Annual baseline for each POU was developed using the CEDs "adjusted consumption" (from the CED final electricity FZ baseline workbook) values minus the CED light-duty EV baseline values, the medium- and heavy-duty EV baseline values, and the CED climate change impact variable. These annual CED transportation and climate change values were removed from the annual CED consumption forecast because updated values were developed for the demand scenario project. This "baseline" (that is, CED adjusted consumption minus the transportation and climate change values) was multiplied by the POUs' loss factors to account for energy lost in delivery to customers' meters. The annual baseline was used to develop 8760 "baseline" forecasts by applying hourly load shape shares developed from historical hourly load data.

To develop the shape of the load, Verdant (the prime consultant supporting the Demand Scenarios Project) started with the historical 8760 load data (from 2016 to 2022) provided by the CEC for each of the POUs. These data were assessed for outliers and missing data. While the quality of these data differ by POU, Verdant reviewed each of the data series with CEC staff to determine if updated data were available. Where updated data were not available, the remaining outliers were removed from the historical data. In addition, estimates of historical hourly PV generation in each POU were added to ensure that the historical hourly data series reflects consumption and not just sales.

Using this historical 8760 hourly consumption time series, hourly load shares were developed using multivariate regression (See Appendix D for the estimation details.) such that each hour's share reflected the historical usage observed in the hour relative to the usage in all other hours of the year. The usage shares were characterized by hour, month, and day of the week type so that they could be correctly assigned to the calendar for each year from 2023 to 2050. Calendarization is the process of taking projected hourly load values resulting from historical data for a specific year and shifting the values for future projections to match the actual day of week, Leap Year, and holidays expected for each future year. Special consideration was given to holidays during this calendarization.

The calendarized load shapes from the historical 8760 load data were applied to the yearly unadjusted consumption to estimate the baseline hourly load forecasts for 2023 to 2050. This estimate served as the starting point for the POU hourly forecast and was called "baseline " in the forecasts. Adjustments for transportation electrification, BTM solar and storage, energy efficiency, and fuel substitution were applied to this baseline consumption forecast. These adjustments are described in the subsections below.

Transportation Electrification Adjustments

Transportation electrification was another adjustment staff made to the baseline consumption forecast. To develop these impacts, staff developed transportation electrification forecasts for each POU by transportation sector. The transportation sectors are grouped together to create a light-duty (LD) vehicle forecast and a medium- and heavy-duty (MDHD) vehicle forecast. The LD vehicle forecast combines single family, multifamily, commercial destination, commercial fleet, and the other vehicle transportation categories. The MDHD vehicle forecast combines the remaining transportation sectors. Both the LD and MDHD transportation electrification forecasts were augmented by the POU loss factors to account for energy lost in delivery to the charging infrastructure.

Staff applied transportation electrification forecast adjustments to the Reference Scenario, Policy Scenario and the Enhanced Policy Scenario.

Climate Change Adjustments

The next adjustment to baseline consumption was the development of changes associated with the impact of climate change. To forecast climate change impacts, the CEC the work of the consulting firm Lumen Energy Strategy that created detrended temperature libraries and estimated elasticities were used. The detrended temperature libraries were prepared under CEC Electric Program Investment Charge (EPIC) Contract No. EPC-22-001 (WARP to Resilience). The temperature detrending purpose and method are described in the August 18, 2023, IEPR workshop.[32]

The first step of the climate change adjustment uses a regression analysis to estimate the impact of changes in weather on baseline electricity consumption, to develop estimates of weather elasticities. Weather elasticities were developed by month, hour, and day type (workday, weekend). The estimated weather elasticities describe how changes in temperature are associated with changes in baseline hourly load for each of the POUs.

To forecast how changes in climate, or changes in future temperatures, will lead to changes in the hourly load forecast for each POU, staff developed a forecast of future changes in temperature using the detrended temperature libraries developed by Lumen. (These libraries were provided by the CEC.) The temperature libraries were used to develop year-over-year percent changes in average hourly temperature. Staff developed these temperature changes for each POU by year, month, and hour of the day for 2023 through 2050.

The series of hourly forecast changes in temperatures were then applied to the estimated elasticities to forecast percentage changes in hourly load caused by the change in temperature (that is, due to climate change). Staff emphasizes that the estimated weather elasticities lead to hours where increases in minimum temperature are forecasted to reduce hourly load (in other words, winter or heating hours) and hours where increases in maximum temperature are forecasted to increase hourly load (that is, summer cooling hours).

Behind-the-Meter Solar and Storage Adjustments

Using the modeling techniques outlined in the section "BTM PV and Storage," CEC staff developed annual adoption forecasts and corresponding hourly projections for BTM PV generation, BTM storage charging, and discharging for each scenario in Table 19. CEC contractors then applied these projections to each POU's baseline energy usage forecast.

Fuel Substitution and Energy Efficiency Adjustments

Impacts of fuel substitution and energy efficiency were two other adjustments that were also made to the baseline consumption forecast. To develop the impact of these load modifiers, CEC staff provided the programmatic AAEE and AAFS and, for other fuel substitution, FSSAT forecasts for each of the POUs. These forecasts were augmented by a line loss factor before being included in the POU forecasts. The estimate of EE changes was subtracted from the overall forecast and the estimates of changes due to fuel substitution (programmatic AAFS and FSSAT) were added to the overall forecast.

Other Adjustment Parameters

There were other adjustment parameters that were not included in this initial POU hourly forecast but were estimated for the IOU hourly forecasts. Specifically, the pumping energy consumption was not estimated for the POUs nor were the TOU impacts or "other adjustments." Although such adjustments may be desirable for individual POUs, staff does not have the same knowledge of the impacts of any relevant adjustments as it does for IOUs.

GHG Module Fuel Blending

As the Demand Scenarios Project did not include supply-side energy modeling, the analysis did not generate a projection of decarbonized fuel consumption in California, and other available projections (for example, from the CARB Scoping Plan or Low Carbon Fuel Standard modeling efforts) are not aligned with the demand-side projections included in the demand scenarios. As a result, it was necessary to develop fixed assumptions regarding decarbonized fuel use in California to generate total emissions projections that align with the demand projections. To develop those assumptions, EER first performed a literature review to understand the range of decarbonized fuel blending included in other California decarbonization analyses. The review focused on a subset of fuels that make up most of California's nonelectric fuel demand: diesel, jet fuel, natural gas, and gasoline.

Table 21 summarizes the results of the literature review.

Table 21: Decarbonized Fuel Blending Literature Review Findings

Analysis	Diesel	Jet Fuel	Natural Gas	Gasoline
CARB Scoping Plan	Uses LCFS forecast through 2030. The 2045 value is based on anticipated in-state renewable diesel production capacity.	Reference scenario assumes 0% blending, Scoping Plan projections assume 100% SAF. Analysis represents only the portion of jet fuel demand included in emissions inventory.	Scoping Plan estimates in-state AD biogas potential. Assumes that today's small quantity of electricity production from RNG persists. All incremental potential allocated to pipeline. Reference scenario assumes that transportation sector natural gas demand converts to 100% RNG.	Assumes that 7% corn-based ethanol blending in gasoline continues from present through 2045
Stanford Pathways to Carbon Neutrality in California	Compares diesel demand at different blending levels to today's global production; evaluates in-state production potential	Matches CARB; one sensitivity looks at 100% biojet fuel	Compares RNG demand at different blending levels to state and national production potentials	Matches CARB
CEC 2021 Demand Scenarios	Assumes same quantity of renewable diesel in all scenarios; equal to renewable diesel maximum in Scoping Plan	No blending reflected	Biogas blending in mitigation scenario only	Assumes that 7% corn-based ethanol blending in gasoline continues from present through 2045

Source: CEC staff.

Based on this literature review, EER reached several fuel-specific conclusions.

Diesel: California's 2023 decarbonized diesel consumption, incentivized by the LCFS program, exceeds 2050 diesel demand in all the demand scenarios modeled in this project, which suggests that decarbonized diesel could meet 100 percent of 2050 diesel demand. However, California's decarbonized diesel is imported via a global market, meaning that as other economies begin to demand more decarbonized fuel, California will face more competition for the available supply, making long-term blending levels highly uncertain.

Jet fuel: EER's literature review found sustainable aviation fuel blending assumptions that ranged from 0 percent to 100 percent. Supply of synthetic jet fuel, produced from electrolytic hydrogen and captured carbon, is theoretically unlimited. Supply of biomass-based jet fuel, which is used to produce most SAF today, is highly feedstock-limited. Decarbonized jet fuel is a relatively high-cost decarbonization strategy, such that the cost-optimal level of blending depends on decarbonization efforts elsewhere in the economy and the residual emissions reductions required to meet targets.

Pipeline gas: Decarbonized pipeline gas can be produced from biomass via anaerobic digestion or dry biomass gasification, or it can be synthesized from hydrogen. Most studies limit decarbonized pipeline gas supply to biomass-based fuels because synthetic methane is assumed not to be cost-competitive. Biomass-based methane supply is limited by feedstock availability, and California is likely to face increasing competition from other economies in purchasing biomethane in the future.

Gasoline: Like diesel, total gasoline demand declines precipitously in the demand scenarios. The studies included in EER's literature review assume that today's 7 percent corn ethanol blending in gasoline persists through 2050 but that no additional decarbonized gasoline is consumed in California.

Given these conclusions, and the difficulty they create for making long-term assumptions about fuel blending levels without supply-side modeling, the emissions projections detailed below assume that decarbonized fuel blending levels in California remain constant from 2023 to 2050. Table 22 shows the current blending percentage for each fuel, derived from LCFS reporting data.

Table 22: 2023 Decarbonized Fuel Blending Levels in California

Fuel	2023 Decarbonized Fuel Supply, BTU (From LCFS Dashboard)	2023 Total Fuel Demand, BTU (From Demand Scenarios)	Share of 2023 Fuel Demand
Diesel[35]	2.84E+14	5.06E+14	56.2%
Gasoline	1.11E+14	1.52E+15	7.3%
Pipeline Gas	2.52E+13	2.84E+15	0.7%
Jet fuel	2.87E+12	5.16E+14	0.6%

Source: CEC staff

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[35] Biodiesel and renewable diesel supply from the LCFS dashboard are summed to generate total decarbonized diesel supply.

GHG Emission Projections

The emission projection model for the CEC Demand Scenarios project was developed by Jai J. Mitchell Analytics (JJMA) to show the emissions projections for various energy consumption projections through 2050. These demand projections were provided by fuel type and in British thermal units (Btu). To provide the fullest opportunity to explore the total emissions impacts of these scenarios, JJMA worked to provide an easily accessible Excel-based tool that would provide basic emissions projections using CARB emission inventory tracking methods.

Staff added capabilities to the tool that allowed various levels of fugitive methane and hydrogen leakage impacts to be included. The tool also can show all climate impacts in the form of carbon dioxide equivalent (CO_2e) for the global warming potential (GWP) 100-year and 20-year time frames. GWP conversions of these values were updated from the current CARB 2014 Intergovernmental Panel on Climate Change(IPCC) values to the slightly higher IPCC 2019 GWP-20 values that are current industry standard practice. Staff derived fugitive hydrogen leakage impact values using peer-reviewed models in the scientific literature since there is no IPCC value found in prior publications. Table 23 shows the various options included within the emissions tool.

All output charts of emissions in this report are, unless otherwise noted, set at the default values shown below. Emission projections for demand scenarios using the default values from Table 23 are reported in Chapter 4 with other high-level results. See Appendix D for emission projection results for an alternative package of settings to illustrate results focused on short-lived climate pollutants (Carbon Dioxide, Methane, Nitrous Oxide).

Table 23: Emissions Tool Capabilities/Selection Criteria

Variable	Possible Settings	Default
Default GHG Pollutants (by fuel consumed)	Carbon Dioxide, Methane, Nitrous Oxide	All
Fuel Demand Scenario	Reference, Policy, Enhanced Policy, Enhanced Policy with CCS, Enhanced Policy with Hydrogen	N/A
Global Warming Potential	GWP-20, GWP-100	GWP-100
Fugitive Methane	0%, 0.67%, 1%, 3%, 5% (of total consumption)	0%
Fugitive Hydrogen	0%, 1%, 5%, 10% (of total production)	0%
Biogenic Combustion Fuels Blending	High Series, Low Series (user input values)	Low Series
Selected Display of Emissions by Sector	Agriculture, Commercial, Industrial, Oil & Gas Extraction, Petroleum Refining, Residential, TCU, Transportation	N/A

Source: CEC staff/JJMA

Emissions Factors

CARB individual fuel-use profiles provide the emissions profile of major greenhouse gases (GHGs) by fuel type. The major GHG gases are carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). CARB provided specific end-use emissions profiles of these gases in the technical documentation of the 2000–2021 GHG inventory reports. These emission profiles provide total emissions of these GHGs in units of grams (g) per Btu.

Table 24 reports the GHG emission factors by fuel type values that were used to translate annual energy demand by fuel type into annual emissions.

Table 24: Emission Factors by Fuel Type (grams/btu)

Type of Fuel	CO_2	CH_4	N_2O
Biomass/Wood	8.96E-02	3.20E-05	4.20E-06
Coal	1.06E-01	1.10E-05	1.60E-06
Coking coal	1.02E-01	3.00E-06	6.00E-07
Distillate (Diesel)	7.41E-02	2.73E-07	1.15E-05
Gasoline (current blend)	7.01E-02	3.19E-06	2.35E-06
Hydrogen	0.00E+00	0.00E+00	1.04E-07
Jet Fuel	7.22E-02	5.30E-07	2.10E-06
Kerosene Fuel	7.52E-02	3.00E-06	6.00E-07
LPG	6.30E-02	3.00E-06	6.00E-07
Natural Gas	5.35E-02	1.24E-06	1.60E-07
Residual Fuel Oil	7.51E-02	3.00E-06	6.00E-07
Steam	6.06E-02	1.00E-06	1.00E-07
Still Gas	1.16E-01	3.02E-06	6.04E-07
Renewable Diesel*	0	3.00E-06	6.00E-07
Synthetic Gasoline*	0	3.19E-06	2.35E-06
Alternative Jet Fuel*	0	5.30E-07	2.10E-06
Biogas*	0	1.24E-06	1.60E-07
Ethanol for Light-Duty Vehicles*	6.84E-02	4.27E-06	3.13E-06

***Alternate fuels**

Source: Index to CARB 2000–2021 Inventory Individual Use Data Sheets

Aggregate GHG emissions associated with electricity generation were developed through use of the CPUC 2023 Avoided Cost Calculator tool developed by Energy and Environmental Economics, Inc. A statewide California ISO total system emissions profile is contained within this tool that shows projections of the total emission by year through 2050 that would be necessary to meet California’s current legislative emissions reduction targets.

The analyses that developed these projected values do not necessarily conform the level of demand resulting from each of the demand scenarios, to the current SB 100 electric generation studies, or any specific future policy implementation strategies. These emissions profiles are also applied to non-ISO generation sources because of the lack of electric generation studies for each non-ISO planning area. Historical line-loss values for specific planning areas were used to develop a statewide system production at the generator for the development of consistent statewide emissions projections.

Specific modeling parameters that were explored by the scenarios team during scenario development required the emissions tool to include a capability to show the blending of synthetic and alternative (for example, biogenic) combustion fuels into future consumption profiles and the modeling of industrial carbon-capture and sequestration (CCS), which could also be adapted as a proxy for industrial sector direct air capture of CO_2. During the project, staff determined that incorporating the aggregate emission consequences of fuel blending was infeasible as described in the previous section. By this time, a fuel-blending capability had been developed in the emission projection model. Inputs to the GHG emission projection tool were modified to freeze emission factors at current values for the fuels mostly likely to be subject to change in emission factor.

Current fuel blending of combustion fuels was addressed by adjusting the CARB emissions inventory profiles where necessary. CARB gasoline emissions profiles show the current statewide emissions profile, on an annual average basis in grams per BTU, that include current ethanol blending levels. These values were maintained through 2050 in the emissions projections for this fuel. Current levels of blending for Diesel, Jet Fuel, and Natural Gas fuel blending were derived using current fuel blending mix values of biogenic-sourced alternatives, and these levels were also maintained through 2050. This was necessary to allow for the inclusion of N_2O emissions from these biogenic fuel sources into the total system emissions profile.

Capability was included in the emissions tool to allow for adjusted levels of combustion fuel blending in future years. Nitrous oxide production levels for hydrogen were assumed to be 65 percent of the value produced by the combustion of natural gas and this level was conservatively applied to all hydrogen consumption. Even so, the impact of this fuel’s emission profile was several orders of magnitude too low to be shown in the statewide profile graphics. Emissions associated with aviation includes all fuels loaded at California airports, regardless of flight destination, in contrast to the CARB convention of including only emissions from in-state flights.[36]

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[36] The inclusion of trans-state and international flights results in a 93 percent increase in total emissions associated with this fuel.

CHAPTER 4:
Demand Scenarios Aggregate Results

As described in the method chapter of this report, the custom tool that EER developed for the Demand Scenarios project produces projections of annual fuel demand by sector, fuel type, and planning area, as well as projections of hourly electricity demand by sector and planning area. The following sections show key annual energy demand scenarios results, key metrics drawn from hourly electric load projections, and annual statewide GHG emission projections by scenario. This chapter provides a broad overview of results at a high level, while Chapter 5 highlights key factors influencing sector results.

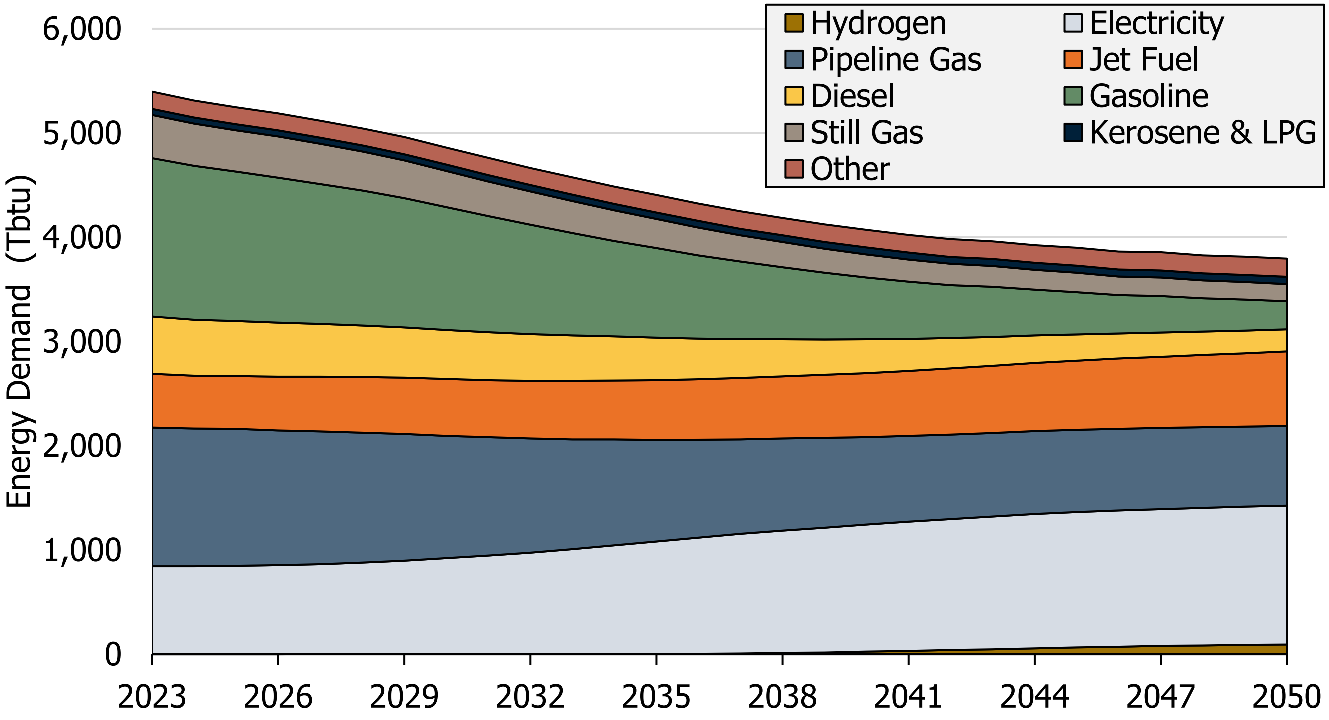
Annual Statewide Energy Consumption

Consumption of Electricity, Natural Gas, and Other Combined Fuels by Scenario

In each of the three primary demand scenarios (Reference, Policy, and Enhanced Policy), total statewide energy demand declines from 2023 to 2050. As shown in Figure 12 through Figure 14, demand for pipeline gas, still gas, diesel, and gasoline declines in all scenarios, largely due to electrification of the building, industrial and transportation sectors. Jet fuel demand increases, reflecting the assumption that neither electricity nor hydrogen are currently largely feasible pathways for most of the aviation sector (as well as the assumption that total aviation passenger miles traveled continues to increase). Electricity demand grows in all scenarios, though the total increase in electricity consumption is addressed by EE measures and the inherent efficiency advantage of electric end-use technologies over fuel-burning technologies.

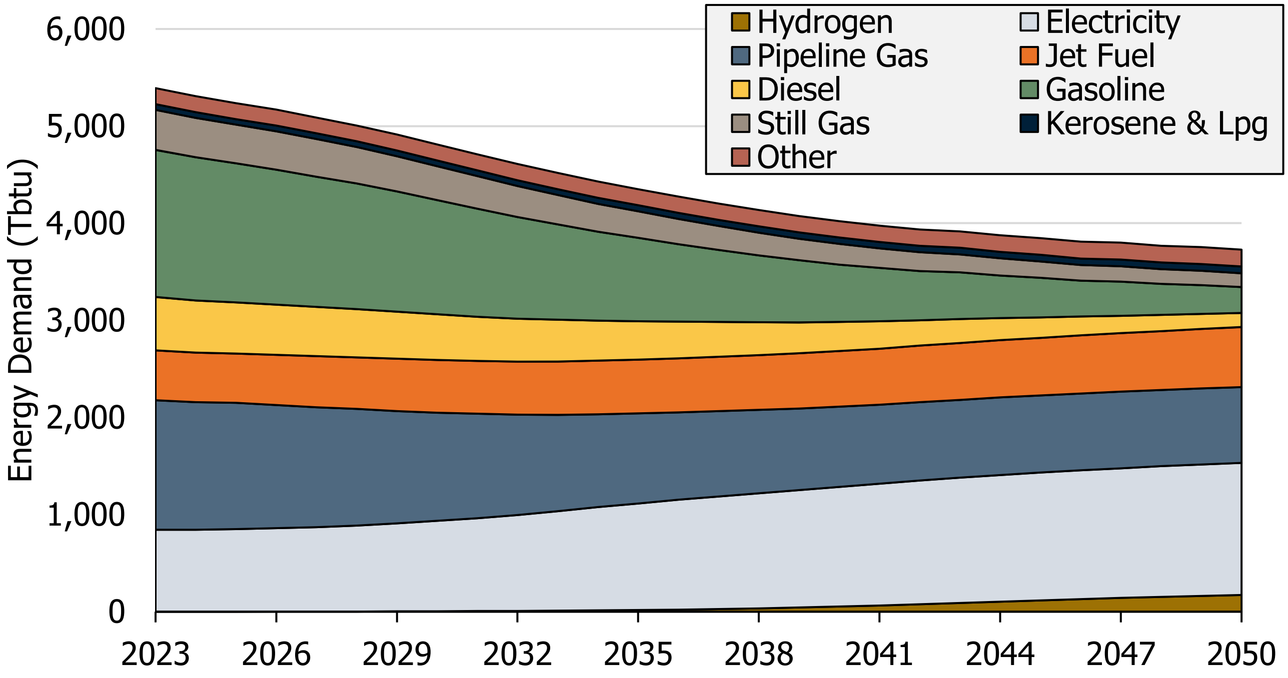
All scenarios show an increase in hydrogen fuel demand, with the total quantity of hydrogen consumption increasing from the Reference Scenario to the Policy Scenario and increasing again from the Policy Scenario to the Enhanced Policy Scenario. Demand for kerosene, liquefied petroleum gas, and other fuels (other includes biomass, wood, coal, and steam in the figure below) remains flat through 2050 across all scenarios.

Figure 12: Reference Scenario Statewide Energy Demand by Fuel



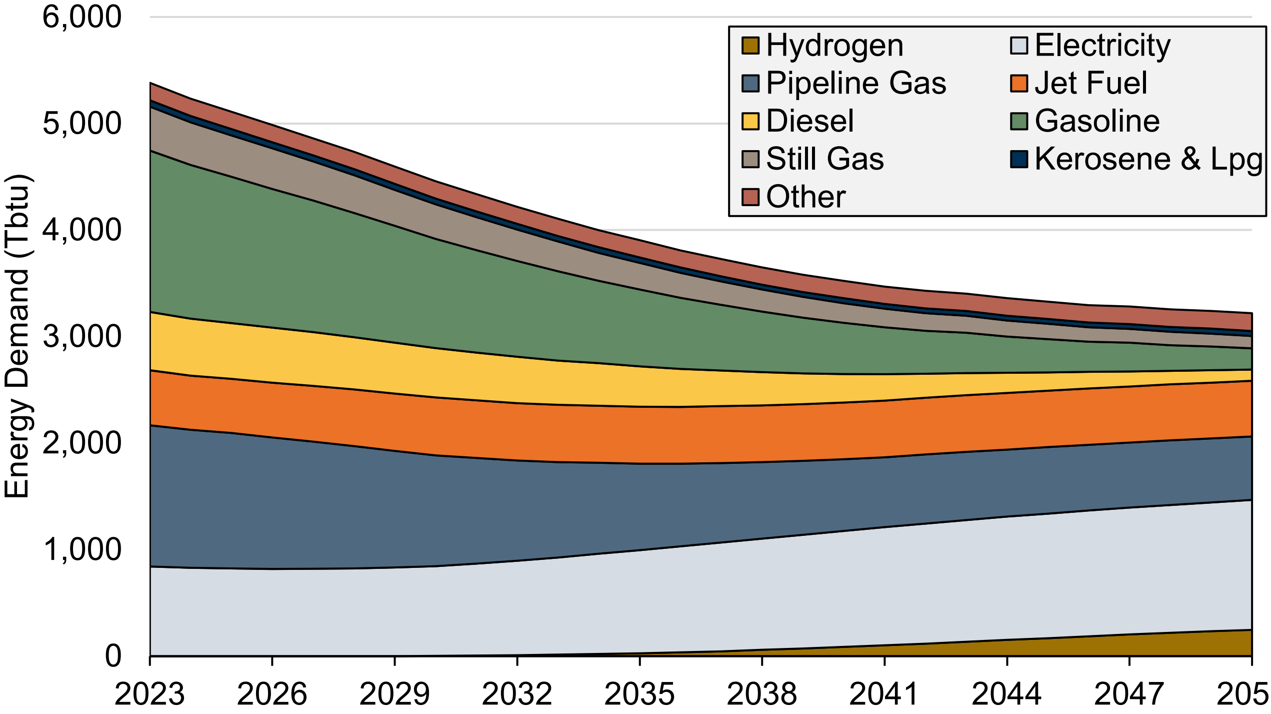
Source: CEC staff/EER

Figure 13: Policy Scenario Statewide Energy Demand by Fuel



Source: CEC staff/EER

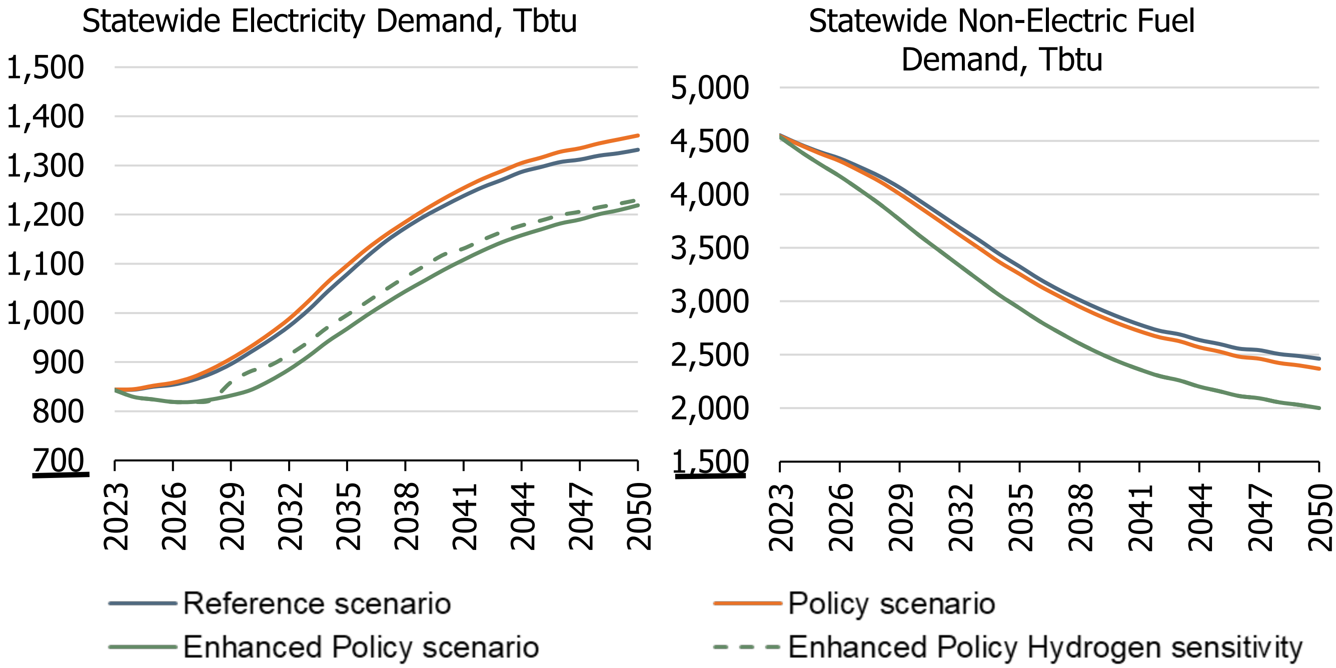
Figure 14: Enhanced Policy Scenario Statewide Energy Demand by Fuel



Source: CEC staff/EER

Figure 15 compares change through time for total statewide demand for electricity and nonelectric fuels, illustrating the variation between scenarios. Given the sector input assumptions described in previous sections, the results broadly match expectations. The Reference Scenario and Policy Scenario have similar statewide energy demand, with higher electricity demand and lower nonelectric fuel demand in the Policy Scenario relative to the Reference Scenario. In both scenarios, electricity demand increases by about 160 percent, and nonelectric fuel demand declines by about 50 percent from 2023 to 2050. The Enhanced Policy Scenario (and the related Enhanced Policy Pipeline Hydrogen sensitivity) results in significantly lower demand for both electricity and non-electric fuels relative to the Reference Scenario and Policy Scenario. In the Enhanced Policy Scenario, electricity demand increases by about 140 percent, and nonelectric fuel demand decreases by 65 percent.

Figure 15: Comparing Electric Versus Nonelectric Demand Change by Scenario



Source: CEC staff/EER

Energy Consumption by Sector

Different input assumptions made in each demand scenario result in different sector-level energy demand.[37] It is important to recognize that CARB's Advanced Clean Cars II ZEV sales mandate for 2035 and the Zero Emission Appliance Standard for residential and commercial buildings are embedded in the Reference Scenario. With these major electrification drivers built into the Reference Scenario, there is a relatively modest difference between it and the Policy Scenario.

Building Energy Demand

Figure 16 and Figure 17 show commercial and residential building energy demand by fuel type for each scenario. The Policy Scenario and Enhanced Policy Scenario reduce electricity demand in buildings relative to the Reference Scenario. In the commercial sector, shown in the Figure 16, electricity demand increases in the Reference Scenario and Policy Scenario through the early 2040s due to fuel substitution, before flattening out and slowly declining after 2045 due to continued EE. In the Enhanced Policy Scenario, more aggressive EE results in a consistent decline in commercial electricity demand, even as significant electrification occurs, as seen in the more substantial decline in pipeline gas demand relative to the Reference Scenario and Policy Scenario. All other commercial fuel demand (biomass/wood, diesel, gasoline, lpg, and

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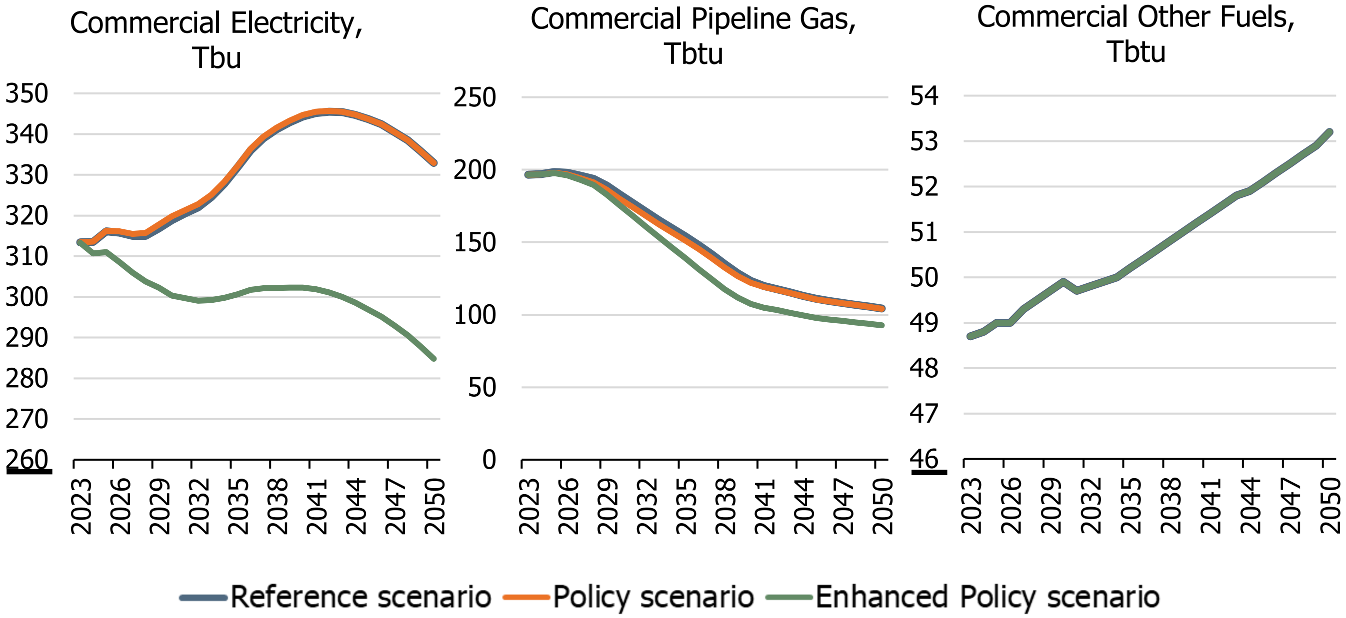
[37] Sector-specific results not shown for agriculture or TCU sectors, which are smaller than the residential, commercial, transportation and industrial sectors. Agriculture and TCU results are included in the demand scenarios data outputs.

steam) makes up a small share of total commercial energy demand and does not vary by scenario.

