2023 Integrated Resource Plan

Silicon Valley Power (SVP)

Final 2023

Energy+Environmental Economics

Respectfully Submitted,

Arne Olson
Aaron Burdick
Jimmy Nelson, Ph.D.
Nathan Lee, Ph.D.
Chen Zhang
Rawley Loken
Sam Schreiber
Cameron Morelli

Energy and Environmental Economics, Inc. (E3)
44 Montgomery Street, Suite 1500
San Francisco, CA 94104

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Acronym Definitions

Acronym	Definition
AAEE	additional achievable energy efficiency
AAFS	annual achievable fuel substitution
AB	assembly bill
ATB	(NREL) annual technology baseline
BESS	battery energy storage system
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CCWD	Calaveras County Water District
CDWR	California Department of Water Resources
CEC	California Energy Commission
CES	clean energy standard
COTP	California-Oregon Transmission Project
CPUC	California Public Utilities Commission
CRAT	capacity resource accounting table
CT	combustion turbine
CVP	Central Valley Project
CVRP	clean vehicle rebate project
DCFC	Direct Current Fast Charger
DER	distributed energy resource
DMV	Department Of Motor Vehicles
DVR	Don Von Raesfeld Power Plant
EBT	energy balance table
ELCC	effective load carrying capability
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
FO&M	fixed operation and maintenance
GEAT	GHG emissions accounting table
GHG	greenhouse gas
HVAC	heating, ventilation, and air conditioning
I&A	(CPUC IRP) inputs & assumptions
IEPR	Integrated Energy Policy Report
IRA	Inflation Reduction Act
IRP	integrated resource plan
ITC	Investment Tax Credit
LCFS	low carbon fuel standard

LCOE	levelized cost of energy
LEC	Lodi Energy Center
LFC	levelized fixed cost
LOLE	loss of load expectation
LSE	load serving entity
LT	(PLEXOS) long-term model
M-S-R PPA	M-S-R Public Power Agency
NCPA	Northern California Power Agency
NREL	National Renewable Energy Laboratory
PBC	Public Benefits Charge
PCC	portfolio content categories
PEV	plug-in electric vehicle
PG&E	Pacific Gas and Electric Company
POU	publicly-owned utility
PPA	power purchase agreement
PRM	planning reserve margin
PTC	Production Tax Credit
PUC	public utilities code
PV	photovoltaic
RA	resource adequacy
REC	renewable energy credit
RNG	renewable natural gas
RPS	renewable portfolio standard
RPT	RPS procurement table
SB	senate bill
SMR	small modular reactor
SVP	Silicon Valley Power
TAC	transmission access charge
TANC	Transmission Agency of Northern California
VO&M	variable operations & maintenance
WAPA	Western Area Power Administration
ZEV	zero-emission vehicle

1. Executive Summary

The 2023 Integrated Resource Plan (IRP) serves as a long-term comprehensive roadmap to continue Silicon Valley Power's long-standing focus on providing customers with affordable and reliable service while meeting State and local goals for greenhouse gas emissions reduction. The IRP provides a framework showing how Silicon Valley Power continues its transition away from carbon-emitting resources towards 100% clean energy resources such as wind, geothermal, hydrogen, hydro-electric, and solar. This aligns with Silicon Valley Power's greenhouse gas emission reduction targets and is in accordance with the State's policy goals required by Senate Bill 350 and Senate Bill 100, including the requirement to update its IRP no less than once every five years. The IRP includes the results of data modeling of customer energy demands balanced against reliability, sustainability, and affordability goals to develop a least-cost portfolio of resources to meet the needs of Santa Clara ratepayers.

Silicon Valley Power's 2023 IRP process commenced in 2023 with customer outreach efforts, which indicated that over 75% of the respondents were satisfied with SVP service and that the top concerns are reliability and affordability. On affordability, the respondents would be willing to pay 10-25% more on their monthly electric bill to achieve clean energy goals faster. These community outreach efforts and directives from the City of Santa Clara set the direction for the current planning process.

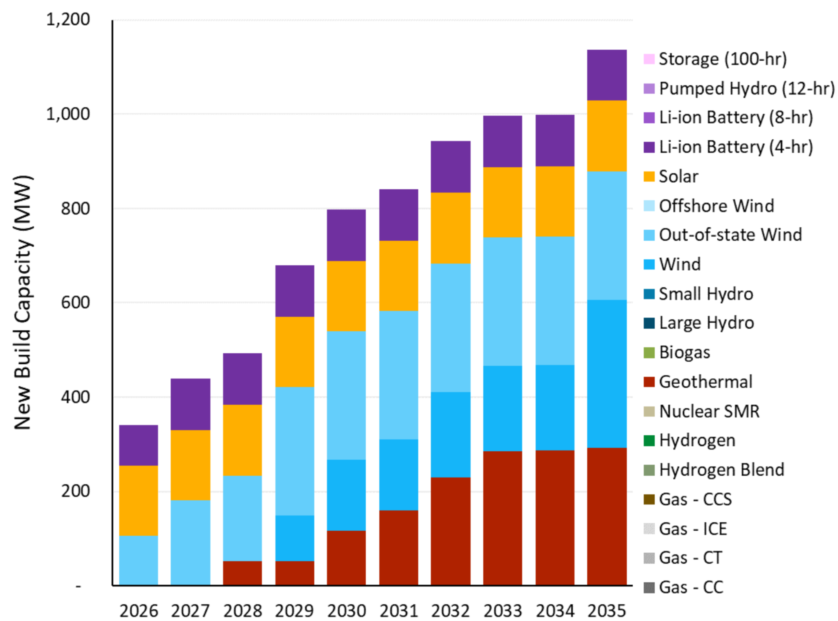
In this IRP, Silicon Valley Power presents three scenarios developed using least-cost optimization, all of which meet or exceed the State's emission and reliability requirements. The base portfolio meets the California Air Resources Board's base targets for Silicon Valley Power and Senate Bill 100 target of 60% renewable energy in 2030, using mature renewable technologies (those commercially available today). The second portfolio moves forward the Senate Bill 100 renewable energy and zero-carbon generation targets for 2045 to 2035, requires a minimum of 70% carbon-free energy (60% renewable) in 2030 and 100% carbon free by 2035, and is limited to mature technology options. The third portfolio achieves a zero-carbon emissions portfolio across all hours of the year and explores the use of emerging technologies (such as biogas, hydrogen, and natural gas with carbon capture and storage) to achieve that goal. In each potential portfolio, the power supply mix will continue Silicon Valley Power's transition away from carbon-based generation, which has already reduced by approximately 50% its carbon emissions per kWh of retail sales since 2017. Figure ES-1 presents the three scenarios explored in this IRP.

Figure ES-1. Silicon Valley Power IRP Scenarios

Scenario 1:	Scenario 2:	Scenario 3:
Base SB 100	Accelerated SB 100	Zero Emissions with Emerging Technology

Figure ES-2 shows the cumulative resource additions through 2035 in Scenario 1: Base SB 100 (Base Scenario). In early years there is an addition of wind, solar and storage to meet load growth and reliability requirements. Starting in 2028, geothermal becomes available and is added to the system in addition to wind capacity as it can provide both clean energy and firm capacity. The baseload operating characteristics of geothermal also align with the relatively high 80% load factor of the SVP system. By 2035, the total cumulative resource additions include 290 MW geothermal, 590 MW wind, 150 MW solar, and 110 MW storage capacity to meet load growth and clean energy requirements.

Figure ES-2. Base Scenario Cumulative New Build Capacity

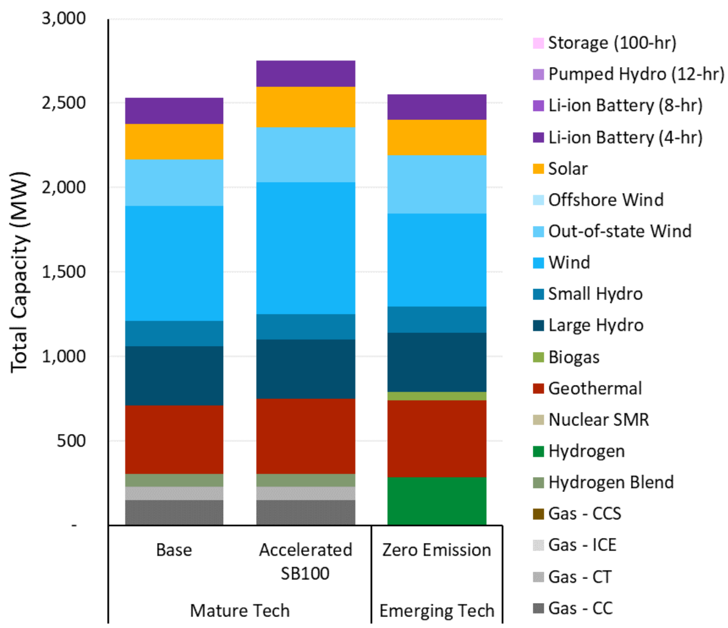


Note: Capacity additions begin in 2026

Figure ES-3 presents the total capacity of the three scenarios in 2035, and although similar there are some key differences in the portfolios.

While the three scenarios have similar resource additions in the near-term, the scenarios diverge towards the end of the planning horizon as more aggressive clean energy targets are applied in Scenario 2: Accelerated SB 100 (Accelerated SB 100 Scenario) and Scenario 3: Zero Emissions with Emerging Technology (Zero Emissions Scenario). The Accelerated SB 100 Scenario, which must meet a higher clean energy requirement in 2035 than the Base Scenario results in additional renewable capacity including geothermal wind, and solar, and a larger total installed capacity. The 2035 total capacity of the Zero Emissions Scenario is similar to the Base Scenario, but less than the Accelerated SB 100 Scenario as it includes the zero-emission fuel conversion of existing gas resources and other emerging technologies. The emerging technologies, such as building new hydrogen plants and converting existing gas plants to burn on hydrogen or biogas, modeled in this IRP offer both clean and “firm capacity” attributes and significantly reduces the potential for “overbuilding” of existing mature technologies like solar, wind, and battery storage.

Figure ES-3. Scenario Comparison – 2035 Total Capacity



Meeting reliability needs is also a critical component of utility integrated resource planning. All scenarios considered in this IRP achieve and/or exceed SVP's reliability requirements, following the "marginal reliability need" long-term planning approach adopted by the California Public Utility Commission for its load serving entities, using marginal ELCC accreditation for all resource types.[1]

Regarding the annual modeled cost compared to the Base Scenario, which reaches $250 million (2022 $; TAC costs and non-modeled system costs are excluded) in 2035, the annual modeled cost increases by about $25 million (2022 $) in the Accelerated SB 100 Scenario and increases by $55 million (2022 $) in the Zero Emissions Scenario. (Figure ES-4). These costs only represent the cost components modeled and do not represent SVP's total revenue requirement.[2] When other forecasted system costs (e.g., TAC and non-modeled costs) are included and spread out over retail sales, the estimated 2035 retail rate in the Accelerated SB 100 Scenario and Zero Emissions Scenario is about 1% and 3% higher than the Base Scenario. However, it is important to note that there are large uncertainties in the availability and cost of emerging technologies and zero-emission fuels by 2035. As discussed above, without the clean firm emerging technologies modeled in this study, achieving zero emissions with only commercially available resources will likely require significant additional resources to maintain reliability, which could result in a higher system cost. Furthermore, the cost of converting some of the existing gas resources to zero-emission fuels is potentially optimistic here due to uncertainties in conversion technologies and limited

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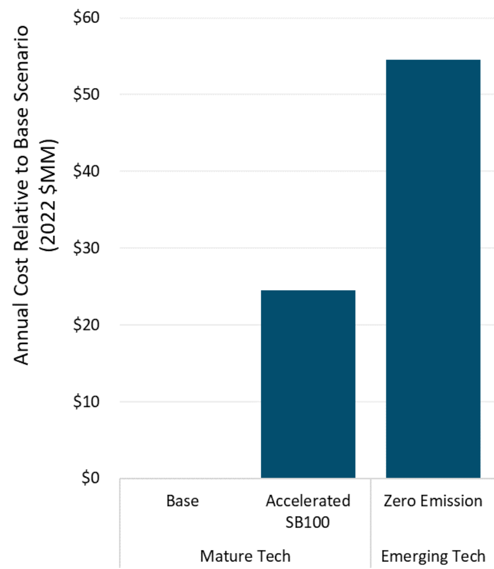
[1] SVP is not a jurisdictional load serving entity subject the California Public Utility Commission. However, as the approach for long-term resource adequacy requirements and the availability of future input data for SVP (PRM, resource accreditation, etc.) remain uncertain with shifts to new approaches, SVP opted to follow the long-term planning method for system reliability needs consistent with the Public Utility Commission's approach for its jurisdictional load serving entities. See Section 6.4 for further details on this approach.

[2] Resulting costs are impacted by the inputs and assumptions to the model (such as resource cost forecasts, fuel prices, and load forecasts, among others). The inputs and assumptions were the best available data at the time of the modeling for this IRP.

data availability at the time of this IRP study. Resource cost and availability uncertainties can have large impacts on the resulting portfolio and system costs, and they should be monitored by SVP in future IRPs.

Figure ES-4. Scenario Comparison – 2035 Annual Cost Relative to Base Scenario (2022 $MM)



Note: Annual modeled cost includes the operational cost of existing/planned capacity, the capital cost, and operational cost of new build capacity. Capital and fixed costs (including PPA cost) of existing/planned capacity, and transmission and distribution costs are not included.

Challenges Ahead to Meet SVP's IRP Goals

Through studying Scenario 1: Base SB 100 (Base Scenario), which meets the current state policies, and two additional scenarios with more aggressive clean energy requirements in this IRP, multiple challenges are identified as SVP continues to provide affordable, clean, and reliable power to its growing customer load.