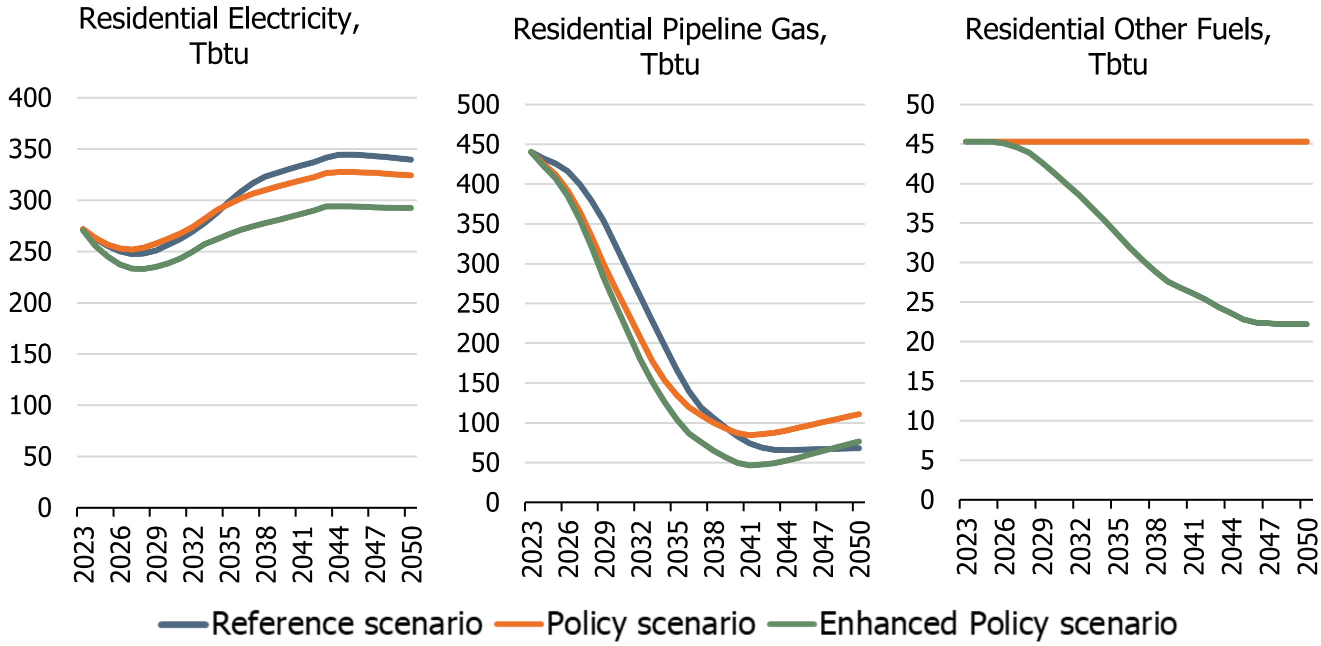
Figure 16: Commercial Energy Demand by Fuel and Scenario



Source: CEC staff/EER

The residential sector follows a similar trend to the commercial sector, as shown In Figure 17, with a significant decline in pipeline gas throughput and a slower increase in electricity demand in all scenarios. Residential pipeline gas demand declines steeply through 2040 in all scenarios and then increases gradually from 2040 to 2050. As in the commercial sector, the more aggressive EE measures in the Enhanced Policy Scenario offset growth in electricity demand from fuel switching, such that the scenario has the lowest electricity demand and the lowest pipeline gas demand. Residential demand for other fuels (biomass/wood, diesel and lpg) remains flat in the Reference Scenario and Policy Scenario but declines in the Enhanced Policy Scenario as lpg demand declines to nearly zero.

Figure 17: Residential Energy Demand by Fuel and Scenario



Source: CEC staff/EER

Industrial Energy Demand

Industrial sector demand reflects similar trends related to fuel switching and energy efficiency.[38] Figure 18 shows that in all scenarios, industrial pipeline gas demand declines as end uses are converted to electricity. This trend is accentuated by shifts to hydrogen in the Policy Scenario and Enhanced Policy Scenario. The inherent EE of electricity versus pipeline gas addresses resulting increases in electricity demand, resulting in net reductions in electricity demand from 2023 to 2050 in the Reference Scenario and Policy Scenario.

In the Enhanced Policy Scenario, electricity demand initially declines due to EE but increases from 2035 to 2050 because of more aggressive fuel switching to electricity or to hydrogen. Since hydrogen is assumed to be produced by onsite electrolysis using grid-supplied sources in the Enhanced Policy Scenario, shifts to hydrogen also increase electricity demand. In the Policy Scenario, incremental industrial hydrogen demand grows through 2035 and then flattens out through 2050. In the Enhanced Policy Scenario, incremental industrial hydrogen consumption continues to grow at an increasing rate through 2050.

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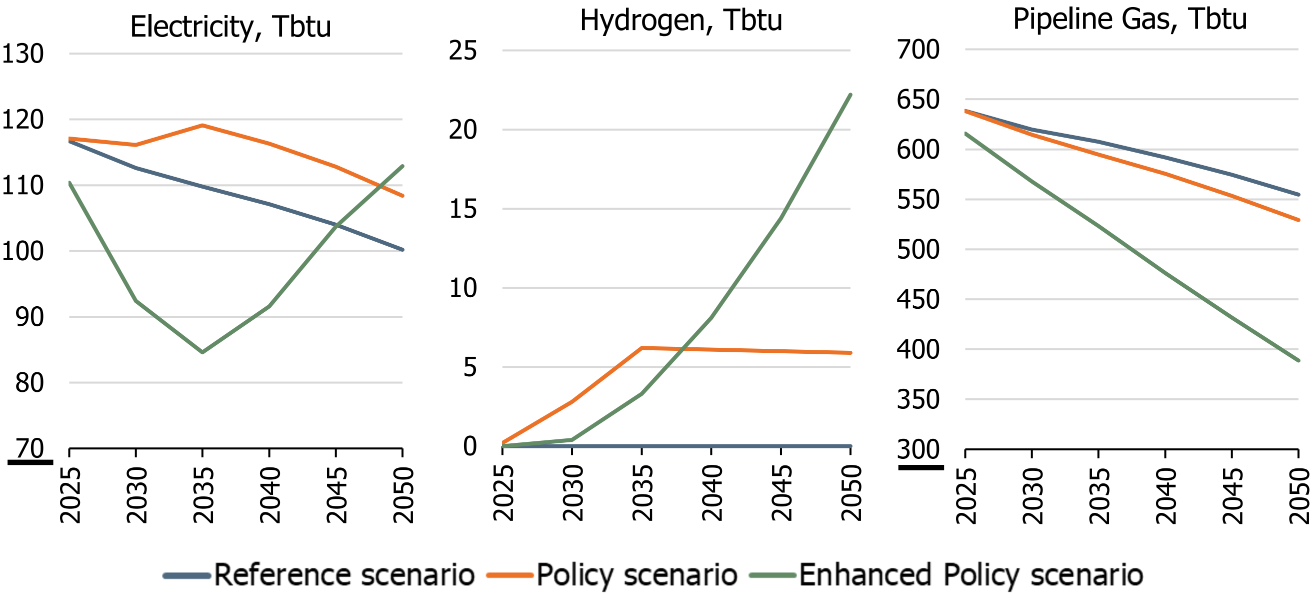
[38] The industrial sector includes oil and gas extraction and petroleum refining. In addition to electricity, hydrogen and pipeline gas, industrial sector demand for still gas, steam, coal, diesel, gasoline and lpg are included in the demand scenarios but not shown in **Figure 18**.

Figure 18: Industrial Energy Demand by Fuel and Scenario



Note: Industrial hydrogen demand is incremental.

Source: CEC staff/EER

Transportation Energy Demand

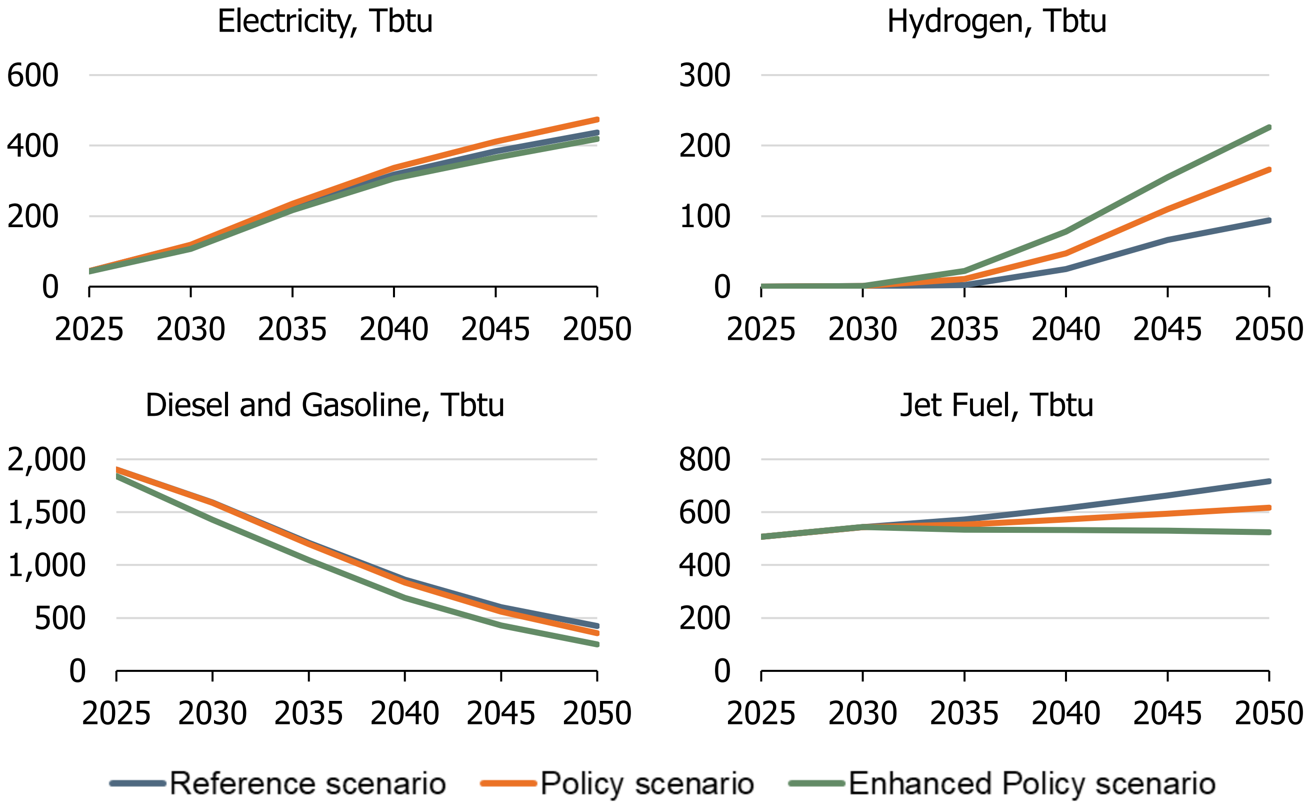
In the transportation sector, adoption of electric vehicles reduces combustion fuel demand and increases electricity demand in all scenarios. Some hydrogen is consumed in transportation in all scenarios. Lower travel demand, implemented as a reduction in light-duty vehicle miles traveled (VMT), reduces energy demand across the board for all energy types used in transportation.

The Reference Scenario has the highest combustion fuel use and the lowest hydrogen demand of the three scenarios. The Policy Scenario sees more significant fuel switching to electricity and hydrogen, and the Enhanced Policy Scenario reflects a high degree of fuel switching and less travel activity, resulting in lower combustion fuel demand, higher hydrogen demand, and lower electricity demand than the other scenarios.

The transportation sector also encompasses aviation fuel demand. In all scenarios, aviation fuel demand increases due to an associated increase in demand for aviation services. Compared to 2024, jet fuel demand increases significantly by 2050 in the Reference Scenario, with a slightly less aggressive increase in the Policy Scenario due to fuel substitution of electricity and hydrogen. In the Enhanced Policy Scenario, more aggressive fuel substitution allows for a net decline in jet fuel demand by 2050. Aviation services in all scenarios, however, remain the same by using a fuel substitution approach and associated energy efficiency ratio.

Pipeline gas demand in the transportation sector, not shown in the figure below, declines from about 20 TBtu in 2023 to near zero in 2050 due to transportation electrification. The use of gasoline and diesel drops sharply and is largely replaced by fewer TBtu of more efficient electricity and more efficient hydrogen. Figure 19 shows demand projections for the four most prominent fuels used in transportation.

Figure 19: Transportation Energy Demand by Fuel and Scenario



Source: CEC staff/EER

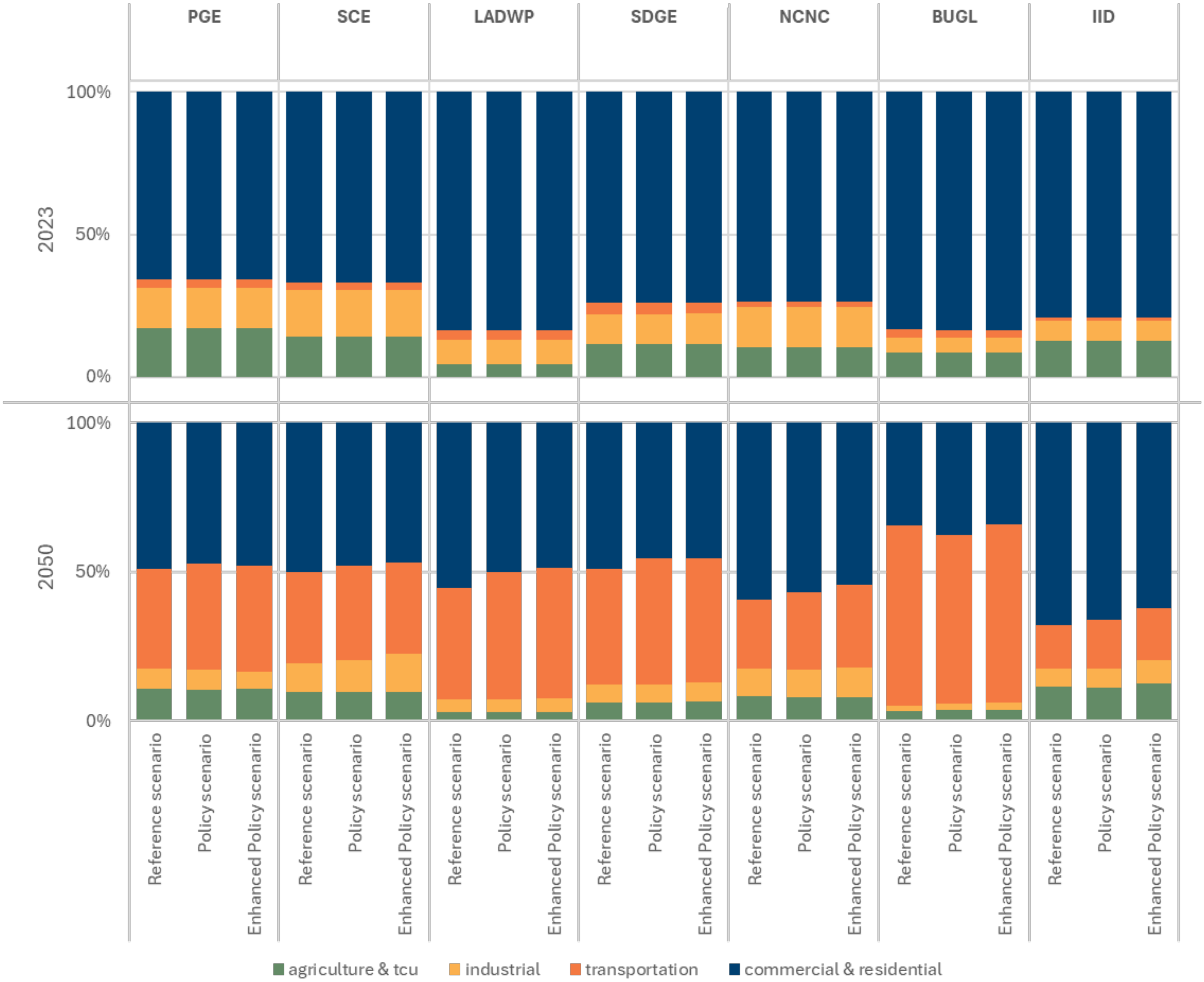
Electric Peak Load and Hourly Results

The 2023 Demand Scenarios Project generated 8760 hourly electricity projections for all CEC electric planning areas for the first time. Different planning areas have different electricity demand makeup by sector. Industrial activity is unevenly spread across California, and variations in weather patterns among the eight planning areas impact building loads. Figure 20 shows the share of each sector's contribution to annual electricity demand in each planning area in 2023 and 2050. In 2023, buildings make up most of the electricity demand in all planning areas (except for MKRP, which is entirely industrial). By 2050, transportation becomes a large share of electricity demand, reducing the share of electricity consumed in other sectors even as electric load grows in those sectors.

There is some variation in electricity demand by sector based on scenario assumptions, but generally all scenarios are comparable. The primary variation across scenarios is the share of building versus transportation electric load.

As a result of shifting of sector-level contribution to total electricity load over time, variations in 8760 electric load profiles by planning area are driven primarily by the transportation, commercial building, and residential building sectors in 2050. Building load profiles are heavily influenced by regional weather variations, while transportation load profiles are largely consistent across planning areas. Industrial and agricultural demands make up a small enough share of total electricity demand that they do not drive regional differences in electricity profiles, although they are spread unevenly across the state.

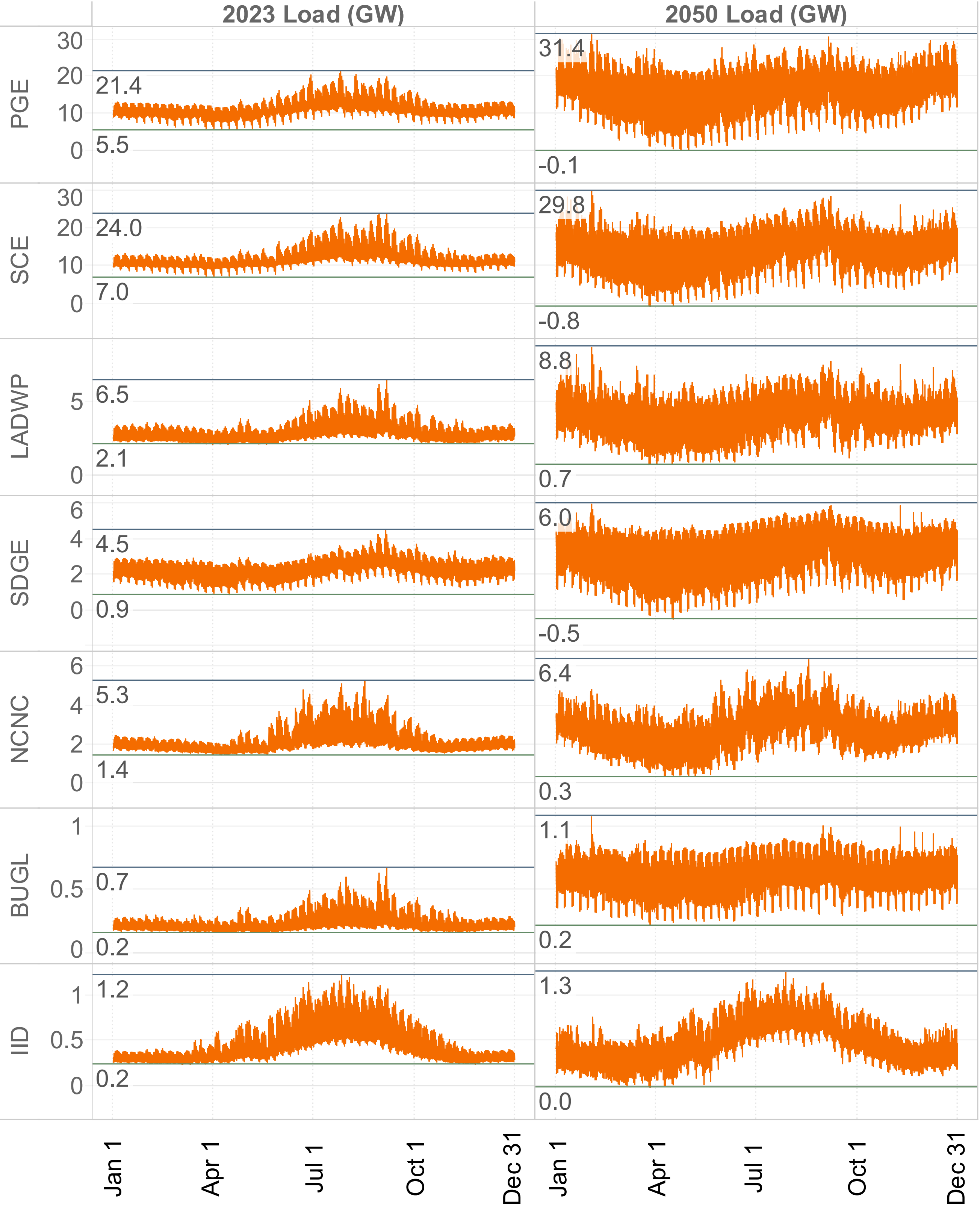
Figure 20: Share of Planning Area Annual Electricity Demand by Sector, 2023 and 2050



Source: CEC staff/ EER

Figure 21 shows total hourly electricity demand across all sectors by planning area in 2023 and 2050 for the Enhanced Policy Scenario (analogous figures for the Reference Scenario and Policy Scenario are included in APPENDIX C). Peak electricity demand increases in all planning areas from 2023 to 2050, while minimum load decreases in nearly all planning areas. With peaks increasing and minimums decreasing, the spread has widened drastically from a normalized 2023 to a projected 2050. In many planning areas, summer electricity demand becomes less dominant as electric building heat and transportation load create more demand in other seasons. Some planning areas become winter peaking by 2050, though all continue to have a high summer load as well.

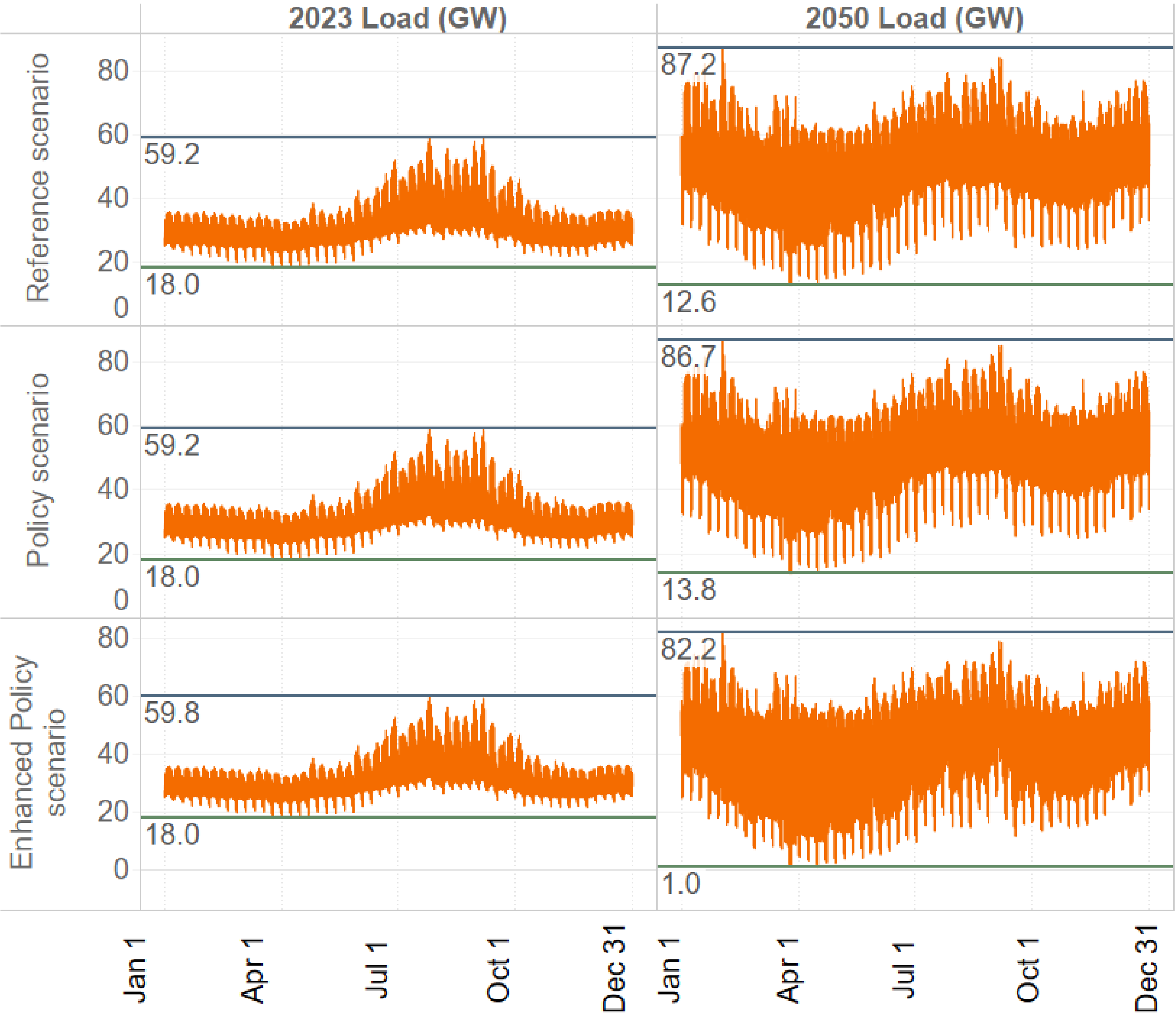
Figure 21: Hourly Power Demand by Planning Area (GW)



Source: CEC staff/EER

Scenario assumptions drive variation in statewide peak electricity demand and minimum load. Figure 22 shows statewide total annual hourly electricity demand in 2023 and 2050 under the Reference, Policy, and Enhanced Policy Scenarios. The Enhanced Policy Scenario has the lowest statewide electric peak because it includes more extensive EE and more behind-the-meter solar generation. High behind-the-meter solar adoption also results in a large reduction in minimum load in the Enhanced Policy Scenario relative to the other scenarios. In all scenarios, the minimum load is lower in 2050 than in 2023, and peak load is higher in 2050 than in 2023, demonstrating the increase in variability in hourly electricity load in 2050 relative to the present.

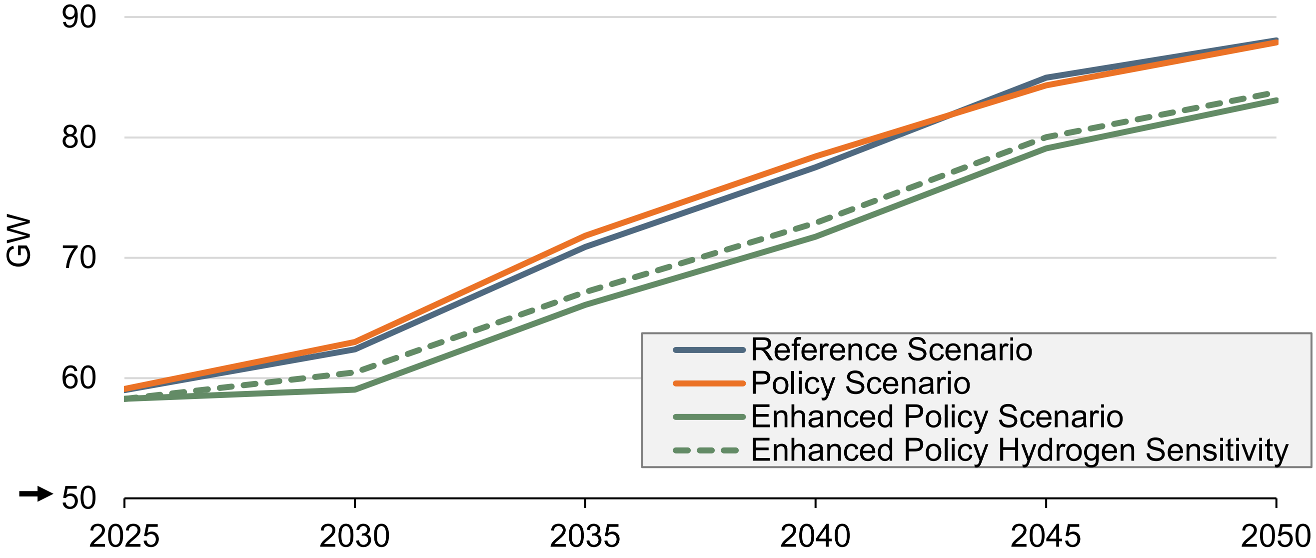
Figure 22: Statewide Hourly Power Demand by Scenario



Source: CEC staff/EER

Figure 23 shows the forecasted coincident peak load for California through 2050 by scenario. Peak growth is relatively constant from 2030 through 2050, although, as shown in Figure 22, the season of peak is not consistent in all planning areas between the "normalized" 2023 and the projected 2050.

Figure 23: Statewide Coincident Annual Peak Load

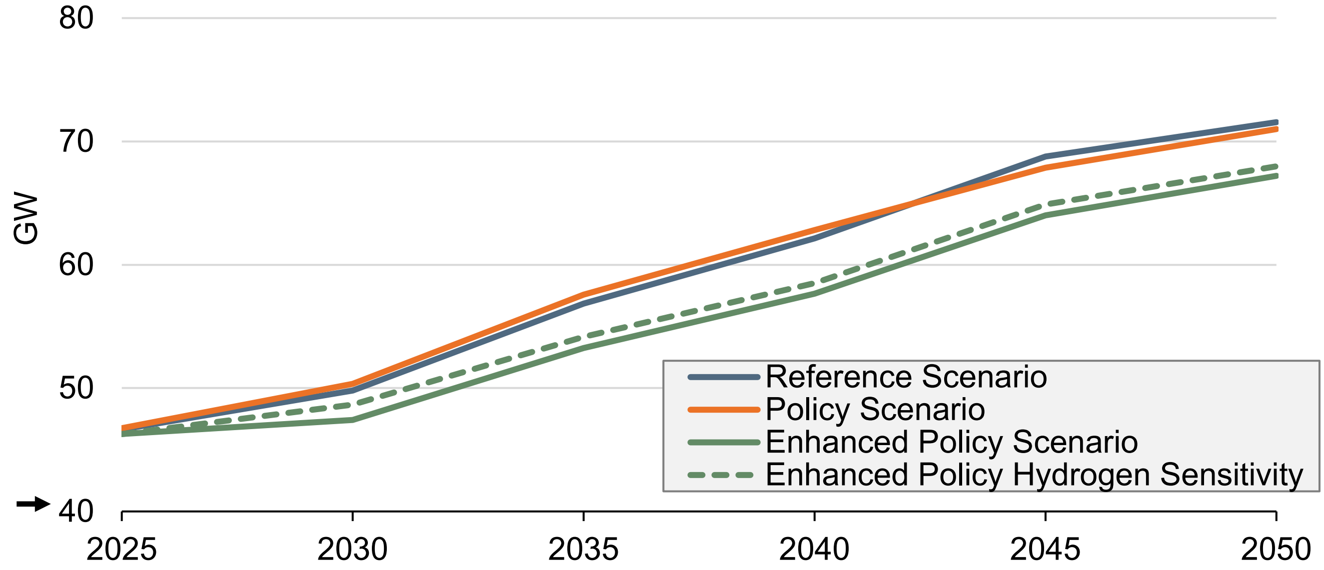


Source: CEC staff

California ISO and Non-ISO Peak Load

California ISO peak load, shown below in Figure 24, grows from 47 GW to 62 GW from 2025 to 2050 in the Reference Scenario. The Policy Scenario has similar peak load growth to the Reference scenario. The Enhanced Policy Scenario and hydrogen sensitivity have lower growth, reaching 67–68 GW in 2050.

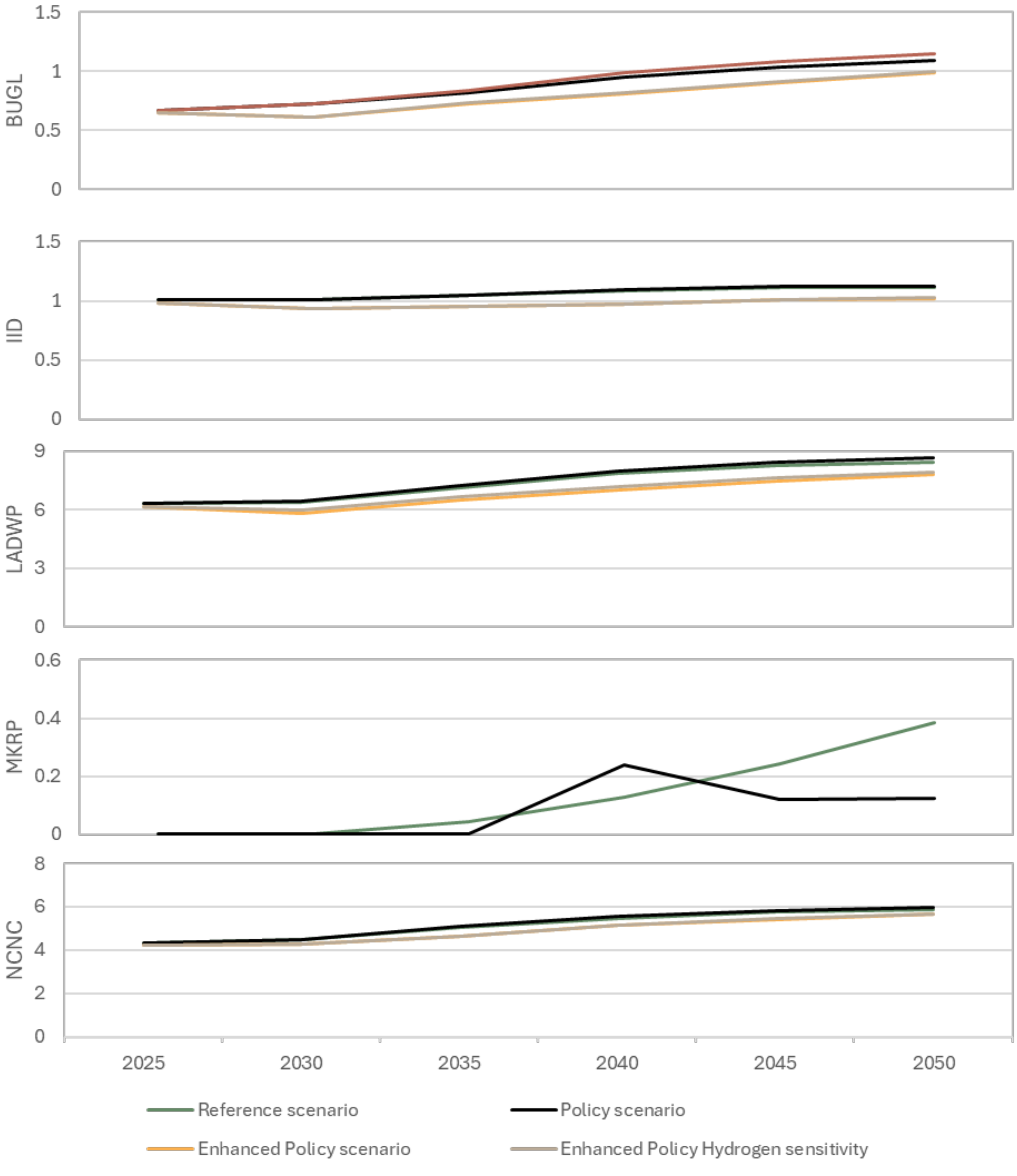
Figure 24: California ISO Coincident Annual Peak Load



Source: CEC staff

Figure 25 shows an annual electric peak from 2023 to 2050 for each planning area outside California ISO. The Imperial Irrigation District (IID) sees more measured peak growth than other planning areas. The Mojave and Kern River Pipelines’ (MKRP’s) peak demand is sensitive to hydrogen assumptions because 100 percent of the electricity load is industrial, and the hydrogen sensitivity focuses on industrial uptake. Although MKRP’s pipeline gas demand is clearly distinguished from deliveries by the regulated pipeline gas utilities, the split in electrical distribution services between SCE and PG&E for these end users is unclear. Rather than make an arbitrary allocation, an incremental electric load is assigned to the MKRP entity for accounting purposes.

Figure 25: Non-ISO Annual Electric Peak by PA (GW)



Source: CEC staff

Annual GHG Emissions by Scenario

The emissions calculations performed for the Demand Scenarios Project use a different emissions accounting method from CARB emissions reporting and California's gross emissions targets, which are defined using CARB's emissions inventory. The key differences between emissions calculation methods are as follows:

1. The demand scenarios account for all aviation emissions from refueling flights either originating or terminating in California. In contrast, CARB's inventory accounts only for flights within the state. As a result, demand scenarios aviation emissions exceed CARB's aviation emissions accounting.
2. CARB's inventory includes process emissions and land-use emissions, which are out of scope for the demand scenarios as the Demand Scenarios Project accounts only for emissions related to energy demand.

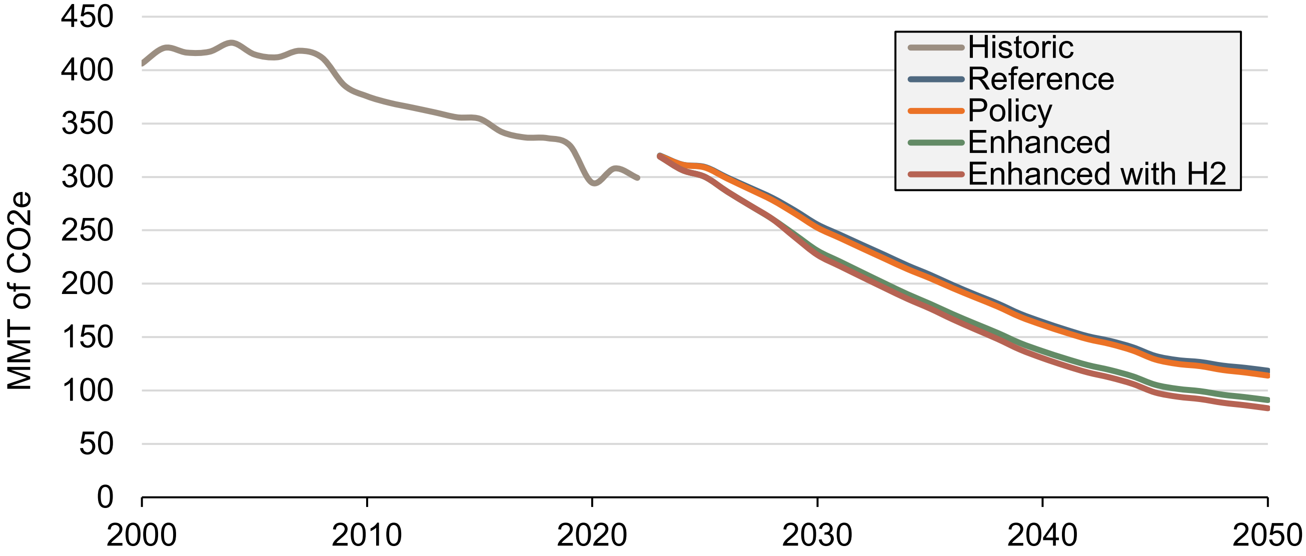
In addition to these important differences in method, the demand scenarios emissions also cannot be compared directly to California's emissions reductions targets because they do not take into account supply-side emissions reduction measures. Critical potential actions for reaching state emissions targets are specific to energy supply and are therefore not explored in this analysis. These include decarbonized fuel blending beyond 2023 levels, point-source carbon capture and sequestration in the electricity generation and industrial sectors, and direct air capture. These supply-side strategies, among others, can be deployed in California to reduce emissions beyond what is captured in these demand scenarios.