+ **SVP's load, primarily data center load, is expected to grow substantially throughout the planning horizon.** The forecasted annual load in 2035 almost doubles the current system load, and significant resource additions are needed to meet this growing load. Also, unlike other utilities, SVP's current and forecasted load is dominated by industrial (datacenter) load, which has a high load factor (or average load divided by peak load) of 80%, meaning that the system demand is relatively constant and there is less ability to shape loads to take advantage of certain resource production, such as low-cost solar. Therefore, SVP's future portfolio requires both clean resources and firm resources that can ensure there is enough energy to meet system load in all hours.
+ **SVP will need clean firm resources, such as geothermal, to meet future needs in a deep decarbonized system.** SVP faces a common challenge of deeply decarbonized systems, which is the ability to provide power reliably without firm dispatchable (emitting) thermal plants. Clean

firm resources not only provide clean energy, but also firm capacity to help ensure system reliability. The clean, firm, and baseload characteristics of geothermal align well with SVP's forecasted load growth and load shape and could provide a key clean firm option.

- **Competition for limited resources in California can add difficulties for SVP to procure some of cost-effective resources for its system.** For example, only a limited amount, about 3,400 MW, of geothermal may be available to California. Furthermore, the CPUC Mid-Term Reliability order requires CPUC-jurisdictional LSEs to procure approximately 1,000 MW long lead-time clean firm resources by 2028, and geothermal is one of the best available candidates to meet that order. An assumption of this IRP is that SVP may not be able to procure that 1,000 MW tranche. SVP would then be limited to a maximum of about 350 MW, which is approximately 15% of the remaining potential. The three scenarios in this IRP build to, or slightly below that limit. However, with the recent IRA including additional incentives for geothermal resources, and with all LSEs in California transitioning to a cleaner portfolio, there is a growing need for clean and firm resources, further driving competition for limited resources, such as geothermal, and adding challenges (and potentially costs) to cost-effective resource procurement.
- **SVP faces uncertainties in project delivery timelines.** To keep pace with near-term load growth to 2030 and longer-term load growth and policy objectives, SVP will need to bring significant quantities of new resources online over the next several years. As development for new resources in California increases to unprecedented rates, SVP may face challenges including, but not limited to supply chain delays, labor shortage, as well as permitting and lengthy interconnection queue processes. To build and begin utilizing new resources, the cost and schedule uncertainty of a complex, multi-step, multi-year interconnection process can significantly complicate other parts of the development process, including financing and project costs.
- **There are uncertainties in long-term resource cost forecasts.** This IRP uses the long-term resource cost forecast from the industry standard public data source, the NREL Annual Technology Baseline (ATB). However, recent market trends have shown that international trade policies and supply chain issues can significantly impact resource costs during procurement. Furthermore, market competition and developer profit markup are difficult to forecast and model but do influence resource costs. While many cost uncertainties are not explicitly studied in this IRP, they can impact the resulting portfolio choices and system costs. SVP should continue to monitor resource costs in future IRPs and resource procurement activities.
- **Achieving zero emission in every hour will likely require a combination of commercially available resources and new emerging technologies to be cost-effective and affordable.** To meet the hourly zero-emission target, all generation needs come from renewable, carbon-free resources, and/or market purchases (also when market emissions are zero) in every hour. If

emerging technologies and emerging zero-emission fuels are not available, SVP would need to add much higher amounts of existing commercially available technologies, such as solar, wind, and battery storage resources. The total nameplate capacity of those resources is likely higher than the system load and the three scenarios presented here. Because they have low and marginally decreasing reliability value, more capacity is needed to cover the most critical hours, even though there might be high curtailment occurring in other normal and/or low load hours. The emerging technologies, such as building new hydrogen plants and converting existing gas plants to burn on hydrogen or biogas, modeled in this IRP offer both clean and "firm capacity" attributes, and reduces the potential for "overbuilding" existing mature technologies.

+ **There are large uncertainties and risks in emerging technologies.** The emerging technologies modeled in this IRP are developed based on various assumptions and limited data. Many of the emerging technologies are still in their research and development and/or piloting phases, and it is difficult to predict when they will be commercially available at scale. Additionally, some emerging technologies, such as green hydrogen, require significant infrastructure development, such as electrolyzers, renewables for electrolyzers, pipelines, and storage. The costs and infrastructure required to support emerging technologies are uncertain and can impact the resulting portfolio feasibility and cost. The development of emerging technologies should continue to be monitored and studied by SVP in future IRPs and resource procurement.
+ **SVP's transmission capabilities with CAISO can have an impact on how much emission reduction SVP can achieve.** DVR and Gianera are the only two resources, both natural gas plants, located within SVP's local zone. When trying to meet more aggressive clean energy goals and reduce gas generation, the local resources' roles and SVP's transmission capabilities with CAISO become important. If the local resources cannot be dispatched to meet SVP's load, all system load must be met with energy delivered via the transmission line from CAISO. However, the existing and planned transmission capacity may not always be sufficient to cover SVP's forecasted peak load. In this IRP, it is assumed that local resources would be able to run on emerging zero-emission fuel and can be dispatched in Scenario 3: Zero Emissions with Emerging Technology, but SVP should continue to study system transmission capabilities and the clean transition of local resources in future IRPs.

2. Introduction

2.1. Silicon Valley Power

The City of Santa Clara (Santa Clara) is a charter California city located at the southern end of the San Francisco Bay. Since 1896 Santa Clara, currently under the name Silicon Valley Power (SVP), has provided all electric service within an area coterminous with the city's boundaries.

SVP is a fully vertically integrated municipal owned (or publicly owned) utility (POU) that provides all aspects of electric services including generation, transmission, and distribution facilities. SVP also purchases power and transmission services from other providers and participates in the California Independent System Operator (CAISO) market. SVP, as a department of Santa Clara, is under the direction of the Chief Electric Utility Officer, who is appointed by and reports to the Santa Clara City Manager. The Santa Clara City Council fulfills the role of a rate making and policy decision board.

SVP has procured renewable energy for multiple decades in the form of wind, hydro-electric and geothermal generation prior to the establishment of any Renewable Portfolio Standard (RPS) mandates. SVP continues to make demonstrable progress towards meeting the Senate Bill (SB) 350 long-term RPS procurement mandates, meeting California's Resource Adequacy (RA) mandates and providing energy efficiency and electrification rebates within Santa Clara's boundaries. SVP has installed over 147 public and fleet electric vehicle (EV) charging stations within Santa Clara. In addition, the city has adopted building codes that surpass the requirements of California Title 24 to facilitate more building electrification and EV charging infrastructure at the time of new construction.

Since 2018, SVP reduced its annual greenhouse gas (GHG) emissions by approximately 50%, primarily by divesting from all coal generation and certain natural gas generation.

SVP also maintains affordable electric rates relative to other California load serving entities (LSEs) and a robust discount program for income-limited residents. Lower rates have been an economic driver for development within Santa Clara, creating a unique customer base with a significant share of large- high-technology manufacturing and data management facilities. These facilities and other industrial customers accounted for over 90% of SVP's customer mix, by retail sales, in 2021.

SVP maintains investment grade credit ratings from Fitch and S&P, which has made SVP a desirable counterparty for generation companies.

2.2. State Laws, Policy, and Regulations

This section details the various California laws and regulations passed in recent years that apply to POU's such as SVP. Although SVP adheres to the guidelines of the California Energy Commission (CEC) as well as the requirements of SB 350 and Public Utilities Code (PUC) 9621, additional laws, policies and regulations also impact long-term planning conducted by SVP.

SB 350, the Clean Energy and Pollution Reduction Act, signed in 2015, required POUs with a three-year (2013-2016) average annual energy requirement of greater than 700 GWh to file an initial IRP consistent with PUC 9621 with the CEC in 2019, to then be updated at least once every five years. This IRP, SVP's first update to the 2019 IRP must be approved by the POU (the Santa Clara City Council) by January 1, 2024, and filed with the CEC by April 30, 2024.

PUC 9621 established several targets that impact future resource additions. These include:

- Meet the GHG emissions reduction targets established by the California Air Resources Board (CARB), in coordination with the CEC, for the electricity sector and each public utility that reflect the sector's share in achieving the economy wide GHG emissions reduction of 40% GHG from 1990 levels by 2030.
- Achieve procurement of a minimum 50% eligible renewable energy resources by 2030 and compliance with the California RPS Program interim goals, which include 40% by 2024 and 45% by 2027.
- These targets are to be met while also complying with PUC 454.52 related to serving customers at just and reasonable rates and minimizing ratepayer impacts, ensuring system reliability, strengthening the transmission and distribution systems, enhancing demand-side management, and minimizing local air pollutants and other GHG emissions with early priority on disadvantaged communities.

SB 100, the 100 Percent Clean Energy Act, signed in 2018, accelerated the RPS requirements from 50% by 2030 to 60% by 2030 with interim targets of 44% by 2024 and 52% by 2027. SB 100 also requires all of California's retail electricity supply be met with RPS-eligible and zero-carbon resources by December 31, 2045—achieving 100% clean energy.

SB 338, effective in January 2018, requires electric utilities in California to utilize energy efficiency, demand management, energy storage, and other strategies to meet peak demand requirements, ultimately reducing the need for new generation and distribution resources in achieving the state's energy goals at the least cost to ratepayers.

SB 1020, the Clean Energy, Jobs, and Affordability Act, signed in 2022, established additional interim targets to ensure that California meets SB 100's 2045 goal of 100% RPS-eligible and zero-carbon resources. These require clean energy generation to reach 90% of retail sales by 2035 and 95% by 2040.

2.3. Relevant State Legislation and Executive Orders

The following sections summarize additional key bills and orders for GHG emissions, energy efficiency, and renewable energy that affect the electric utility industry and have led up to SB 350 and PUC 9621.

GHG Emissions Reductions

Assembly Bill (AB) 32, or the Global Warming Solutions Act of 2006, extended in 2016, sent an absolute limit on GHG emissions for the state requiring economy wide emissions reductions to 40% below 1990 levels by 2030. AB 32 required utilities to report GHG emissions to the CARB and permitted the CARB to set regulations for GHG emissions reductions—leading to the implementation of a cap-and-trade program and GHG Planning Target Ranges for POUs. SVP’s IRP must ultimately align with the requirements of AB 32.

SB 1368, or the Emissions Performance Standard, enacted in 2007, restricts new investments in baseload fossil fuel generation resources that exceed the rate of GHG emissions for existing combined-cycle natural gas baseload generation. SB 1368 also allows the CEC to establish a regulatory framework to enforce this standard for POUs. CEC regulations prohibit investment in generation that exceeds 0.55 tons CO_2/MWh of electricity produced, with limited exceptions.

Relatedly, SB32, implemented in 2017, requires CARB to ensure the above stated GHG emissions reductions targets are met by 2030, and AB 197, also implemented in 2017, increased the legislative oversight of the CARB. AB 197 also requires that the CARB, in any consideration of limits beyond the existing statewide GHG emissions targets, protect the state’s most impacted disadvantaged communities consider the social costs of emissions, and prioritize emissions reduction rules and regulations that achieve specified results.

AB 1279, signed in 2022, establishes a binding goal for California to achieve caron neutrality no later than 2045 and establishes an 85% emissions reduction of emissions target (below 1990 levels) as part of the goal.

Energy Efficiency

SB 1037, signed in 2005, requires POUs to consider energy efficiency prior to investment in any other resources to meet growing energy demand, pursuant to the statewide commitment to cost-effective and feasible energy efficiency. One year later in 2006, AB 2021 was signed into law requiring POUs to establish annual efficiency targets and report on a on a triennial basis over a 10-year horizon. Subsequent decisions changed the time interval for establishing the annual targets to every four years.

Renewable Energy

The California Renewable Energy Resources Act (SB X1-2), signed in 2011 codified the RPS target for POUs, but also established specific Portfolio Content Categories (PCCs), which further divided the eligible renewable energy resources to be procured and established limits. The four PCC categories classify renewable resources by interconnection location and additional factors:

+ **PCC1**: Products must be bundled and the POU cannot resell the energy; the resource’s first point of interconnection must be to a distribution system serving end-users within a California balancing authority area; renewable energy products having a first point of interconnection outside a state balancing authority area must be scheduled hourly into the area without substituting electricity from another source.

- **PCC2**: Products must be bundled and interconnected to Western Electricity Coordinating Council network; the electricity bust be scheduled into a California balancing authority area; the products must have a first point of interconnection outside of a state balancing authority area, and the electricity must not be in the portfolio of the POU prior to the date of contract or ownership agreement; the electricity must be scheduled into the state balancing authority area within the same calendar year that the electricity is generated, and the energy may not be sold back by the POU.
- **PCC3**: unbundled renewable energy credits (RECs) and products not meetings the requirements of PCC1 or PCC2
- **PCC0**: renewable energy under contract prior to June 1, 2010 provided that the resource meets the RPS eligibility requirements in effect when the procurement agreement was executed; subsequent amendments do not increase the capacity or production or substitute a different resource (any such change would be classified into PCC1, 2 or 3 and follow the portfolio balance requirements); and the duration of the contract may be extended if the original contract was for 15 years or more.

"Climate change is a real threat to all our lives. Baby steps aren't going to be enough." -Santa Clara resident survey response

2.4. Federal Legislation

Future federal-level laws or regulations could possibly mandate new renewable and GHG emissions standards implemented by the Environmental Protection Agency (EPA) that would impact POU operations. However, regulation of GHG emissions at the federal level has been uncertain at times, and it is difficult to foresee how future federal policy on GHG emissions may impact on SVP operations. This IRP was prepared assuming that California GHG emission reduction requirements are the most stringent applicable for planning.

2.5. CEC IRP Guidelines

Beginning on January 1, 2019 SVP, as a POU, was obligated by SB 350 to develop and submit it to the CEC to review at least every five years. SVP filed its first IRP with the CEC in accordance with SB 350 in 2019.

This IRP process, will fulfill CEC requirements for SVP to receive POU (the Santa Clara City Council) approval of its second IRP by January 1, 2024, and file with the CEC by April 30, 2024.