Differences in emissions method from CARB's accounting practices limit ability to directly compare demand scenarios emissions to statutory goals or targets, but it is still possible to draw qualitative conclusions from the statewide emissions projections for each scenario. The demand scenarios indicate that the levels of fuel substitution and EE represented in the Enhanced Policy Scenario (the highest levels modeled in the demand scenarios) are likely insufficient to achieve California's emissions targets.

Supply-side efforts will also be required to reduce the carbon intensity of electricity and nonelectric fuels beyond the assumptions used in the demand scenarios emissions projections. Carbon dioxide removal technologies can also be deployed to reach targets. To the extent that demand-side measures can be deployed even more extensively than represented in the 2023 Demand Scenarios Project, they can lessen the remaining emissions reduction burden that will otherwise fall to supply-side measures.

Figure 26 shows total emissions for all scenarios through 2050, including historical emissions going back to 2000. The state's greenhouse gas emissions remain on a downward trajectory, with some minor differences across scenarios. Greenhouse gas emissions for the Reference Scenario and Policy Scenario are similar. The emissions for the Enhanced Policy Scenario, and the Enhanced Policy Scenario Hydrogen Pipeline sensitivity are very close.

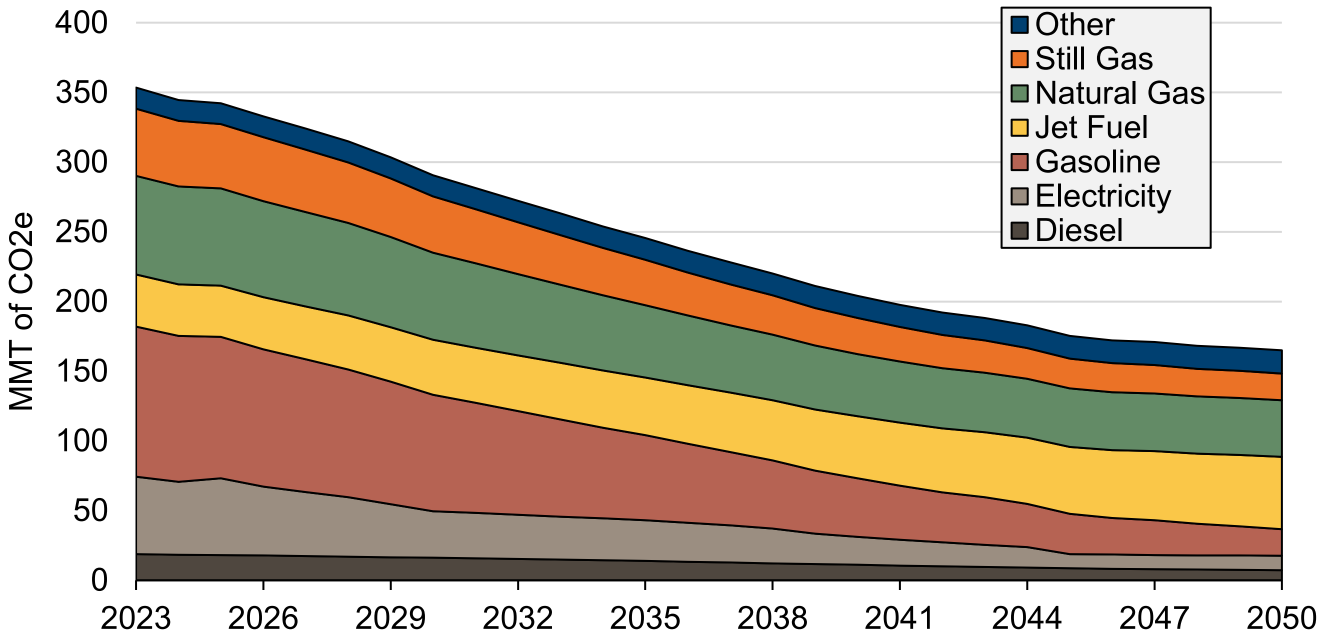
Figure 26: Total GHG Emissions for All Fuel Types by Scenario



Source: CEC staff/Verdant

Figure 27 through Figure 30 show greenhouse gas emissions by fuel type for the Reference Scenario, Policy Scenario, and Enhanced Policy Scenario through 2050 (including the hydrogen sensitivity). In all cases, there is a decrease in emissions associated primarily with a decrease in gasoline consumption and decarbonization of the electricity supply.

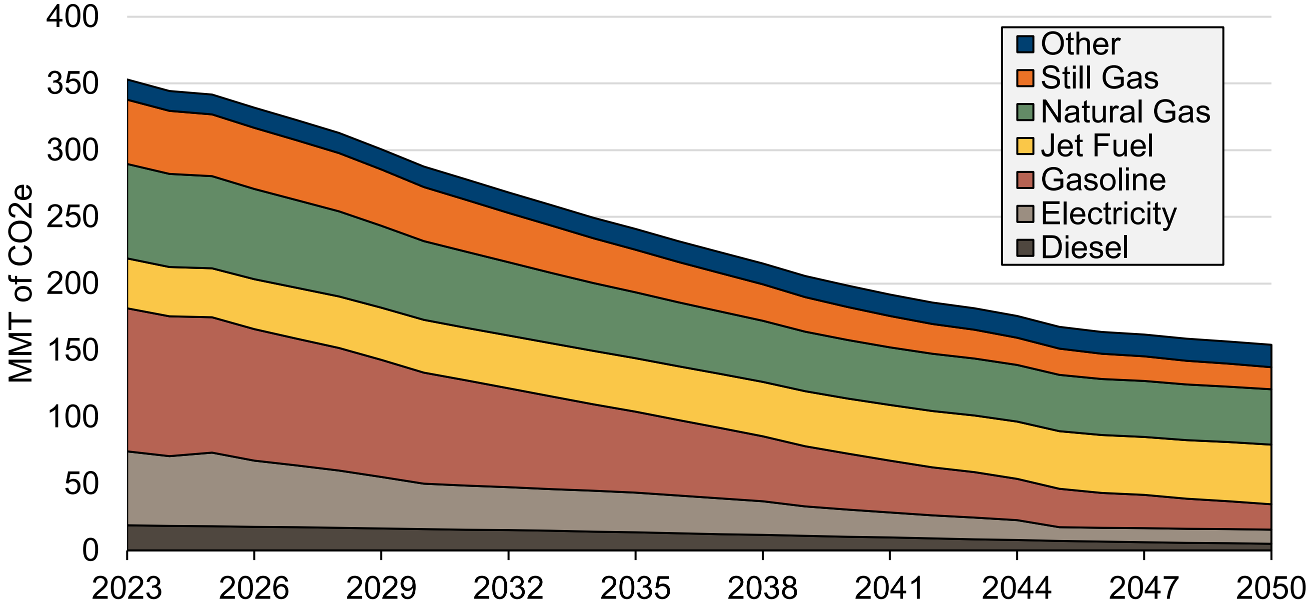
Figure 27: Reference Scenario Statewide GHG Emissions by Fuel Type



Other: Biomass/Wood, Coal, Coking Coal, Hydrogen, Kerosene Fuel, LPG, Residual Fuel Oil, Steam.

Source: CEC staff/Verdant

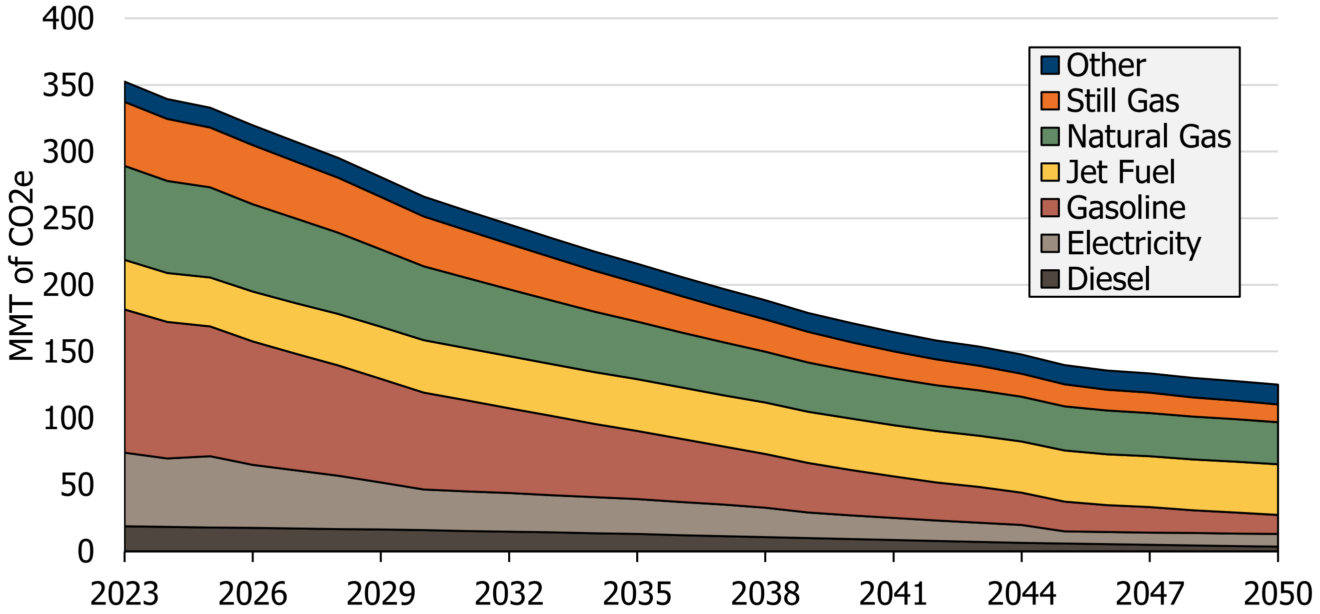
Figure 28: Policy Scenario Statewide GHG Emissions by Fuel Type



Other: Biomass/Wood, Coal, Coking Coal, Hydrogen, Kerosene Fuel, LPG, Residual Fuel Oil, Steam.

Source: CEC staff

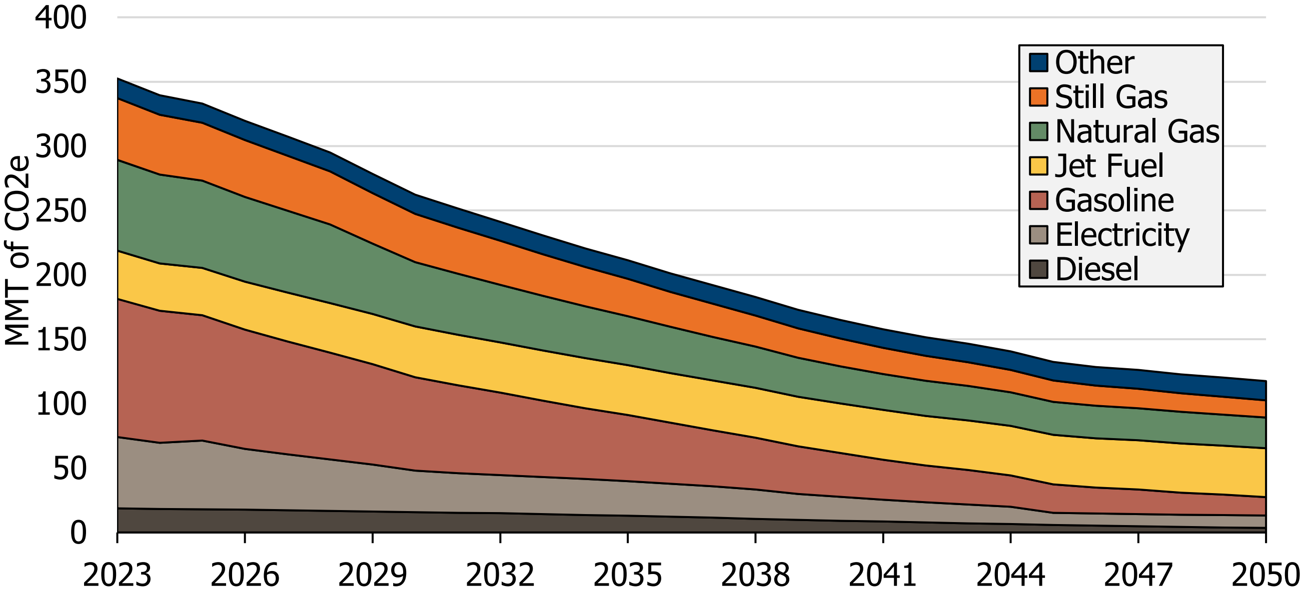
Figure 29: Enhanced Policy Scenario Statewide GHG Emissions by Fuel Type



Other: Biomass/Wood, Coal, Coking Coal, Hydrogen, Kerosene Fuel, LPG, Residual Fuel Oil, Steam.

Source: CEC staff

Figure 30: Enhanced Policy Sensitivity - Pipeline Hydrogen Emissions by Fuel Type



Other: Biomass/Wood, Coal, Coking Coal, Hydrogen, Kerosene Fuel, LPG, Residual Fuel Oil, Steam.

Source: CEC staff

Summary

In each demand scenario, fuel substitution from natural gas to electricity and from liquid fuels to electricity increases California's electricity load and decreases demand for nonelectric fuels through 2050 in all planning areas. The extent of this electric sector transformation depends on assumptions about how energy policies translate to changes in energy demand. The degree of fuel substitution (or fuel switching), EE, behind-the-meter solar generation, and industrial decarbonization all influence projected annual electricity consumption. Scenarios with more energy efficiency see mitigated peak electricity demand increases and total annual electricity demand growth.

Several factors also lead to important changes in the hourly pattern of electric load. Increased adoption of behind-the-meter solar reduces bulk system demand in midday hours and leads to dramatically lower minimum load conditions. Conversely, electric vehicle charging in nighttime hours and building electrification space heating loads induces unprecedented winter peaks in morning hours, leading to higher loads in this period of the year. In many planning areas, growth of new types of electric load, particularly building electrification, causes a transition from summer to a winter electric peak. The timing of that transition depends on scenario assumptions but is as early as 2038 in some planning areas under some conditions.

The emissions projections developed for each demand scenario indicate the level of emissions reduction that is likely to be achieved through 2050 via fuel substitution and energy efficiency, assuming existing decarbonized fuel blending levels persist. The demand scenario emissions method is different from CARB's emissions inventory method such that the projections cannot be directly compared to state emissions targets. The projections, however, give an indication of the additional energy emissions reductions that will be required on the supply side. The general implication is that carbon capture and sequestration, direct air capture, and further decarbonization of electric and nonelectric fuels are necessary to meet California’s 2050 targets. Future modeling efforts that combine demand- and supply-side decarbonization can help the state understand how to meet emissions targets most cost-effectively by drawing on a broad portfolio of complementary emissions reduction strategies.

CHAPTER 5: Key Scenario Drivers

The previous chapter provided basic results at the planning area, fuel type, or customer sector level. This chapter focuses on the modeling details of specific measures that drive those aggregate results. Three specific topics are presented:

- Building electrification
- Industrial decarbonization
- Rooftop photovoltaic production and behind the meter storage

These three topics greatly influence the scenario and sector level outcomes that may be obscured when reporting overall scenario results.

Building Electrification: AAEE/AAFS/FSSAT

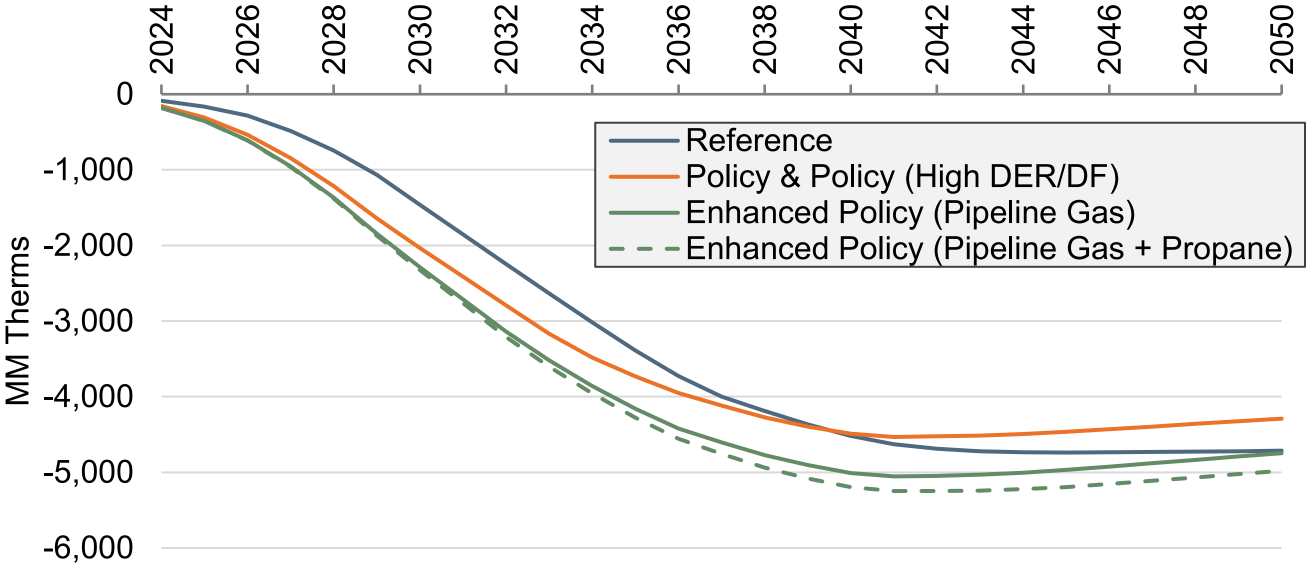
Figure 31 and Figure 32 summarize the annual fuel combustion and electric impacts from buildings for the Reference Scenario, Policy Scenario, and Enhanced Policy Scenario. Most of the energy impacts stem from zero-emission appliances, particularly from existing buildings, above and beyond the impacts assumed from the programmatic gas AAEE and AAFS input assumptions of the scenarios. (See Appendix A, Table A-1.) The results reported in these figures reflect the change in propane, pipeline gas, and electric demand and do not reflect any impacts in demand from the blending of alternative fuels such as biogas and hydrogen.

All scenarios show significant propane and pipeline gas displacement relative to the baseline forecast, where roughly between 4,300 Million therms (MM therms)and 4,700 MM therms of pipeline gas (excluding propane) will be displaced by 2050 (Figure 31). The gas displacements are identical for the Policy Scenario and Policy Scenario High DER/DF sensitivity since they assume the same gas displacement assumptions and vary only on the programmatic AAEE electric assumptions. The dashed line for the Enhanced Policy Scenario represents the additional impact zero-emission appliances have on residential propane end uses, which increases displacement by roughly 230 MM therms in 2050.

The impacts of the Reference Scenario and Policy Scenario intersect around 2040. This intersection can be explained by the FSSAT modeling assumptions, primarily the accounting of the increased size of programmatic AAFS impacts (Table 7) and how these programmatic impacts account for savings decay.

The same 2040 intersection between the Reference and Policy Scenarios can be seen in the combined electric impacts from the building scenarios (Figure 32). Most of the differences among the scenarios can be attributed to the sizeable programmatic AAEE electric assumptions (Table 7), which are added to the modeled programmatic AAFS and FSSAT-ZEAS AAFS impacts. The Reference Scenario in Figure 32 shows that, by 2050, buildings will increase electricity consumption by roughly 40,000 GWh, or roughly 11,000 GWh more than in the Enhanced Policy Scenario.[39] The authors emphasize that all these scenarios can have further potential energy efficiency savings depending on the FSSAT electrification technology assumptions. The modeling assumptions used for adopting zero-emission appliances (FSSAT-ZEAS AAFS) assume an even distribution of efficiency levels for the eligible replacement technologies. For example, for water heating, which has two potential replacement technologies, an electric resistance water heater has an equal adoption rate (in other words, 50 percent) as an efficient heat pump water heater. As such, efficient electrification policies and market transformation efforts to encourage adoption of efficient technologies, particularly efficient heat pumps, can reduce the additional load from building electrification relative to the assumptions used in this project.

Figure 31: Combined Pipeline Gas and Propane Impacts from Buildings (MM Therms)



Source: CEC staff

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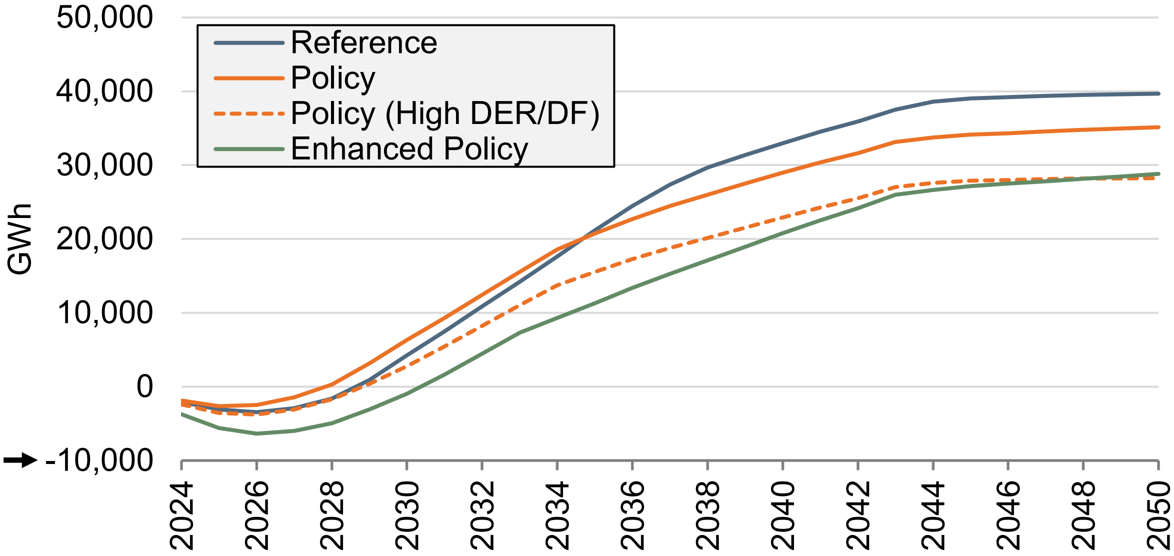
[39] The difference between the Policy and Policy (High DER/DF) Sensitivity Scenarios can solely be attributed to the different programmatic electric AAEE assumptions (**Table 7**).

Figure 32: Combined Electric Impacts From Buildings (GWh)



Source: CEC staff

Figure 33 displays for the California ISO region's building AAFS hourly load on the peak day of different scenarios and sensitivities for the year when peak demand switches from summer to winter peaking. The AAFS impacts on the ISO system switches to winter peaking in 2041 for all scenarios except for the Policy Scenario, which switches in 2042. During these winter peaks, AAFS load increases load most noticeably in the early morning, primarily due to electric space and water heating. This added load helps illustrate the critical role that the AAFS load modifiers have on shifting the ISO system loads to the winter, leading to a winter peak. High demand remains during the previously traditional summer peak. As mentioned, this potential growth in electric loads can be moderated with EE measures, since all the scenarios include a distribution of EE levels of the zero-emission appliances and do not assume "efficient electrification" for all appliance replacements.

This observed shift to a winter peak is not as apparent for the added AAFS load to some of the non-California ISO POU planning areas. Both the Burbank-Glendale (BUGL) and Los Angeles Department of Water & Power (LADWP) electric planning areas follow a similar pattern to the ISO system by switching from summer to winter peaking during the demand scenarios time horizon. However, the Northern California Non-CAISO (NCNC) planning area, which includes the Sacramento Municipal Utilities District (SMUD), and the Southern California Imperial Irrigation District (IID) electric planning areas maintain summer peaking throughout the entire demand scenario time horizon.[40] The added hourly AAFS load during these summer peaks would have the greatest impacts between the afternoon and early evening period,

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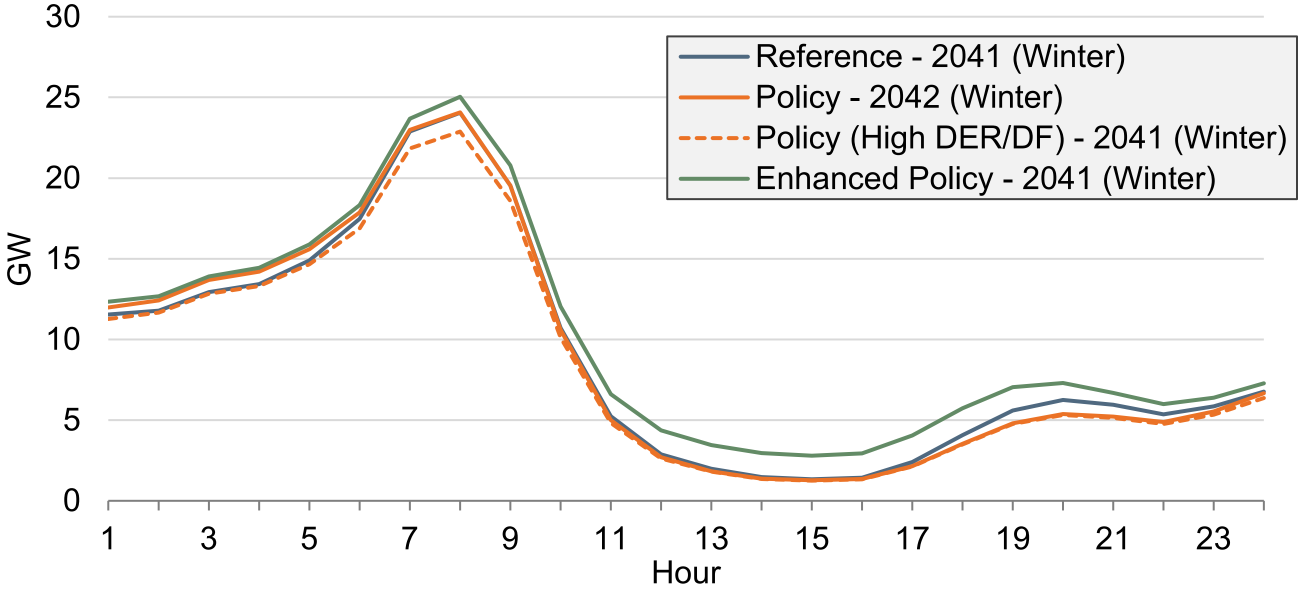
[40] Details on the summer to winter peak shift for the non-California ISO electric planning areas can be found on slide 35 of the "2023 Demand Scenarios Project — Joint Contractor Presentation" presentation from the CEC's November 20, 2024, Staff Workshop on Demand Scenarios Project, available at https://www.energy.ca.gov/event/workshop/2024-11/staff-workshop-demand-scenarios-project.

predominantly from new cooling load in existing residential buildings, which gain air conditioning load from heat pump installation.

Figure 33: Added California ISO System Hourly AAFS Load From Buildings on the Annual System Peak Day for the Year When Annual System Peak Switches From Summer to Winter for Each Scenario



Source: CEC staff

Industrial Decarbonization

Industrial sector impacts come from two modeling sources. The first is the new Ag-Ind Fuel Substitution module described in Chapter 3. The second comes from the integration tool developed by EER, which merges outputs from the CEC tools and the complementary outputs of EER's EP model. The integration tool produces several highly targeted impacts on specific industries. This section provides results of the impacts of key scenario assumptions and special adjustments.

Scenario and Sensitivity Results

The results of the three main scenarios and the EPS Pipeline Hydrogen Sensitivity are shown in Table 25 using key metrics for 2050. The EPS Pipeline Hydrogen Sensitivity displaces more than four times the pipeline gas consumption, reducing remaining pipeline gas by a corresponding amount. There is no change in the direct substitution of electricity for pipeline gas for water heat and process heat-low since these assumptions for specific industries pipeline gas displacement by onsite electrolysis were unchanged from the primary EPS. Roughly eight times as much hydrogen is consumed in the pipeline hydrogen sensitivity as in the primary EPS.

Electricity consumption from onsite electrolysis is about 35 percent higher because some new consumption of hydrogen displacing pipeline gas process heat-high is supplied via onsite electrolysis, especially in early years, until access to pipeline hydrogen is more widespread.

Finally, there is a large increase in total electricity consumed in electrolytic hydrogen production supplied by renewable electric generating resources. The ratio of combined electricity for electrolysis in the EPS pipeline hydrogen sensitivity compared to the parent EP scenario is similar to the ratio of hydrogen consumed in sensitivity compared to the parent EP scenario since the same kilowatt-hour/kilogram (kWh/kg) conversion factor was used.

Table 25: Statewide Industrial Sector Scenario and Sensitivity Results for Key Metrics in 2050

Variable	Units	Reference (2023 IEPR Forecast)	Policy	Enhanced Policy	EPS-Pipeline Hydrogen Sensitivity
Pipeline Gas Displaced	MM Therms	0.0	109	371	1,830
Remaining Industrial PG	MM Therms	6,283	5,840	5,537	4,097
Direct Fuel Substitution Electricity Added	GWh	0.0	442	1,223	1,223
Hydrogen Added	MM Kg	0.0	44	165	1,250
Electricity From Onsite Electrolysis	GWh	0.0	2,313	8,650	11,772
Electricity for Renewable Hydrogen via Pipeline	GWh	0	0	0	52,600

Source: CEC staff

The FSSAT Ag-Ind tool has been designed to facilitate a wide range of alternative input assumptions. The Policy Scenario reflects a scale of fuel substitution compatible with the funding authorized in the Inflation Reduction Act and other federal tax credit and incentive legislation. However, whether such stimuli and California compliance mechanisms are sufficient to elicit the growth in potential or adoption rates that were assumed is uncertain. The EPS and the EPS Pipeline Hydrogen sensitivity specifications are even more uncertain, being largely based on judgment, and many alternative specifications are also plausible. However, the issues addressed in this initial exploration of industrial fuel switching as a decarbonization mechanism highlight some of the many challenges facing the industrial sector and the energy and environmental agencies in California.

Given these limitations, these projections should not be considered certain enough to be included in forecasts used for actual resource planning or project commitments. More extensive data about industrial sector processes are needed to reduce the uncertainty of these projections. Incomplete data about industrial energy use have limited development of detailed understanding of industrial energy consumption for many years, but it is an even more severe problem given the state's decarbonization goals.[41] An interagency effort to acquire and share improved data is necessary to thoroughly understand the real issues confronting decarbonization of the industrial sector.

Refinery Adjustments

As described in Chapter 4, EER developed an assessment of the CARB 2022 Scoping Plan control measure that links refinery energy consumption to reductions in demand for petroleum refinery products. This adjustment was implemented for each of the three demand scenarios. For the Reference Scenario, this refinery adjustment was the principal change in industrial energy demand compared to the 2023 IEPR electricity and pipeline gas forecasts.

Table 26 provides annual reductions for the Policy Scenario for each of five fuel types used in refineries and the scalar that represents the ratio of future annual transportation petroleum fuel consumption compared to the base year of 2023. As the scalar value for 2050 of 0.518 implies (a 48 percent reduction in gasoline and diesel consumption), the implications of transportation demand reductions in the Policy Scenario are quite large, and the impact on refinery energy consumption is assumed to be correspondingly large.

As noted earlier in Chapter 3, a refinery adjustment reflecting the reduced consumption of petroleum-based fuels compared to the base 2023 IEPR industrial demand forecast affects all fuel consumption in refineries. The impact on refinery energy usage is greater the more each scenario reduces transportation usage in each scenario. The impact shown in Table 26 would be smaller in the Reference Scenario and greater in the Enhanced Policy Scenario.

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[41] McMillan, Colin A., Carrie Schoeneberger, Sarang Supekar, and David Thierry. September 2024. *The Foundational Industrial Energy Dataset (FIED): Open-Source Data on Industrial Facilities.* Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-90442, https://www.nrel.gov/docs/fy24osti/90442.pdf.

Table 26: Refinery Energy Consumption Reduction From Reduced Petroleum Product Demand — Policy Scenario

Year	Transportation Product Scalar	Electricity (GWh)	Pipeline Gas (MMbtu)	Petroleum Coke (MMbtu)	Steam (MMbtu)	Still Gas (MMbtu)
2023	1.000	0	0	0	0	0
2024	0.975	-166	-3479566	-1354182	-226167	-10537067
2025	0.951	-320	-6713463	-2579813	-431035	-20388735
2026	0.905	-624	-13182734	-4990671	-825213	-42063795
2027	0.898	-665	-14143156	-5246343	-867489	-44218727
2028	0.891	-711	-15200691	-5521413	-912972	-46537145
2029	0.882	-763	-16391382	-5804369	-959759	-48922038
2030	0.873	-822	-17717107	-6098351	-1008369	-51399866
2031	0.860	-902	-19508726	-6514889	-1077244	-54910643
2032	0.846	-991	-21468226	-6959198	-1150711	-58655500
2033	0.831	-1083	-23523743	-7397565	-1223196	-62350269
2034	0.814	-1189	-25877989	-7868155	-1301008	-66316630
2035	0.798	-1288	-28093162	-8298886	-1372230	-69947039
2036	0.780	-1395	-30497029	-8716556	-1441292	-73467362
2037	0.762	-1507	-32997889	-9150493	-1513044	-77124800
2038	0.743	-1619	-35522089	-9564493	-1581500	-80614186
2039	0.724	-1734	-38112073	-9977902	-1649857	-84098602
2040	0.705	-1849	-40709843	-10387854	-1717643	-87553875
2041	0.686	-1966	-43338431	-10786056	-1783486	-90910113
2042	0.665	-2087	-46076819	-11206495	-1853007	-94453781
2043	0.648	-2185	-48316926	-11610277	-1919772	-97857048
2044	0.626	-2315	-51287572	-12039998	-1990827	-101478951
2045	0.607	-2424	-53807160	-12441467	-2057211	-104862725
2046	0.586	-2547	-56590912	-12846654	-2124209	-108277834
2047	0.571	-2627	-58431978	-13246305	-2190291	-111646286
2048	0.551	-2739	-60987866	-13656325	-2258089	-115102139
2049	0.535	-2825	-62949536	-14068454	-2326235	-118575759
2050	0.518	-2922	-65152161	-14483036	-2394786	-122070063

Source: CEC staff

Oil and Gas Extraction Adjustments

The downward adjustment for the refinery industry is implemented for oil and gas extraction energy consumption as well. It assumes that the scale of operations in this industry will decline due to reduced use of petroleum-based fuels for the transportation sector, although the linkage is not as tight as in the refinery sector. In the overall scenario design, these adjustments were only included in the Enhanced Policy Scenario and not the Reference Scenario or Policy Scenario.

Table 27 provides annual statewide impacts for the fuel types used in oil and gas extraction for the Enhanced Policy Scenario.