The CEC developed the *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines* document in July 2017 which established several requirements to be included in the IRP filing process.[3] CEC is proposing amendments to the IRP Guidelines; however, as of the writing of this IRP, the proposed changes are not yet formally adopted. Therefore, SVP followed the current approved CEC Guidelines, except for the planning horizon, which is detailed in Figure 1. These requirements include the following:

- POUs must submit the following four standardized tables to the CEC as part of the IRP Filing:
    - **Capacity Resource Accounting Table (CRAT):** Annual peak capacity demand in each year and the contribution of each energy resource (capacity) in the POU's portfolio to meet that demand.
    - **Energy Balance Table (EBT):** Annual total energy demand and annual estimates for energy supply from various resources.
    - **GHG Emissions Accounting Table (GEAT):** Annual GHG emissions associated with each resource in the POU's portfolio to demonstrate compliance with the GHG emissions reduction targets established by CARB.
    - **RPS Procurement Table (RPT):** A detailed summary of a POU resource plan to meet the RPS requirements.
- The minimum planning period begins January 1 of the year that the POU's governing board adopts the IRP and must go through December 31, 2030. POU's are encouraged to address longer planning periods in post-2030.
- POUs are encouraged to evaluate alternative resource options through various scenarios and sensitivity analyses.
- The IRP Filing must include supporting information used to develop the Standardized Tables and other studies, data, analyses used or relied upon in developing the IRP.
- POUs are required to report the forecasted peak demand in the CRAT and forecasted retail sales, other loads, and net energy for load in the EBT. The IRP must explain the demand forecasting methodology and assumptions used. The CEC encourages alternative demand forecast scenarios to be part of the IRP.

[3] CEC, "Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines - Adopted" (Sacramento, CA: California Energy Commission (CEC), 2017), https://www.energy.ca.gov/rules-and-regulations/energy-suppliers-reporting/clean-energy-and-pollution-reduction-act-sb-350-0.

- The IRP must report the mix of resources in the required tables; this includes RPS procurement information in the RPT. The mix of resources refers to short-term and long-term electricity, electricity-related, and demand response products. RPS information provided must demonstrate the achievement of the RPS target by listing the RPS procurement targets, the projection of renewables as contained in a RPS procurement plan. The reporting of resource mix must also include the impacts of energy efficiency and demand response resources. Energy storage and transportation electrification should also be addressed in the IRP and included in the required tables, as appropriate.
- The IRP should address system reliability. This includes explaining how the planning reserve margin (PRM) was established and a discussion of any local transmission constrained areas.
- GHG emission intensities must be reported in metric tons of carbon dioxide equivalent (CO_2e) per MWh for each supply resource reported in the EBT.
- The IRP should be consistent with the goal of achieving just and reasonable rates and must include as supporting information, a report on rate impacts under the IRP plan if that report was considered in the IRP planning.
- The IRP should report on the contribution of the IRP to increasing the diversity, sustainability, and resilience of the transmission and distribution system.
- The IRP should be consistent with minimizing localized air pollutants and other GHG emissions with early priority on disadvantaged communities.

Figure 1 summarizes the IRP filing requirements as listed in the CEC guidelines document. The location where this information can be found in SVP's IRP is outlined below.

Figure 1. Summary of CEC IRP Filing Requirements

Item	CEC Guidelines	IRP Location
A. Planning Horizon and Objective of Expansion Plan	"requires each POU to adopt an IRP that ensures the utility achieves specific goals and targets by 2030, including meeting the electricity sector and utility specific GHG emissions reduction targets established by the CARB that reflect the electricity sector's percentage in achieving economy-wide GHG emissions reductions of 40% below 1990 levels, and ensuring procurement of at least 50%of eligible renewable resources…The minimum planning horizon that achieves this objective begins no later than January 1 of the year that the POU's governing board adopts the plan and ends no earlier than December 31, 2030".* *Proposed revisions through 2045[4]	Section 2

[4] CEC, "Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines - Draft Proposed" (Sacramento, CA: California Energy Commission (CEC), 2022), https://www.energy.ca.gov/publications/2022/publicly-owned-utility-integrated-resource-plan-submission-and-review-guidelines.

B. Scenarios and Sensitivity Analysis	"POUs are encouraged to also evaluate other scenarios and sensitivity analyses to consider the feasibility and cost-effectiveness (and rate impacts) of alternative resource options."	Sections 6 and 8
C. Standardized Tables	"POUs must submit the following four standardized tables to the Energy Commission as part of the IRP Filing." Capacity Resource Accounting Table (CRAT) Energy Balance Table (EBT) RPS Procurement Table (RPT) GHG Emissions Accounting Table (GEAT)	Appendix A
D. Supporting Information	"(1) analyses, studies, data, and work papers, or other material that the POU used or relied upon (including inputs and assumptions) in creating the IRP…(2) additional information required by these guidelines. Supporting Information supplements the data submitted in the standardized tables and must be submitted to the Energy Commission as part of the IRP Filing"	Sections 3, 4, 5, 6, 7 and Appendix A Appendix C
E. Demand Forecast	1. Reporting Requirements: "report annual forecasted peak demand (megawatt [MW]) in the CRAT and annual forecasted retail sales, other loads, and net energy for load in the EBT" 2. Demand Forecast Methodology and Assumptions: "describe the demand forecasting methodology and assumptions used." 3. Demand Forecast – Other Regions "If the POU uses system modeling as part of the IRP development, the IRP Filing must include the demand forecast assumptions for regions outside the POU jurisdiction."	Section 3, Appendix B
F. Resource Procurement Plan	"The IRP Filing must report the mix of resources used by the POU in the IRP. This information must be reported on the CRAT, EBT, and GEAT, and RPS procurement must be reported on the RPT." The IRP Filing must address the following: Diversified Procurement Portfolio RPS Planning Requirements Energy Efficiency and Demand Response Resources Energy Storage Transportation Electrification	Section 8, Appendix A
G. System and Local Reliability	"requires Filing POUs to adopt an IRP to ensure that each POU meets the goal of ensuring system and local reliability." 1. Reliability Criteria "must include projections of annual peak capacity needs and the contribution of both demand and supply-side resources… must report the PRM and how it was determined." 2. Local Reliability Area "must identify any local transmission constrained areas in the POU service territory" 3. Addressing Net Demand in Peak Hours "must include a narrative describing how existing renewable resources, grid operational efficiencies, multi-hour energy storage, and distributed energy resources (DERs), including energy efficiency, were considered for meeting energy and reliability needs during the net-peak hours."	Sections 6, 7, 8, and Appendix A
H. Greenhouse Gas Emissions	"requires POUs to adopt an IRP to ensure the utility meets, by 2030, the GHG emissions reduction target established by CARB…must	Sections 6, 8, Appendix A

	report in the GEAT estimated emissions intensities (in metric tons of CO2e per/megawatt hour [mt CO2e/MWh] and total metric tons of carbon dioxide [mt CO2e] emissions for each supply resource reported in the EBT.”	
I. Retail Rates	“requires POUs to adopt an IRP to ensure the POU achieves the goals of fulfilling its obligation to serve its customers at just and reasonable rates and minimizing impacts on ratepayer bills… must include, as Supporting Information, a report or study on rate impacts under the IRP scenario”	Section 8
J. Transmission & Distribution Systems	“ensure that the POU achieves the goal of strengthening the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities.”	Section 4 and 7
K. Localized Air Pollutants and Disadvantaged Communities	“ensure the POU achieves the goal of minimizing localized air pollutants and other GHG emissions, with early priority on disadvantaged communities”	Section 8

2.6. Public Stakeholder Engagement

The public stakeholder engagement process for the IRP involved seeking groups who have an interest in future energy resource plans (i.e., stakeholders), gathering their feedback and addressing their goals and concerns. Through this process, participants were engaged and involved early in IRP development. Stakeholders included large customers, local businesses, and the community at large.

The community engagement activities that shaped the IRP were conducted in two phases. The first phase was the creation of the Santa Clara Climate Action Plan, organized by Santa Clara and a consultant team in 2020 and 2021. The community feedback collected during this process was used to help shape the Climate Action Plan, which would then be used as a guiding document for the IRP. The Climate Action Plan community engagement included:

- Online surveys,
- Virtual community workshops,
- Focus group interviews, and
- Public comment on the draft CAP.

Additional community engagement specifically for the IRP included:

- A community survey, open from September – November 2023 (results are in Appendix A)
- A community workshop was presented in-person and virtually, attended by both residential and commercial customers.
- Publication through newsletters.
- Social media posts on various online platforms from September to November 2023

+ Informational outreach and survey promotion at the Santa Clara Art & Wine Festival and the State of the City Events

There are plans to hold another community workshop after the IRP is presented to the City Council in December 2023 to discuss the results and the path forward.

"Consider cost and reliability above other considerations." -Santa Clara resident survey response

"I have no trouble paying extra for electricity to accelerate sustainability." -Santa Clara resident survey

2.7. The Integrated Resource Planning Process

Integrated Resource Planning identifies a long-term resource portfolio plan that provides for future peak load and energy demand, while maintaining system reliability, and achieves a reasonable balance between fiscal responsibility and environmental stewardship. The IRP is a formal planning document to be submitted for approval by the Santa Clara City Council prior filing with the CEC.

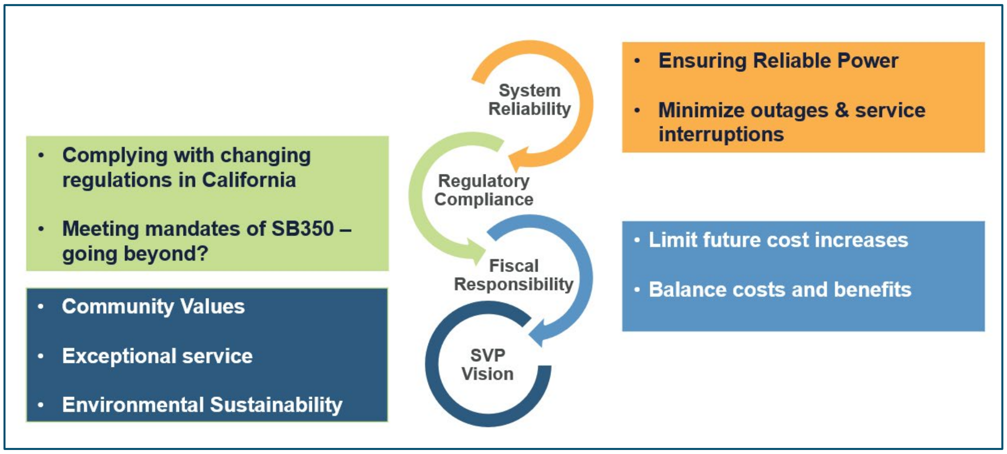
The IRP process can be summarized in the following steps:

1. Identify Objectives: Establish a clear vision with a set of goals for the IRP that will drive the planning process and ground it in the priorities and concerns of local stakeholders (Figure 2).
2. Design Scenarios: Build realistic potential futures that capture the key external forces and internal planning decisions to be explored in the IRP.
3. Determine Future Capacity Needs: Utilizing the latest load forecast that incorporates load modifiers for energy efficiency and transportation and building electrification and comparing that to current information for existing supply-side resources, expected retirement dates, and planned resource additions, identify a baseline for future capacity needs.
4. Identify Resource Options: Identify potential candidate resources that can be reliably utilized to serve load if a need is determined. This requires consideration of technology advancements, cost, resource location and potential, and performance characteristics.
5. Analyze Resource Options: Conduct analyses to identify resource options that ensure reliability and regulatory compliance at least cost.
6. Evaluate Resource Portfolios: Compare least-cost resource portfolios, their costs, achievement of policy goals (i.e., GHG, clean energy, and reliability), and potential rate impacts to understand trade-offs, and achievement of planning objectives.

7. Finalize Plan: SVP will work with the Santa Clara City Council to a identify preferred, cost-effective portfolio resource expansion plan to file with the CEC, and update, as appropriate, as part of ongoing utility due diligence. The current document presents a set of scenarios to aid decision making; however, a preferred scenario is not identified.

The goal of SVP's 2024 IRP is to "identify a plan that meets or exceed the State's clean energy mandates while balancing affordability and reliability," with the core objectives shown in Figure 2 that support SVP's vision for the 2024 to 2035 planning horizon.

Figure 2. Core Objectives of SVP's IRP



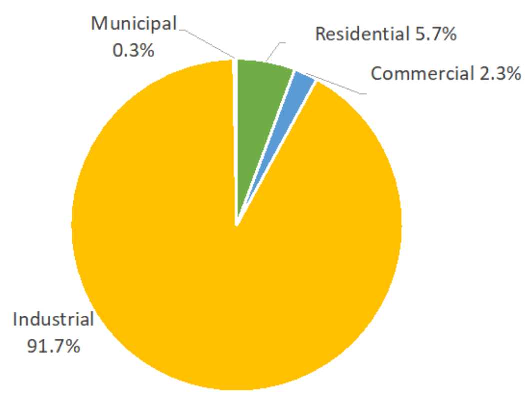
The sections that follow detail the additional steps of the SVP's planning process.

3. Energy and Demand Forecast

3.1. Historic Energy Use and Demand

As of 2023, Santa Clara's population was estimated at just over 128,000, and SVP served approximately 60,685 customer meters with 4,480 GWh of sales and a peak demand of 669 MW. The makeup of SVP's customer base is unique for the state. While 85% of the total number of customers are residential, 94% of the utility retail sales are to commercial and industrial customers, consisting of high-technology manufacturing and data management facilities, shown in Figure 3. This results in a relatively flat demand profile and a high load factor. SVP's demand has consistently increased in recent years, mostly due to growth of the industrial customer sector.

Figure 3. SVP Customer Mix by Retail Sales in 2023



3.2. Demand Forecast Methodology and Assumptions

A range of sources were leveraged to develop an SVP Reference scenario for the planning horizon 2024-2035 of annual peak load and an hourly energy demand forecast.[5] The Reference Scenario is a business-as-usual forecast of energy demand in SVP territory using the utility's baseline forecast of energy demand with additional energy efficiency and electrification projections from the Planning Forecast of the CEC 2022 Integrated Energy Policy Report (IEPR).[6]

[5] Sensitivities were also explored to build High electrification and a IEPR local reliability load forecast, discussed in Appendix B.
[6] CEC, "CEC 2022 Integrated Energy Policy Report (IEPR)" (Sacramento, CA: California Energy Commission (CEC), 2022), https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2022-integrated-energy-policy-report-update.