Table 27: Oil and Gas Energy Consumption Reduction From Reduced Petroleum Product Demand — Enhanced Policy Scenario

Year	Transportation Product Scalar	Electricity (GWh)	Pipeline gas (MMbtu)	Steam (MMbtu)	Still Gas (MMbtu)
2023	1	0	0	0	0
2024	0.964	-187	-5,819,599	-23,100	-623,458
2025	0.934	-351	-10,801,065	-42,292	-1,141,434
2026	0.908	-482	-14,848,673	-58,460	-1,578,972
2027	0.885	-600	-18,588,145	-72,047	-1,945,940
2028	0.861	-718	-22,322,240	-85,041	-2,296,887
2029	0.835	-846	-26,457,093	-99,205	-2,679,474
2030	0.806	-987	-30,946,684	-114,313	-3,087,513
2031	0.779	-1,122	-35,287,710	-129,009	-3,484,450
2032	0.750	-1,261	-39,698,567	-143,927	-3,887,380
2033	0.721	-1,403	-44,281,849	-158,914	-4,292,157
2034	0.690	-1,547	-48,906,213	-173,289	-4,680,426
2035	0.664	-1,666	-52,863,148	-184,385	-4,980,128
2036	0.636	-1,795	-57,138,489	-195,819	-5,288,938
2037	0.608	-1,918	-61,231,349	-206,386	-5,574,353
2038	0.582	-2,031	-65,084,712	-215,430	-5,818,624
2039	0.556	-2,140	-68,778,143	-224,164	-6,054,530
2040	0.533	-2,238	-72,154,103	-231,556	-6,254,179
2041	0.511	-2,328	-75,321,366	-237,459	-6,413,597
2042	0.489	-2,411	-78,308,408	-242,118	-6,539,441
2043	0.474	-2,462	-80,308,017	-242,855	-6,559,352
2044	0.453	-2,538	-83,163,676	-245,330	-6,626,189
2045	0.436	-2,588	-85,272,505	-244,665	-6,608,229
2046	0.419	-2,641	-87,528,932	-243,446	-6,575,329
2047	0.409	-2,653	-88,488,779	-237,723	-6,420,757
2048	0.394	-2,692	-90,312,392	-234,879	-6,343,920
2049	0.383	-2,708	-91,375,451	-229,799	-6,206,727
2050	0.371	-2,725	-92,595,300	-224,245	-6,056,713

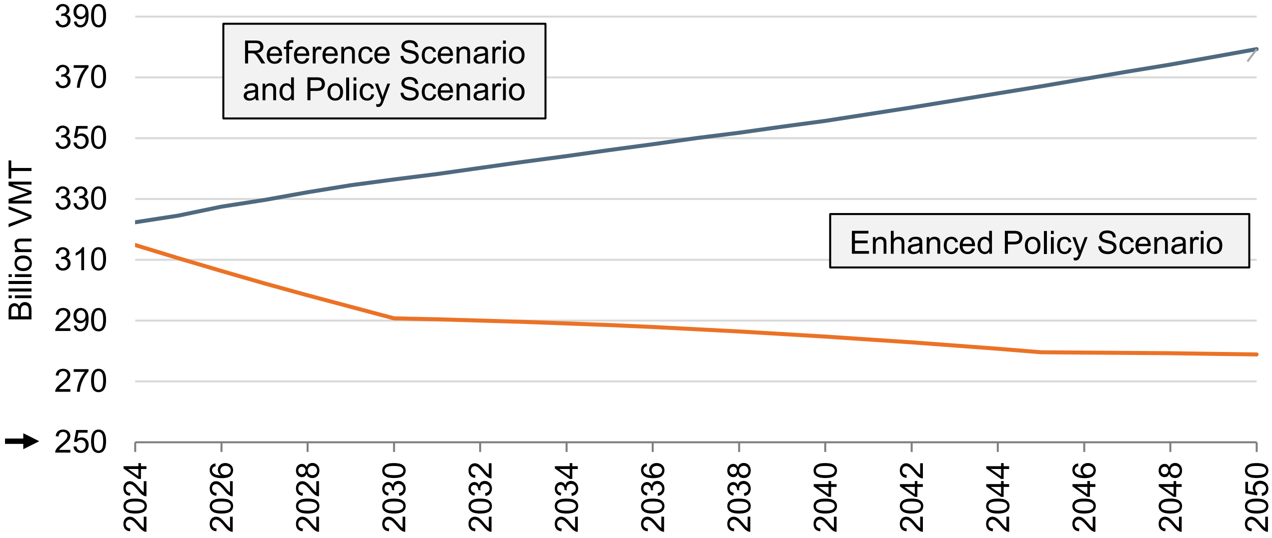
Source: CEC staff

Transportation Electrification

Vehicle Miles Traveled

In terms of vehicle miles traveled (VMT), the various dynamics at play for the VMT reduction in the EPS have a significant impact compared to the Reference and Policy Scenarios. The EPS assigns a light-duty per capita VMT decline of 15 percent by 2045 compared to the per capita VMT from 2023. However, the Reference and Policy Scenarios have increasing per capita VMT from 2024 to 2050, an approximate 16 percent increase. The result of the divergence in direction from the other scenarios means that total VMT in the EPS is about 26 percent lower than the other scenarios. Figure 34 shows this trend over the scenario period with key year markers in 2030, 2040, and 2050.

Figure 34: Total Light-Duty VMT by Demand Scenario



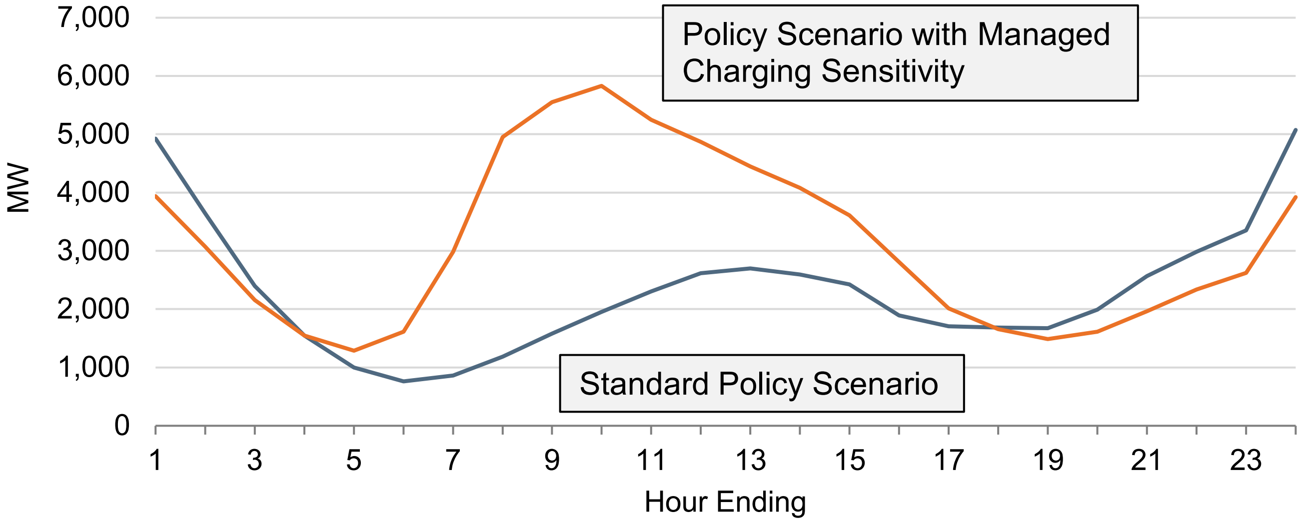
Source: CEC staff

The VMT decline affects all fuel types, with somewhat less of an impact on combustion fuels, as combustion vehicles are more prominent in rural areas. Gasoline demand declines by about 25 percent in the EPS compared to the other two scenarios, but this effect is somewhat muted because few of the miles, about 10 percent of them, are driven by gasoline cars in 2050. Electricity demand decline is similar in proportion, but because electric vehicles represent 85 percent of the miles in 2050, the decline in electric miles is large.

Managed Charging Sensitivity

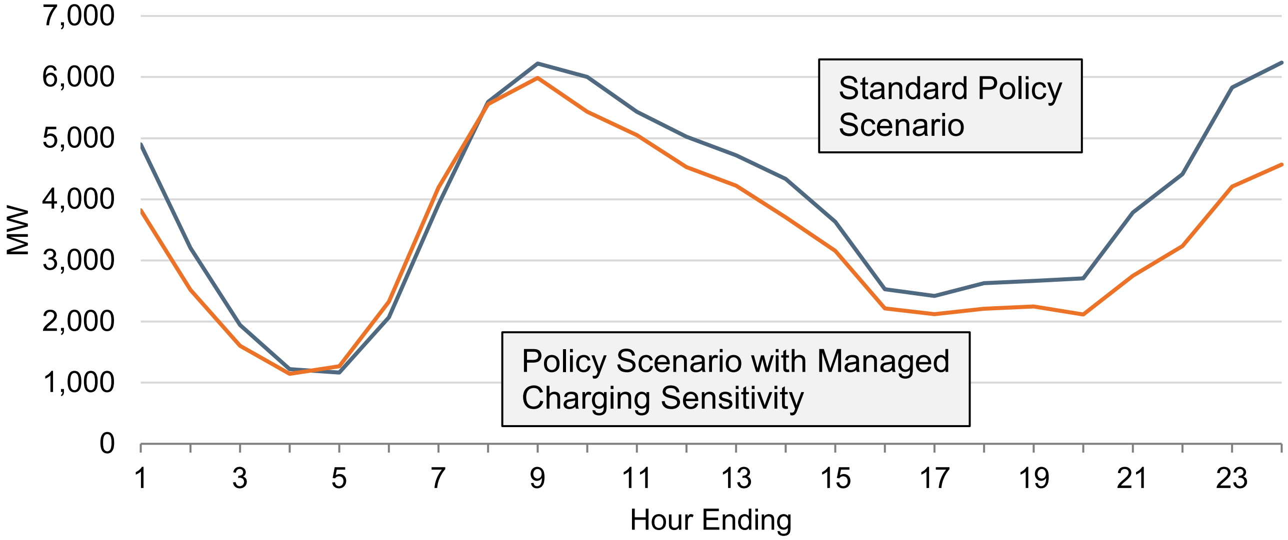
As mentioned in Chapter 3, the RESHAPE-EV hourly blending with the existing Policy Scenario light-duty hourly results shows a significant shift of load to weekends by 2050. No significant impacts to peak-load timing or magnitude occurs in the sensitivity. However, the load at midnight is lower, and the weekend light-duty EV load is much higher. Figure 35 and Figure 36 below show respective weekend and weekday light-duty profiles for the September average of 2050.

Figure 35: Average California ISO September 2050 Weekend Load Profile for Light-Duty Vehicles



Source: CEC staff

Figure 36: Average California ISO September 2050 Weekday Load Profile for Light-Duty Vehicles

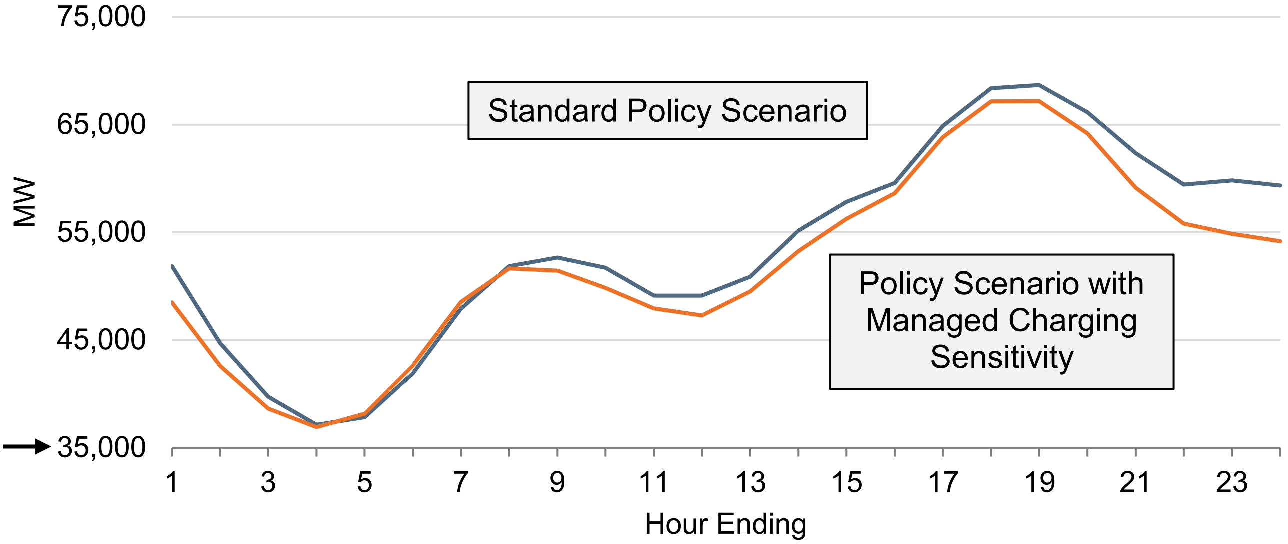


Source: CEC staff

The primary Policy Scenario assigns about 20 percent of LD charging load to weekends, while the Managed Charging Sensitivity results in about 27 percent to weekends. For time of day, about 26 percent of LD load occurs in the 10:00 a.m. to 3:00 p.m. period for all days in the primary Policy Scenario, with about 31 percent for the Managed Charging Sensitivity.

The Managed Charging Sensitivity has a noticeable impact on summer peak. Figure 37 shows about a 1.5 GW reduction in demand using managed charging, an opportunity to reduce summer peak. No appreciable effect occurs in the post-2041 February system peak in the Managed Charging Sensitivity.

Figure 37: Total 2050 California ISO Load Comparison for September Peak (Monthly Average)



Source: CEC staff

Opportunities for managed charging include real-time rates, managed charging programs, and more aggressive TOU pricing. It is uncertain if charging load could be shifted to weekends, although price signals may be able to achieve such goals where drivers are less concerned with range anxiety. Driving is more pronounced in some areas during the weekend, but it is less subject to rush hour effects. This finding suggests that fast charging could be more prominent.

BTM PV and Storage

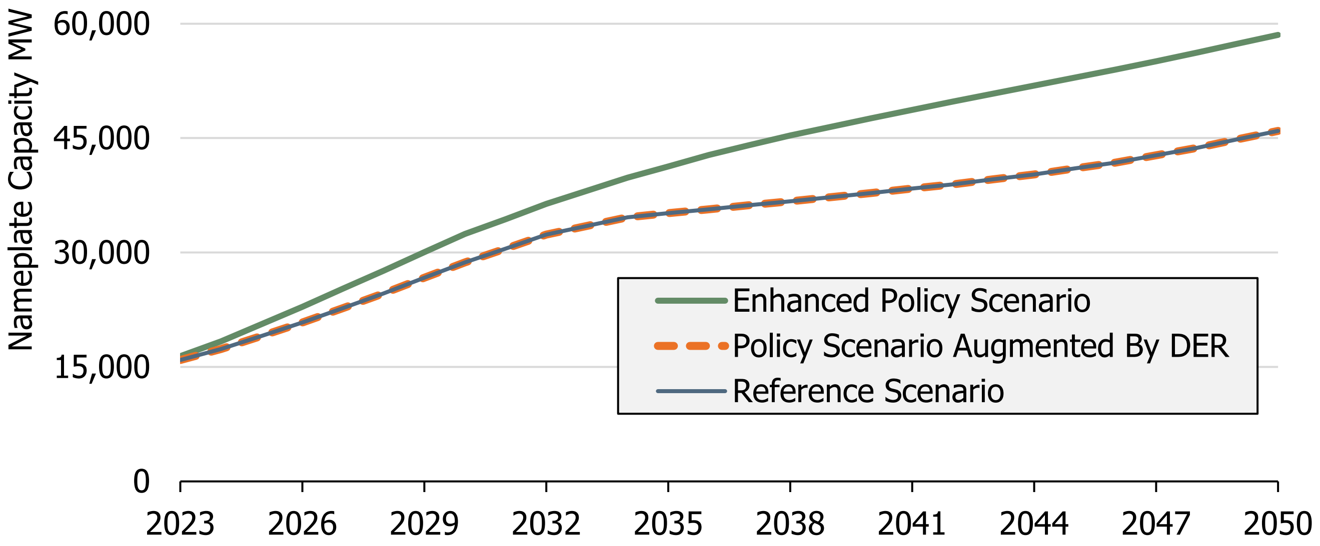
The BTM PV and storage demand scenarios framework described in Chapter 3 resulted in projections reflecting different levels of PV and storage adoption.

Solar PV

There are no changes to BTM PV forecast assumptions in the Policy Scenario High DER Sensitivity, so the projections remain the same as the CEC Reference Scenario. ITC extension and discounts on BTM storage CapEX, which reduced paired system costs, result in additional PV adoption in the Enhanced Policy Scenario.

Figure 38 shows statewide annual capacity growth by scenario. By 2050, cumulative PV capacity in the Enhanced Policy Scenario is 12,600 MW, or 27 percent higher than the Reference Scenario. Of this increase, 10,500 MW are in IOU territories, and 2,100 MW are in POU territories, roughly matching the planning area distribution of added PV in the 2023 IEPR PV forecast.

Figure 38: Statewide Cumulative PV Capacity Comparison by Scenario



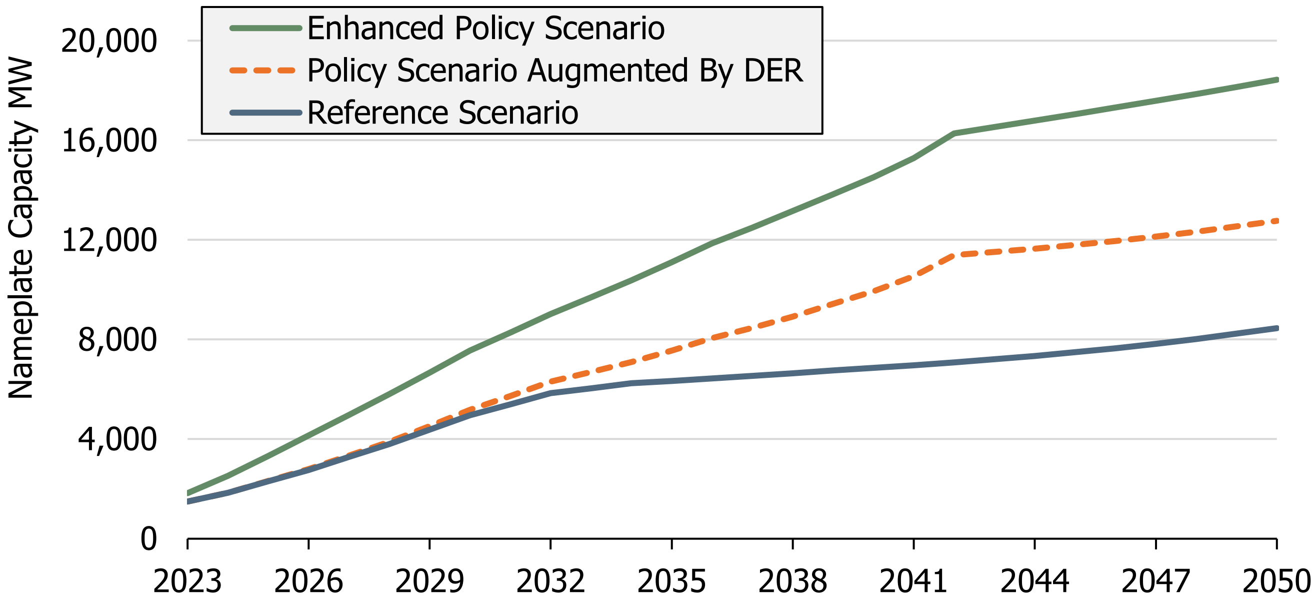
Source: CEC staff

Storage

Figure 39 depicts the growth in storage capacity through time for the scenarios and sensitivities that were assessed. Compared to the Reference Scenario, NEM contractual turnover in the Policy Scenario High DER sensitivity increases cumulative nameplate storage capacity by 4,300 MW in 2050. The Enhanced Policy Scenario, with a 50 percent reduction to storage CapEx costs and ITC extension, adds 5,700 MW of cumulative nameplate storage capacity in 2050. Thus, the Policy High DER sensitivity forecasts an increase of 4,300 MW of cumulative storage in 2050, and the Enhanced Policy Scenario forecasts an increase of 10,000 MW by 2050, which aligns with scenario goals. The Policy Scenario High DER sensitivity anticipates a 51 percent increase in storage capacity compared to the Reference Scenario, while the Enhanced Policy scenario projects a 118 percent increase.

In terms of storage distribution, the Policy Scenario High DER sensitivity adds 4,100 MW of storage in IOU territories and 200 MW in POU territories. In comparison, the Enhanced Policy Scenario adds 9,000 MW of storage in IOU territories and 900 MW in POU territories. More storage added from NEM contract turnover is allocated to IOUs because of higher forecast attachment rates, which, along with historical standalone PV adoption, are key factors in determining this allocation. Higher forecast attachment rates in IOU territories are driven by the switch to NBT and higher electricity rates. Both factors provide a greater financial incentive to install storage. This means that 4,300 MW of new storage capacity could be installed without any policy changes, while the additional 5,700 MW would require new policy implementation.

Figure 39: Statewide Cumulative Storage Capacity Comparison by Scenario



Source: CEC staff

CHAPTER 6: Observations, Insights, and Next Steps

This chapter summarizes key observations, insights emerging from the scenario and sensitivity analyses, and next steps that may be addressed in future cycles of this project.

Observations

Most of the broad results of this cycle of demand scenarios confirm expectations. Electrification through fuel substitution can have a major impact on energy consumption for electricity (increase) and pipeline gas (decrease). By design, a demand-side-only analysis cannot capture the impact of the broader set of control measures in CARB's 2022 Scoping Plan (for example, carbon capture and natural and working lands carbon mitigation). Thus, the largely demand-side policies and programs assessed in this project, absent these omitted control measures, fall short of statutory GHG emission reduction goals.

Fuel Substitution

In each demand scenario for all planning areas, fuel substitution (including fuel switching) from pipeline gas and combustion fuels to electricity increases California's electricity load and decreases demand for nonelectric fuels through 2050. The extent of this electric sector transformation depends on assumptions about how energy policies translate to changes in energy demand. The degree of fuel substitution and energy efficiency from programs or inherent efficiency of electric substitutes, behind-the-meter solar generation, and industrial decarbonization all influence projected electricity demand patterns. Scenarios with more EE see mitigated peak electricity demand increases, as well as total annual electricity demand growth.

Increased adoption of behind-the-meter solar and increased electric space heating from building electrification creates different hourly load patterns. In many planning areas, growth of new types of electric load, particularly building electrification, causes a transition from summer to a winter electric peak. The timing of that transition depends on scenario assumptions but is as early as 2038 under some conditions in some planning areas. BTM rooftop solar greatly reduces midday hourly loads in seasons without much space heating or air conditioning, leading to reduced minimum loads.

GHG Emission Projections

The emissions projections developed for each demand scenario indicate the level of emissions reduction that is likely to be achieved through 2050 via fuel substitution and energy efficiency, assuming existing decarbonized fuel blending levels persist. The demand scenario emissions method differs from CARB's emissions inventory method, so the projections cannot be directly compared to state emissions targets. The projections give an indication of the additional energy emissions reductions that will be required on the supply side. Carbon capture and sequestration, direct air capture, and further decarbonization of electric and nonelectric fuels are all likely to be required to meet California's 2050 targets. Future modeling that combines demand and supply-side decarbonization can help the state understand how to meet emissions targets most cost-effectively by drawing from a broad portfolio of complementary emissions reduction strategies.

Insights From Load Modifier Assumptions in Scenario Specifications

The assumptions for the Enhanced Policy Scenario greatly expand the scale of load modifiers compared to those in the Policy Scenario. The list below highlights the important features and speculates about the direction of the impact of each using previous modeling experience:

- Expanded Rooftop PV and BTM storage modifying grid-connected loads (reduction in electric load)
- AAEE scenarios reflecting more aggressive electric efficiency programs (reduction in electric load)
- CARB ZEAS (increase annual electricity consumption, but the hourly impacts vary greatly from season to season)
- Quantifying several niche transportation applications that are electrified (increase electric consumption)
- Significant levels of passenger vehicle VMT reduction (reduces energy and emissions from all vehicle types, including EVs)

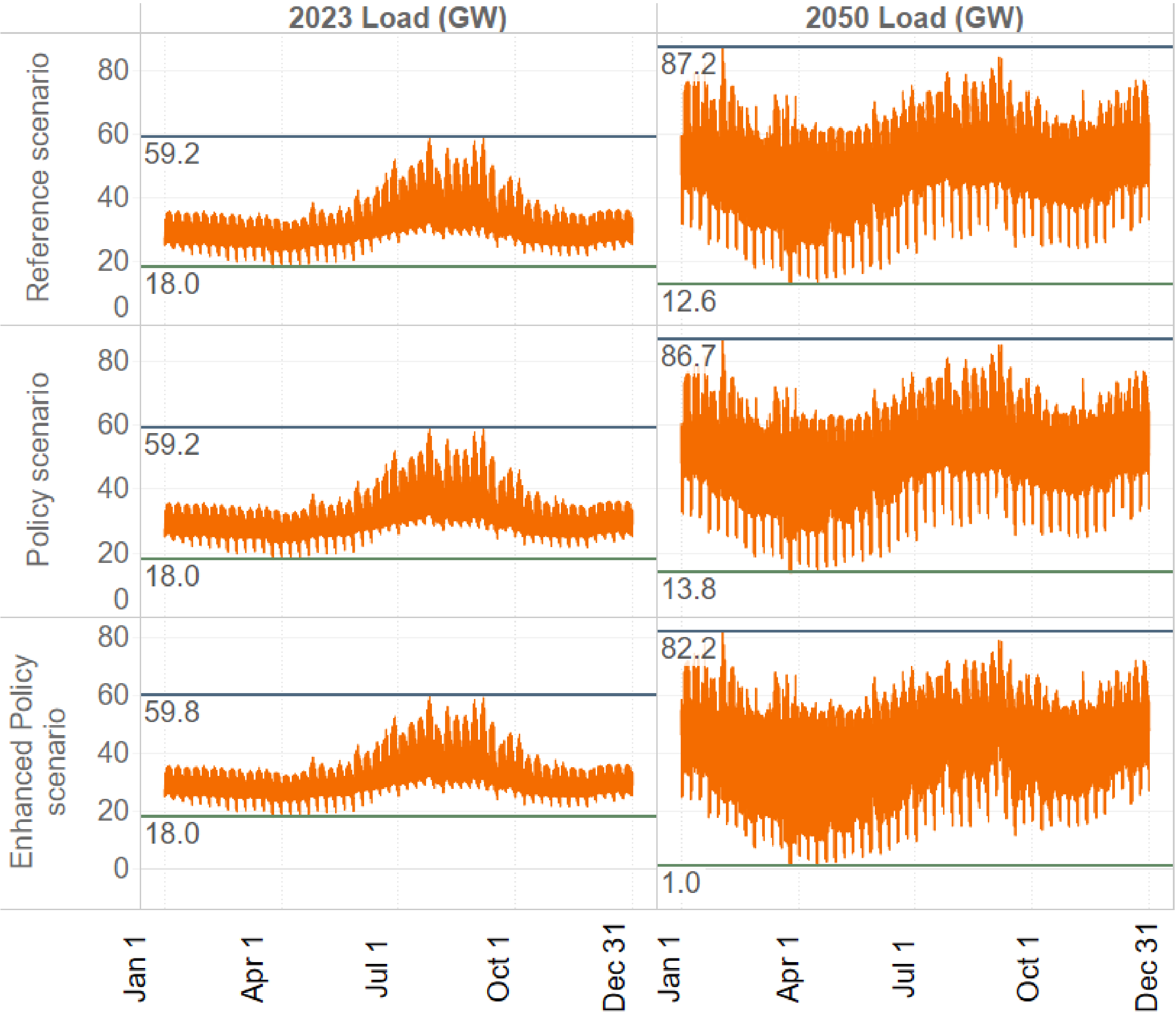
Although staff's intuition and assessment results don't disagree, the impact of multiple changes on electric demand and especially the pattern of electric hourly loads, were not fully anticipated.

Unforeseen Implications of EPS Scenario Input Assumptions

Figure 40 (a repeat of Figure 22) shows that each of the three main scenarios has more volatile hourly electric loads in 2050 than in "normalized" 2023. The spread between highs and lows is markedly higher in all seasons of the year, but 2050 hourly loads in winter months are higher than in 2023 and highly variable. Previous discussions of building electrification have noted the possible shift to winter peaking, but the high variability on a day-to-day or week-to-week timescale is a newly realized impact.

The building electrification analysis uses 2020 as the single historical weather year to create space-heating and air-conditioning load profiles for heat pumps. However, a more complete understanding of winter weather does not exist. That is, there is no analogous CEC forecasting approach of projecting peak demand variants assuming more extreme weather than the standard 1-in-2 (for example, 1-in-5, 1-in-10, and 1-in-20) traditionally used for summer electric peak demand. There may be lessons from pipeline gas planning that has focused on the weather-based extremes of pipeline gas flows to residential and commercial "core" customers.

Figure 40: Evolution of Statewide Electric Load Variability by Demand Scenario



Source: EER

In addition to the electric load variability shared in all scenarios, the Enhanced Policy Scenario has encountered negative minimum load results. Any modern electric resource planning study always assumes nonzero system loads at all hours of the year. Such assumptions are true for this analysis as well, but at the sector or even end-use level in some sectors. In the staff/EER method, it is the change in the mix of various load components through time that leads to aggregate negative minimum loads. This outcome requires electric generation and transmission planning studies to determine what minimum load thresholds the electricity system can accept for any future mix of generating and battery resources.

Table 28 depicts the peak and minimum loads for each year for each of the IOU planning areas, with rows for 2030 through 2040 omitted to reduce the table size. While peak loads grow steadily through time, as shown earlier in Chapter 4, minimum loads decline just as steadily. The red font indicates the years during which the minimum loads become negative.

Generally, this outcome is seen in only a few hours of each year and in months that have relatively low loads due to mild weather requiring little space heating or air conditioning.

Table 28: EPS Scenario Assumptions Cause Negative Minimum Loads

	PGE		SCE		SDGE	
Year	**Peak**	**Min**	**Peak**	**Min**	**Peak**	**Min**
2023	21430	5548	23958	7033	4543	854
2024	21154	4889	23414	6284	4512	706
2025	21112	4357	23011	5598	4478	569
2026	21162	3718	22479	4857	4456	440
2027	21118	3120	22370	4226	4460	308
2028	21250	2597	22407	3481	4490	178
2029	21482	2067	22294	2969	4491	83
2030	21760	1574	22265	2296	4560	**-33**
2031	22059	1272	22452	1794	4587	**-122**
2041	27692	650	25816	41	5393	**-298**
2042	28442	763	26559	**-96**	5334	**-358**
2043	29209	613	27758	**-57**	5417	**-378**
2044	29666	584	28220	**-35**	5564	**-377**
2045	30033	565	28348	**-295**	5672	**-380**
2046	30455	398	28582	**-161**	5677	**-397**
2047	30663	205	28518	**-537**	5762	**-368**
2048	30893	153	29159	**-643**	5847	**-463**
2049	31277	**-63**	29645	**-666**	5933	**-469**
2050	31432	**-92**	29788	**-848**	5987	**-514**

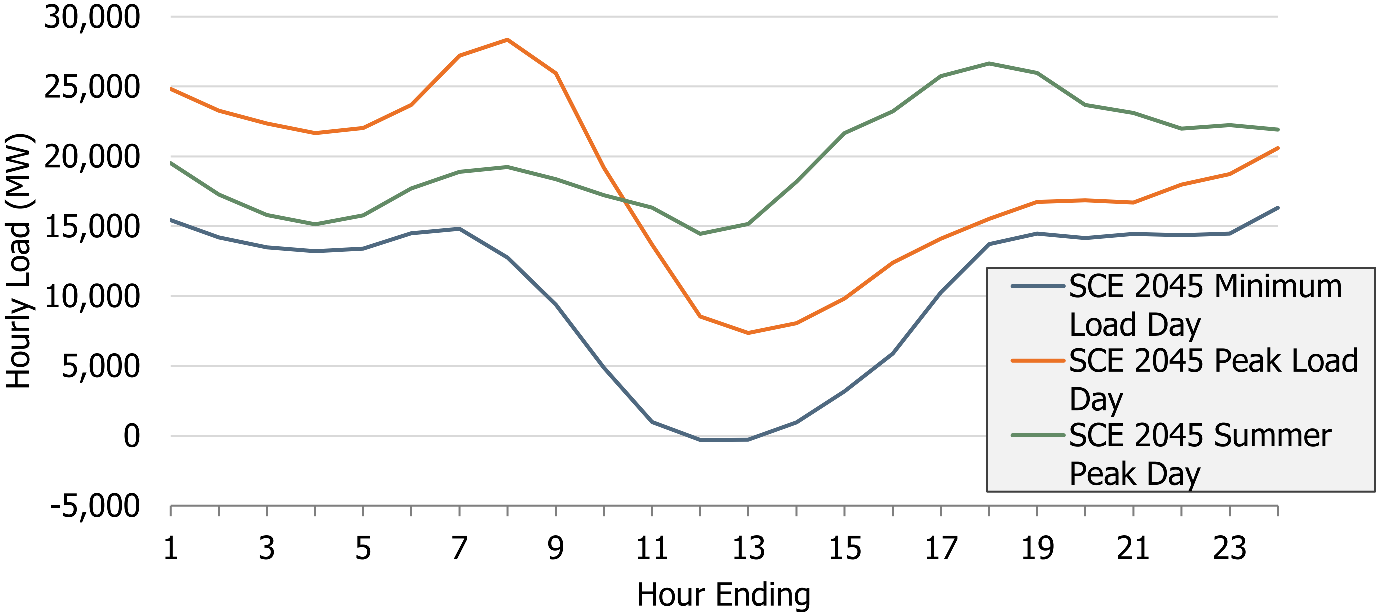
Source: CEC staff

Recognizing the outcome depicted in Table 28, staff sought an explanation. Among the many assumptions of the Enhanced Policy Scenario, some induce greater electric loads through time due to increased levels of electrification, but two assumptions reduce future electric loads. Review of the components of hourly electric loads for these three IOU planning areas in the days when minimum loads were found revealed that the higher levels of residential BTM roof top photovoltaic systems (BTM PV) and storage were the likely explanation.

Figure 41 and Figure 42 show the hourly loads of SCE's system to illustrate how large levels of BTM PV and BTM storage appear to cause unforeseen minimum loads in a few hours in the middle of the day. Other IOU planning areas or future years with minimum loads could have been selected as well. Figure 41 shows the pattern of hourly load for the SCE TAC system on several characteristic days in 2045. The blue line in Figure 41 shows the two hours when the 2045 minimum load day (March 26, 2045) shows total SCE TAC area loads below zero. The orange line shows the hourly loads on the 2045 SCE TAC system peak day, while the green line shows the hourly load pattern on a typical day in early September, which is the traditional point at which the SCE system peaks before extensive electrification.

One observation is that the base level of loads on the minimum load day (blue line) is fairly uniform in Hours 1–7 and 18 to 24 but gradually dips lower starting in Hour 8, reaches a minimum in Hour 13, and gradually rises to Hour 17. What explains a load reduction unique to the hours in the middle of a spring day?

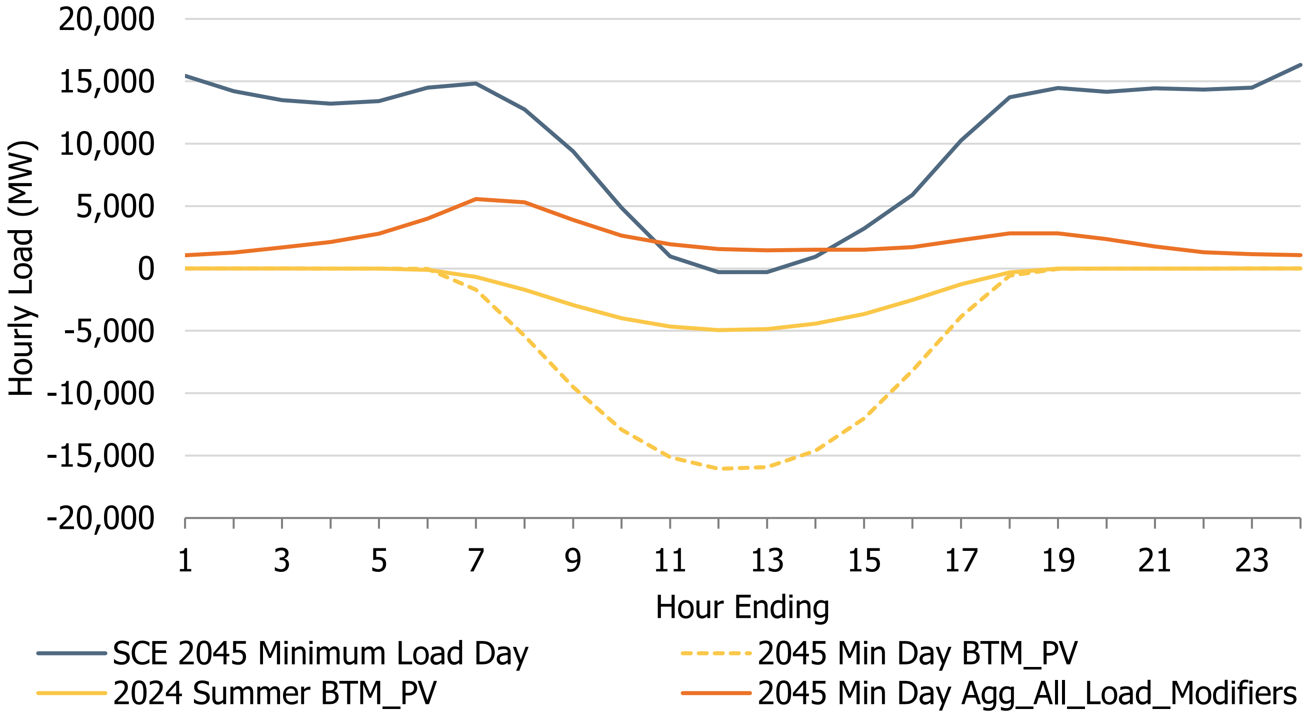
Figure 41: Comparing Hourly Managed Load for the Minimum Load Day (3/26/2045) to Other Key Days for SCE TAC Area in the 2045 Enhanced Policy Scenario (MW)



Source: CEC staff

Figure 42 repeats the hourly load information in the same style as the previous figure, but it plots only data from the minimum load day itself. The blue line is the hourly system load shown in Figure 41, displaying the negative net system load. The figure adds the hourly patterns of load from all load modifiers other than BTM PV or BTM storage (orange line) and hourly loads for BTM PV for 2045 (solid gold line). Finally, the hourly load for BTM PV in 2024 (dashed gold line) illustrates the large growth in BTM PV between 2024 and 2045. There is about an 11,000 MW increase in load reduction from BTM PV between 2024 and 2045. The large increment of BTM PV between an approximation of recent history and that expected in 2045 at the prime hours of BTM PV solar production drives the entire system load down below zero in Hours 11–13.