Annual Energy Demand Forecast

Baseline Energy Demand

SVP baseline energy demand is developed from hourly energy forecasts for 2023-2035 originally submitted as part of the 2022 IEPR process and the Pacific Gas and Electric (PG&E) extended IRP process.[7] SVP also utilized annual energy forecasts for 2023-2035 by customer class for the Residential, Commercial, Industrial, and Municipal customer sectors. As shown in Figure 4, baseline energy demand grows quickly from 2023 to 2035 mainly due to increases in the Industrial sector (e.g., datacenter loads).

Figure 4. SVP Baseline Energy Demand Forecast (GWh)

Customer Class	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Residential	271	290	321	366	430	469	481	485	485	487	485	502	502
Commercial	98	132	161	195	241	288	325	355	355	356	355	368	368
Industrial	4,184	4,555	5,078	5,521	5,882	6,396	6,810	7,249	7,729	8,234	8,498	8,642	8,810
Municipal	17	17	17	17	17	17	17	17	17	17	17	18	18
Baseline Total	**4,570**	**4,993**	**5,577**	**6,099**	**6,570**	**7,170**	**7,633**	**8,106**	**8,586**	**9,094**	**9,356**	**9,530**	**9,698**

Energy Demand Modifiers

After establishing the baseline energy demand forecast, load modifiers for energy efficiency, building electrification, and transportation electrification were developed and layered onto the baseline forecast to establish the total annual demand for the Reference Scenario. Figure 5 shows these energy demand modifiers and SVP resulting total annual demand, and the assumptions behind these modifiers are explained in the following paragraphs. The Reference Scenario also includes a 2.9% line-loss factor for losses between the CAISO point of interconnection and SVP's retail load when reporting final electricity demand.[8]

Figure 5. Reference Scenario Annual Electricity Demand and Demand Modifier Impacts (GWh)

Scenario	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Baseline Total	4,570	4,993	5,577	6,099	6,570	7,170	7,633	8,106	8,586	9,094	9,356	9,530	9,698
Energy Efficiency	-62	-97	-136	-171	-204	-226	-248	-271	-294	-313	-333	-350	-365
Building Electrification	13	21	29	36	43	51	59	67	74	81	88	94	99
Transportation Electrification	8	15	24	32	40	49	59	69	81	94	107	120	135
Total Annual	**4,529**	**4,933**	**5,494**	**5,995**	**6,449**	**7,044**	**7,503**	**7,971**	**8,448**	**8,955**	**9,218**	**9,394**	**9,567**

For energy efficiency the Reference Scenario reflects the "Scenario 3 (Mid)" additional achievable energy efficiency (AAEE) modeled by CEC from the 2022 IEPR for Residential and Commercial sector energy efficiency, aligning with the assumptions used in the 2022 IEPR Planning Forecast.[9] These assumptions lead to 130 GWh and 169 GWh of annual savings by 2035 for the residential and commercial sectors,

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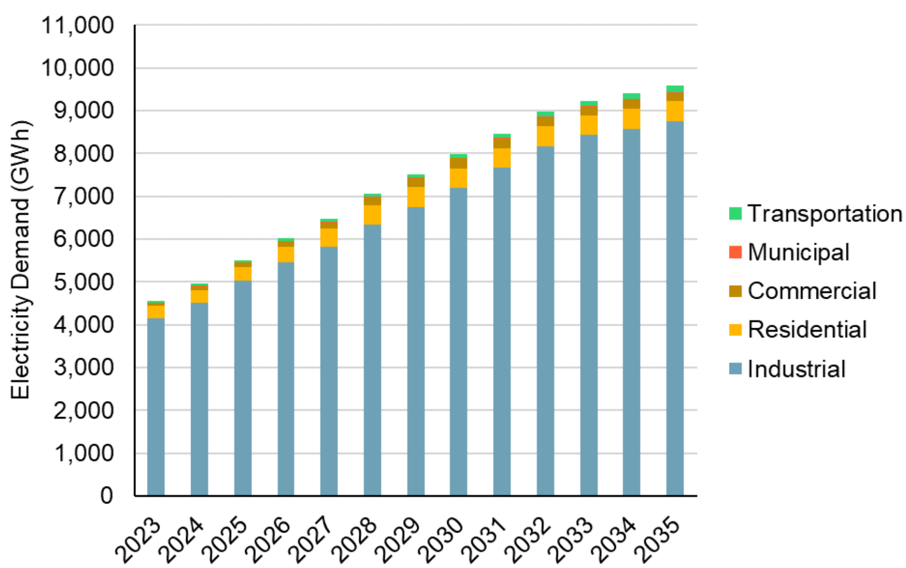
[7] SVP, "SVP Hourly Energy Forecasts: 2023-2035," 2023, Data Provided by Silicon Valley Power.
[8] Line-loss factor from SVP
[9] CEC, "2022 IEPR AAEE-AAFS Annual Impacts," 2022, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=22-IEPR-03.

respectively, from measures targeting lighting, heating, ventilation, and air conditioning (HVAC), water heating, and other end uses. Finally, the Reference scenario includes the cumulative total energy efficiency potential of 66 GWh by 2031, with most of these savings occurring for non-residential customers.

For building electrification assumptions, the Reference Scenario follows the assumptions of "Scenario 3 (Mid)" Annual Achievable Fuel Substitution (AAFS) modeled by CEC for the 2022 IEPR, aligning with the assumptions used in the 2022 IEPR Planning Forecast.

Finally, the Reference Scenario reflects the base level of transportation electrification from the 2022 IEPR assumptions from CEC. The total annual electricity demand for the Reference Scenario is shown in Figure 6.

Figure 6: Total Annual Electricity Demand - Reference Scenario



Hourly Energy Demand Forecast

To facilitate capacity expansion modeling for the integrated planning process an hourly demand forecast was developed from this annual forecast. A separate hourly load profile was assigned to the annual baseline energy demand, energy efficiency and electrification load modifiers to develop a complete hourly energy demand forecast for the Reference Scenario forecast. Figure 7 lists the sources used to develop these hourly demand profiles.

As IEPR does not provide an hourly load profile for SVP, PG&E-wide hourly load shapes for energy efficiency and building and transportation electrification were downscaled from the 2022 IEPR PG&E Planning Scenario.

Figure 7. Hourly Demand Profile Components

Energy Demand Component	Source for Hourly Demand Profile
Baseline Energy Demand	SVP Hourly Energy Demand Forecast 2023-2035
Energy Efficiency	2022 IEPR Hourly Forecast – PG&E Planning Scenario[10]
Building Electrification from 2022 IEPR	
Transportation Electrification	

[10] CEC, "CED 2022 Hourly Forecast - PGE - Planning Scenario," 2022, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=22-IEPR-03.

4. Existing and Planned System and Resources

4.1. Existing Resources and System Description

This section provides a description of all the resources currently procured to meet customer load. SVP's portfolio includes Santa Clara-owned resources, jointly owned resources, and resources procured through Power Purchase Agreements (PPAs). Santa Clara is a member of two joint powers agencies: the Northern California Power Agency (NCPA) and the M-S-R Public Power Agency (M-S-R PPA).[11] Each of these agencies has shared interests in several facilities, as described later in this section.

This IRP accounts for Santa Clara's Metered Subsystem Aggregation Agreement (MSSA) between the NCPA and California Independent System Operator (CAISO). The NCPA serves as SVP's schedule coordinator and is not obligated to offer its generation into the CAISO market. SVP pays a Transmission Access Charge (TAC) to CAISO for energy delivered into its service area (see Sections 4.7 and 7.5).

SVP's energy resource planning strategies, methods and processes are consistent with applicable Western Electricity Coordinating Council and North American Electric Reliability Corporation (NERC) standards, SVP's Strategic Plan, the MSSA and other relevant contracts into which Santa Clara has entered, good utility practice, and sound economic and business principles. SVP will continue to maintain an integrated and balanced portfolio of resources that is sufficient to meet its obligations.

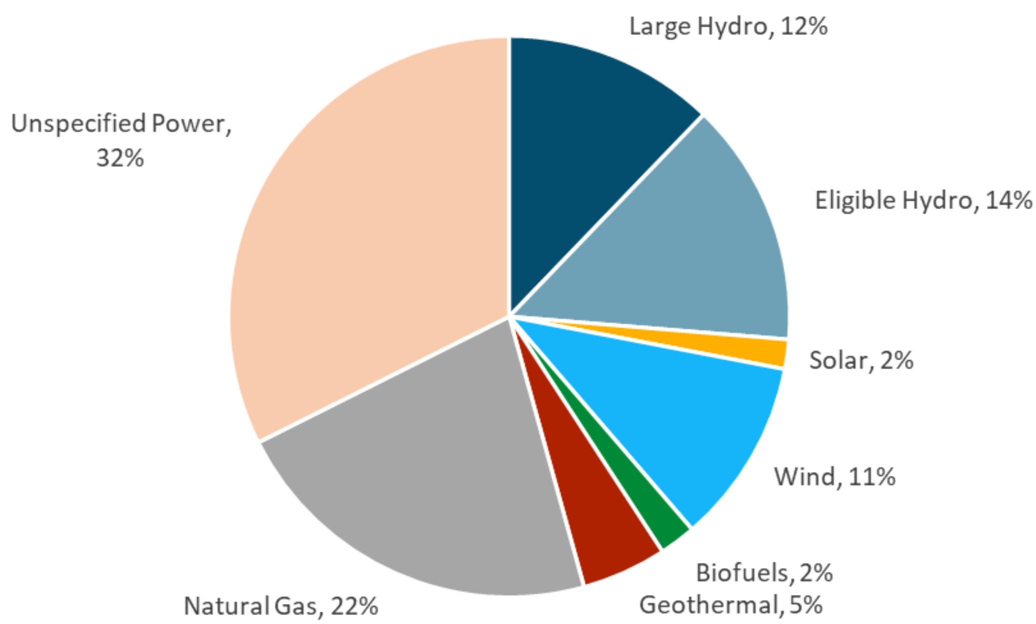
When procuring resources to serve customer load, risk management processes and procedures are followed using Santa Clara's official Risk Management Policy. Risk management practices apply to decisions concerning the mix of resources and their loading order, including the decision to use supply or demand-side resources, whether to operate inside Santa Clara versus remote resources, what type of generation to procure and other questions. In general, SVP's approach is to maintain a diverse portfolio of generating resources and market energy resources to reduce risk and minimize exposure to loss of generating capacity. Due to SVP's dependence on transmission services provided by the CAISO and others to import power, SVP is exposed to costs increases and to potential power delivery interruptions failures. SVP continually seeks strategies to reduce the impacts of transmission cost increases and maintains contingency plans for such occurrences. SVP also procures fuel for its natural gas-fired generating facilities with supply contracts that are laddered with staggered start times and durations to limit its exposure to fuel price fluctuations.

A summary of SVP's calendar year 2022 generation portfolio mix by resource type is presented in Figure 8. This does not include SVP's excess renewable resources sold to third parties. Due to SVP's long position in renewables, SVP will either sell excess renewable generation to other entities, or bank surplus RECs for

[11] M-S-R Public Power Agency (M-S-R PPA) was created through a Joint Exercise of Powers Agreement among **M**odesto Irrigation District, the City of **S**anta Clara (as Silicon Valley Power), and the City of **R**edding for the purposes of acquiring, constructing, operating, and maintaining, any project for the purpose of providing electrical energy or other project benefits for public or private uses.

utilization in future years. This allows SVP to evaluate additional eligible renewable resources projects that will optimize the value for the customers.

Figure 8. SVP Generation Portfolio Mix by Technology, 2022

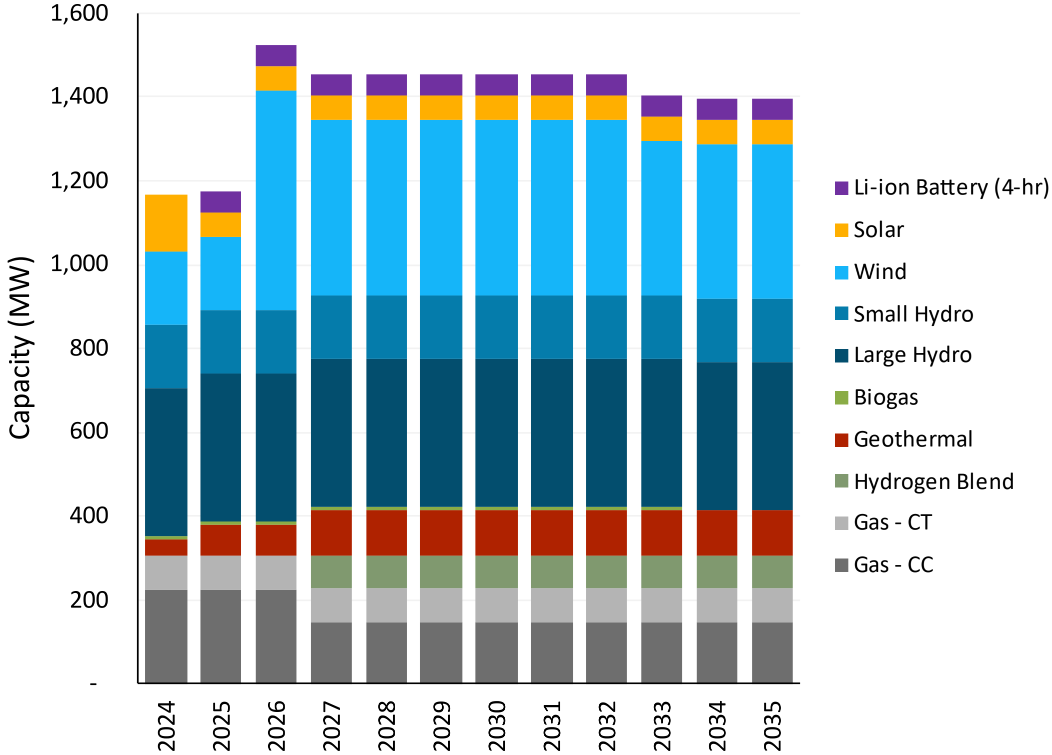


Note: Unspecified Power is electricity that has been purchased through open market transactions and is not traceable to a specific generation source.

4.2. Existing and Planned Resources

SVP's portfolio of existing (owned, jointly owned and/or contracted) generators and planned resource additions through the modeling horizon to 2035 is shown in Figure 9. This portfolio includes resources that are currently in SVP's portfolio, those that are planned for future delivery, and those that retire within the planning horizon.

Figure 9. SVP Existing and Planned Resource Portfolio, 2024-2035



More information on the individual resources under contract to deliver electricity in 2023 to SVP is provided in Figure 10.

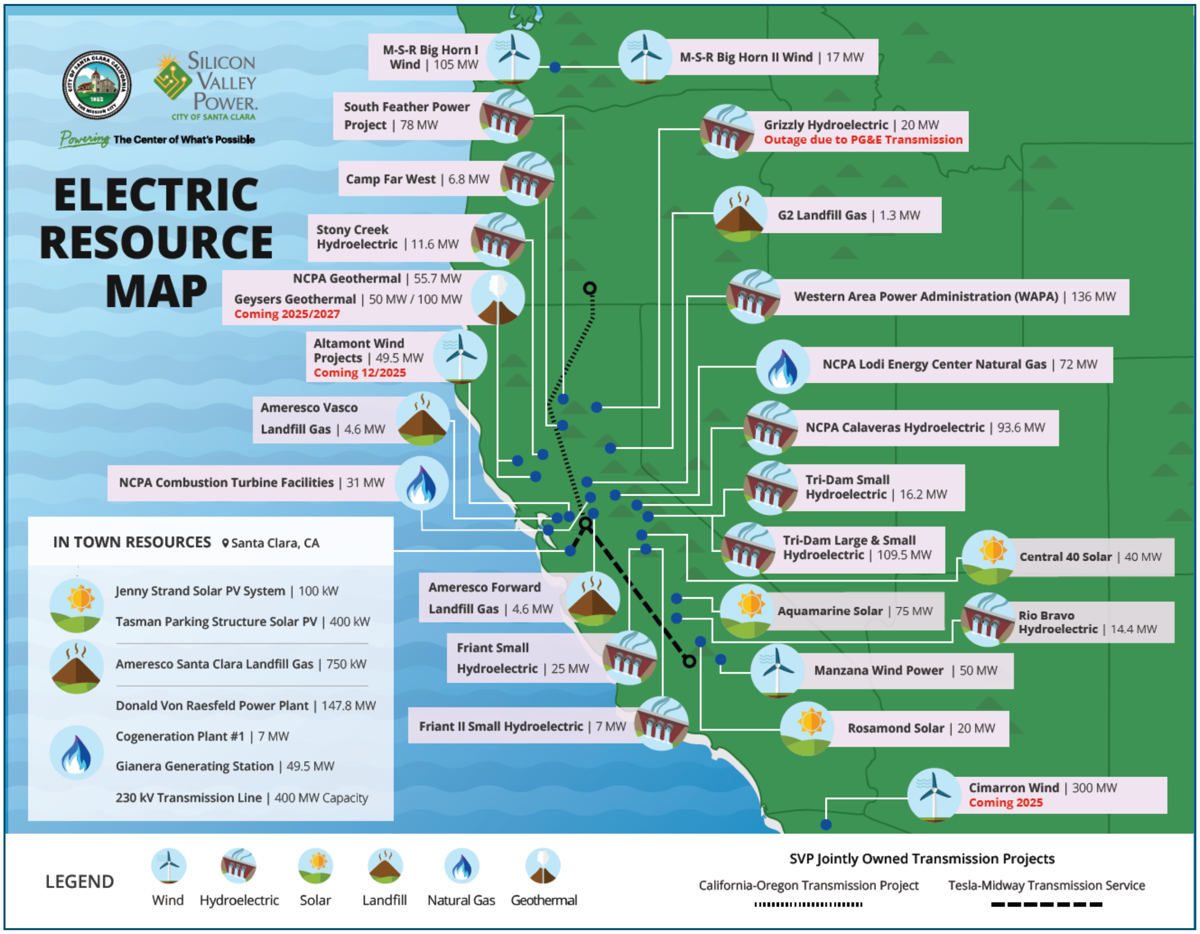
Figure 10. SVP's Resource Portfolio in 2023

Portfolio	Resource	Type	RPS Eligible	PCC Type	System RA	Capacity, MW
City-Owned / Contracted	Tri-Dam Donnells	Hydro	No		Yes	72.0
	WAPA Base Resource	Hydro	No		Yes	126.0
	Ameresco Forward	Landfill Gas	Yes	PCC1	Yes	4.2
	Ameresco VASCO	Landfill Gas	Yes	PCC1	Yes	4.3
	G2 Landfill	Landfill Gas	Yes	PCC0	Yes	1.6
	Donald Von Raesfeld (DVR)	Natural Gas	No		Yes	147.8
	Gianera Generating Station	Natural Gas	No		Yes	49.5
	Black Butte	Small Hydro	Yes	PCC0	Yes	6.2
	Camp Far West Hydro (Index+)	Small Hydro	Yes	PCC1	Yes	6.8
	Friant 1	Small Hydro	Yes	PCC1	Yes	25.0
	Friant 2 (Quinten)	Small Hydro	Yes	PCC1	No	7.3
	Grizzly Hydro	Small Hydro	Yes	PCC0	Yes	17.7
	Rio Bravo (Index+)	Small Hydro	Yes	PCC1	Yes	14.0
	Stony Gorge	Small Hydro	Yes	PCC0	Yes	4.9
	Tri Dam Southern/Sandbar	Small Hydro	Yes	PCC1	Yes	16.2
	Tri-Dam Beardsley	Small Hydro	Yes	PCC1	Yes	11.5
	Tri-Dam Tulloch	Small Hydro	Yes	PCC1	Yes	25.9

	Aquamarine Westside (Index+)	Solar	Yes	PCC1	Yes	75.0
	Central 40	Solar	Yes	PCC1	Yes	40.0
	Rosamond Solar	Solar	Yes	PCC1	Yes	20.0
	Manzana Wind	Wind	Yes	PCC1	Yes	50.0
					Total, City-Owned and Contracted	**725.9**
NCPA	Geo Plant 1-4 4	Geothermal	Yes	PCC0	Yes	58.4
	Collierville	Hydro	No		Yes	91.4
	South Feather - Woodleaf	Hydro	No		Yes	38.5
	South Feather – Forbstown	Hydro	No		Yes	24.0
	Alameda 1 & 2	Natural Gas	No		Yes	19.6
	Lodi CT	Natural Gas	No		Yes	9.9
	Lodi Energy Center (LEC)	Natural Gas	No		Yes	77.9
	New Spicer	Small Hydro	Yes	PCC0	Yes	2.2
	South Feather – Kelly Ridge	Small Hydro	Yes	PCC1	Yes	7.0
	South Feather – Sly Creek	Small Hydro	Yes	PCC1	Yes	8.3
					Total, NCPA-Owned and Contracted	**337.2**
MSR	Big Horn 1	Wind	Yes	PCC0	Yes	105.0
	Big Horn 2	Wind	Yes	PCC0	Yes	17.5
					Total, MSR Resources	**122.5**
					Total, Renewable	**529.0**
					Total, Zero Carbon Resources	**880.9**
					TOTAL	**1,185.6**

SVP's diverse portfolio of resources is located throughout California and Washington State and soon in the Country of Mexico, as mapped in Figure 11.

Figure 11. SVP's Current Power Resource Locations (Owned and Contracted)



Additional resources that are under contract and scheduled to come online in future years are summarized in Figure 12.

Figure 12. SVP's Planned Resource Additions in Future Years

Portfolio	Resource	Type	RPS Eligible	System RA	Delivery Year	Capacity, MW
City-Owned / Contracted	BESS 200 MWh	Li-ion Battery	No	Yes	2025	50.0
	Calpine Geothermal 1	Geothermal	Yes	Yes	2025	35.0
	Calpine Geothermal 2	Geothermal	Yes	Yes	2027	35.0
	Rooney Ranch	Wind	Yes	Yes	2026	19.0
	Sand Hill A	Wind	Yes	Yes	2026	13.0
	Sand Hill B	Wind	Yes	Yes	2026	17.5
	Cimmaron Wind	Wind	Yes	No	2026	300.0
Total, City-Owned and Contracted						**469.5**

Several resources in SVP's portfolio are expected to be retired due to aging units or expiration of the PPA contracts. The schedule of planned contract expirations and resource retirements is provided in Figure 13. Among the resources leaving SVP's portfolio are 8.5 MW of biogas generators and 172.5 MW of aging wind assets.

Figure 13. Planned Resource Retirements

Year	Capacity Retired (MW)
2026	105.0
2032	50.0
2034	8.5
2035	17.5
Total	181

4.3. Description of Santa Clara Owned and Contracted Resources

Aquamarine Westside Solar

In 2021, Santa Clara entered into a PPA with Aquamarine Westside LLC., a solar PV generator project located in Kings County, CA. Under this agreement SVP owns a share of the system and receives up to 75 MW of the total project.

Ameresco Landfill Gas

In 2010, Santa Clara signed PPAs with Ameresco for the Ameresco Forward and Ameresco Vasco projects. Ameresco Forward is a landfill gas generator located in Manteca, CA. Ameresco Vasco is a landfill gas generator located near Livermore, CA. SVP is contracted to receive up to 4.6 MW (and potentially up to 9.2 MW) from Ameresco Forward and up to 5 MW from Ameresco Vasco.

Stony Creek Hydroelectric System

SVP owns and operates the Stony Creek Hydroelectric System, which consists of three small hydroelectric plants. The 4.9-MW Stony Gorge generator is located at the Stony Gorge Dam near Willows, CA. The 6.2-MW Black Butte generator is located at the Black Butte Dam near Orland, CA. A third, 0.53-MW generator located near the Black Butte dam, is not modeled.

Central 40 Solar

In 2017, Santa Clara signed a PPA with Samsung to develop the Central 40 project. Central 40 is a solar PV generator located in Stanislaus County, CA. SVP is contracted to receive 40 MW from the project.

Donald Von Raesfeld (DVR)

In 2005, Santa Clara commissioned the Donald R. Von Raesfeld (DVR) natural gas combined cycle power plant located within the City of Santa Clara. DVR is a 122 MW nominal / 147 MW peaking generator. SVP economically bids DVR into the CAISO market and is operated based on CAISO dispatch instructions.

Friant 1 & 2 Hydro Facilities

In 2016, Santa Clara signed a PPA with the Friant Power Authority for Facility 1. Facility 1 consists of three run-of-river hydroelectric facilities in Madera County, CA, totaling 25 MW: the River Outlet (2 MW), the Friant-Kern (15 MW), and the Madera (8 MW). SVP is contracted to purchase up to 68,000 MWh per year from Facility 1.

In 2012, Santa Clara entered a PPA with the Friant Power Authority for Facility 2, a run-of-river hydroelectric generator in Madera County, CA. Facility 2 consists of the Quinten Luallen Power Plant, rated at 7.3 MW.

G2 Landfill Gas

In 2009, Santa Clara signed a PPA for the G2 landfill gas project in Wheatland, CA. G2 has a nameplate rating of 1.6 MW.

Gianera Generating Station

In 1987, Santa Clara completed the construction of the Gianera Generating Station, located within the City of Santa Clara. Gianera consists of two dual-fuel (natural gas and fuel oil) combustion turbines, each with a nominal rating of 25 MW. Gianera 1 & 2 combine to provide 49.5 MW of capacity for SVP. Due to the plant's air permit, Gianera can only be operated up to 877 hours annually.

Grizzly Hydro Project

In a 1990 settlement agreement with PG&E, Santa Clara purchased the Grizzly Creek hydroelectric facility in Plumas County, CA. Grizzly Creek is nominally a 20-MW facility, and SVP contracted to receive all electricity produced by the system, less transmission losses, which amounts to an effective contracted capacity of 17.7 MW.

Manzana Wind

In 2012, Santa Clara signed a PPA with Avangrid for the Manzana Wind Power Project. Manzana is a 50-MW wind project located in Kern County, CA.

Rosamond Solar

In 2011, SVP entered PPA with Recurrent Energy for the entire output from the RE Rosamond One LLC project, a 20-MW solar PV project in Kern County, CA.

Rio Bravo

In 2019, Santa Clara signed a PPA with the Olcese Water District for the Rio Bravo project. Rio Bravo is a 14-MW hydroelectric power plant located in Kern County, CA.

Jenny Strand Solar Park

Santa Clara originally entered into an agreement with MiaSole on December 6, 2011, for the purpose of having MiaSole donate one thousand (1,000) solar PV modules to Santa Clara at no cost to Santa Clara to further the city's ability to provide renewable power.[12]

Tioga Solar

On February 2, 2012, Santa Clara entered a 20-year PPA with Tioga Solar Santa Clara, LLC. The project is located on the City of Santa Clara's multi-level parking structure on Tasman Drive in the City of Santa Clara. Nameplate capacity is 389.76 kW. [13]

Tri-Dam Large and Small Hydroelectric Project

In 2013, Santa Clara signed a PPA with the Tri-Dam Power Authority to purchase the output from four hydroelectric power plants located on the Middle Fork of the Stanislaus River in Tuolumne County. The Donnell's Powerhouse is a large hydroelectric generator rated at 72 MW. The other three power plants are small hydroelectric generators: Tulloch (25.9 MW), Beardsley (11.5 MW), and Southern (16.2 MW).

Western Area Power Administration

In 2005, Santa Clara signed a PPA with the Western Area Power Administration (WAPA) for the purchase of hydroelectricity from the Central Valley Project (CVP). In 2021, Santa Clara City Council approved an amendment to the PPA extending the purchase of output through calendar year 2054. The CVP is a collection of federal hydroelectric facilities operating in Northern California. SVP is contracted to receive approximately 9.6% of the electricity from WAPA, which translates to a nameplate capacity of approximately 126 MW.

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[12] Because of the size of this resource relative to the City's load, it was not included in the model for this IRP.
[13] Like the Jenny Strand Solar Park, due to the size of this resource relative to the City's load, it was not included in the model.