Figure 42: Hourly Load Projections for Components of Load for the SCE TAC Area on the Minimum Load Day



Source: CEC staff

The impact of the BTM PV input assumptions on minimum load only came to light as the various components of the Enhanced Policy Scenario hourly electric load were integrated together (the last step of a scenario assessment.) This result is not a forecast of what will happen, but it clearly represents the possible outcome unless this issue is studied more closely and appropriate mitigation measures are implemented.

This unforeseen impact of higher BTM PV should inspire further assessments of BTM PV and storage assumptions. There is also the broader unknown of the minimum load that an electric system can tolerate, especially when it is designed to include higher levels of demand-side resources that comprise a mix of generation and storage. Other transmission system dynamics from large power flow fluctuations across seasons, days, or hours induce new contingencies that likely need study and resolution.

Enhanced Policy Scenario Pipeline Hydrogen Sensitivity

Much of the support for a potential “hydrogen economy” rests on the requirement that hydrogen is produced by electrolysis supported by renewable electricity generation. Yet virtually all hydrogen produced and consumed in California today uses steam methane reforming. What is the path from the present to this future?

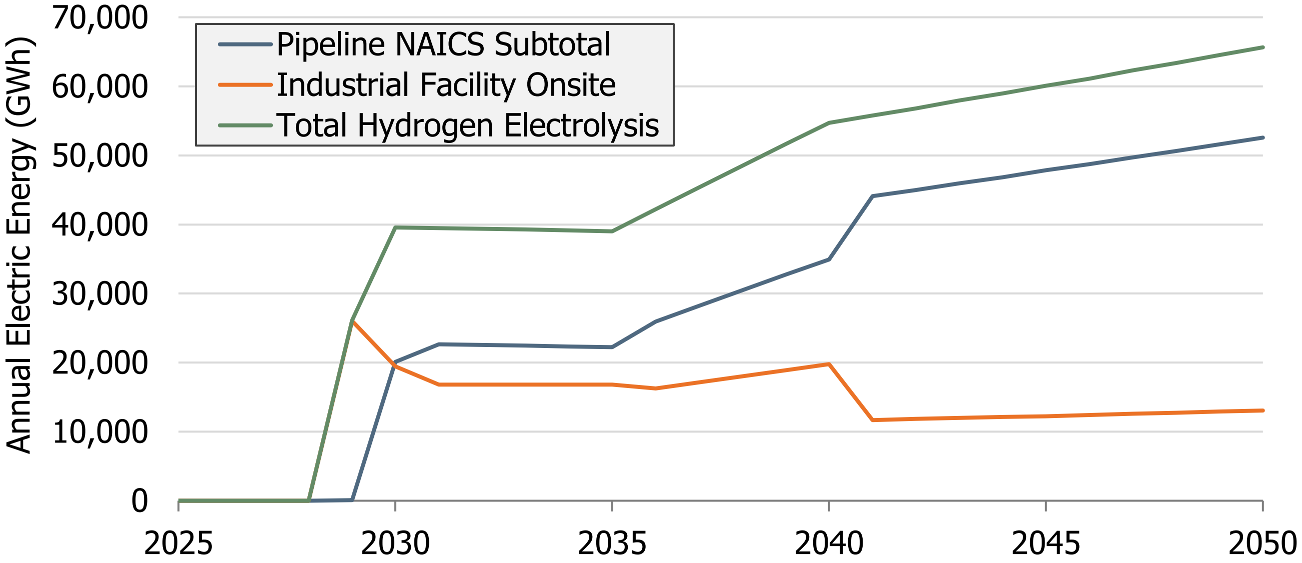
Although the Demand Scenarios Project could be literally constrained to just examining alternative levels of hydrogen consumption, devising scenarios for the expansion of hydrogen consumption necessarily confronts what mixtures of technologies are assumed for the production and delivery of hydrogen. In the Policy and Enhanced Policy Scenarios, staff addressed this question simplistically by assuming that all incremental hydrogen consumption above current usage was supplied by onsite electrolysis using grid-supplied electricity. While California's electric generating system is getting cleaner through time as the electric grid eventually comes into compliance with the SB 100 mandate for zero-carbon sources by 2045, it is not yet capable of producing the level of hydrogen consumption in these scenario projections as "green" hydrogen. However, even with the current mix of electric generating resources supporting California's load, producing hydrogen onsite using grid-supported electrolysis is cleaner than steam methane reforming.

In a hydrogen economy, with large volumes of hydrogen consumption, the current methods of delivering hydrogen to consumers are infeasible. Pipelines will have to be constructed from centers of hydrogen production to concentrations of usage. Since most centers of usage are in cities that cannot develop sufficient renewable resources for the electrolysis loads necessary, future centers of green hydrogen production are most likely going to be remote areas where renewable electric generating resources can be developed and water is available. Thus, low-carbon hydrogen delivery to consumers requires additional segments of pipeline development.

How can a hydrogen pipeline network be developed? Since electrification rather than conversion to hydrogen consumption is preferred for residential and commercial end users, collaborations of hydrogen producers, pipeline developers, and numerous large consumers need to be created to foster financial commitments to build infrastructure. The public-private ARCHES partnership is an example of a process that emphasizes consumption by power plants, ports, and trucking and imagines that in a later phase, industrial hydrogen consumption will build out as well.

CEC staff developed the EPS Pipeline Hydrogen Sensitivity to explore industrial-oriented hydrogen usage to replace pipeline gas used for industrial Process Heat-High applications. All other assumptions of the Enhanced Policy Scenario were held constant in this sensitivity. Chapter 3 provided the basic input assumptions and results of this sensitivity. What is instructive about this sensitivity are the large annual electric consumption requirements through time. Figure 43 graphs these results through time for onsite electrolysis and renewable/remote electrolysis.

Figure 43: Onsite and Remote Annual Electricity Consumption for Hydrogen Electrolysis



Source: CEC staff

The electric planning area location of the onsite electrolysis consumption cannot be pinpointed at this time. As described in Chapter 3, implementing CARB's "grid-friendly" approach to electrolysis means that a demand-side-only analysis cannot determine where electrolyzers will be located or what pattern of hourly operation they will follow. These decisions must be determined through a supply-side study in the context of a specific mix of electric generating resources. It is likely that the preferred locations and especially the hourly pattern of operation of these hydrogen electrolyzers will differ under various assumptions of other clean electricity generating and storage capacities through time. That effort is underway in the SB 100 proceeding. Interested parties can consult the SB 100 proceedings.

The results of this sensitivity illustrate many possible futures, and the Agricultural and Industrial FSSAT module can be used to examine more of them. Staff emphasizes that these results are not a forecast.

Next Steps

Two topics stand out as requiring greater effort in subsequent cycles of the Demand Scenarios Project. Each essentially requires more extensive coordination with supply-side assessment capabilities than currently exists within the CEC staff.

Decarbonization Through Fuel Blending

The Demand Scenarios Project uses the term "fuel blending" to describe how the composite properties of fuel types evolve through time as noncarbon fuels, low-carbon fuels, or carbon products with no net GHG emissions are blended with traditional fuels. Although the Demand Scenarios Project investigated mainly the consequences of fuel substitution, such as pipeline gas replaced by electricity in buildings, some fuel types can be decarbonized with little or no change in end-user equipment. As an example, by 2024 diesel fuel obtained at neighborhood filling stations has reached about 56 percent renewable diesel or biodiesel blending, greatly changing the emission factor for the "blended" product used mainly by trucks.

There are several methods by which traditional fuel types can be partly or fully decarbonized. The Low Carbon Fuel Standard is a CARB regulation (supported by the CEC) that is designed to decrease the carbon intensity of California's transportation fuels. Other programs could be devised to use fuel blending as either a transitional or long-term means to achieving California's GHG reduction goals.

Unfortunately, making long-term projections for fuel blending is beyond the scope of the Demand Scenarios Project. Doing so requires more extensive supply-side analysis capabilities, such as assessing feasibility or cost-effectiveness compared to straight fuel switching, than staff has. Supply-side assessment capability is needed to understand the costs and benefits of e-fuel production for those applications where a carbonaceous combustion fuel seems necessary given foreseeable technological development.

Carbon Capture, Utilization, and Sequestration

CARB's 2022 Scoping Plan includes GHG emission reductions from carbon capture in the refinery and cement industries, but it does not address how the carbon that is captured is used for e-fuel or other products or where and how it is sequestered when not used to generate a product. Carbon capture, utilization and sequestration refers to removing carbon from an emission source (such as a smokestack), using that captured carbon to make a product (cement blocks), or piping the gaseous carbon to a suitable depleted oil or natural gas reservoir and injecting it into reservoir.

The DS project team considered assessing CCUS but determined that the capability in the project team was limited to assessing only the incremental increase in electricity and waste heat required to operate carbon capture technologies at locations of major carbon emissions. The DS project did not have the resources to examine utilization and sequestration and the energy impacts of these two "downstream" uses for captured CO2.

Carbon capture and direct air capture (extracting carbon dioxide from ambient air rather than a more concentrated source such as a smokestack) technologies require new assessment capabilities, especially the geoengineering aspects of piping captured CO2 from "source" to "sink." In this instance the term "sink" refers to the place where captured CO2 is disposed of in a manner that prevents release to the atmosphere. There are complex engineering aspects of transforming CO2 into useful products or sequestering it in suitable reservoirs (depleted oil or natural gas reservoirs) that are beyond the scope of demand scenario assessments.

Conclusion

Most of the results of this cycle of demand scenarios confirm expectations. Electrification through fuel substitution can have a major impact on energy consumption for electricity (increase) and pipeline gas (decrease). The measures included in these demand scenarios alone are unlikely to reach statutory GHG emission targets by 2045. Other measures, such as fuel blending, carbon capture, utilization and sequestration, and direct air capture may be necessary, but staff was unable to assess these using only demand-side analytic tools. A robust supply-side assessment capability, especially focused on liquid fuels production, is necessary.

The improved modeling conducted for this Demand Scenarios Project cycle has revealed some insights that seem consistent across the scenarios examined:

- California is likely to shift from summer to winter peaking by the early 2040s in most electric planning areas of the state.
- High levels of rooftop PV systems, building electrification, and EV battery recharging may create swings in hourly electric load patterns far outside any operational experience. These swings require further examination of the electric generating system mix, including demand-side storage, that can accommodate the load mix in transitional seasons of the year with low space-conditioning loads in buildings.
- Even moderate levels of hydrogen substitution in transportation or industrial sectors will create large increases in electric energy consumption that require more in-depth comparison of whether this hydrogen should be supplied by onsite, grid-supported electrolysis, or remote renewable-supported electrolysis. There are a wide range of issues regarding this choice as recognized by the initial analysis required by SB 1075.[42]

Improvement in the assessment capabilities used for this cycle of the Demand Scenarios Project has improved the scope and quality of the results, but better data and further modeling improvements are necessary to tackle the issues described in this chapter.

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[42] California Energy Commission staff. 2023. *2023 Integrated Energy Policy Report*. Chapter 2. https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2023-integrated-energy-policy-report

GLOSSARY

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

Additional achievable fuel substitution refers to 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.

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.

Behind-the-meter refers to energy activities on the consumer's side of the grid.

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

Carbon intensity refers to the amount of carbon released for a unit of energy produced or consumed, and it is often measured in grams per kilowatt-hour.

Demand response is a set of programs that incentivize electricity consumers to modify their short-term use of electricity to assist in maintaining the necessary balance of aggregate supply and demand

NREL's **Distributed Generation Market Demand Model** uses the agent modeling approach to project adoption of rooftop solar photovoltaic systems and storage batteries on residential and non-residential buildings based on system costs, incentives, rates, prices of power exported to the grid in a cost-effectiveness framework.

Direct air capture refers to extracting carbon dioxide from ambient air rather than a more concentrated source such as a smokestack

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

Electrofuels or **e-fuels** are a class of synthetic fuels that are manufactured using captured CO2 or carbon monoxide and hydrogen.

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.

The **Fuel Substitution Scenario Analysis Tool** is a CEC-produced tool that models technology-based fuel substitution options.

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

Green hydrogen denotes one of multiple methods for producing hydrogen according to the carbon associated with the production method. Green hydrogen is produced using electrolysis with the necessary electricity provided exclusively by renewable resources.

A **load modifier** is an add-on to the baseline forecast which may have a different hourly profile. Load modifiers can be used to account for changes in technology, policy, or other trends which are not yet certain but are reasonably expected to occur.

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

Net metering refers to the practice of compensating electricity customers for supplying power to the power grid. This system is often seen among customers with photovoltaic systems that produce more power than what is consumed by the building it supplies.

Short-lived climate pollutants are potent climate pollutants with relatively short atmospheric lifetimes such as Carbon Dioxide, Methane, Nitrous Oxide

A **Therm** is equal to 100,000 Btu

The California code of regulations **Title 24** is the California Building Standards Code and includes unmodified national standards, adapted national standards for California's conditions, and state-specific amendments addressing local concerns. **Title 24 energy standards** refer to the energy efficiency standards found in part 6 of Title 24, and the voluntary provisions found in part 11.

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

Term	Definition
AAEE	additional achievable energy efficiency
AAFS	additional achievable fuel substitution
AATE	additional achievable transportation electrification
AB	Assembly Bill
AEO	Annual Energy Outlook
Ag-Ind	agriculture and industrial
AQMD	air quality management district
ARCHES	Alliance for Renewable Clean Hydrogen Energy Systems
BAAQMD	Bay Area Air Quality Management District
BAU	business as usual
BEV	battery electric vehicle
BTM	Behind-the-meter
BTU	British thermal unit
BUILD	Buildings Initiative for Low-Emissions Development Program
CAISO	California Independent System Operator
CapEx	capital expenditures
CARB	California Air Resources Board
CCS	carbon capture and sequestration
CCUS	carbon capture utilization and storage
CEC	California Energy Commission
CED	California Energy Demand Forecast
CH4	methane
CO2	carbon dioxide
CO2e	carbon dioxide equivalent
CPUC	California Public Utilities Commission
DER	distributed energy resources
DF	demand flexibility

DG	Distributed generation
dGen	Distributed Generation Market Demand Model
DOE	United States Department of Energy
DSM	demand scenarios model
E3	Energy and Environmental Economics, Inc.
EE	energy efficiency
EER	Evolved Energy Research
EIA	United States Energy Information Administration
EIN	Energy Independence Now
EP	EnergyPATHWAYS
EPIC	Electric Program Investment Charge
EPS	enhanced policy scenario
ES	executive summary
EV	electric vehicle
FCEV	fuel-cell electric vehicle
FSSAT	Fuel Substitution Scenario Analysis Tool
FZ	forecast zone
GHG	greenhouse gas
GW	gigawatt
GWh	gigawatt-hours
GWP	global warming potential
HE	high electrification
HELM	hourly electricity load model
HLM	hourly-load model
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
IOU	investor-owned utility
IPCC	Intergovernmental Panel on Climate Change
ISO	Independent system operator
ITC	Investment Tax Credit

JJMA	John J Mitchell Analytics
KG	kilogram
kW	kilowatt
kWh	kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LD	light-duty
LPG	liquified petroleum gas
MDHD	medium-duty/heavy-duty
MKRP	Mojave and Kern River pipelines
MMBTU	million British thermal units
MMT	million metric tons
MMTCO2e	million metric tons carbon dioxide equivalent
MW	megawatt
MWh	megawatt-hour
NAICS	North American Industrial Classification System
NBT	Net Billing Tariff
NC	new construction
NCNC	Northern California Non-CAISO
NEM	net-energy metering
NOX	oxides of nitrogen
NREL	National Renewable Energy Laboratory
OGV	ocean-going vessels
OOS	out-of-state
PA	planning area
PG	pipeline gas
PG&E	Pacific Gas and Electric
POU	publicly owned utility
PS	policy scenario
PV	photovoltaic
RASS	Residential Appliance Saturation Survey

RNG	renewable natural gas
ROB	replace on burnout
SAF	sustainable aviation fuel
SB	Senate bill
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SGIP	Self-Generation Incentive Program
SIP	State Implementation Plans
SLCP	Short-Lived Climate Pollutant
SMR	steam methane reformation
SMUD	Sacramento Municipal Utility District
SoCalGas	Southern California Gas Company
SOx	oxides of sulfur
TAC	transmission access charge
TBTU	trillion British thermal unit
TCU	transportation, communications, and utilities
TECH	Technology and Equipment for Clean Heating Program
TID	Turlock Irrigation District
TOU	time of use
TRL	technology readiness level
VMT	vehicle miles traveled
ZEAS	zero-emission appliance standards
ZEV	zero emission vehicle

APPENDIX A:
Building Sector Penetration Assumptions

This appendix provides a detailed schedule of the penetration assumptions for CARB and AQMD Zero Emission Appliance Standards. Table A-1 is referenced in Chapter 5.

Table A-1: Detailed Zero-Emission Appliance AAFS Modeling Assumptions for Residential and Commercial Buildings (Earliest adoption rates begin in 2026)

Scenario(s)	Jurisdiction/Regulation Amendment	Fuel Type	End Uses	Replacement Type/Sector	Description
All	Statewide	Gas	Space & Water Heating	NC/Res	100% adoption starting in 2026
All	Statewide	Gas	Space & Water Heating	NC/Comm	100% adoption starting in 2029
All	BAAQMD 9-4	Gas	Space Heating	ROB/Res & Comm	Linear ramp-up to 100% adoption in 2029
All	BAAQMD 9-6	Gas	Water Heating	ROB/Res	Linear ramp-up to 100% adoption in 2027
All	South Coast AQMD 1146.2[43]	Gas	Water Heating	ROB/Comm	Linear ramp-up to 100% adoption in 2029
Reference (AAFS 3)	Statewide (Initially proposed CARB SIP)	Gas	Space & Water Heating	ROB/Res & Comm	Beginning in 2026, a gradual ramp-up to 100% adoption in 2030 (10% haircut in ramp-up adoption rates relative to AAFS 4 & 5)
Policy & Enhanced Policy	Statewide (Initially proposed CARB SIP)	Gas	Space & Water Heating	ROB/Res & Comm	Linear ramp-up to 100% adoption in 2029

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[43] For the *2024 IEPR Update*, CEC staff has since revised the compliance date assumption for South Coast AQMD's amendment to rule 1146.2 to be 2031 instead of 2029 to be consistent with the schedules proposed by the Bay Area AQMD (amendment to Rule 9-6) and the California Air Resources Board announced at their May 29, 2024, workshop.

Scenario(s)	Jurisdiction/Regulation Amendment	Fuel Type	End Uses	Replacement Type/Sector	Description
(AAFS 4 & 5)					
Enhanced Policy (AAFS 5)	Statewide	Gas	Cooking & Clothes Drying	NC/Res	100% adoption starting in 2029
Enhanced Policy (AAFS 5)	Statewide	Gas	Cooking	NC/Comm	100% adoption starting in 2029
Enhanced Policy (AAFS 5)	Statewide	Gas	Cooking & Clothes Drying	ROB/Res	Linear ramp-up to 80% in 2030; continuing to 100% in 2035
Enhanced Policy (AAFS 5)	Statewide	Gas	Cooking	ROB/Comm	Linear ramp-up to 80% in 2030; continuing to 100% in 2045
Enhanced Policy (AAFS 5)	Statewide	Propane	Cooking, Space & Water Heating	NC/Res	100% adoption starting in 2029
Enhanced Policy (AAFS 5)	Statewide	Propane	Cooking, Space & Water Heating	ROB/Res	Linear ramp-up to 80% in 2030; continuing to 100% in 2035

Source: CEC staff

APPENDIX B: Customizing End-Use Shares of Pipeline Gas Consumption and Hydrogen Production/Delivery Combinations in the Enhanced Policy Hydrogen Pipeline Sensitivity

The CEC industrial demand forecasting model uses seven end-use shares to characterize electricity and pipeline gas consumption. Each of the 46 industries can have its own shares. Table B-1 provides the shares for pipeline gas used in the 2023 IEPR pipeline gas demand forecast.

The thermal share is the only one currently eligible for fuel switching in the Ag-Ind Fuel Switching tool, but this single thermal end use is too coarse. Therefore, the thermal share was subdivided into three more specific applications: Process Heat-High, Process Heat-Low, and Water Heat.

CEC staff consulted Figures B-1 and B-2 to determine how to allocate total thermal pipeline gas energy use into temperature ranges for each industry. These figures provide typical temperature ranges for specific industrial processes. Staff used judgment to determine the proportion of total thermal usage represented by specific process in each of the 46 NAICS codes. These figures are taken from *Decarbonizing Low-Temperature Industrial Heat in the U.S.*[44]

Table B-2 documents the assumed shares of total process heat by temperature range drawn from Figures B-1 and B-2 and then how these temperature ranges were assigned to Process Heat-High, Process Heat-Low, and Water Heat. Much judgment was required to translate these generic technology characterizations to the specific industries located in California.

Table B-3 provides the final split of the original thermal end use into the three more granular end uses for which fuel substitution or switching from pipeline gas to either electricity or hydrogen could be projected.

Table B-4 provides the shares of hydrogen production and delivery method combinations for the industries that were evaluated in the Enhanced Policy Scenario —

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[44] Jefferey Rissman. 2022. *Decarbonizing Low-Temperature Industrial Heat in the U.S.,* Energy Innovation Policy and Technology, LLC, October 2022. https://energyinnovation.org/wp-content/uploads/Decarbonizing-Low-Temperature-Industrial-Heat-In-The-U.S.-Report-2.pdf

Hydrogen pipeline sensitivity. Each NAICS/Planning area has three lines showing the share of that method which was assumed.

Table B-1: Pipeline Gas End-Use Shares in the CEC Industrial Demand Forecast Model

		CEC Industrial Model End-use Share of Total Natural Gas Consumption						
NAICS	**Description**	**Motor**	**Pr.Cooling**	**Thermal**	**HVAC**	**Lighting**	**Elec/Cogen**	**Misc**
211	Oil and Gas Extraction	0.00%	0.00%	96.00%	4.00%	0.00%	0.00%	0.00%
213	Drilling & Support Activities for Mining	0.00%	0.00%	96.00%	4.00%	0.00%	0.00%	0.00%
212	Other Mining	0.00%	0.00%	96.09%	3.91%	0.00%	0.00%	0.00%
230	Construction	0.00%	0.00%	96.52%	3.48%	0.00%	0.00%	0.00%
3111	Animal Food Manufacturing	0.82%	0.00%	69.67%	9.02%	0.00%	17.21%	3.28%
3112	Grain and Oilseed Milling	0.75%	0.00%	63.91%	2.26%	0.00%	27.07%	6.02%
3113	Sugar and Confectionery Product Manufacturing	0.00%	0.00%	50.00%	0.00%	0.00%	50.00%	0.00%
3114	Fruit and Vegetable Preserving and Specialty Food Manufacturing	0.00%	0.00%	44.33%	7.22%	0.00%	47.42%	1.03%
3115	Dairy Product Manufacturing	1.52%	0.00%	54.55%	6.06%	0.00%	34.85%	3.03%
3116	Animal Slaughtering and Processing	0.80%	0.00%	41.60%	6.40%	0.00%	39.20%	12.00%
3117	Seafood Product Preparation and Packaging	0.82%	0.00%	69.67%	9.02%	0.00%	17.21%	3.28%
3118	Bakeries and Tortilla Manufacturing	0.82%	0.00%	69.67%	9.02%	0.00%	17.21%	3.28%
3119	Other Food Manufacturing	0.82%	0.00%	69.67%	9.02%	0.00%	17.21%	3.28%
3121	Beverage Manufacturing	0.00%	0.00%	57.50%	10.00%	0.00%	32.50%	0.00%
3122	Tobacco Manufacturing	0.00%	0.00%	80.00%	0.00%	0.00%	20.00%	0.00%
313	Textile Mills	0.00%	0.00%	57.14%	7.14%	0.00%	32.14%	3.57%
314	Textile Product Mills	0.00%	0.00%	62.50%	25.00%	0.00%	12.50%	0.00%
315	Apparel Product Manufacturing	0.00%	0.00%	60.00%	13.33%	0.00%	24.44%	2.22%
316	Leather Product Manufacturing	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
1133	Logging	4.08%	0.00%	65.31%	12.24%	0.00%	14.29%	4.08%
321	Wood Product Manufacturing	4.08%	0.00%	65.31%	12.24%	0.00%	14.29%	4.08%
3221	Pulp, Paper, and Paperboard Mills	4.40%	0.00%	35.23%	2.07%	0.00%	57.25%	1.04%
3222	Paper Manufacturing	0.00%	0.00%	59.18%	18.37%	0.00%	20.41%	2.04%
323	Printing and Related Support Activities	2.78%	0.00%	58.33%	30.56%	0.00%	8.33%	0.00%
324	Petroleum and Coal Products Manufacturing	1.34%	0.00%	70.01%	0.52%	0.00%	24.92%	3.21%
325	Chemical Manufacturing	4.57%	0.00%	52.29%	2.41%	0.00%	36.16%	4.57%
326	Plastics and Rubber Products Manufacturing	1.15%	0.00%	50.57%	22.99%	0.00%	24.14%	1.15%
3271	Ceramic, Clay Product and Refractory Manufacturing	0.00%	0.00%	94.12%	2.94%	0.00%	2.94%	0.00%
3272	Glass Product Manufacturing	3.17%	0.00%	85.71%	4.76%	0.00%	3.17%	3.17%
3273	Cement and Concrete Product Manufacturing	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
3274	Lime and Gypsum Product Manufacturing	3.85%	0.00%	94.23%	1.92%	0.00%	0.00%	0.00%
3279	Other Nonmetallic Mineral Product Manufacturing	0.00%	0.00%	85.00%	10.00%	0.00%	0.00%	5.00%
331	Primary Metal Manufacturing	1.88%	0.00%	74.45%	6.11%	0.00%	9.72%	7.84%
332	Fabricated Metal Product Manufacturing	0.00%	0.00%	63.79%	25.86%	0.00%	9.20%	1.15%
333	Machinery Manufacturing	3.03%	0.00%	33.33%	46.97%	0.00%	15.15%	1.52%
3341	Computer and Peripheral Equipment Manufacturing	0.00%	0.00%	43.48%	34.78%	0.00%	13.04%	8.70%
3342	Communications Equipment Manufacturing	0.00%	0.00%	43.48%	34.78%	0.00%	13.04%	8.70%
3343	Audio and Video Equipment Manufacturing	0.00%	0.00%	43.48%	34.78%	0.00%	13.04%	8.70%
3344	Semiconductor and Other Electronic Component Manufacturing	0.00%	0.00%	45.83%	29.17%	0.00%	8.33%	16.67%
3345	Navigational, Measuring, Electromedical, and Control Instruments	0.00%	0.00%	43.48%	34.78%	0.00%	13.04%	8.70%
3346	Manufacturing and Reproducing Magnetic and Optical Media	0.00%	0.00%	43.48%	34.78%	0.00%	13.04%	8.70%
335	Electrical Equipment, Appliance, and Component Manufacturing	0.00%	0.00%	75.00%	25.00%	0.00%	0.00%	0.00%
336	Transportation Equipment Manufacturing	0.00%	0.00%	53.68%	36.03%	0.00%	5.15%	5.15%
337	Furniture and Related Product Manufacturing	0.00%	0.00%	46.15%	53.85%	0.00%	0.00%	0.00%
339	Miscellaneous Manufacturing	0.00%	0.00%	41.67%	50.00%	0.00%	0.00%	8.33%
511	Newspaper, Periodical, Book, and Directory Publishers	2.78%	0.00%	58.33%	30.56%	0.00%	8.33%	0.00%

Source: CEC staff Industrial Demand Forecasting Model, 2023 IEPR version.

Figure B-1: Estimated Industry-Specific Use of Process Heat by Temperature Range

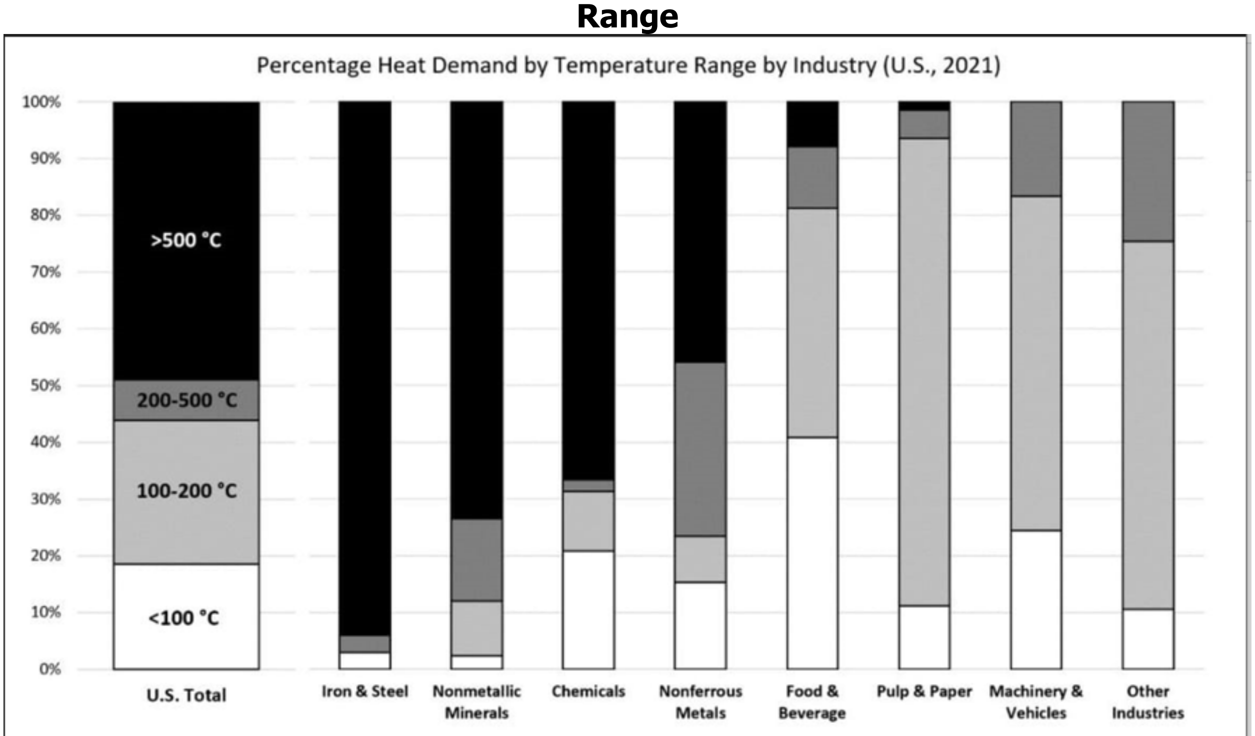


Figure 2. U.S. industrial heat demand by temperature range by industry in 2021. "Nonmetallic minerals" include cement, lime, glass, brick, tile, etc. Excludes heat for non-process uses, such as HVAC services for the comfort of workers.[4,5]

Source: Energy Innovation, *Decarbonizing Low Temperature Industrial Heat in the US*, October 2022, page 6.

Figure B-2: Heat Pump Technology Status for Common Processes Within Key Industries

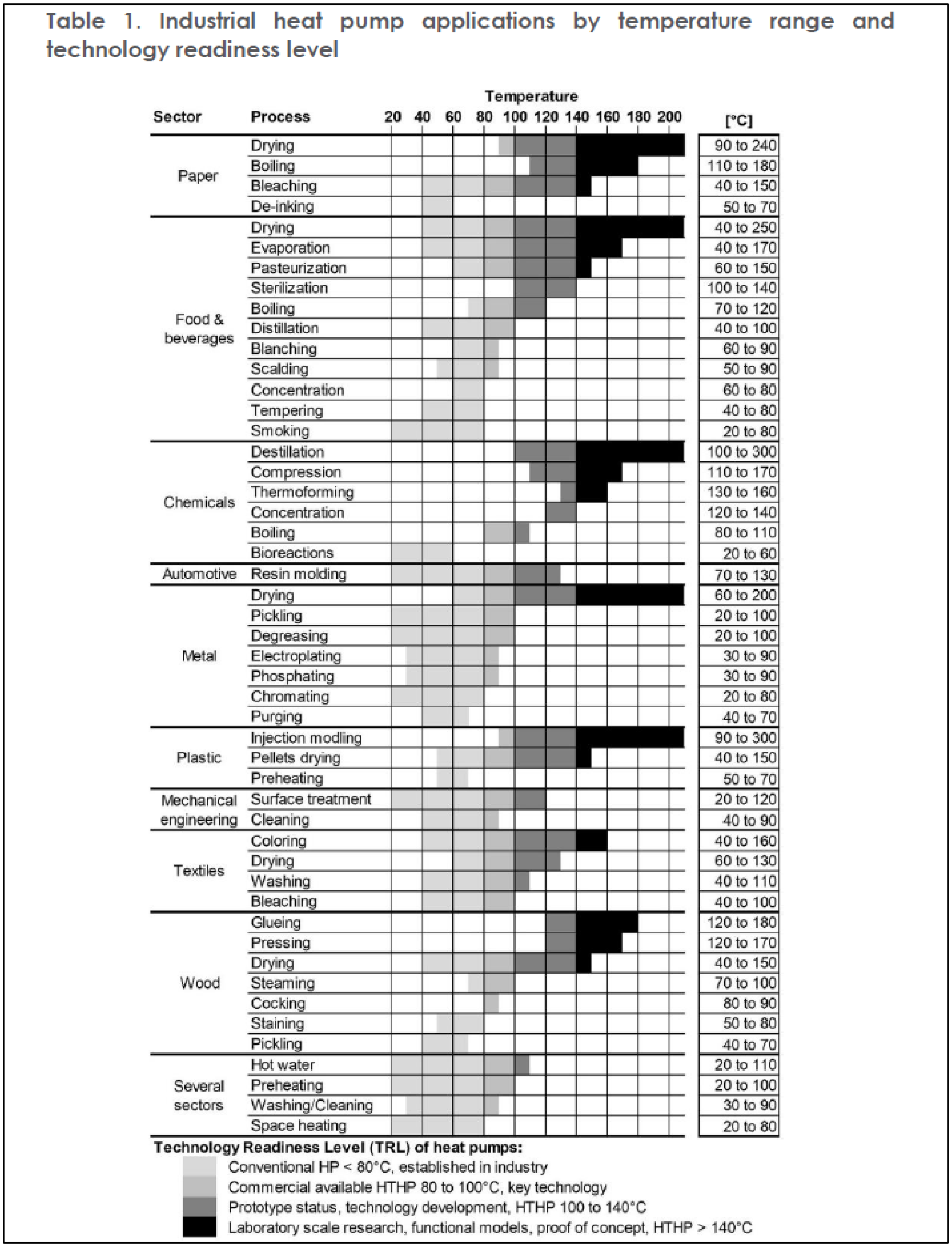


Table 1. Industrial heat pump applications by temperature range and technology readiness level

Sector	Process	[°C]
Paper	Drying	90 to 240
	Boiling	110 to 180
	Bleaching	40 to 150
	De-inking	50 to 70
Food & beverages	Drying	40 to 250
	Evaporation	40 to 170
	Pasteurization	60 to 150
	Sterilization	100 to 140
	Boiling	70 to 120
	Distillation	40 to 100
	Blanching	60 to 90
	Scalding	50 to 90
	Concentration	60 to 80
	Tempering	40 to 80
	Smoking	20 to 80
Chemicals	Destillation	100 to 300
	Compression	110 to 170
	Thermoforming	130 to 160
	Concentration	120 to 140
	Boiling	80 to 110
	Bioreactions	20 to 60
Automotive	Resin molding	70 to 130
Metal	Drying	60 to 200
	Pickling	20 to 100
	Degreasing	20 to 100
	Electroplating	30 to 90
	Phosphating	30 to 90
	Chromating	20 to 80
	Purging	40 to 70
Plastic	Injection modling	90 to 300
	Pellets drying	40 to 150
	Preheating	50 to 70
Mechanical engineering	Surface treatment	20 to 120
	Cleaning	40 to 90
Textiles	Coloring	40 to 160
	Drying	60 to 130
	Washing	40 to 110
	Bleaching	40 to 100
Wood	Glueing	120 to 180
	Pressing	120 to 170
	Drying	40 to 150
	Steaming	70 to 100
	Cocking	80 to 90
	Staining	50 to 80
	Pickling	40 to 70
Several sectors	Hot water	20 to 110
	Preheating	20 to 100
	Washing/Cleaning	30 to 90
	Space heating	20 to 80

Technology Readiness Level (TRL) of heat pumps:

- ░ Conventional HP < 80°C, established in industry
- ▒ Commercial available HTHP 80 to 100°C, key technology
- ▓ Prototype status, technology development, HTHP 100 to 140°C
- █ Laboratory scale research, functional models, proof of concept, HTHP > 140°C

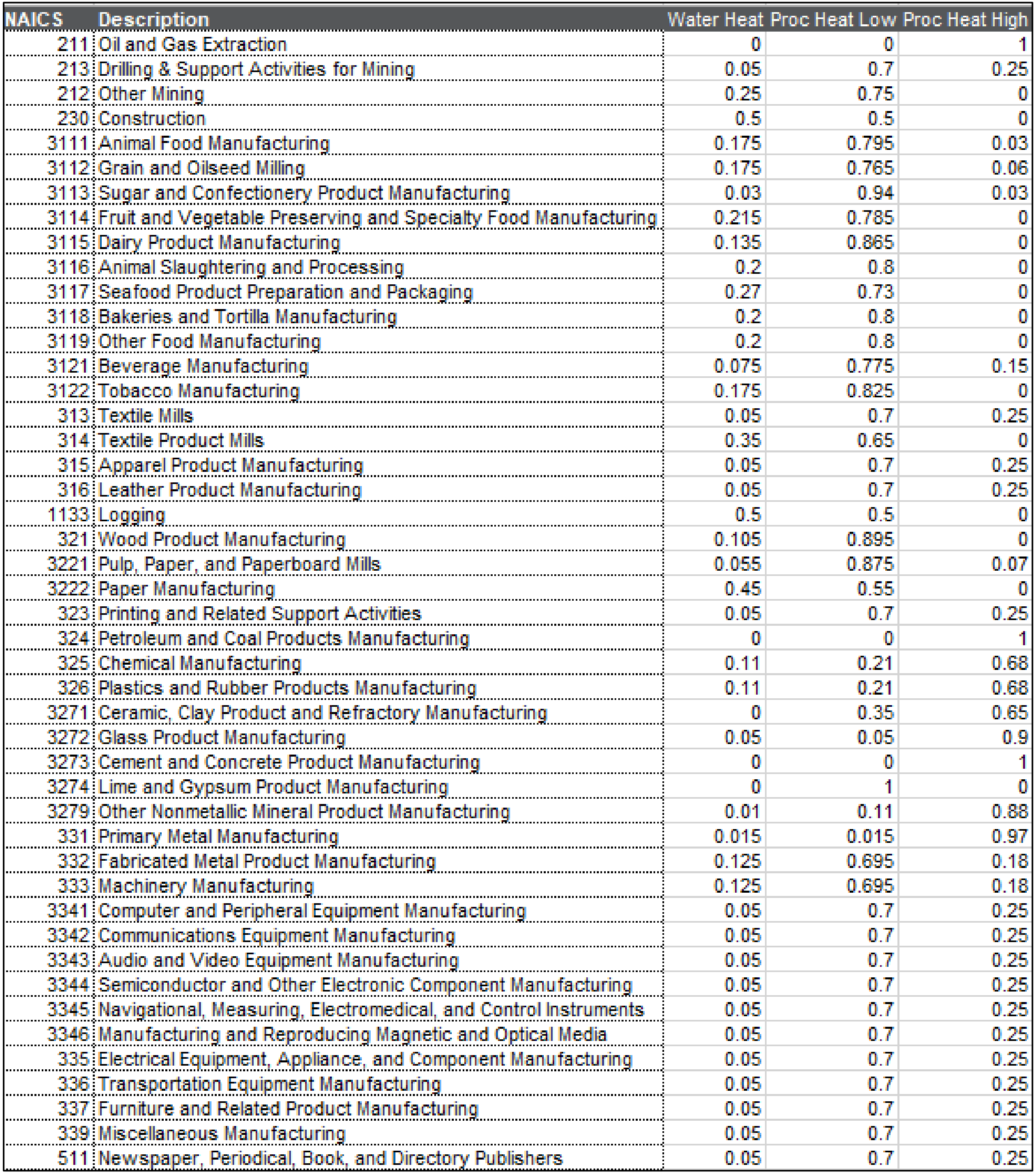
Ibid., page 11 (taken from Cordin Arpagaus et al., "High Temperature Heat Pumps: Market Overview, State of the Art, Research Status, Refrigerants, and Application Potentials," *Energy* 152 (2018): 985–1010, doi:10.1016/j.energy.2018.03.166.)

Table B-3: Translating Figures B-1 and B-2 to Split Thermal Share to More Specific End-Use Shares

NAICS	Description	Water Heat	Proc Heat Low	Proc Heat High	Temp>500C	Temp200-500C	Temp100-200C	Temp<100C	Temp Range Source
211	Oil and Gas Extraction	0	0	1	100	0	0	0	judgment
213	Drilling & Support Activities for Mining	0.05	0.7	0.25	0	25	65	10	Figure 2 from Energy Innovations report, p.6
212	Other Mining	0.25	0.75	0	0	0	50	50	judgment
230	Construction	0.5	0.5	0	0	0	0	100	judgment
3111	Animal Food Manufacturing	0.175	0.795	0.03	0	3	62	35	Table 1 from Energy Innovations report
3112	Grain and Oilseed Milling	0.175	0.765	0.06	0	6	59	35	Table 1 from Energy Innovations report
3113	Sugar and Confectionery Product Manufacturing	0.03	0.94	0.03	0	3	91	6	Table 1 from Energy Innovations report
3114	Fruit and Vegetable Product Food Manufacturing	0.215	0.785	0	0	0	57	43	Table 1 from Energy Innovations report
3115	Dairy Product Manufacturing	0.135	0.865	0	0	0	73	27	Table 1 from Energy Innovations report
3116	Animal Slaughtering and Processing	0.2	0.8	0	0	0	60	40	judgment
3117	Seafood Product Preparation and Packaging	0.27	0.73	0	0	0	46	54	Table 1 from Energy Innovations report
3118	Bakeries and Tortilla Manufacturing	0.2	0.8	0	0	0	60	40	judgment
3119	Other Food Manufacturing	0.2	0.8	0	0	0	60	40	judgment
3121	Beverage Manufacturing	0.075	0.775	0.15	8	7	70	15	judgment
3122	Tobacco Manufacturing	0.175	0.825	0	0	0	65	35	Table 1 from Energy Innovations report
313	Textile Mills	0.05	0.7	0.25	0	25	65	10	Table 1 from Energy Innovations report
314	Textile Product Mills	0.35	0.65	0	0	0	30	70	Table 1 from Energy Innovations report
315	Apparel Product Manufacturing	0.05	0.7	0.25	0	25	65	10	Figure 2 from Energy Innovations report, p.6
316	Leather Product Manufacturing	0.05	0.7	0.25	0	25	65	10	Figure 2 from Energy Innovations report, p.6
1133	Logging	0.5	0.5	0	0	0	0	100	judgment
321	Wood Product Manufacturing	0.105	0.895	0	0	0	79	21	Table 1 from Energy Innovations report
3221	Pulp, Paper, and Paperboard Mills	0.055	0.875	0.07	2	5	82	11	Figure 2 from Energy Innovations report, p.6
3222	Paper Manufacturing	0.45	0.55	0	0	0	10	90	Table 1 from Energy Innovations report
323	Printing and Related Support Activities	0.05	0.7	0.25	0	25	65	10	Figure 2 from Energy Innovations report, p.6
324	Petroleum and Coal Products Manufacturing	0	0	1	50	50	0	0	judgment
325	Chemical Manufacturing	0.11	0.21	0.68	66	2	10	22	Figure 2 from Energy Innovations report, p.6
326	Plastics and Rubber Products Manufacturing	0.11	0.21	0.68	66	2	10	22	Figure 2 from Energy Innovations report, p.6
3271	Ceramic, Clay Product and Refractory Manufacturing	0	0.35	0.65	25	40	35	0	judgment
3272	Glass Product Manufacturing	0.05	0.05	0.9	90	0	0	10	judgment
3273	Cement and Concrete Product Manufacturing	0	0	1	100	0	0	0	judgment
3274	Lime and Gypsum Product Manufacturing	0	1	0	0	0	100	0	judgment
3279	Other Nonmetallic Mineral Product Manufacturing	0.01	0.11	0.88	73	15	10	2	Figure 2 from Energy Innovations report, p.6
331	Primary Metal Manufacturing	0.015	0.015	0.97	94	3	0	3	Figure 2 from Energy Innovations report, p.6
332	Fabricated Metal Product Manufacturing	0.125	0.695	0.18	0	18	57	25	Figure 2 from Energy Innovations report, p.6
333	Machinery Manufacturing	0.125	0.695	0.18	0	18	57	25	Figure 2 from Energy Innovations report, p.6
3341	Computer and Peripheral Equipment Manufacturing	0.05	0.7	0.25	0	25	65	10	Figure 2 from Energy Innovations report, p.6
3342	Communications Equipment Manufacturing	0.05	0.7	0.25	0	25	65	10	Figure 2 from Energy Innovations report, p.6
3343	Audio and Video Equipment Manufacturing	0.05	0.7	0.25	0	25	65	10	Figure 2 from Energy Innovations report, p.6
3344	Semiconductor/Electronic Component Manufacturing	0.05	0.7	0.25	0	25	65	10	Figure 2 from Energy Innovations report, p.6
3345	Instrument Manufacturing	0.05	0.7	0.25	0	25	65	10	Figure 2 from Energy Innovations report, p.6
3346	Manufacturing Magnetic and Optical Media	0.05	0.7	0.25	0	25	65	10	Figure 2 from Energy Innovations report, p.6
335	Electrical, Appliance, and Component Manufacturing	0.05	0.7	0.25	0	25	65	10	Figure 2 from Energy Innovations report, p.6
336	Transportation Equipment Manufacturing	0.05	0.7	0.25	0	25	65	10	Figure 2 from Energy Innovations report, p.6
337	Furniture and Related Product Manufacturing	0.05	0.7	0.25	0	25	65	10	Figure 2 from Energy Innovations report, p.6
339	Miscellaneous Manufacturing	0.05	0.7	0.25	0	25	65	10	Figure 2 from Energy Innovations report, p.6
511	Newspaper, Periodical, Book, and Directory Publishers	0.05	0.7	0.25	0	25	65	10	Figure 2 from Energy Innovations report, p.6

Source: CEC staff

Table B-4: Final End-Use Splits Used to Subdivide Thermal End-Use by Process Heat-High, Process Heat-Low, and Water Heat for Each Industry



NAICS	Description	Water Heat	Proc Heat Low	Proc Heat High
211	Oil and Gas Extraction	0	0	1
213	Drilling & Support Activities for Mining	0.05	0.7	0.25
212	Other Mining	0.25	0.75	0
230	Construction	0.5	0.5	0
3111	Animal Food Manufacturing	0.175	0.795	0.03
3112	Grain and Oilseed Milling	0.175	0.765	0.06
3113	Sugar and Confectionery Product Manufacturing	0.03	0.94	0.03
3114	Fruit and Vegetable Preserving and Specialty Food Manufacturing	0.215	0.785	0
3115	Dairy Product Manufacturing	0.135	0.865	0
3116	Animal Slaughtering and Processing	0.2	0.8	0
3117	Seafood Product Preparation and Packaging	0.27	0.73	0
3118	Bakeries and Tortilla Manufacturing	0.2	0.8	0
3119	Other Food Manufacturing	0.2	0.8	0
3121	Beverage Manufacturing	0.075	0.775	0.15
3122	Tobacco Manufacturing	0.175	0.825	0
313	Textile Mills	0.05	0.7	0.25
314	Textile Product Mills	0.35	0.65	0
315	Apparel Product Manufacturing	0.05	0.7	0.25
316	Leather Product Manufacturing	0.05	0.7	0.25
1133	Logging	0.5	0.5	0
321	Wood Product Manufacturing	0.105	0.895	0
3221	Pulp, Paper, and Paperboard Mills	0.055	0.875	0.07
3222	Paper Manufacturing	0.45	0.55	0
323	Printing and Related Support Activities	0.05	0.7	0.25
324	Petroleum and Coal Products Manufacturing	0	0	1
325	Chemical Manufacturing	0.11	0.21	0.68
326	Plastics and Rubber Products Manufacturing	0.11	0.21	0.68
3271	Ceramic, Clay Product and Refractory Manufacturing	0	0.35	0.65
3272	Glass Product Manufacturing	0.05	0.05	0.9
3273	Cement and Concrete Product Manufacturing	0	0	1
3274	Lime and Gypsum Product Manufacturing	0	1	0
3279	Other Nonmetallic Mineral Product Manufacturing	0.01	0.11	0.88
331	Primary Metal Manufacturing	0.015	0.015	0.97
332	Fabricated Metal Product Manufacturing	0.125	0.695	0.18
333	Machinery Manufacturing	0.125	0.695	0.18
3341	Computer and Peripheral Equipment Manufacturing	0.05	0.7	0.25
3342	Communications Equipment Manufacturing	0.05	0.7	0.25
3343	Audio and Video Equipment Manufacturing	0.05	0.7	0.25
3344	Semiconductor and Other Electronic Component Manufacturing	0.05	0.7	0.25
3345	Navigational, Measuring, Electromedical, and Control Instruments	0.05	0.7	0.25
3346	Manufacturing and Reproducing Magnetic and Optical Media	0.05	0.7	0.25
335	Electrical Equipment, Appliance, and Component Manufacturing	0.05	0.7	0.25
336	Transportation Equipment Manufacturing	0.05	0.7	0.25
337	Furniture and Related Product Manufacturing	0.05	0.7	0.25
339	Miscellaneous Manufacturing	0.05	0.7	0.25
511	Newspaper, Periodical, Book, and Directory Publishers	0.05	0.7	0.25

Source: CEC staff

Table B-5: Hydrogen Production/Delivery Assumptions for the EPS Hydrogen Pipeline Sensitivity

NAICS	Description	Electric Utility	Production Method	Trans-portation Method	2020	2025	2030	2035	2040	2045	2050
211	Oil and Gas Extraction	PGE	SMR - No CCS	Onsite	0	0	0	0	0	0	0
211	Oil and Gas Extraction	PGE	Electrolysis Grid-Stnd	Onsite	0	0	0	0	0	0	0
211	Oil and Gas Extraction	PGE	Electrolysis Renewable	Pipeline	1	1	1	1	1	1	1
211	Oil and Gas Extraction	SCE	SMR - No CCS	Onsite	0.1	0.1	0.1	0.1	0.1	0.05	0.05
211	Oil and Gas Extraction	SCE	Electrolysis Grid-Stnd	Onsite	0.9	0.9	0.9	0.2	0.2	0.1	0.1
211	Oil and Gas Extraction	SCE	Electrolysis Renewable	Pipeline	0	0	0	0.7	0.7	0.85	0.85
211	Oil and Gas Extraction	MKRP	SMR - No CCS	Onsite	0.1	0.1	0.1	0.1	0.1	0.05	0.05
211	Oil and Gas Extraction	MKRP	Electrolysis Grid-Stnd	Onsite	0.9	0.9	0.9	0.2	0.2	0.1	0.1
211	Oil and Gas Extraction	MKRP	Electrolysis Renewable	Pipeline	0	0	0	0.7	0.7	0.85	0.85
3221	Pulp, Paper, and Paperboard Mills	SCE	SMR - No CCS	Onsite	1	1	0	0	0	0	0
3221	Pulp, Paper, and Paperboard Mills	SCE	Electrolysis Grid-Stnd	Onsite	0	0	0.2	0.2	0.2	0.2	0.2
3221	Pulp, Paper, and	SCE	Electrolysis Renewable	Pipeline	0	0	0.8	0.8	0.8	0.8	0.8

NAICS	Description	Electric Utility	Production Method	Trans-portation Method	2020	2025	2030	2035	2040	2045	2050
	Paperboard Mills										
324	Petroleum and Coal Products	PGE	SMR - No CCS	Onsite	0.8	0.8	0.2	0.2	0.2	0	0
324	Petroleum and Coal Products	PGE	Electrolysis Grid-Stnd	Onsite	0.2	0.2	0.2	0.2	0.2	0.2	0.2
324	Petroleum and Coal Products	PGE	Electrolysis Renewable	Pipeline	0	0	0.6	0.6	0.6	0.8	0.8
324	Petroleum and Coal Products	SCE	SMR - No CCS	Onsite	0.8	0.8	0.2	0.2	0.2	0	0
324	Petroleum and Coal Products	SCE	Electrolysis Grid-Stnd	Onsite	0.2	0.2	0.2	0.2	0.2	0.2	0.2
324	Petroleum and Coal Products	SCE	Electrolysis Renewable	Pipeline	0	0	0.6	0.6	0.6	0.8	0.8
324	Petroleum and Coal Products	LADWP	SMR - No CCS	Onsite	0.8	0.8	0.2	0.2	0.2	0.1	0.1
324	Petroleum and Coal Products	LADWP	Electrolysis Grid-Stnd	Onsite	0.2	0.2	0.2	0.2	0.2	0.2	0.2
324	Petroleum and Coal Products	LADWP	Electrolysis Renewable	Pipeline	0	0	0.6	0.6	0.6	0.7	0.7

NAICS	Description	Electric Utility	Production Method	Transportation Method	2020	2025	2030	2035	2040	2045	2050
325	Chemical Manufacturing	PGE	SMR - No CCS	Onsite	1	1	1	1	0.1	0	0
325	Chemical Manufacturing	PGE	Electrolysis Grid-Stnd	Onsite	0	0	0	0	0.1	0.1	0.1
325	Chemical Manufacturing	PGE	Electrolysis Renewable	Pipeline	0	0	0	0	0.8	0.9	0.9
325	Chemical Manufacturing	SMUD	SMR - No CCS	Onsite	0.5	0.5	0.5	0.5	0.25	0	0
325	Chemical Manufacturing	SMUD	Electrolysis Grid-Stnd	Onsite	0.5	0.5	0.5	0.5	0.25	0.25	0.25
325	Chemical Manufacturing	SMUD	Electrolysis Renewable	Pipeline	0	0	0	0	0.5	0.75	0.75
331	Primary Metal Manufacturing	SCE	SMR - No CCS	Onsite	0	0	0	0	0	0	0
331	Primary Metal Manufacturing	SCE	Electrolysis Grid-Stnd	Onsite	1	1	1	1	0.5	0.5	0.5
331	Primary Metal Manufacturing	SCE	Electrolysis Renewable	Pipeline	0	0	0	0	0.5	0.5	0.5
332	Fabricated Metal Manufacturing	SCE	SMR - No CCS	Onsite	0	0	0	0	0	0	0
332	Fabricated Metal Manufacturing	SCE	Electrolysis Grid-Stnd	Onsite	1	1	1	1	0.5	0.5	0.5
332	Fabricated Metal Manufacturing	SCE	Electrolysis Renewable	Pipeline	0	0	0	0	0.5	0.5	0.5

Source: CEC staff

APPENDIX C: Hourly POU Load Forecast

For each POU, Verdant created an hourly forecast of the various component parts that closely resemble the sample TAC area and California ISO hourly projections developed by CEC staff. To complete this task, staff followed the same computational methods that the CEC forecasting staff used for the IOU hourly forecasts as follows:

- For each POU, the historical hourly loads at the system level were used to create an hourly load ratio for a year. Load ratios were assigned to specific hours of the calendar by rank. Ranks were mapped to the rank of simulated load ratios averaged across hour and day type (day type is first Tuesday of May, third Friday of November, and so forth, with special consideration for New Year's Day, Fourth of July, Christmas). The hourly load ratio was calendarized to create an hourly load ratio for each year from 2022 to 2050.
- Weather elasticities were created by running a regression on each month, hour, workday.
- To estimate hourly climate change impacts, year-over-year percent changes in average hourly temperature were calculated using Lumen's detrended temperature libraries. Averages were taken across all variants by month and hour-of-day. These percentage changes were then applied to the estimated load elasticities for each hour-of-day by month and day-type (weekday/weekend) and resulted in an hourly percentage load change.
- The baseline hourly load ratios, hourly percentage load changes, transportation forecasts, AATE, AAFS, FSSAT load modifiers, IEPR forecasts, and historical PV load shapes were all combined to create the final forecasts for 2023–2050 for each POU. The columns in the final output are:
    - **UNADJUSTED_CONSUMPTION** estimated from "CED 2023 Final Electricity FZ Baseline.xlsx" as: (((Adjusted_Consumption GWh - LDV_GWh - MDHD_GWh - cc_impact) * loss factor)/8760) * hourly load ratio (see #1 above) * 1000
    - **PUMPING** estimated at 0 for the POUs
    - **CLIMATE_CHANGE** estimated from Lumen's detrended temperature libraries (see #3 above)
    - **LIGHT_EV** estimated from baseline transportation forecasts in "i23 LD PEV Regional Fuel consumption_BASE.xlsx" as: ((SF + MF + COMMERCIAL.DESTINATION + COMMERCIAL.FLEET + OTHER) – Year 2022 value) * loss factor
    - **MEDIUM_HEAVY_EV** estimated from baseline transportation forecasts in "i23_MDHD_Regional_Energy_Baseline.csv" as: ((GVWR3 + GVWR456 +

GVWR7 + GVWR8.COMBO + GVWR8.IRP + GVWR8.PORT + GVWR8.REFUSE.AND.RECYCLING + GVWR8.SU + INTERCITY.BUS + OTHER.BUS + SCHOOL.BUS + URBAN.BUS) – Year 2022 value) * loss factor

- **TOU_IMPACTS** estimated at 0 for the POUs
- **OTHER_ADJUSTMENTS** estimated at 0 for the POUs
- **BASELINE_CONSUMPTION** sum of the columns listed above (a through g)
- **BTM_PV** estimated from the historical PV load shape in "historical_hourly_gen_pous.csv" and the annual forecasts in "CED 2023 form_12.csv" and as: -historical_pv_gen_mw * the percent increase of PV generation as: (Form 1.2 PV_Generation) / (historical_pv_gen_mw)/1000 for Year 2022)
- **BTM_STORAGE_RES** added by the CEC for the POUs
- **BTM_STORAGE_NONRES** added by the CEC for the POUs
- **AAEE** estimated from the reference scenario forecast in "Reference Demand Scenario (AAEE 3 - AAFS 3) Hourly Results 05-01-2024.xlsx" as -AAEE * loss factor
- **AAFS** estimated from the scenario forecasts in "Reference Demand Scenario (AAEE 3 - AAFS 3) Hourly Results 05-01-2024.xlsx" and "Policy-Compliance Demand Scenario (AAEE 3 - AAFS 4) Hourly Results 05-01-2024.xlsx" as - AAFS * loss factor
- **FSSAT_IndAg** estimated from the scenario forecasts in the files "AgIndFSSATHourly_allElec_'tac'.xlsx" as the "AgIndTotal" variable
- **AATE_LDV** estimated from scenario transportation forecasts in the files "5. HELM_by_category_FZ_'tac'_AATE3_2023-12-19_172126.csv" and "5. HELM_by_category_'tac'_Policy_Compliance_2023-12-19_161914.csv" as: ((SF + MF + COMMERCIAL.DESTINATION + COMMERCIAL.FLEET + OTHER) – Year 2022 value) * loss factor
- **AATE_MDHD** estimated from scenario transportation forecasts in the files "5. HELM_by_category_FZ_'tac'_AATE3_2023-12-19_172126.csv" and "5. HELM_by_category_'tac'_Policy_Compliance_2023-12-19_161914.csv" as: ((GVWR3 + GVWR456 + GVWR7 + GVWR8.COMBO + GVWR8.IRP + GVWR8.PORT + GVWR8.REFUSE.AND.RECYCLING + GVWR8.SU + INTERCITY.BUS + OTHER.BUS + SCHOOL.BUS + URBAN.BUS) – Year 2022 value) * loss factor
- **BASELINE_NET_LOAD** sum of h through k
- **MANAGED_NET_LOAD** sum of h through p

Input Data Sources

The input data sources received from the CEC and used to calculate the POU forecasts are:

- **Loss factors** — "loss_factors.csv" file containing transmission and distribution line loss factors by POU.
- **Historical EMS data** — "Copy of CA POU loads_EV qry_07_27_23.xlsx" file containing 2016–2022 hourly historical MW load by POU. These data were cleaned to remove outliers.
- **Historical weather data**
    - "WS_hourly_20231001.csv" file containing Jan. 2000–Sep. 2023 hourly historical weather data by weather station.
    - "WS_hourly_synthSANTEE.csv" file containing Jan. 2000–Feb. 2010 hourly historical weather data for the SANTEE weather station.
- **Weather data weights** — "station_weights_04122019.xlsx" file containing weights by weather station, POU, and month.
- **Historical PV generation data** — "historical_hourly_gen_pous.csv" file containing 2016–2022 hourly historical MW of PV generation by POU.
- **Climate change temperature forecasts** — "PA_hourly_TEMP_detrended_'tac'_20230922.csv" files from Lumen's detrended temperature libraries containing 204 temperature variants at the hourly level for 2022–2050 for each POU.
- **Reference Scenario (AATE3) transportation forecasts**
    - "CED 2023 LDEV by FZ and Sector 2022 - 2050.csv" file containing forecasts of GWh load from light-duty electric vehicle (LDEV) in each forecast zone, sector, and POU from 2022-2050
    - "CED 2023 MDHD by FZ and Sector 2022 - 2050.csv" file containing forecasts of GWh load from medium- and heavy-duty electric vehicles (MDHD EV) in each forecast zone, sector, and POU from 2022 to 2050.
    - "5. HELM_by_category_FZ_'tac'_AATE3_2023-12-19_172126.csv" file containing forecasts of hourly GWh load by transportation type from 2022 to 2050 for each POU.
    - "BUGL_LADWP_MDHD_Reallocation.xlsx" file containing yearly GWh load reallocations for medium- and heavy-duty electric vehicles for BUGL and LADWP
- **Policy Compliance Scenario (AATE4) transportation forecasts**
    - "DSPC Transportation Electricity Forecast By FZ.xlsx" file containing yearly GWh load for light-, medium- and heavy-duty electric vehicles used for the POU IID.
    - "5. HELM_by_category_'tac'_Policy_Compliance_2023-12-19_161914.csv" file containing forecasts of hourly GWh load by transportation type from 2022 to 2050 for each POU.
- **Baseline transportation forecasts**

  - "i23 LD PEV Regional Fuel consumption_BASE.xlsx" file containing yearly GWh load for light duty electric vehicles by POU from 2022 to 2050.
  - "i23_MDHD_Regional_Energy_Baseline.csv" file containing yearly GWh load for medium- and heavy-duty electric vehicles by forecast zone from 2019 to 2050.
- **Load modifiers**
  - "Reference Demand Scenario (AAEE 3 - AAFS 3) Hourly Results 05-01-2024.xlsx" file containing hourly electricity impacts of the AAEE and AAFS that are used for the Reference Demand Scenario by POU.
  - "Policy-Compliance Demand Scenario (AAEE 3 - AAFS 4) Hourly Results 05-01-2024.xlsx" file containing hourly electricity impacts of the AAEE and AAFS that are used for the Policy-Compliance Demand Scenario by POU.
  - "AgIndFSSATHourly_allElec_'tac'.xlsx" file containing hourly MW impacts of the agriculture and industrial FSSAT for each POU.
- **Baseline**
  - "CED 2023 Final Electricity FZ Baseline.csv" file containing IPER forecasts by year and POU from 2023 to 2050 to estimate the "unadjusted consumption."
- **PV generation forecasts**
  - "CED 2023 form_12.csv" file containing "PV generation" by year and POU from 1990 to 2050 used to estimate forecasts of PV generation
  - "historical_hourly_gen_pous.csv" file containing historical hourly MWs of PV generation by POU used to estimate forecasts of PV generation.

APPENDIX D:
Short-Lived Climate Pollutants and Analysis Tool Use for GWP-20 Impacts

To explore the demand scenario impact on short-lived climate pollutants (SLCPs), a series of selection toggles have been included in the emissions tool to help illustrate the impacts of potential future policy decisions on these substances.[45] For this discussion, the only SLCPs that were analyzed were fugitive methane and hydrogen leakage. A review of the current scientific literature produced a range of fugitive leak rate values and a modeled impact of hydrogen as a GHG for the 20-year and 100-year impact periods.[46] This emissions tool uses an updated version of the GWP-20 impact potential multiplier of methane, as compared to CO_2, from the currently cited 2014 multiplier values of 76 to a new value of 81.2.

GWP-20 and Fugitive SLCPs as an Illustrative Study

Various ranges of emissions rates of methane and hydrogen were provided within the emissions tool, and the worst-case scenario is illustrated here with a total fugitive methane and hydrogen leak rate, as a percentage of total statewide consumption levels, of 5 percent and 10 percent respectively.

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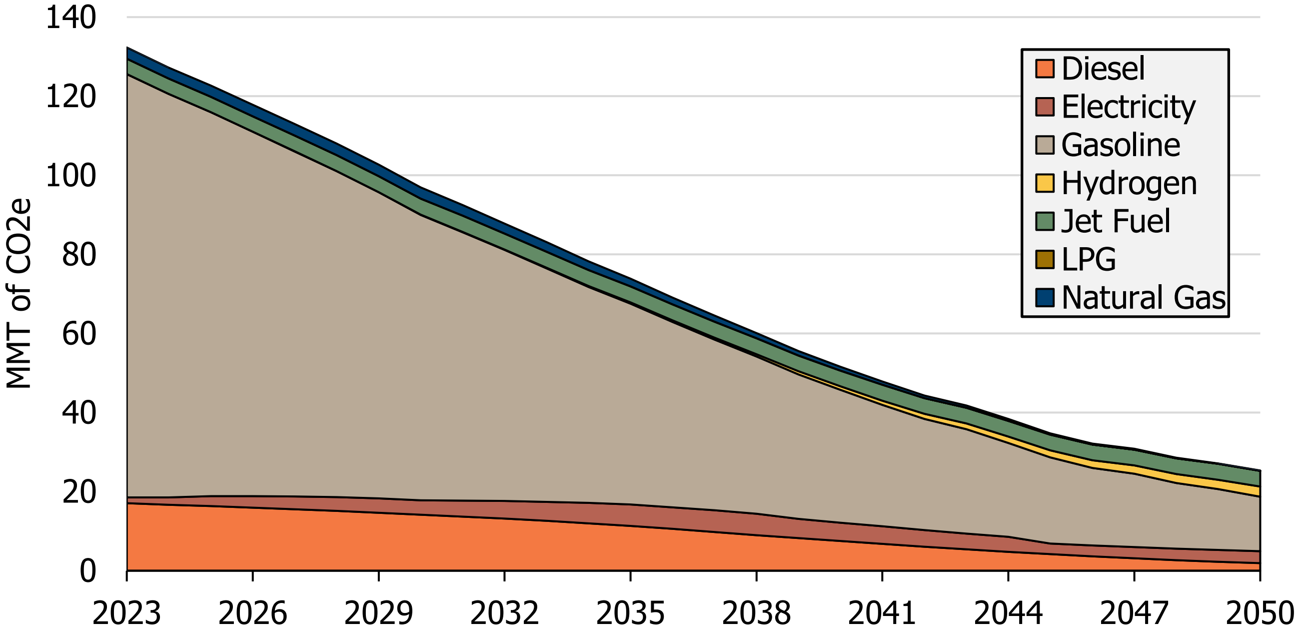
[45] For this discussion, *SLCPs* refer to emissions components that have a high near-term climate impact in compared to the associated equivalent impact on a 100-year timeline, the current benchmark for the comparison of all GHGs to CO_2.

[46] Sand, M., Skeie, R.B., Sandstad, M. *et al.* 2023. "A Multi-Model Assessment of the Global Warming Potential of Hydrogen." *Commun Earth Environ* 4, 203, https://doi.org/10.1038/s43247-023-00857-8.

Ocko, I. B. and Hamburg, S. P. 2022. "Climate Consequences of Hydrogen Emissions." *Atmos. Chem. Phys.,* 22, 9349–9368, https://doi.org/10.5194/acp-22-9349-2022.

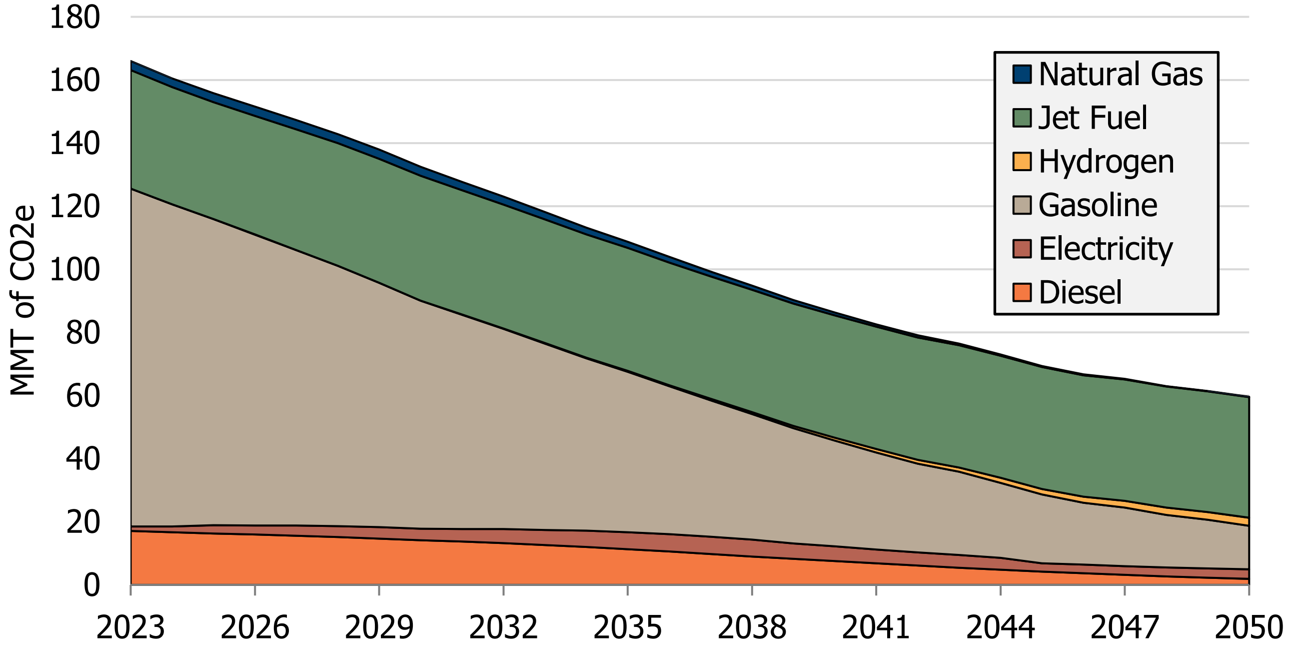
Figure D-1: Total Emissions by Fuel Type (CO_2e) Transportation Sector, Enhanced With Hydrogen Scenario — Intrastate Aviation Only



SLCP transportation sector demonstration with hydrogen emissions set at 10% of total production and GWP-20 year equivalent impact. Jet fuel emissions are set to mimic intrastate travel only.