Altamont Wind Repower

In 2016, Santa Clara commenced a re-power project with S-Power at its existing Altamont Wind Project site. S-Power will own and operate 19 MW capacity of wind generation. Two additional PPAs were entered with S-Power under the Rooney Ranch, LLC, including Sand Hill A (13 MW) and Sand Hill B (17.5 MW). In total, the re-power project will be upgraded to deliver 49.5 MW of capacity to SVP and is scheduled to be completed by 2026.

Kifer Receiving Station Battery Energy Storage System Project

SVP is currently contracting with a third party to build and operate a 50-MW, 4-hour (200 MWh) utility-scale lithium-ion BESS within the City of Santa Clara at the City's Kifer Receiving Station. The BESS project is expected to be completed in late 2025.

Cimmaron Wind

SVP entered a PPA for the long-term supply of renewable energy from Cimmaron, a cross-border wind generation facility under development in Baja California, Mexico. Cimarron is expected to be a 300 MW wind generation facility that utilizes existing cross-border high voltage transmission line to interconnect and deliver clean energy to the East County Substation in San Diego County. The project has a commercial operation date of December 31, 2025.

4.4. Northern California Power Agency (NCPA) Resources

Santa Clara, together with the Cities of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Redding, Roseville and Ukiah, the Plumas-Sierra Rural Electric Cooperative, the Truckee-Donner Public Utility District, the Bay Area Rapid Transit District and the Port of Oakland, is a member of the California joint powers agency known as Northern California Power Agency (NCPA). The resources that Santa Clara jointly shares with other NCPA members are presented here.

NCPA Hydroelectric Project

In 1982, the NCPA jointly developed the NCPA Hydroelectric Project with the Calaveras County Water District (CCWD). CCWD is the licensee and NCPA is the project operator. The NCPA Hydroelectric Project includes the 246.86 MW Collierville Powerhouse and 6.0 MW Spicer Powerhouse. Santa Clara has a 37% share in NCPA's Hydroelectric Project, amounting to 91.4 MW of the Collierville project and 2.2 MW of Spicer.

NCPA Geothermal Project

The NCPA owns and operates geothermal projects in Sonoma and Lake Counties, CA. NCPA's leasehold agreement with the federal government was renewed in 2013. The Geothermal Project consists of two electric generating stations (Geothermal Plant 1 and Geothermal Plant 2), each with two 55-MW nameplate turbines. Santa Clara is contracted for 54.65% and 34.13% entitlement shares, respectively, in both plants.

NCPA Combustion Turbine Project No. 1 – Alameda 1 & 2 and Lodi CT

NCPA owns and operates the Combustion Turbine Project Number One (CT 1) (the Combustion Turbine Project), originally consisting of five CT units, each nominally rated 25 MW. Two of the units are in the City of Roseville, two are in the City of Alameda and one is in the City of Lodi. Santa Clara purchased a 25% entitlement share in NCPA's Combustion Turbine Project pursuant to a power sales contract with NCPA, which has recently been amended to reflect that Santa Clara's 25% share comes specifically from the two Alameda plants (Alameda CT 1 & 2) and the one Lodi plant (Lodi CT).

NCPA Lodi Energy Center Project

NCPA owns and operates the Lodi Energy Center (LEC), a 302 MW natural gas-fired, combined-cycle power generation plant located in Lodi, CA, which was placed into commercial operation in 2012. Pursuant to the LEC Power Sales Agreement, Santa Clara has purchased from NCPA a 25.75% generation entitlement share of the capacity and energy from LEC.

NCPA Lodi Energy Center Project – Hydrogen Transition

NCPA is planning a transition of natural gas units to hydrogen beginning with LEC's conversion to a 45% hydrogen blend in 2027. By 2032, NCPA expects to have LEC running on 100% hydrogen.

For the 45% hydrogen blend in 2027, NCPA plans to install an electrolyzer with 60 MW of capacity at the LEC providing the capability of producing 24 tons of hydrogen per day. The cost of the electrolyzer is expected to be $145 million with an additional $80 million needed for the installation. By 2032, NCPA estimates an additional 360 MW of electrolyzer capacity will be needed to operate LEC at 100% hydrogen, at a rough cost of an additional $2 billion. The renewable generation that powers the electrolysis (for hydrogen generation) would be eligible for the standard IRA tax incentives.

South Feather River Hydroelectric

In 2021, Santa Clara entered a PPA, via third party agreement with NCPA, to purchase 64.2% of the electricity output from the South Feather Power Project. The project consists of four hydroelectric power plants: the 37.5 MW Forbestown Powerhouse, the 11 MW Kelly Ridge Powerhouse, the 13 MW Sly Creek Powerhouse and the 60 MW Woodleaf Powerhouse. The four plants that make up the South Feather Power Project are located across Butte, Plumas and Yuba counties on the South Fork of the Feather River and Slate Creek. Santa Clara's project participation share of the generation output is expected to be approximately 245 GWh annually.

Camp Far West Hydroelectric

In 2022 Santa Clara entered into a PPA, via third phase agreement with the NCPA, with the South Sutter Water District for the generation output of the Camp Far West Hydroelectric Facility. Camp Far West is a run-of-river hydroelectric facility with a capacity of 6.8 MW and will produce approximately 23,700 MWh of electricity per year. SVP is the sole off-taker of this project's output.

Calpine Geothermal

SVP entered into a long-term PPA for renewable geothermal energy that will begin delivery energy to SVP in 2025. The PPA will allow the City of Santa Clara to receive clean, renewable energy produced from multiple Calpine geothermal power plants located in Sonoma and Lake Counties. It will deliver up to 50 MW of renewable energy during the period of 2025 to 2026 and, in 2027, the amount delivered will increase to 100 MW through 2036.

4.5. M-S-R Resources

Santa Clara, along with the Modesto Irrigation District and the City of Redding, is a member of the M-S-R PPA. The resources that are jointly owned, or procured through PPAs are described below:

M-S-R PPA Purchased Power – Big Horn Project I and II

In 2005, the M-S-R PPA entered a series of PPAs with Avangrid Renewables for the purchase of energy from the Big Horn I Project. Big Horn I is a 199.5-MW wind project located near the town of Bickleton, WA. Santa Clara receives 52.5% of the power purchased by the M-S-R PPA from Big Horn I, which equates to approximately 105 MW. Santa Clara uses a portion of its transfer capability of the California-Oregon Transmission Project (COTP) to provide for the transmission of the output from the Big Horn I Project to the California-Oregon border.

In 2010, the M-S-R PPA subsequently negotiated with Avangrid for the purchase of the output from a 50-MW expansion of Big Horn I, called the Big Horn II Project. Santa Clara receives 35% of the output from this project, or approximately 17.5 MW of project capacity.

4.6. Renewable Energy Strategy

A significant portion of the energy received by Santa Clara customers is generated from renewable energy resources. Santa Clara's power mix in Calendar Year 2022 consisted of 34% eligible renewable resources. When large hydroelectric resources are included, Santa Clara's power mix consisted of 74% renewable and large hydroelectric power. On December 6, 2016, the Santa Clara City Council adopted revisions to Santa Clara's Environmental Stewardship and RPS Policy Statement (Santa Clara Resolution 16-8392), and adopted a new RPS Enforcement Program, to conform to the standards and timetable set forth in SBX1-2, signed by the Governor on October 6, 2016.

- Santa Clara satisfied the RPS target for Compliance Period 1 (from 2011 through 2013), with an average of approximately 20%of Santa Clara's energy portfolio supplied from renewable resources over such period.
- Santa Clara satisfied the RPS target for Compliance Period 2 (from 2014 through 2016), meeting the compliance requirement of 20% of retail sales in 2014 and 2015, and 25%of retail sales in 2016.
- Santa Clara satisfied the RPS target for Compliance Period 3 (from 2017 through 2020), meeting the compliance requirement of 27%of retail sales in 2017, 29%of retail sales in 2018, 31%of retail sales in 2019, and 33%of retail sales in 2020.

Compliance Periods 1-3 have been verified and approved by the State of California. In the first and second year of Compliance Period 4 (from 2021 through 2024), Santa Clara satisfied the RPS target, meeting the requirement of 35.75% of retails sales in 2021 and 38.5% of retail sales in 2022. Santa Clara expects to fulfill the Compliance Period 4 RPS requirement by procuring eligible renewable energy resources (excluding "large hydro") amounting to 44% of total retail sales by 2024. SB 100 requires 60% eligible renewable energy compliance by December 31, 2030. Santa Clara is well positioned to meet the new renewable energy compliance requirements of SB 100.

Due to SVP's long position in renewables, SVP will either sell excess renewable generation to other entities or accumulate RECs that exceed RPS requirements as excess procurement to be utilized in future years in case of unplanned curtailment, plant interruptions, and unexpected load growth, future project delays or as needed to ensure compliance with the RPS. Excess procurement allows SVP to evaluate additional eligible renewable resources projects, other generation and potential battery storage projects that will optimize the value for the customers. SVP starts new procurement processes for a forecasted need at a minimum 3-5 years before the resource is needed. SVP is fully compliant with the State requirement that 65% of eligible renewables are under long term contracts.

4.7. Transmission and Distribution System Assets and Adequacy

Santa Clara's service area is surrounded by PG&E's service area and the two systems are interconnected at two Santa Clara-owned 115 kV receiving stations – Northern Receiving Station (NRS) and Kifer Receiving Station, each located within Santa Clara's city limits. In addition, Santa Clara has a 230-kV interconnection with PG&E at PG&E's Los Esteros Substation (LES) in the City of San Jose. Power received at LES is transmitted by Santa Clara approximately six miles to NRS. Santa Clara owns facilities for the distribution of electric power within its city limits (approximately 18.4 square miles), which includes approximately 27 miles of 60 kV power lines, approximately 500 miles of 12 kV distribution lines (approximately 64% of which are underground), and 27 stations. Santa Clara's electric system experiences approximately 0.5 to 1.5 hours of outage time per customer per year. This compares favorably with other utilities in California with reliability factors ranging from 1.0 to 2.5 hours outage per customer per year. To the extent Santa Clara requires additional transmission beyond its current transmission system limit, the city will need to advocate at the CAISO for additional transmission capability through the CAISO annual Transmission Planning Process (TPP) (See SVP Transmission Projects Below).

NCPA Geysers Transmission Project

To meet certain obligations required of NCPA to secure transmission and other support services for the NCPA Geothermal Project, NCPA undertook the geysers transmission project (the Geysers Transmission Project). The Geysers Transmission Project includes (i) a co-tenancy interest in PG&E's 230 kV line from Castle Rock Junction in Sonoma County to the Lakeville Substation (the Castle Rock to Lakeville Line), (ii) additional firm transmission rights in the Castle Rock to Lakeville Line and (iii) the Central Dispatch Facility. Santa Clara has a 55 MW share in the Geysers Transmission Project, which provides a link from the Geysers to PG&E's bulk transmission system.

TANC California–Oregon Transmission Project (COTP)

The Transmission Agency of Northern California (TANC) is a joint power agency established by a group of California publicly-owned utilities in 1984. Its purpose was to plan, design and construct the California Oregon Transmission Project (COTP), a 240-mile long, 500-kilavolt (kV) alternating current (AC) transmission line between the California-Oregon border and Central California. The COTP was completed and energized in 1993. Santa Clara is a member of the TANC and has an approximate 10% of TANC's share of COTP transfer capability. Santa Clara is using a portion of its share of the project transfer capability of the COTP to provide transmission of energy generated from the Big Horn Projects.

TANC Tesla–Midway Transmission Service

TANC and certain TANC Members have arranged for PG&E to provide TANC and such TANC Members with 300 MW of firm, bi-directional transmission capacity on its transmission system between PG&E's Midway Substation and the electric systems of the TANC Members or the COTP (the Tesla-Midway Service) under a long-term agreement known as the South of Tesla Principles (SOTP). Santa Clara's share of Tesla–Midway Transmission Service is 81 MW. Santa Clara utilizes its share of the TANC Tesla–Midway Transmission Service to provide access to power supplies located in the southwest.

SVP Transmission Projects

On September 6, 2022 SVP set a system peak load of 702 MW. With recent load growth of 5 to 7% and increasing industrial sector demand, SVP is looking to increase the capacity of its existing transmission system. Figure 14 presents the projects have been approved to increase the capacity or enhance reliability of the transmission system. Even with these additional transmission projects, the City of Santa Clara will face challenges to fully decarbonize by 2035 while also meeting its growing load requirements.

During the CAISO 2021-2022 TPP, CAISO approved the development of two new 500 MW high voltage direct current (HVDC) lines in the South Bay area. One of those lines will connect from the Newark substation to Los Esteros substation and into SVP's Northern Receiving Station while the other 500 MW line will connect from Metcalf substation to San Jose B substation. In March 2023, LS Power Grid California, LLC, was selected to finance, construct, own, operate and maintain these two new lines. The Newark-Northern Receiving Station line is anticipated to be in service in 2028.

Figure 14. Current approved SVP Transmission Projects

Transmission and Distribution Upgrades/Replacements Identified and in Budget	Cost (Million $)
60KV Breaker Upgrades	$3.10
Duane-Scott 115kV	$1.62
Esperanca Substation	$26.92
Fiber Development, Design, and Expansion	$3.44
Homestead Substation Rebuild	$1.45
KRS Rebuild and Replacement	$86.46
Northwest Loop Capacity Upgrade	$4.75
NRS Transformer and Breaker Upgrades	$87.55
NRS-KRS 115kV Line	$31.35
Operations and Planning Technology	$1.61
Serra Substation Re-Build	$0.22
South Loop Reconductor	$18.61
SRS Rebuild and Replacement	$90.55
Storm Water Compliance	$0.72
Substation Capital Maintenance and Betterments	$1.03
Substation Control and Communication System Replacement	$0.14
Substation Physical Security Improvement	$0.23
System Capacity Expansion	$3.35
Transmission and Distribution Capital Maintenance and Betterments	$9.44
Transmission Loop 1	$4.69
Transmission Loop 2	$2.00
Transmission System Reinforcements	$0.40
Walsh-Uranium 60kV Reconductor	$2.41
Total	**$382.02**

4.8. Natural Gas Commodity, Transportation and Storage

SVP owns several gas-fired power plants in its portfolio. Through the gas pre-pay agreement described below, SVP aims to hedge the impact of gas supply and price volatility on its customers.

Natural gas is the primary fuel and the primary variable operating cost of Santa Clara's Gianera Generating Station, DVR Power Plant and the LEC. These plants can require delivery of up to 49,000 MMBtu per day fuel, with current average daily requirements of 24,400 MMBtu per day. Santa Clara has developed a comprehensive natural gas program to both manage supply and price volatility. This includes the procurement of a supply of natural gas at a discount from the monthly index price pursuant to a gas prepayment arrangement and several fixed price contracts for 10,000 MMBtu from 2020 to 2025.

M-S-R Energy Authority – Gas Prepay

In 2009, Santa Clara participated in the M-S-R EA Gas Prepay Project. The Gas Prepay Project provides, through a Gas Supply Agreement between M-S-R EA and Santa Clara, for a secure and long-term supply of natural gas of 7,500 MMBtu daily (or 2,730,500 MMBtu annually) through December 31, 2012, and 12,500 MMBtu daily (or 4,562,500 MMBtu annually) thereafter until September 30, 2039. The Gas Supply Agreement provides this supply at a discounted price below the monthly market index price (the PG&E Citygate index) over the 30-year term.

4.9. Wholesale Energy Trading

For several years, Santa Clara has used its energy and transmission resources together with its power scheduling capabilities to buy and sell energy in the western North American market. As deregulation unfolded, a greater need to manage resources on a day-to-day basis evolved, resulting in a more comprehensive approach to trading operations at Santa Clara. The principal reason for wholesale power trading is to optimize the value of the utility’s assets and cost-effectively serve its retail load. Since a substantial portion of Santa Clara’s energy needs are being met through contracts, SVP uses its energy, RA and transmission resources to buy and sell actively in five established wholesale power trading market zones: Mid-Columbia (MID-C), California-Oregon Border (COB), North of Path 15 (NP15), South of Path 15 (SP15) and Palo Verde Hub. Trades may be directly with counterparties or through clearinghouses, such as the InterContinental Exchange (ICE).

5. Customer Programs, Energy Efficiency and Demand Response Resources

5.1. Energy Efficiency Program Background

Targets for energy efficiency programs (and established under PUC section 9505) are based on the estimated net market potential.[14] The net market potential provides a forecast of market potential for specific utility energy efficiency programs. The net market potential is a subset of the total economic potential and technical potential and recognizes that not all impacts that are technically or economically achievable will be realized.

Santa Clara's energy efficiency programs are separated into residential and non-residential programs. Total Public Benefits Charge (PBC) funds are about $16 million in fiscal year ending 2023. Residential programs include rate assistance for income-qualified customers, energy efficiency rebates (heat pump water heaters, room air cleaners, pre-owned EV rebates for income-qualified customers and variable speed pool pumps), energy audits, an income-qualified solar grant program and programs for schools and libraries. Non-residential programs include energy audits, installation management assistance for small companies, rebates for a wide variety of equipment (lighting, air conditioning systems, chillers, motors, new construction, food service equipment and customized installations, etc.), energy efficiency grants for nonprofit organizations and Homeowners Associations, building electrification rebates and design and construction assistance.

The goals and objectives of the programs are as follows:

+ Implement cost-effective energy efficiency programs to lower energy use. The cost to implement energy efficiency programs should be lower than the capital cost to build new generation and benefits of the total programs should exceed costs under the Total Resource Cost test under the methodology reviewed and approved by the NCPA Demand Management Working Group, of which SVP is a member.
+ Provide the public benefit programs in a manner that creates value to the community and meets all applicable legal requirements.
+ Assist Divisions and City Departments in achieving optimal energy efficiency at City facilities and assist in implementing new energy related technologies for the benefit of Santa Clara and community.

[14] CMUA, "2020 Energy Efficiency Potential Forecast" (Sacramento, CA: California Municipal Utilities Association, 2020), https://www.cmua.org/sb1037-reports.

- Implement programs to support renewable power generation that increase resource diversity and minimize adverse environmental impacts from electric generation and operation of the electric system.
- Support emerging technologies to speed up market acceptance therefore, allowing energy efficiency services and products to compete in the open market.
- Assist income-qualified residents in lowering their electric bills and in installing energy efficient appliances and other measures.
- Determine the best energy programs to offer Santa Clara customers by collecting input from community organizations, businesses, and other city departments.

SVP participated in the California Municipal Utilities Association (CMUA) Energy Efficiency Potential Forecasting Study. The most recent study was adopted by the Santa Clara City Council in 2021. Figure 15 presents the results of energy efficiency potential forecasting study.[15]

Figure 15. Forecasted Energy Efficiency Potential

Year	Utility Specified Feasible Goal (MWh)
2021	11,584
2022	11,536
2023	11,013
2024	10,604
2025	8,913
2026	7,305
2027	6,651
2028	5,808
2029	5,817
2030	5,372

5.2. Current Energy Efficiency and Building Electrification Initiatives

SVP maintains a robust suite of energy efficiency programs that will contribute to the state's goal of doubling statewide energy efficiency savings as codified in SB 350. Energy efficiency programs are intended to offer maximum benefit to the community while meeting all regulatory requirements. The regulatory requirements include the following:

- PUC 385 requires that the utilities collect and spend a percentage of their base retail electric revenues on qualified Public Benefits Programs. The customary amount collected by public utilities in California is a minimum 2.85%of annual base retail electric revenues. The funds must

[15] CMUA.

be spent on programs in four categories including energy efficiency, research and development, renewable energy resource development and income-qualified assistance.

- PUC 386 requires each local POU to ensure that income-qualified families have access to affordable electricity, and the level of assistance reflects the level of need. Furthermore, utilities shall ensure that income-qualified families have access to low-cost, no-cost measures that reduce energy consumption.
- PUC 454.5 and PUC 9615 both require utilities to address unmet resource needs through energy efficiency and demand response prior to procuring new sources of power.
- PUC 9505 requires each local POU to annually report investments and achievements in energy efficiency and demand reduction programs. Furthermore, utilities must identify all potentially achievable cost-effective electricity efficiency saving and report savings targets to the CEC.
- Public Resources Code 25305.2 requires the CEC to report to the Legislature a comparison of the annual energy savings targets versus the actual energy efficiency savings and demand reduction for each local POU.
- Public Resources Code 25310 I(1) requires the CEC to set goals that will double statewide energy efficiency savings in California by 2030 and will require specific targets for SVP.

A comprehensive list of energy efficiency projects and programs under consideration is presented here.

New Programs for Fiscal Year 2023/2024 to 2028/2029

- **Commercial Solar and/or Solar Plus Battery Storage Performance Incentive Program –** This program will provide performance-based incentives to commercial customers who install large solar plus battery storage systems to assist in reducing the coincident peak demand and/or assist in areas where electric transmission and distribution resources are constrained. A performance-based incentive for installation of large solar systems may also be offered if there are significant grid benefits to SVP for installations without battery storage systems.
- **Nonprofit Solar Grant Program –** As part of the commercial solar rebate initiative, funds have been designated to provide grants to nonprofit facilities in Santa Clara interested in installing a PV system at their facility. The grant allows a portion of the funding to be spent on roof repairs or replacement to make the facility ready for a PV system.
- **Municipal Energy Efficiency Project On-Bill Financing Program –** This program will provide on-bill financing for projects implemented at Santa Clara facilities where the city is the utility account holder and that meet all other requirements of SVP's energy efficiency programs. Projects must have a payback period not more than 5 years after rebates. Payments will be spread across utility bills based on the payback period, not to exceed 5 years. The intent of this

program is to help Santa Clara city departments fund energy efficiency projects through utility bill savings.

- **Scholarship Program for Income-qualified Residents –** This program will provide scholarships to customers who meet specified income requirements. Eligibility will be working age adults who enroll in a technical school or training program for a career that will support the energy industry. Examples include but are not limited to HVAC technicians, solar system installers, utility line workers, etc. The intent of the program is to assist those with the lowest incomes to obtain the skills and certifications necessary to obtain higher paying jobs and to support workforce development in the energy industry or industries that support energy efficiency and building electrification programs.
- **Income-Qualified Used EV Rebate –** This program will provide an incentive for income-qualified customers to purchase a used EV or plug-in hybrid EV. Incentives will be tiered to provide a higher incentive for an EV over a plug-in hybrid and will include an equity component with a bonus incentive for those who qualify for the Low-Income Home Energy Assistance Program. An additional bonus incentive may be included for vehicles meeting the specified minimum charging efficiency (kWh per 100 miles driven). Funding for past Income-Qualified EV Rebates came from Low Carbon Fuel Standard Credit funding, and this program will be funded under the income-qualified category of the Public Benefit Charge.

> *"Santa Clara could perhaps focus more on investing in distributed solar in the near term." -KJ, Santa Clara resident*

Ongoing Programs

- **Residential Pool Pump Rebate –** This program provides a rebate to residential customers installing a new variable speed pool pump with a qualifying controller.
- **Residential Heat Pump Electric Water Heater Rebate –** SVP offers a rebate for the purchase of a qualified electric heat pump water heater with bonus incentives to income-qualified customers.
- **Residential In-Home Energy Audits, Education, and Hot Line:** The program encourages residents to become more energy efficient and reduce their energy bills through home audits, online and in person classes, school programs and community outreach at events. Energy audits include free items to improve home weatherization where needed. This program also includes

support of the Santa Clara libraries and schools through donation of materials on the topics of energy efficiency and renewable energy for libraries and classrooms.

+ **Tier II Advanced Power Strip Giveaway Program:** SVP provides free Tier II Advanced Power Strips (APS) to income-qualified customers and residents of multifamily apartment complexes. A Tier II APS is also included in the energy saving items provided during a home energy audit.
+ **Tool Lending Library:** This program provides tools and equipment to the Santa Clara libraries so they may be checked out to library patrons to assist in measuring energy consumption and installing energy efficient measures in their homes.
+ **Silicon Valley Power Marketplace:** The Marketplace is an online marketplace where residential customers can purchase energy saving equipment and electric yard care equipment. Instant rebates are available on some types of equipment, with higher rebate levels available to income-qualified customers. Shipping is free on all purchases over $50 and is a flat rate of $5 per order for all other orders.
+ **Residential Blower Door and Duct Testing Pilot Program:** To help customers improve the efficiency and comfort of their homes through the reduction of leaks, this pilot program will be available to residential customers in single family homes who have central air conditioning. A free SVP audit will be required to determine if the home is a good candidate for the blower door test. Duct testing is a much more involved process and will be offered to those customers who are a good candidate for reducing the leaks in their air conditioning duct system, who demonstrate an interest in taking action to improve the duct work, and who are not already doing an air conditioning system upgrade where a duct test is required by building code. The service will be free to eligible customers under the pilot program. At the time of this report, this pilot program is still in the design phase and has not yet been launched.
+ **Customer Directed Rebate –** This program provides incentives based on actual energy saved for energy efficiency measures that do not fall into SVP's standard business rebate programs. The program also includes a performance incentive option for projects where persistence savings is questionable.
+ **Data Center Efficiency Program –** This program targets data centers with IT server load greater than 350 kW or cooling load greater than 100 tons. The incentive is paid as a performance incentive over multiple years.
+ **Commercial New Construction Rebate:** This program provides a rebate to customers who exceed Title 24 by 10 percent for the measure being incentivized, in line with other prescriptive rebates for retrofit projects. A Design Team Incentive matching the Investor-Owned Utilities program is provided.

- **Business Energy Audits:** Provides free energy efficiency audits to business customers. Energy and Resource Solutions administers this and other business PBC programs.
- **Business Rebates:** Encourages businesses to install energy efficient lighting, HVAC equipment, enhanced ventilation controls, food service equipment, etc. The programs are occasionally changed to match statewide programs.
- **Small Business Efficiency Services Program –** This program is targeted at small business customers, and aids in identifying energy efficiency projects, selecting and managing contractors, and help with filling out rebate application paperwork. The program also provides a 35%incentive for lighting and HVAC rebates, if customers to install the lighting measures within 6 months of program enrollment and HVAC measures within 12 months of enrollment in order to receive the additional incentive.
- **Energy Efficiency Grant for Nonprofit Organizations:** This program provides grants to non-profit organizations to improve the energy efficiency of their facilities.
- **Building Operator Certification Training Scholarships:** This program provides scholarships to building operators responsible for facilities in Santa Clara who meet the Building Operator Certification Training Program's prerequisites. The coursework helps customers identify energy efficiency opportunities within their facilities, which can lead to energy efficiency project implementation.
- **Energy Efficiency Grant for Homeowners Associations:** This program provides a grant for Homeowners Associations to upgrade to more energy efficient equipment in the common areas of their communities.
- **Community Outreach Grants for Energy Efficiency and Building Electrification Education:** This program provides an opportunity for nonprofits and community-based organizations to receive a grant up to $10,000 to promote energy efficiency and building electrification benefits within our community. A focus on traditionally underserved communities or diversity, equity and inclusion is required.
- **Student Grants for Energy Efficiency and Renewable Energy Projects or Awareness Campaigns:** SVP offers grants up to $5,000 for high school students to create projects or awareness campaigns that will educate the Santa Clara community about energy efficiency and/or renewable energy. Examples include but are not limited to educational videos, public art displays, online resources, outreach materials, demonstration projects, webinars, or workshops.
- **Controls Program:** This program is available for projects where at least 80% of the savings come from the control strategies. Incentives are paid on a performance basis over 5 years.

- **Building Optimization Rebate:** For buildings with HVAC systems controlled by building automation systems, a rebate is provided for reprogramming the control system to optimize HVAC performance. Typically, this involves conducting an energy assessment that provides an implementation plan for testing and making control system improvements that optimize HVAC operation.
- **Public Facilities' Energy Efficiency Program:** SVP provides technical assistance and financial incentives for the expansion, remodel, and new construction of Santa Clara buildings. Included in this program are higher levels of rebates for qualifying equipment and energy management assistance.