Source: CEC staff

Figure D-2: Total Emissions by Fuel Type (CO_2e) Transportation Sector, Enhanced With Hydrogen Scenario — All Aviation

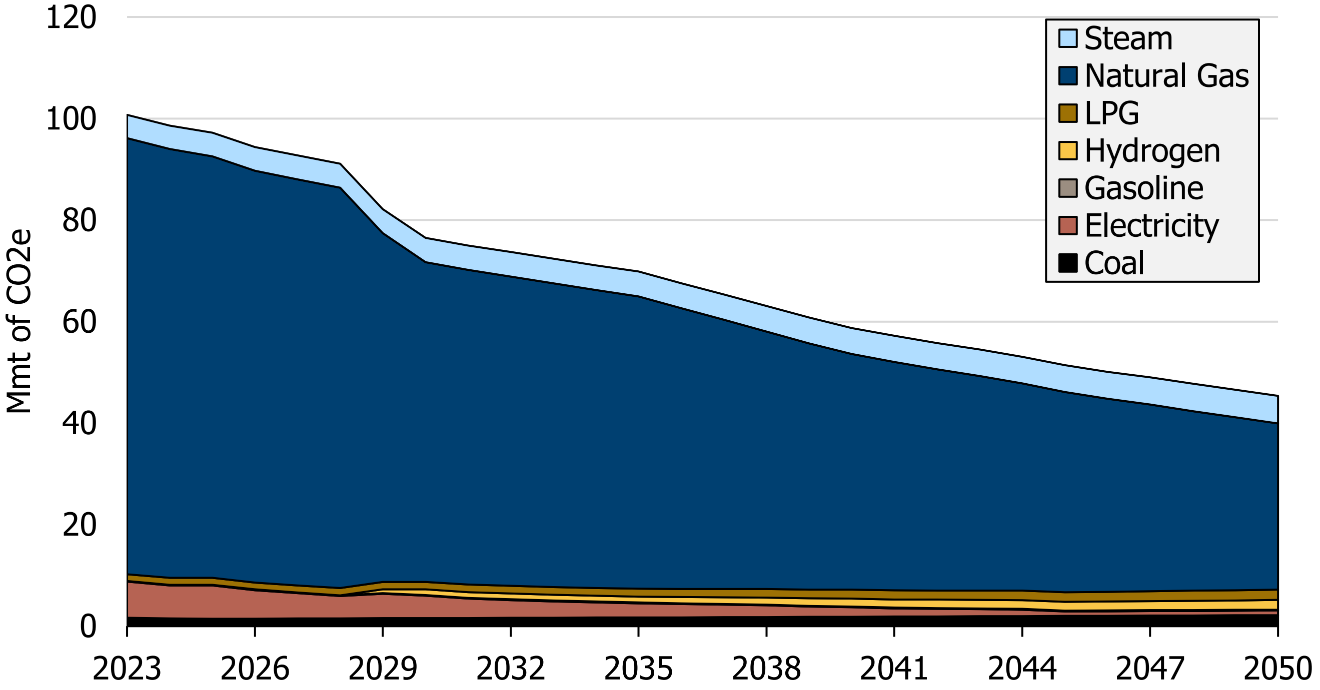


SLCP transportation sector demonstration with hydrogen emissions set at 10% of total production and GWP-20 year equivalent impact. Jet fuel emissions are set to all air travel

departures.

Source: CEC staff & JJMA

Figure D-3: Total Emissions by Fuel Type (CO2e) Industrial Sector, Enhanced With Pipeline Hydrogen Sensitivity



SLCP transportation sector demonstration with hydrogen emissions set at 10% of total production, fugitive methane set at 5% of total consumption and GWP-20 year equivalent impact.

Source: CEC staff & JJMA

Under this analysis, the total impacts of SLCPs in 2045 for the Enhanced Policy Scenario Hydrogen Sensitivity were an additional 3.5 million metric tons of CO2e for hydrogen, including N2O produced through hydrogen combustion, and an additional 40 million metric tons of CO2e for fugitive methane emissions on a 20-year impact timeline. Total statewide CO2e emissions in 2045 for this analysis were 176 million metric tons, a 33 percent increase in total statewide emissions under the GWP-20 analysis.

If only intrastate air travel were considered for this study, then the relative impact of fugitive emissions would result in a 40 percent increase in 2045 of the total statewide emissions profile to a value of 141 million metric tons. The change in emissions profile timelines do not allow for the comparison of current state legislative emission targets that are directed to be analyzed using the longer, 100-year timeline. Hence, this discussion is for illustration only.

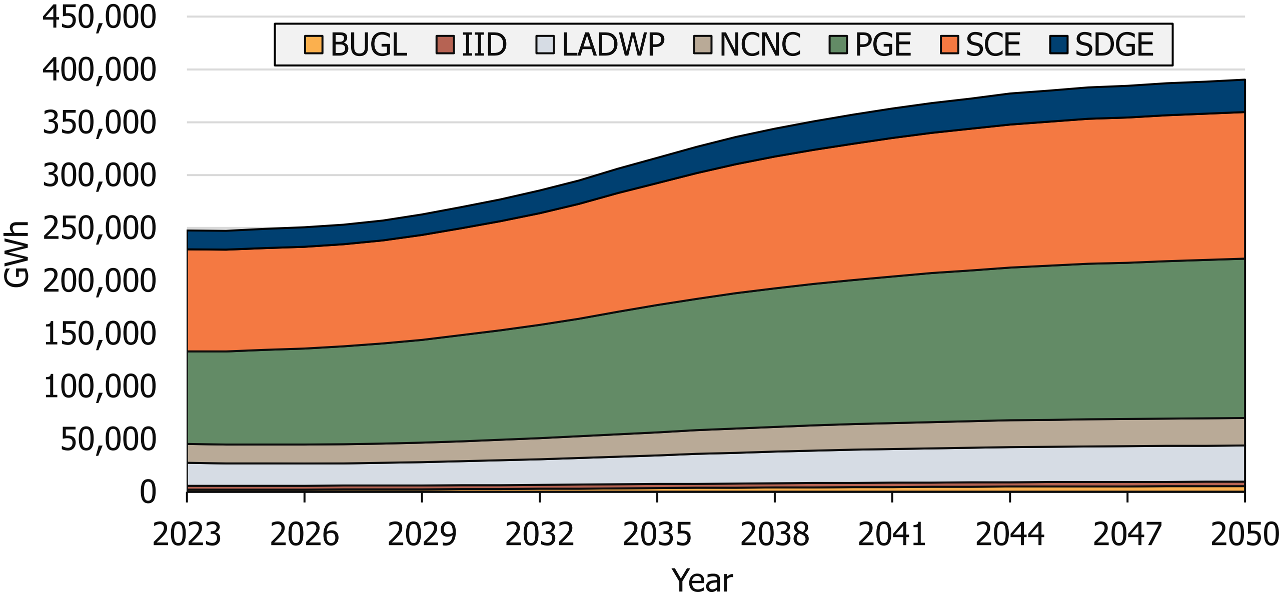
Under the Enhanced Policy Scenario Pipeline Hydrogen sensitivity, where large amounts of hydrogen production are forecast for the transportation and industrial industry sectors, the relative impacts of hydrogen leakage, at a worst-case scenario, are minor when compared to the overall emissions profiles of each sector.

The impact of fugitive methane emissions on the industrial sector emissions profile raises the 2045 emissions levels from 27.5 million metric tons of CO2e to 51.4 million metric tons on a GWP-20 timeline.

APPENDIX E: Statewide Annual Energy and Peak Results Figures

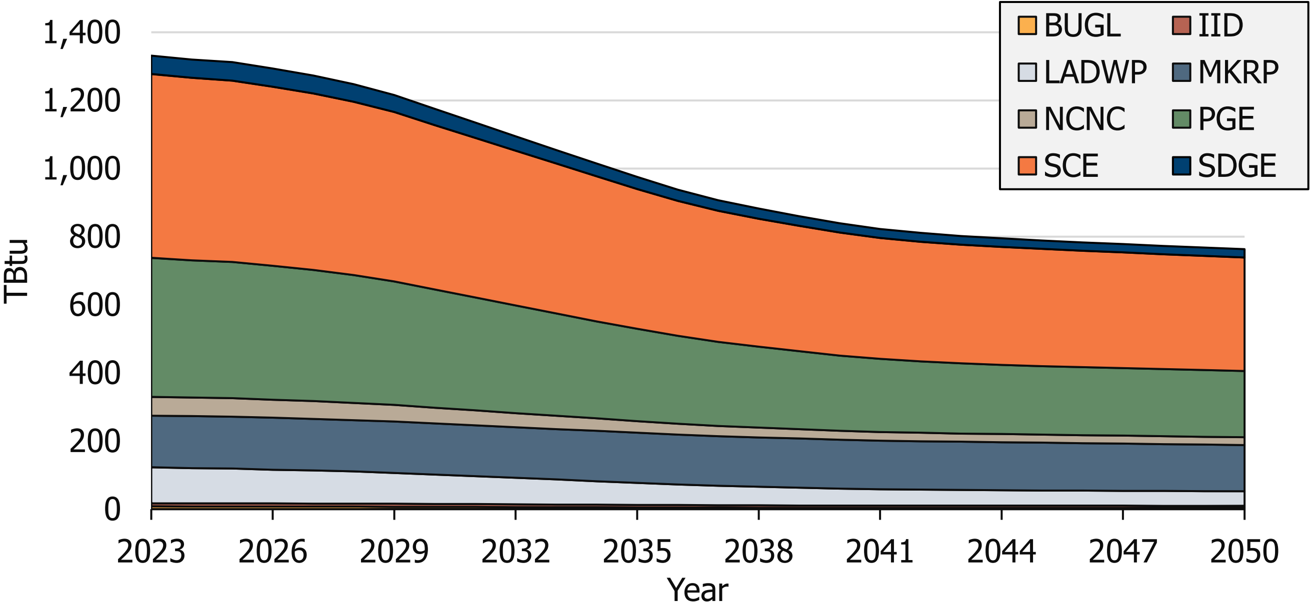
Reference Scenario

Figure E-1: Reference Scenario Annual Electric Energy by Planning Area



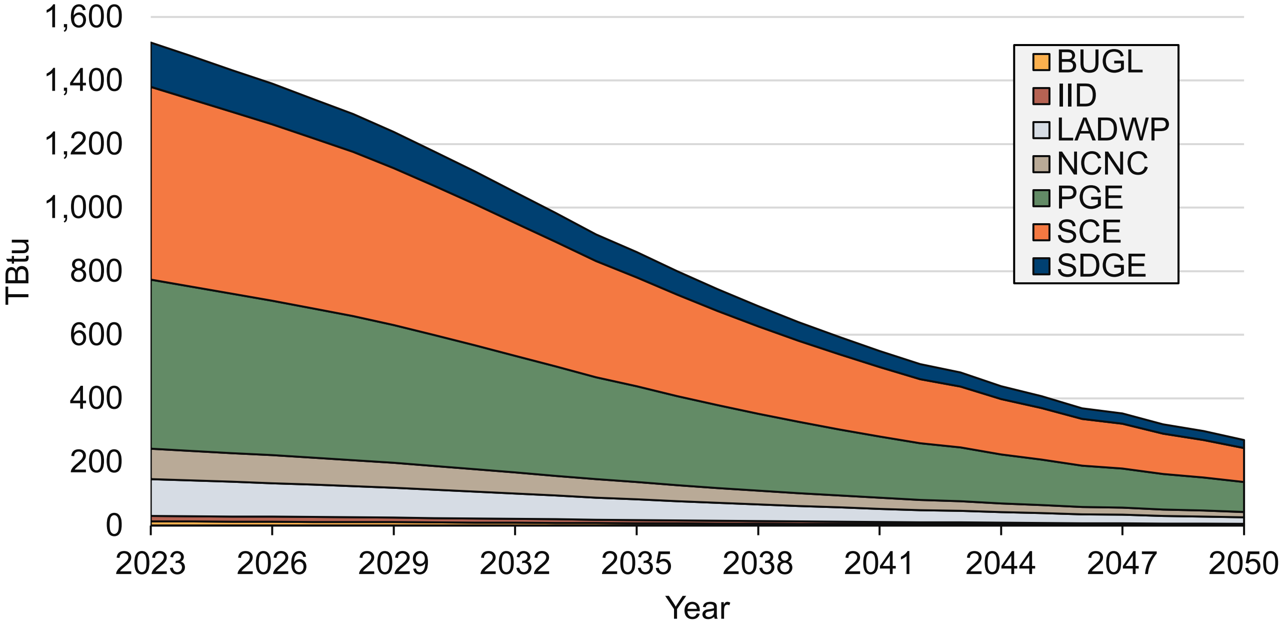
Source: CEC staff and EER

Figure E-2: Reference Scenario Annual Pipeline Gas by Planning Area



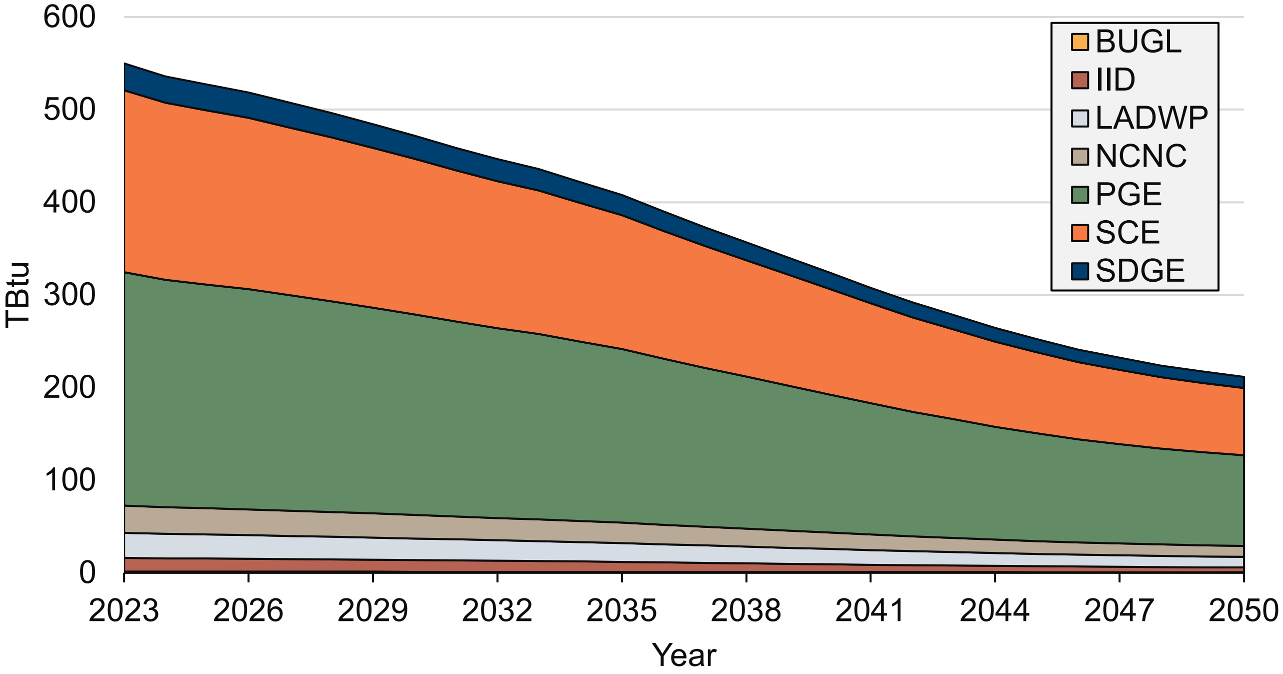
Source: CEC staff and EER

Figure E-3: Reference Scenario Annual Gasoline Energy by Planning Area



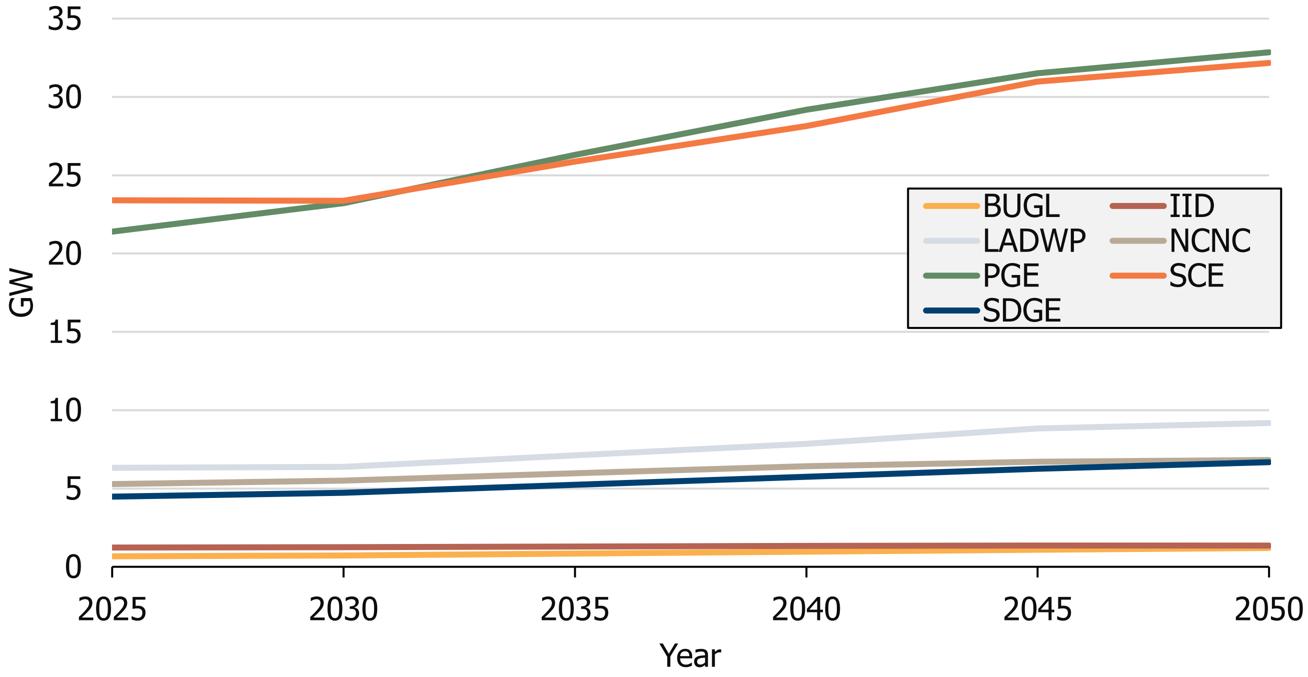
Source: CEC staff and EER

Figure E-4: Reference Scenario Annual Diesel by Planning Area



Source: CEC staff and EER

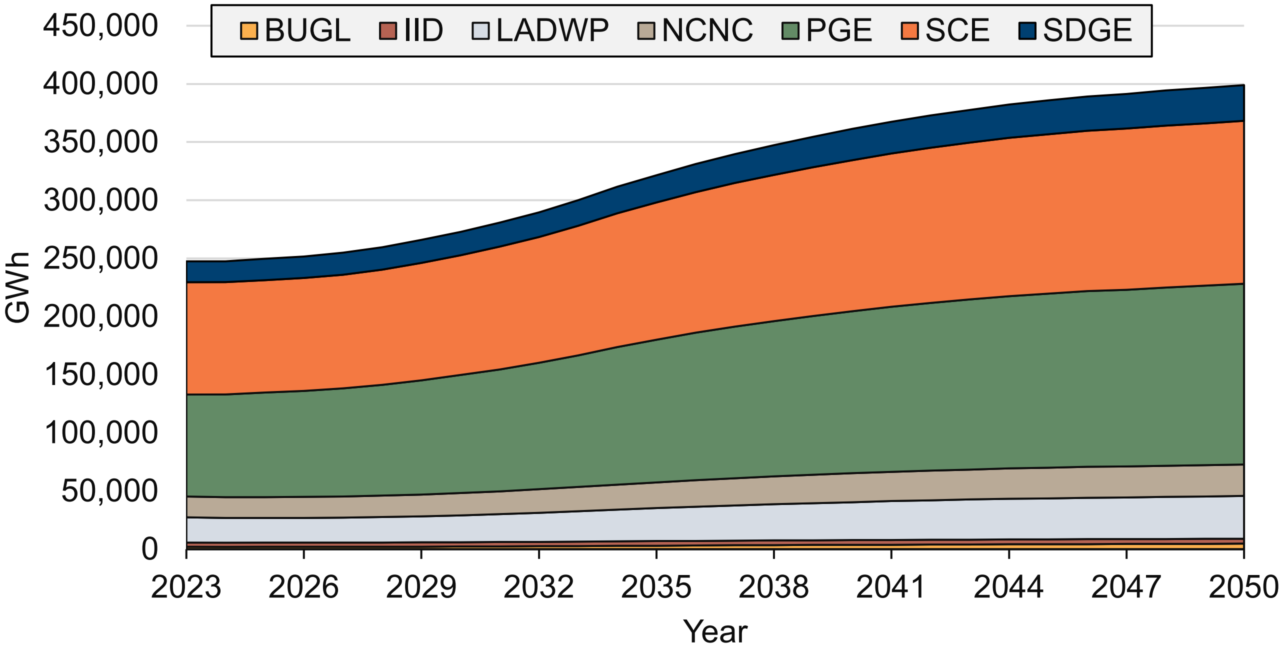
Figure E-5: Reference Scenario Annual Electric Peak Load by Planning Area



Source: CEC staff and EER

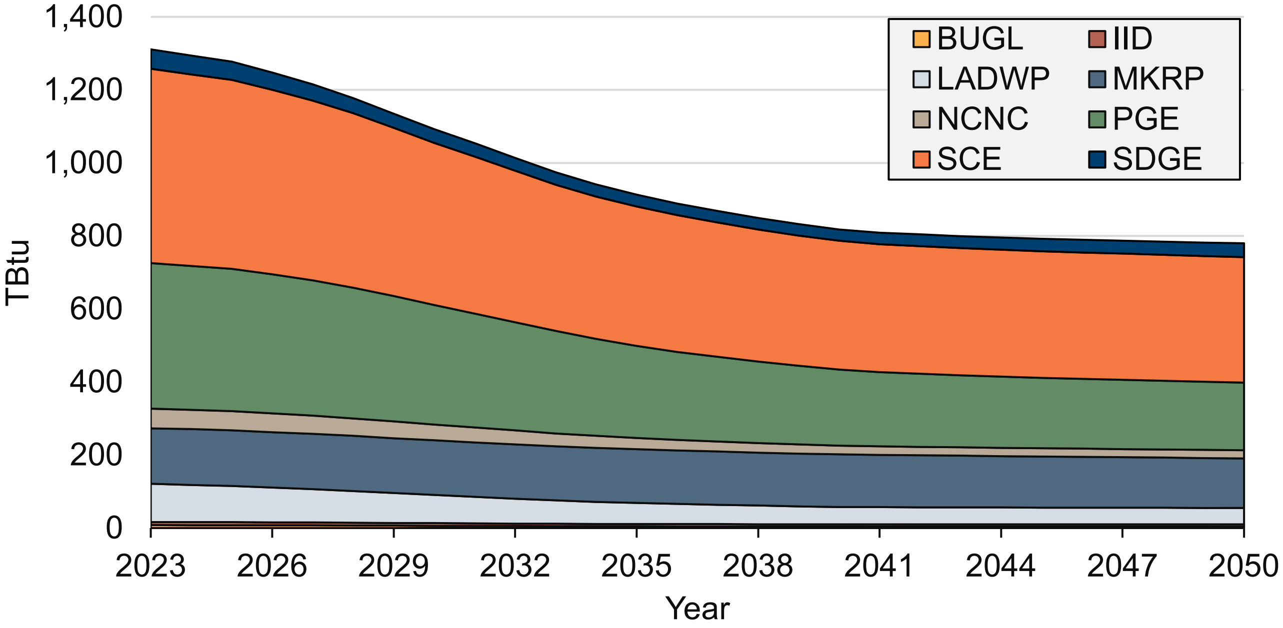
Policy Scenario

Figure E-6: Policy Scenario Annual Electric Energy by Planning Area



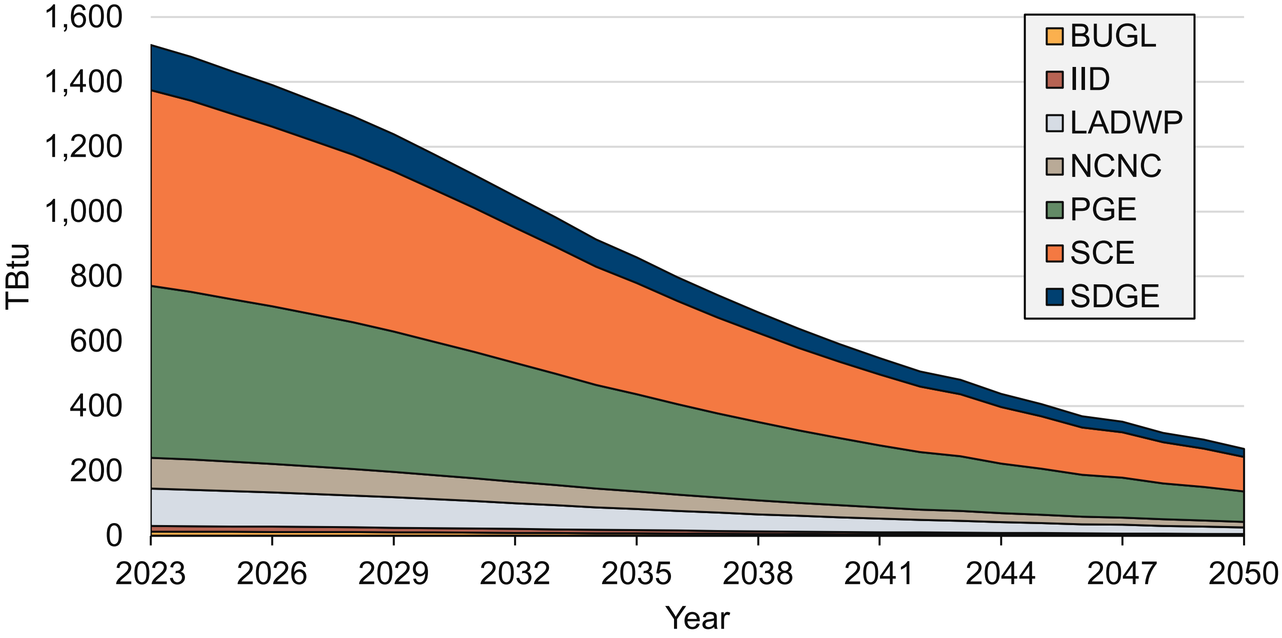
Source: CEC staff and EER

Figure E-7: Policy Scenario Annual Pipeline Gas by Planning Area



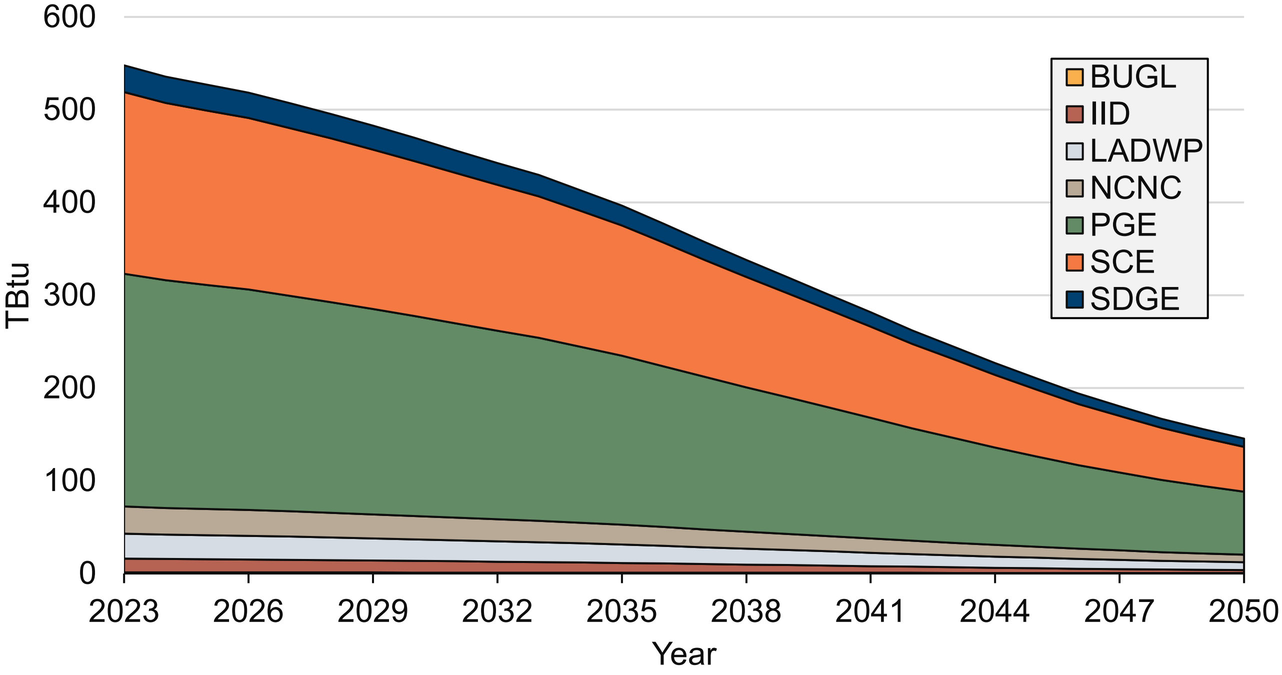
Source: CEC staff and EER

Figure E-8: Policy Scenario Annual Gasoline by Planning Area



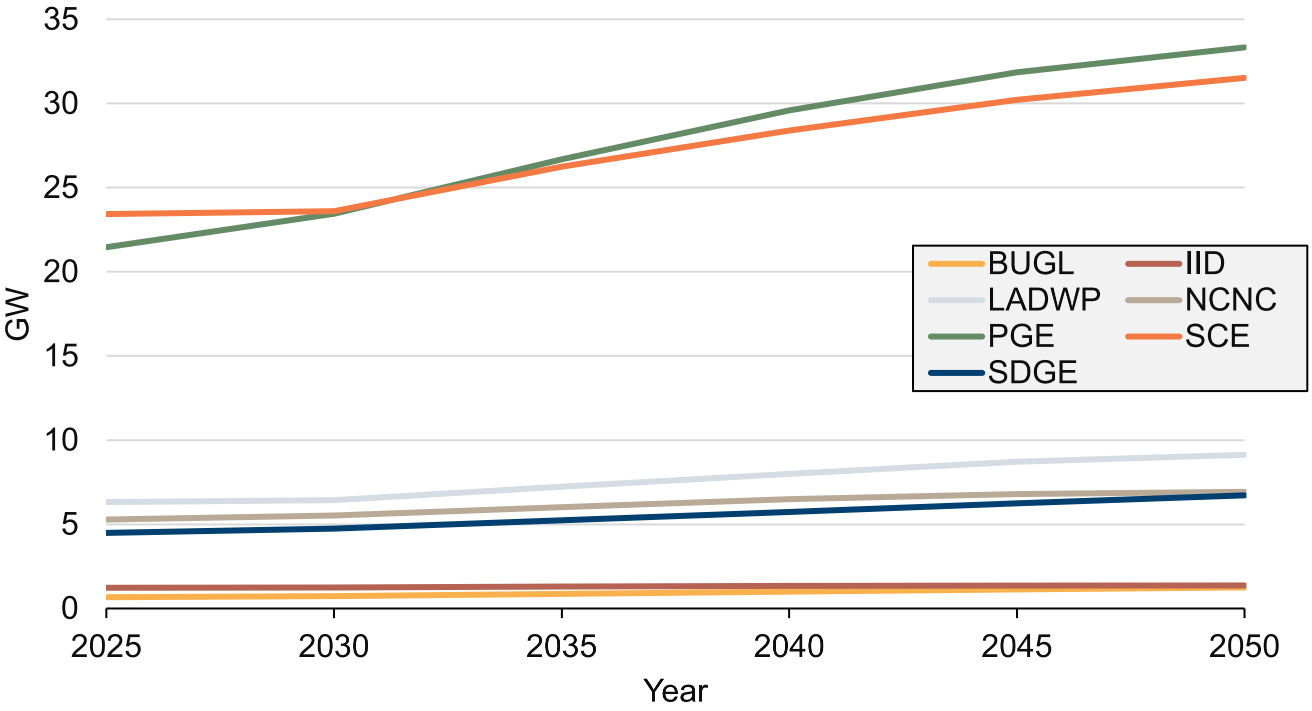
Source: CEC staff and EER

Figure E-9: Policy Scenario Annual Diesel by Planning Area



Source: CEC staff and EER

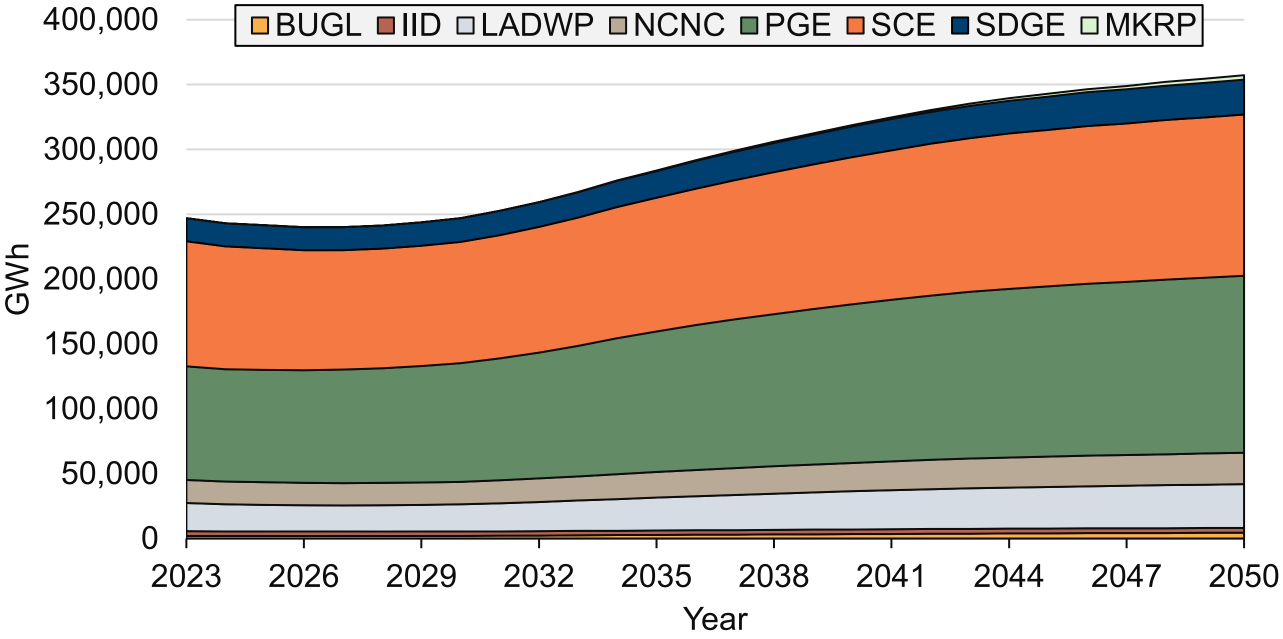
Figure E-10: Policy Scenario Annual Electric Peak Load by Planning Area



Source: CEC staff and EER

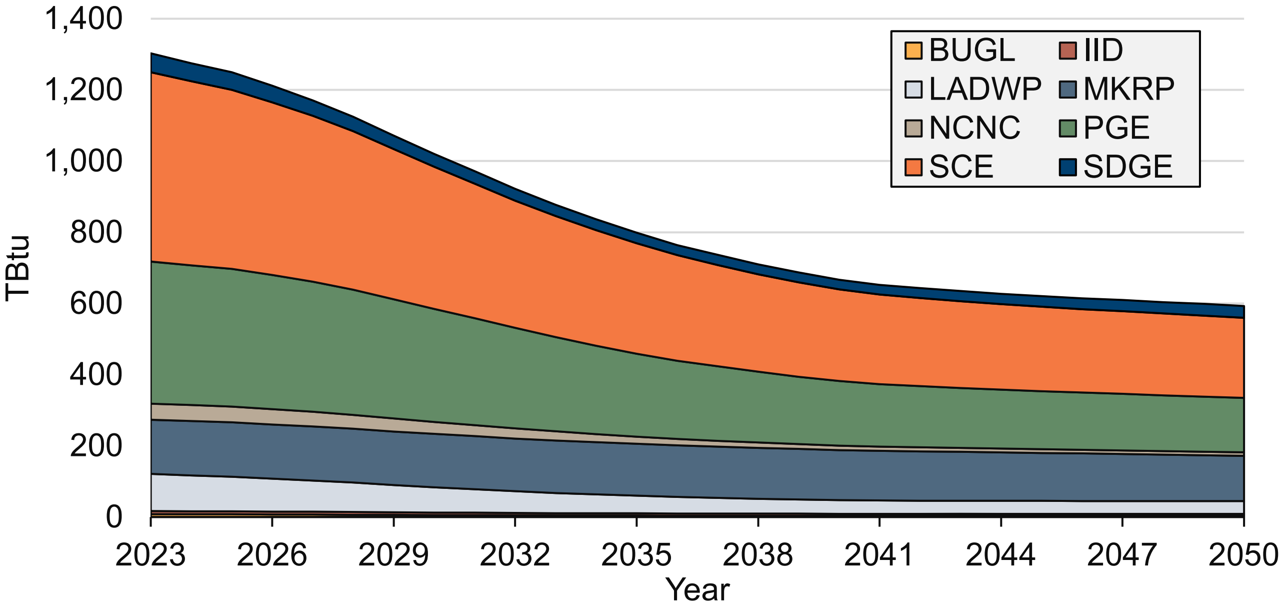
Enhanced Policy Scenario

Figure E-11: Enhanced Policy Scenario Annual Electric Energy by Planning Area



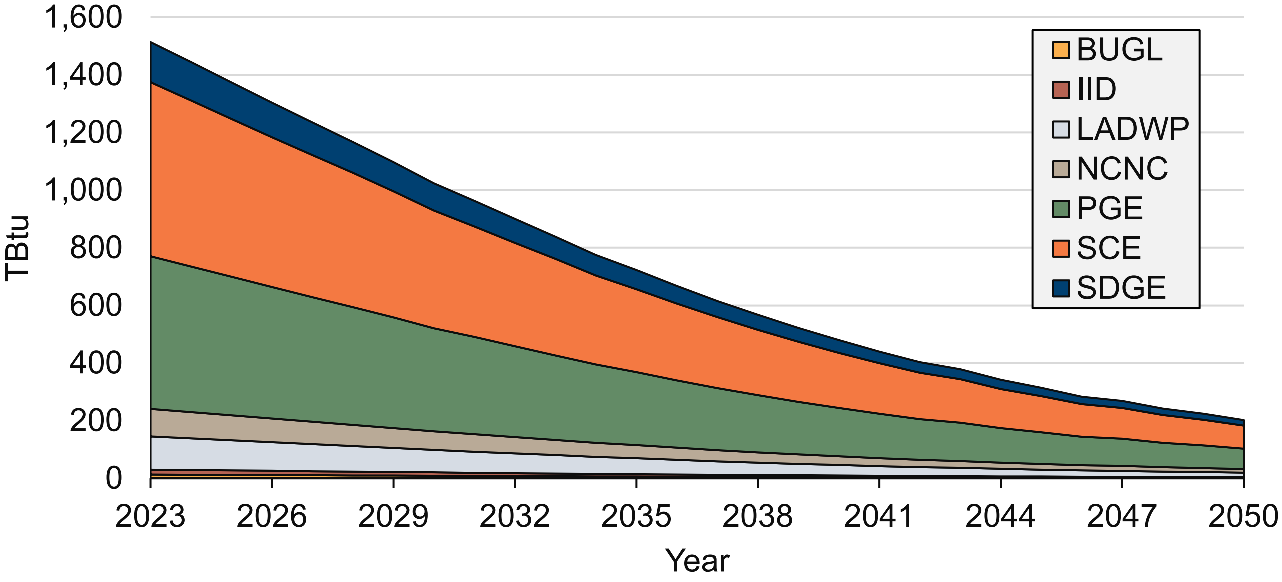
Source: CEC staff and EER

Figure E-12: Enhanced Policy Scenario Annual Pipeline Gas by Planning Area



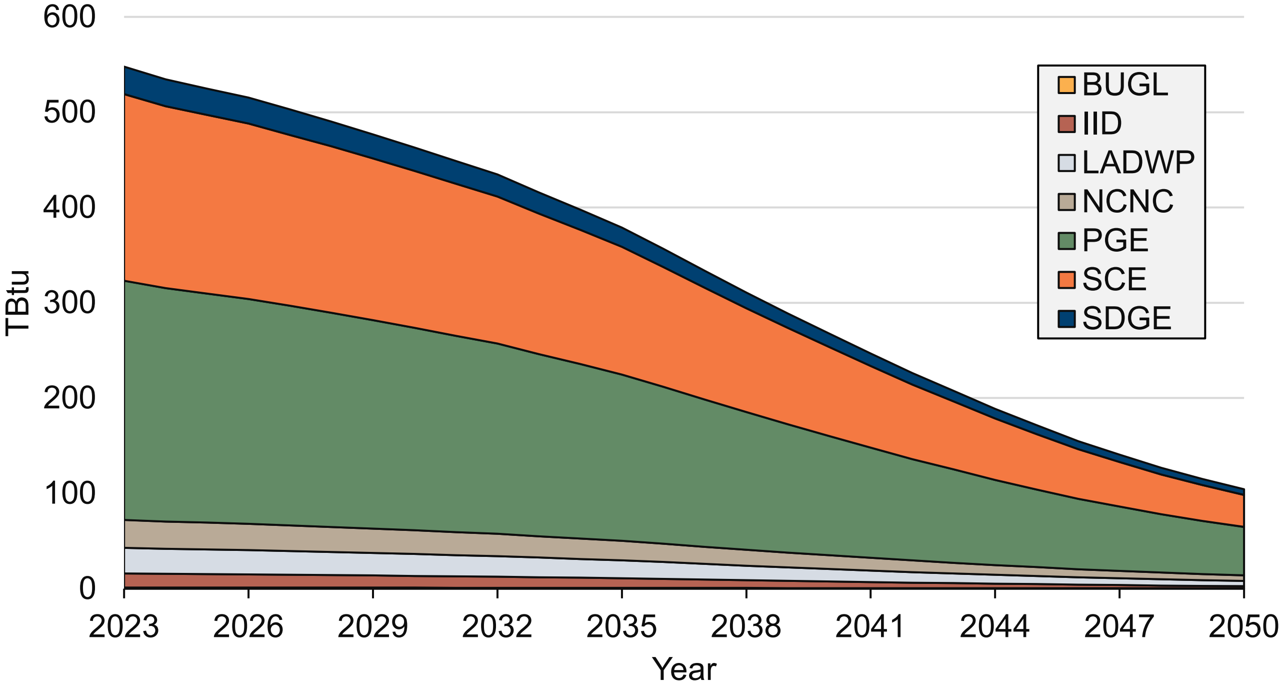
Source: CEC staff and EER

Figure E-13: Enhanced Policy Scenario Annual Gasoline by Planning Area



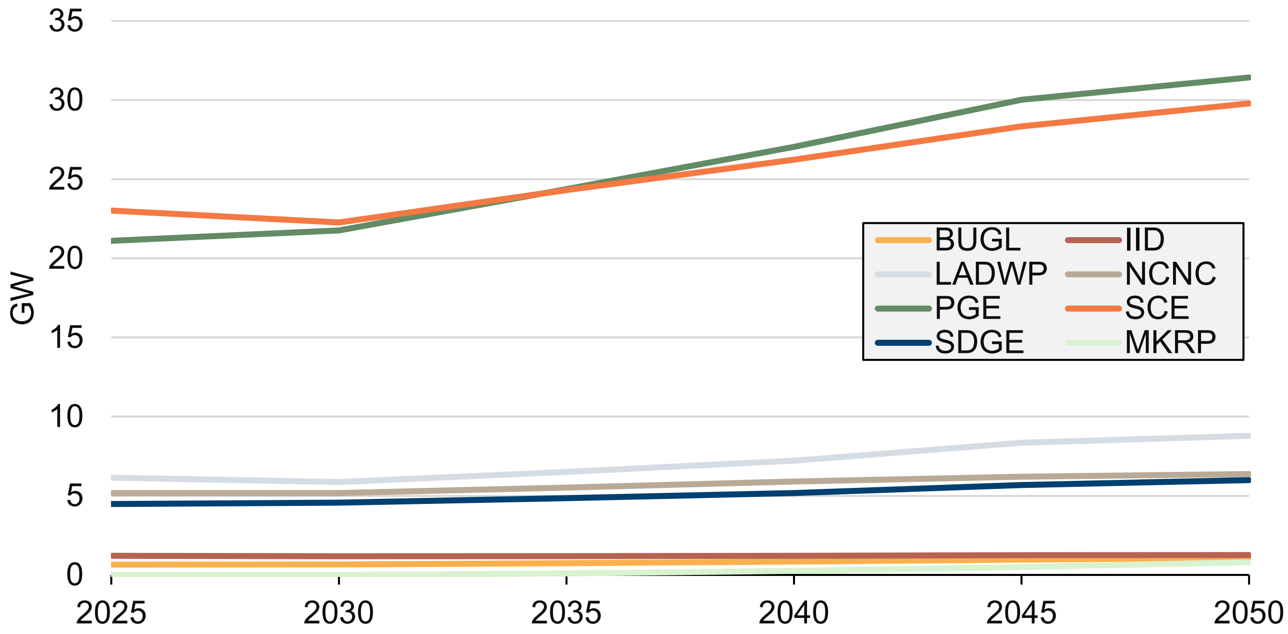
Source: CEC staff and EER

Figure E-14: Enhanced Policy Scenario Annual Diesel by Planning Area



Source: CEC staff and EER

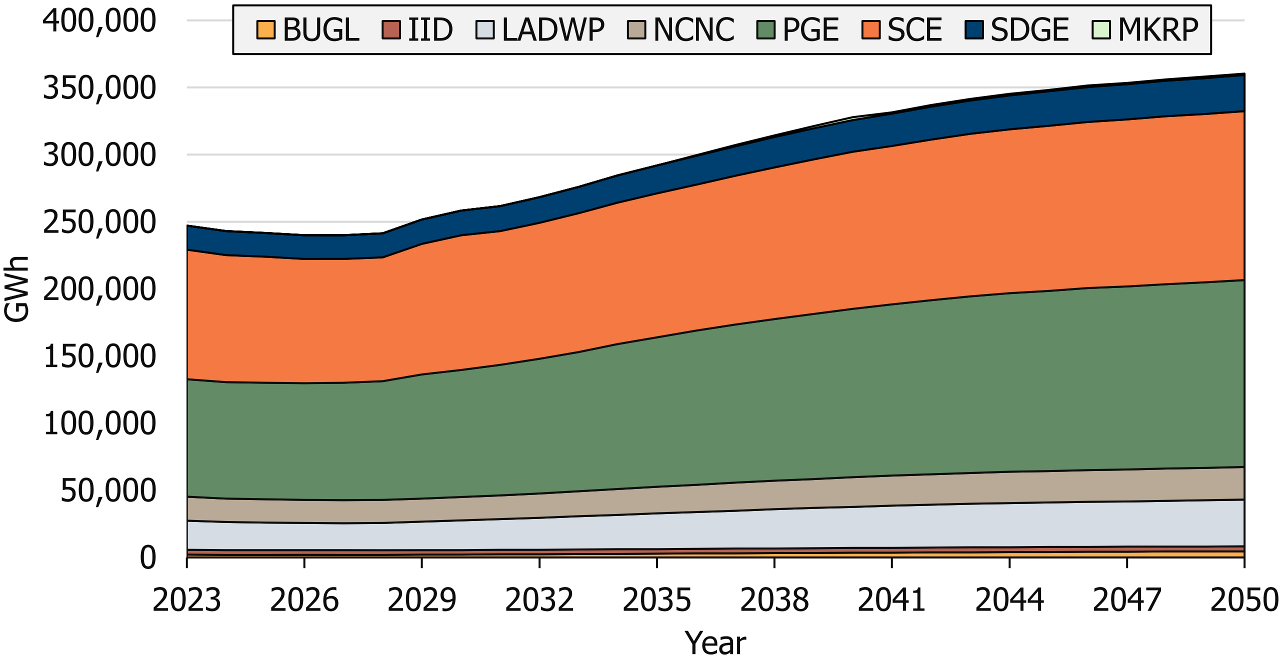
Figure E-15: Enhanced Policy Scenario Annual Electric Peak Load by Planning Area



Source: CEC staff and EER

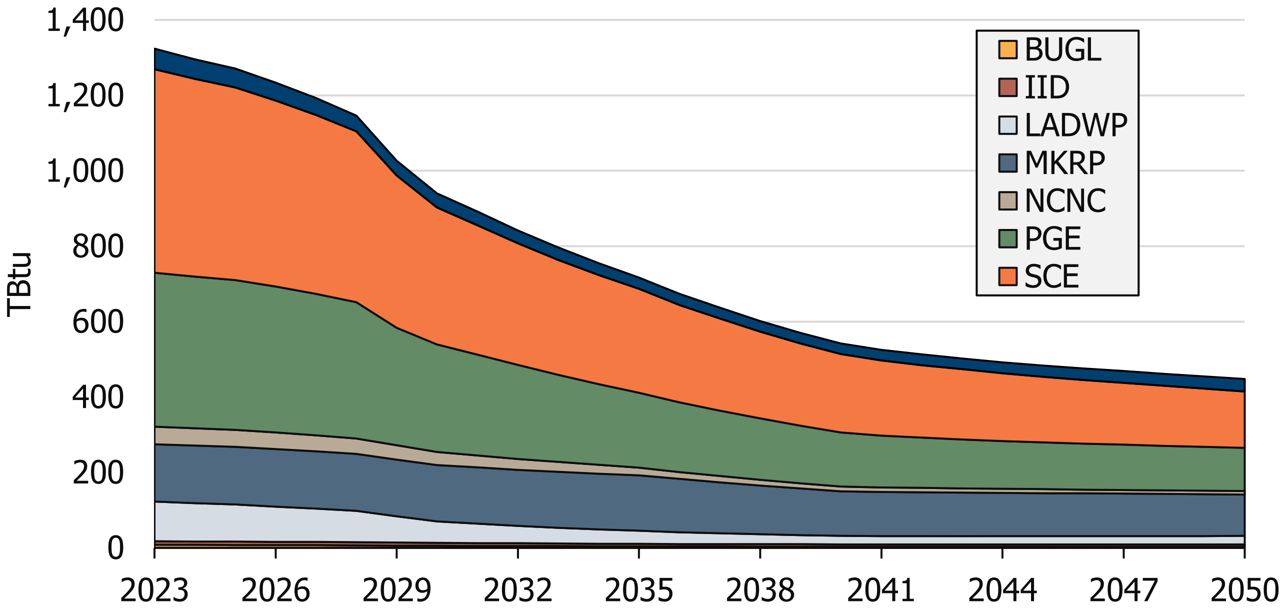
Enhanced Policy — Pipeline Hydrogen Sensitivity

Figure E-16: Enhanced Policy Pipeline Hydrogen Sensitivity Annual Electric Energy by Planning Area



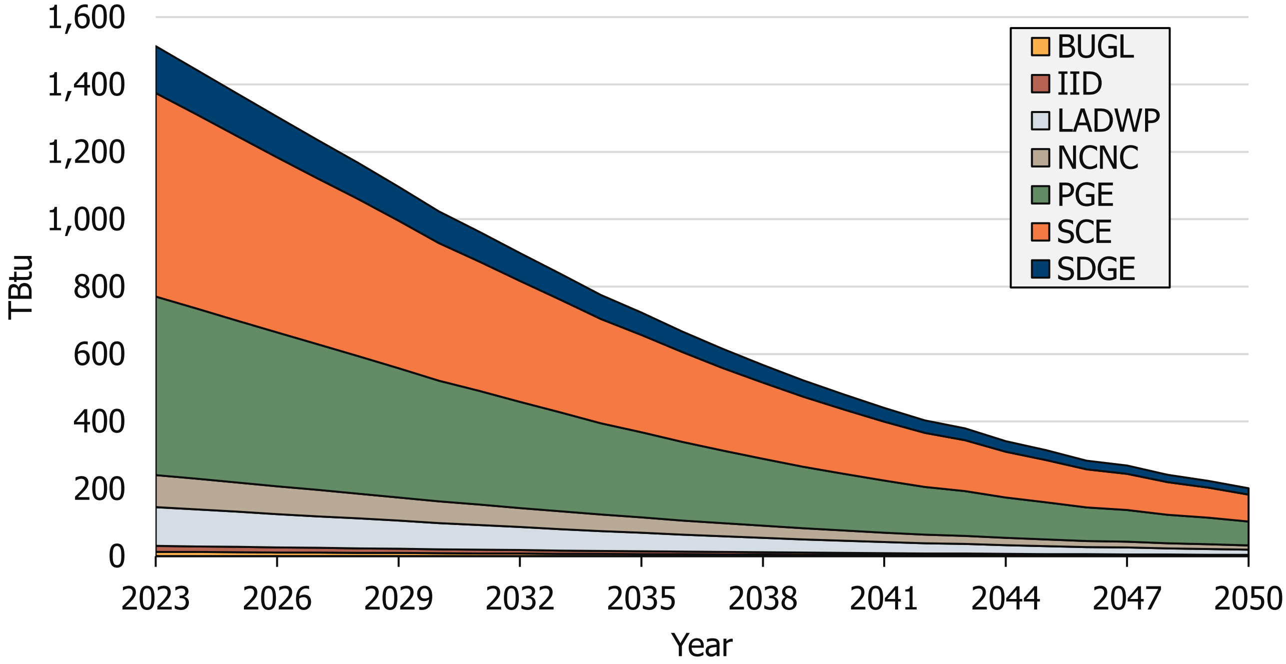
Source: CEC staff and EER

Figure E-17: Enhanced Policy Pipeline Hydrogen Sensitivity Scenario Annual Pipeline Gas by Planning Area



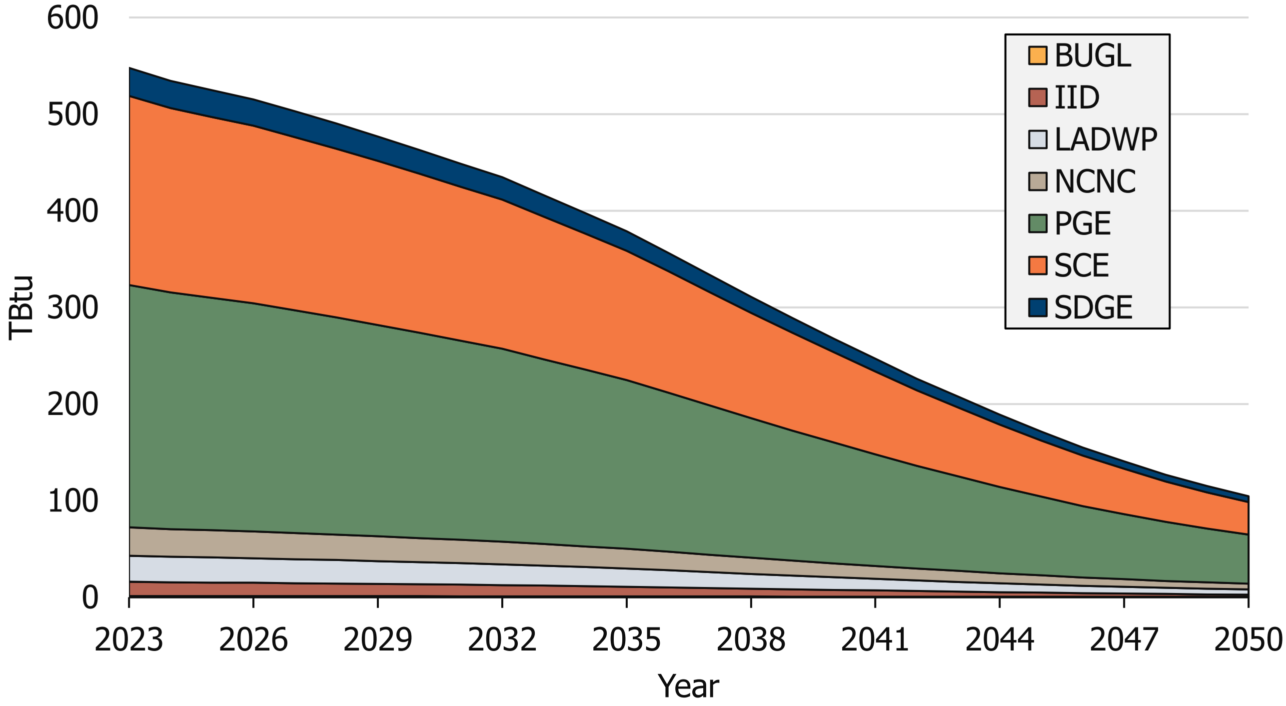
Source: CEC staff and EER

Figure E-18: Enhanced Policy Pipeline Hydrogen Sensitivity Annual Gasoline by Planning Area



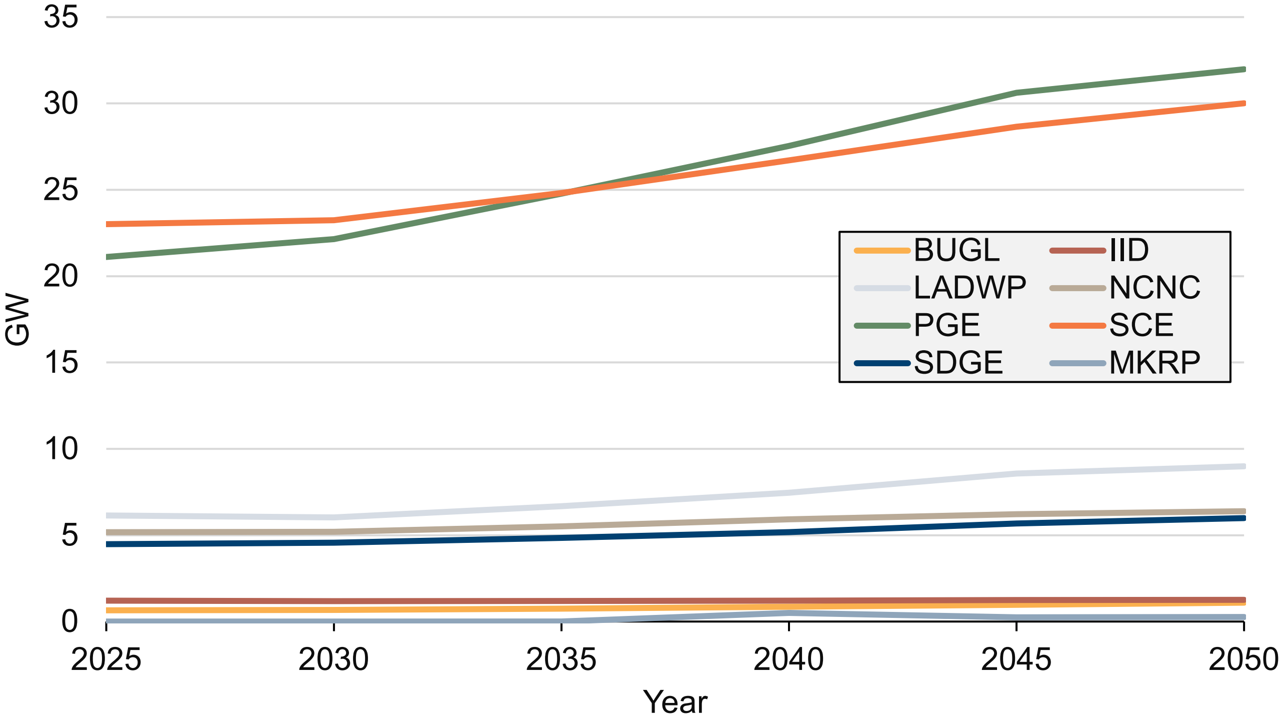
Source: CEC staff and EER

Figure E-19: Enhanced Policy Pipeline Hydrogen Sensitivity Annual Diesel by Planning Area



Source: CEC staff and EER

Figure E-20: Enhanced Policy Pipeline Hydrogen H2 Sensitivity Annual Electric Peak Load by Planning Area



Source: CEC staff and EER

APPENDIX F:
Comparison Between Demand Scenarios and CARB Scoping Plan

Table F-1: Comparison Between Demand Scenarios and 2022 CARB Scoping Plan Modeling Assumptions for the Residential and Commercial Sectors

Sector	CARB 2022 Scoping Plan	Jurisdiction /Regulation	Replacement Type	Sector	Fuel Type	End Uses	Reference Scenario	Policy Scenario	Enhanced Policy Scenario
New Residential and Commercial Buildings	All electric appliances beginning 2026 (residential) and 2029 (commercial), contributing to 6 million heat pumps installed statewide by 2030	Statewide	New Construction	Residential	Natural Gas	Space and Water Heating	100% adoption beginning in 2026	100% adoption beginning in 2026	100% adoption beginning in 2026
		Statewide	New Construction	Residential	Propane	Space Heating, Water Heating, Cooking	N/A	N/A	100% adoption beginning in 2029
		Statewide	New Construction	Residential	Natural Gas	Cooking, Clothes Drying	N/A	N/A	100% adoption beginning in 2029
		Statewide	New Construction	Commercial	Natural Gas	Space and Water Heating	100% adoption beginning in 2029	100% adoption beginning in 2029	100% adoption beginning in 2029
		Statewide	New Construction	Commercial	Natural Gas	Cooking	N/A	N/A	100% adoption beginning in 2029

Existing Residential Buildings	80% of appliance sales are electric by 2030 and 100% of appliance sales are electric by 2035.	Statewide	Replacement On Burnout	Residential	Natural Gas	Cooking, Clothes Drying	N/A	N/A	Ramp up from 16% adoption in 2026 to 80% in 2030, and then to 100 % in 2035
Existing Residential Buildings	80% of appliance sales are electric by 2030 and 100% of appliance sales are electric by 2035. Appliances are replaced at end of life such that by 2030 there are 3 million all-electric and electric-ready homes—and by 2035, 7 million homes—as well as contributing to 6 million heat pumps installed statewide by 2030.	Statewide	Replacement On Burnout	Residential	Propane	Space Heating, Water Heating, Cooking	N/A	N/A	Ramp up from 16% adoption in 2026 to 80% in 2030, and then to 100 % in 2035
		Statewide (Initial CARB SIP)	Replacement On Burnout	Residential	Natural Gas	Space and Water Heating	Ramp up from 10% adoption in 2026 to 100% in 2030	Ramp up from 20% adoption in 2026 to 100% in 2030	Ramp up from 20% adoption in 2026 to 100% in 2030
		BAAQMD 9-4	Replacement On Burnout	Residential	Natural Gas	Space Heating	Ramp up from 25% adoption in 2026 to 100% in 2029	Ramp up from 25% adoption in 2026 to 100% in 2029	Ramp up from 25% adoption in 2026 to 100% in 2029
	Appliances are replaced at end of life such that by 2030 there are 3 million all-electric and electric-ready homes—and by 2035, 7 million homes—as well as contributing to 6 million heat pumps installed statewide by 2030.	BAAQMD 9-6	Replacement On Burnout	Residential	Natural Gas	Water Heating	Ramp up from 50% adoption in 2026 to 100% in 2027	Ramp up from 50% adoption in 2026 to 100% in 2027	Ramp up from 50% adoption in 2026 to 100% in 2027

Existing Commercial Buildings	80% of appliance sales are electric by 2030, and 100% of appliance sales are electric by 2045.	Statewide	Replacement On Burnout	Commercial	Natural Gas	Cooking	N/A	N/A	Ramp up from 16% adoption in 2026 to 80% in 2030, and then to 100% in 2045
Existing Commercial Buildings	80% of appliance sales are electric by 2030, and 100% of appliance sales are electric by 2045. Appliances are replaced at the end of life, contributing to 6 million heat pumps being installed statewide by 2030.	Statewide (Initial CARB SIP)	Replacement On Burnout	Commercial	Natural Gas	Space and Water Heating	Ramp up from 10% adoption in 2026 to 100% in 2030	Ramp up from 20% adoption in 2026 to 100% in 2030	Ramp up from 20% adoption in 2026 to 100% in 2030
		BAAQMD 9-4	Replacement On Burnout	Commercial	Natural Gas	Space Heating	Ramp up from 25% adoption in 2026 to 100% in 2029	Ramp up from 25% adoption in 2026 to 100% in 2029	Ramp up from 25% adoption in 2026 to 100% in 2029
	Appliances are replaced at the end of life, contributing to 6 million heat pumps being installed statewide by 2030.	BAAQMD 9-6	Replacement On Burnout	Commercial	Natural Gas	Water Heating	Ramp up from 50% adoption in 2026 to 100% in 2027	Ramp up from 50% adoption in 2026 to 100% in 2027	Ramp up from 50% adoption in 2026 to 100% in 2027
		South Coast AQMD (1146.2)*	Replacement On Burnout	Commercial	Natural Gas	Water Heating	Ramp up from 25% adoption in 2026 to 100% in 2029	Ramp up from 25% adoption in 2026 to 100% in 2029	Ramp up from 25% adoption in 2026 to 100% in 2029

Source: CEC staff and EER

Table F-2: Basic Architecture of the FSSAT Modeling Approach in the Industrial Sector

Modeling Characterization	CEC Reference Scenario	CEC Policy Compliance	CEC Enhanced Policy (DRAFT)	Enhanced Policy Sensitivity - Pipeline Hydrogen Development	Enhanced Policy Sensitivity - Carbon Capture and Sequestration	CARB 2022 Scoping Plan
Industry Scope	46 NAICS code industries and 8 planning areas	Same as Reference Scenario	It also includes Natural Gas supplied to Oil and Gas Extraction via MKRP pipelines	Sensitivity based on EP scenario	Sensitivity based on EP scenario	presumably complete, but specifics unknown
Fuel Substitution End-Uses	No fuel substitution but rather assumes fuel end use shares are constant through time from CEC industrial forecast model	Fuel substitution limited to Process Heat-High, Process Heat-Low and Water Heating	Same as PC scenario	Sensitivity based on EP scenario	Sensitivity based on EP scenario	level of detail in E3's PATHWAYS modeling, possibly with some separate CARB-staff assessments
Models Used for Fuel Types	CEC - industrial demand forecast for electricity and natural gas EER - Energy Pathways for all other fuels	CEC industrial FSSAT module (Electricity, pipeline gas and hydrogen) and EER Energy Pathways (all others)	Same as PC scenario	Sensitivity based on EP scenario	Sensitivity based on EP scenario	consistent with CARB GHG emission inventory
General approach for fuel substitution or other GHG mitigation strategies	No fuel substitution	Industry-specific fuel substitution potential and Adoption rates result in displacement of NG projections to either electricity or hydrogen depending upon the end-use	Same as PC, but supplemented by energy fuel substitution for other fuels using EER Energy Pathways model	Same as EP, with revised H2 penetration by proximity to hypothetical H2 pipeline expansion stemming from ARCHES funding from federal agencies and private sources	same as EP scenario, but CCS technologies applied in selected industries reducing GHG emissions, but selectively adding energy consumption	iterative process of "what if" scenario specification, review of results, and eventual package across sectors that satisfies "carrying capacity" level of GHG emissions

Source: CEC staff and EER

Table F-3: General Assumptions for Fuel Substitution and Other Control Measure Penetration Through Time in the Industrial Sector

Scenario Assumptions	CEC Reference Scenario	CEC Policy Compliance	CEC Enhanced Policy (DRAFT)	Enhanced Policy Sensitivity - Pipeline Hydrogen Development	Enhanced Policy Sensitivity - Carbon Capture and Sequestration	CARB 2022 Scoping Plan
Energy Efficiency and Fuel Substitution Programs	2023 IEPR forecast assumptions for existing programs and BAU expansion of energy efficiency and related fuel substitution programs	Same as Reference scenario	2023 IEPR scenarios with greater impact	Same as EP scenario	Same as EP scenario	Unknown
Electrification Potential	N/A	Industry/end-use specific potential (Process Heat-Low and Water heat) increase through time (see Notes and charts below)	Some slightly higher penetration of potential (see Notes and charts below)	Same as EP scenario	Same as EP scenario	Total electrification for many industries, partial for others
Hydrogen Substitution Potential	N/A	Industry/end-use specific potential (Process Heat-High) increase through time (see Notes and charts below)	Similar, but some increase after 2035 as costs decline, familiarity grows, equipment is replaced (see Notes and charts below)	Selectively increase potential based on H2 pipeline route	Same as EP scenario	SP documentation from E3 shows H2 possibilities in all industry groups, but specific potential unclear.
treatment of H2 production	N/A	100% onsite electrolysis	Same as PC scenario	Mix of onsite electrolysis and pipeline delivered H2 based on hypothetical H2 pipeline route	Same as EP scenario	all electrolysis happens at the bulk power system in "grid friendly" manner

Industry-specific Adoption (Penetration) pattern toward assumed potential	N/A	Industry/end-use specific Adoption rate gradually increase 2025 to 2035, then plateauing (see Notes and charts below)	Similar, but some increase after 2035 as costs decline, familiarity grows, equipment is replaced (see Notes and charts below)	Somewhat increased NG to H2 shift compared to EP scenario	Same as EP scenario	SP introduces H2 in all industry groups, but average H2 share of total consumption only about 2% by 2045. Methodology is unclear.
Special Cases - Refineries	Refinery energy consumption for all fuels reduced in proportion to predicted petroleum product consumption (largely transportation) through time	Same as Reference scenario	Selective fuel switching of H2 displacing NG consumption	Same as EP scenario	Same as EP scenario	SP assumes refinery energy consumption scales down to match end-user fuel demand
Special Cases - Oil & Natural Gas Extraction	No adjustment to base Oil & Gas industry projections	Limited fuel switching for facilities receiving NG from utilities	- Oil & Gas energy consumption for all fuels reduced in proportion to predicted petroleum product consumption through time - expand to encompass all NG suppliers to Oil & Gas facilities	As of 10/1 haven't yet decided how to differentiate among TEOR vs other extraction technologies	Same as EP scenario	Unknown, but E3 results do not differentiate among types of Oil and NG Extraction
Carbon Capture and Sequestration	N/A	N/A	N/A	NA	Limited penetration for where Process Heat-High cannot be displaced and where CO2 pipeline and repositories are accessible. Likely to include cement, glass, refineries, and a few other industries	SP has a limited focus on CCS for cement non-process and coal combustion, and for refinery CO2 emissions

Source: CEC staff and EER

Table F-4: Comparison Between Demand Scenarios and 2022 CARB Scoping Plan Modeling Assumptions for the Transportation Sector

Sector	CARB 2022 Scoping Plan	Reference Scenario	Policy Scenario	Policy Scenario (High Hydrogen Use)	Enhanced Policy Scenario
LDV	100% of LDV sales are ZEV by 2035	ACC II *	-	-	-
Smart Growth / Vehicle Miles Traveled (VMT)	VMT per capita was reduced to 25% below 2019 levels by 2030, and 30% below 2019 levels by 2045	N/A	-	-	VMT per capita reduced 10% below 2023 levels by 2030, and 15% below 2023 levels by 2045.
MD/HD	100% of medium-duty (MDV)/HDV sales are ZEV by 2040 (AB 74 University of California Institute of Transportation Studies [ITS] report)	ACF - increasing ZEV Fleets, 100% MDHD ZEV for new sales starting in 2036. Higher ZEV Trucks for CARB's ZE Truck Measure (non-ACF Trucks)	-	Post-Process enhancement of freight hydrogen demand to ~1.4B kg in 2045.	-
		100% of drayage trucks are zero emission by 2035.	-	-	-
Aviation	20% of aviation fuel demand is met by electricity (batteries) or hydrogen (fuel cells) in 2045. All remaining fuel is satisfied by SAF (Intra State)	N/A	10% of aviation fuel demand is met by electricity (batteries) or 10% by hydrogen (fuel cells) in 2045. 50% of the remaining fuel is satisfied by SAF. (Intra State)	-	-

	The Scoping Plan has no requirements for out of state (OOS) travel.		5% of OOS aviation fuel demand is met by electricity (batteries) or hydrogen (fuel cells) in 2045. 10% of the remaining fuel is satisfied by SAF.	-	10% of aviation fuel demand is met by electricity (batteries) or hydrogen (fuel cells) in 2045. 10% of the remaining fuel is satisfied by SAF. (Out Of State)
Ocean-going Vessels (OGV)	2020 OGV At-Berth regulation fully implemented, with most OGVs utilizing shore power by 2027.	Off-Road Model captures most visits using shore power by 2027	-	-	-
	25% of OGVs utilize hydrogen fuel cell electric technology by 2045.	N/A	5% of OGVs utilize hydrogen fuel cell electric technology by 2045.	25% of OGVs utilize hydrogen fuel cell electric technology by 2045.	50% of OGVs utilize hydrogen fuel cell electric or other hydrogen-adjacent technology by 2045 (e.g., green methanol, green ammonia). Increase efficiency in OGV by 10% by 2035.
Port Operations	100% of cargo handling equipment is zero-emission by 2037.	69% of CHE is ZE by 2037	Off Road Electrification model with top-down enhanced diffusion 100% CHE electrification by 2045.	-	-
		Shore Power aligns with CARB	-	-	-

Freight and Passenger Rail (Line haul and passenger rail rely primarily on hydrogen fuel cell technology, and others primarily utilize electricity.)	100% of passenger and other locomotive sales are ZEV by 2030.	Baseline: No ZEV penetration	Increasing Zero Emission Fuel Substitution in lieu of diesel fuel to approximate the in-use locomotive regulation beginning in 2027 - passenger	-	-
	100% of line haul locomotive sales are ZEV by 2035.	Baseline: No ZEV penetration	Increasing Zero Emission fuel substitution in lieu of diesel fuel to approximate the in-use locomotive regulation beginning in 2032 - line haul	-	-
Other Off-Road Vehicles	Unclear what CARB is proposing	AATE 3	Enhanced to 80% electrification for all off road devices by 2050	-	Enhanced to 100% electrification for all off road devices by 2050
Low Carbon Fuels for Transportation	Biomass supply is used to produce conventional and advanced biofuels, as well as hydrogen.	Address LCFS implications when developing GHG projections.	Address LCFS implications when developing GHG projections.	-	Address LCFS implications when developing GHG projections.

Source: CEC staff and EER