Third Party Programs for Business Customers

As one of the ways to enhance energy savings through the PBC programs and meet kilowatt hour and kilowatt demand reduction goals, SVP periodically embarks on an Request for Proposal process to add third party energy efficiency programs to its Public Benefit Program offering. Of the responses received each cycle, a review team selects responses that are both cost-effective and the most likely to help customers without overlapping with programs already being provided. The last Request for Proposal was issued in April 2018 and all selected programs have ended. An Request for Proposal is currently in process.

Complementary Programs

- **Income-Qualified Programs:**
  - Financial Rate Assistance Program: SVP's income-qualified programs include a Rate Assistance Program, where income-qualified customers receive a 25% discount on their electric bill.
  - Income-Qualified EV Charging Station Grant for Multi-family Properties: Under its income-qualified programs, SVP offers a grant of up to $1,000 per charging station for multi-family properties where a specified percentage of customers residing at the property qualify for SVP's income-qualified programs. This is in addition to the rebate program the utility offers to all multifamily complexes in Santa Clara.
- **Medical Assistance Programs**
  - Medical Rate Assistance Program: Customers receive a 25% discount on their electric bill if they qualify due to high electric use for medical reasons. The programs are managed in-house.
- **Research, Development, and Demonstration:**

- Emerging Technologies Grant: This program encourages businesses to demonstrate new products and product applications not yet commercially viable in today's marketplace, install energy efficient technologies not generally known or widely accepted, yet show potential for successful market growth, successfully apply energy efficiency solutions in new ways, or introduce energy efficiency into industries or businesses that are resistant to adopting new technologies or practices.
- APPA DEED Program: SVP is a paying member of the American Public Power Association (APPA) Demonstration of Energy & Efficiency Developments (DEED). This program funds grants, internships and student scholarships to further R&D in the electric utility industry and support innovative applications of energy efficient or renewable technologies. Over the years, SVP has applied for and received several DEED grants. Most recently, SVP has received grants for additional research of ductless mini split HVAC units and for commercial food preparation appliance energy savings.
- California Lighting Technology Center (CLTC): SVP provides financial support to the CLTC to further research and testing of emerging lighting technologies.

+ **Building Electrification Programs:**
  - Heat Pump Water Heater Electrification Program: SVP provides funding for a regional midstream heat pump water heater electrification program through BayREN where enrolled contractors receive a $1000 incentive for installing an electric heat pump water heater in place of a natural gas water heater. SVP pays an additional incentive to income-qualified customers.
  - Multifamily Boiler Electrification Pilot Program: This program provides up to $100,000 in funding for the conversion of a natural gas boiler to an electric boiler at multifamily complexes with at least 25 dwelling units. The program covers up to 100% of the incremental cost of replacing the gas boiler with an efficient boiler.
  - Smart Electric Panel Upgrade Rebates: SVP provides a rebate to residential customers who upgrade their electric panel to a smart panel and install circuits for both an EV charger and an appliance converted from natural gas to electricity. A bonus incentive is available to income-qualified customers.
  - Commercial Electrification Incentives: SVP provides bonus incentives for the electrification of efficient food service equipment. Incentives are also available for heat pump water heaters, heat recovery chillers, heat pump pool heaters and heat pump air conditioners. The utility also offers a Customer Directed Electrification Rebate that pays

an incentive based on measured and verified energy savings for any building electrification project that does not fall within its standard electrification rebates.

- Induction Cooking Demonstration Project: SVP retrofitted the Santa Clara Unified School District's Adult Education cooking classroom with induction cooktops and new cookware. The utility sponsors classes once or twice per month for residents to learn to cook new cuisine while trying out an induction cooktop. Adult Education cooking instructors were provided with training on the benefits of induction cooktops and lessons they can teach to demonstrate the benefits. Handouts are also provided to all program participants.

Ending Programs

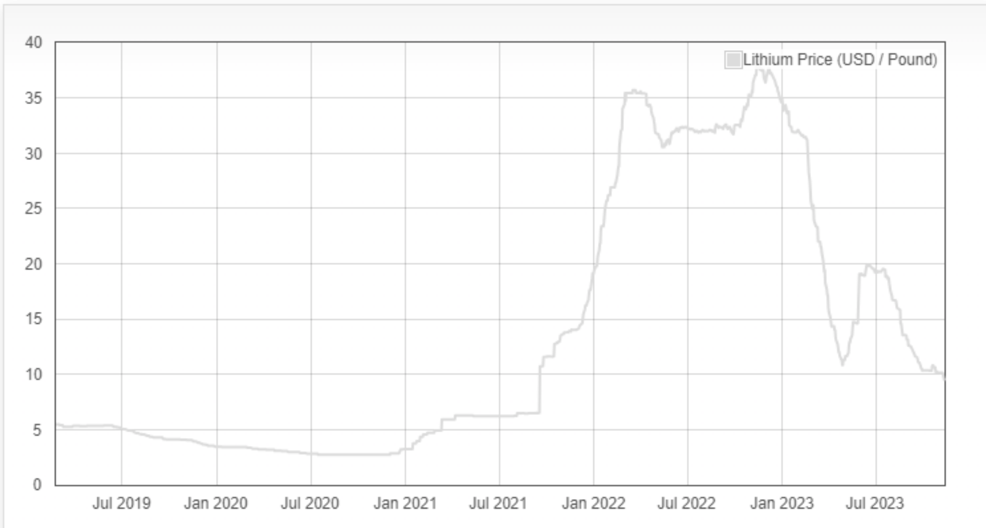
- **Residential Electric Dryer Rebate –** This program provided a rebate for ENERGY STAR-qualified electric clothes dryers that meet the minimum Combined Energy Factor rating. Due to low energy savings that can be claimed, this program ended June 30, 2023.
- **Variable Frequency Drive Air Compressor Rebate –** This measure is for Variable Frequency Drives on rotary screw air compressors of 5hp – less than 25hp, as the energy code requires Variable Frequency Drives on compressors of 25hp or greater. Following customer outreach for this program, we found very little potential within Santa Clara, so this program was retired on June 30, 2023. If a customer has a qualifying air compressor and would like to install a Variable Frequency Drive, an incentive can be provided under the Customer Directed Rebate program.

5.3. Storage

In 2013, AB2514 codified Public Utilities Code Section 2836(B) that requires the governing board of each local publicly owned electric utility (POU) to determine appropriate targets for the utility to procure viable and cost-effective energy storage systems to be achieved by December 31, 2016, and December 31, 2020, on or before October 1, 2014, as part of their supply plan. There are no requirements for POUs to set future targets for energy storage. The statute also requires each governing board to re-evaluate the determinations made pursuant to this subdivision not less than once every three years, where the first three-year period ended in 2017, and the second evaluation period ended December 31, 2020. All future updates are now included in the IRP process.

In 2017, SVP determined that energy storage was not cost-effective, therefore, did not pursue energy storage targets. At the time, SVP analyzed three potential Research and Development pilot projects at the transmission, distribution point-of-interconnections, and behind-the-customer meter and provided updates in the 2020 AB2514 submittal to the CEC, Docket Number 20-MISC-01 TN# 235878). In 2020, SVP had four on-going pilot projects that were to be commercially operational from 2021 through 2023. What was unanticipated was the supply chain issues that arose during the COVID pandemic and the price escalation of Lithium that changed the economics of battery storage projects (Figure 16). Updates on these projects are included in this plan.

Figure 16. Lithium Price ($/lbs) 2019-2023 [16]



Current Utility-Scale Energy Storage Projects

SVP is currently contracting with a third party to build and operate up to a 50 MW 4-hour (200 MWh) utility-scale lithium-ion BESS within SVP's service territory. This contract will allow SVP to be the beneficiary of the BESS for a twenty-year term with an option to extend it for an additional five years. The BESS will participate in the CAISO market and will have the capability of performing intraday energy arbitrage by charging the BESS when market prices are low (buying the energy from the CAISO market) and discharging the BESS when market prices are high (selling the energy into the CAISO market) and capturing the difference between these prices. Typically, the BESS will charge when there is surplus renewable electricity on the CAISO grid. The BESS will also be able to help control voltage and frequency. Using the BESS may help integrate renewables, reduce dependence on gas-fired generation, and reduce GHG and criteria air pollutant emissions in Santa Clara. The BESS will also qualify as a resource adequacy resource and can be used to meet SVP's RA requirements along with the other resources in SVP's portfolio. The BESS project is expected to be in commercial operation in late-2025.

Current Microgrid Projects

SVP was developing two Renewable Energy Microgrids to support two City of Santa Clara Fire Stations for up to four hours of run-time providing back-up power during grid outages. SVP studied the feasibility of meeting and exceeding 6-8 hours long-duration run-times for the energy storage systems. SVP is

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[16] Daily Metal Price: Lithium Price. https://www.dailymetalprice.com/metalpricecharts.php?c=li&u=lb&d=1200

partnering with the Fire Department to prioritize Fire Station #1 , and Fire Station #2 with the potential to co-locate the microgrid at Fire Station #2with co-located public sites to enable a community microgrid concept. Due to increased costs, the microgrid project at Fire Station #1 is no longer feasible. Only Fire Station #2 is moving forward but has been combined to include more structures like the Emergency Operations Center for the City of Santa Clara. The project will demonstrate the installation of solar and storage and potentially EVs, integrated with smart microgrid components. The microgrids will support the research, design, deployment, and operations of a microgrid through the implementation of advanced energy management controller/software, load control, for standby power, energy and capacity and test feasibility to serve grid ancillary services. This project will also pilot an SVP specific engineered switch to enable future microgrids to interconnect with the SVP grid in the future. The design was a result of a previous data center pilot that SVP had to cancel.

SVP is piloting microgrid concept to create more redundancy in its grid, enable the detection of outages and faults on the grid, to prevent outages, and power quality events. The microgrid automatically responds to a grid outage by islanding. The microgrid remains in island mode supporting the Fire Station and auxiliary load until a resynchronization command is issued. This allows the microgrid to autonomously support the islanded loads during grid outages and then automatically resynchronize and resume grid connection upon restoration of normal grid voltage and frequency. Additionally, built-in software will perform an analysis of the microgrid components to detect equipment and process inefficiencies.

SVP will be receiving $500,000 in Federal funding to help bring the project on-line. SVP will also be exploring funding through the California Electricity Backup Assets Program when it launched later in 2023 or early 2024. The project is targeted to be commercially online in 2025.

Customer-Sited Battery Storage and Solar Power Purchase Agreement

SVP partnered with one of its commercial customers on a 2 MW/4MWh behind-the-meter battery energy storage system, charged for the most part from on-site PV solar generation. The battery will be cycled daily to increase renewable energy consumption from the on-site solar PV system, while also being discharged, to reduce run-times for natural gas generation dispatch during the evening peak. Commercial operation of the solar PV and battery storage system was originally planned for October 2021 but due to cost increases and supply chain delays the new target is 2024.

Data Center Battery Storage Project

In 2018, SVP was awarded a grant of $300,000 from the Bay Area Air Quality Management District to implement a behind-the-meter lithium-ion battery storage pilot project. SVP has partnered with a battery equipment manufacturer and a data center to pilot a demonstration project. The project was cancelled in 2022 due to the doubling of the project costs, from $2.5M to $5M. What was salvaged out of the four-year project was the engineering design of a specific switch that allows for easy “plug-in” of future microgrids. This switch is projected to be utilized in the Fire Station Microgrid project (previously detailed).

The project was to demonstrate the use-case for lithium-ion batteries as longer-duration uninterruptible power supply for data centers that are instantaneous and reliable, delaying or avoiding the use of diesel generators as backup power. Additionally, the pilot will demonstrate the economic viability and flexibility of a 2 MW/4 MWh battery energy storage system (BESS) that can be simultaneously dispatched at 2 MW capacity to support critical loads during a power quality event or outage. The main target was to reduce GHG and particulate matter, with a focus on vulnerable communities.

Residential Distributed Energy Resources Resilience and Equity Program

In 2019, SVP joined three community-choice aggregators (CCAs), East Bay Community Energy, Silicon Valley Clean Energy, and Peninsula Clean Energy in the release of a joint request for proposal for Resource Adequacy and load modification capacity to reduce SVP's system and CAISO coincident peak. SVP requested a total of 0.7 MW for the residential sector, and 2 MW for the commercial and industrial sectors.

SVP's Residential Distributed Energy Resources (DER) Resilience and Equity program was meant to operationalize a fleet of residential PV-paired battery systems as a peak shaving instrument and also to increase renewables and reduce GHG emissions in the most vulnerable communities through a virtual power plant concept. The program would prioritize customer segments including income-qualified, medical baseline, and the disadvantaged communities. Additionally, the program intended to mitigate localized grid congestion and provide back-up power during grid outages or PG&E's Public Safety Power Shutoff events. The program would also evaluate installations at single-family homes and multi-unit dwellings.

In 2021, the selected vendor decided that SVP was not a big enough market and noted that our residential pricing structure is not high enough to make the venture work out economically SVP will re-evaluate a new residential program in the future.

Green Lots – Tasman Drive Parking Structure

SVP completed a pilot energy storage project at the Tasman Drive Parking Structure with the intent to reduce customer-side peak demand charges due to high energy consumption from EV level 2 and Direct Current (DC) fast charging. Green Charge Networks, a Santa Clara based energy storage company, approached SVP to install a 30 kW "GreenStation" battery energy storage system along with an EV DC fast charger station at this location. The cost of the energy storage system, the DC fast charger and the installation was covered by a CEC grant program, resulting in no costs to the City of Santa Clara or SVP.

The pilot ended in 2018, and through the monitoring of the EV Charging Station patterns, the pilot resulted in an increased usage of the EV charging stations from 2015 through 2018. It was concluded that given the large station count (49 in total), power demand is still peaking at a small fraction of the system capacity (under 17% for the 30-day period from February 19, 2018 to March 21, 2018). The GreenStation is installed behind-the-meter and dampens the demand spikes that occur when the DC fast charging station is used, therefore reducing the operating costs for the City's Streets Department due to the management of spikes to avoid an increase in demand charges. The battery was decommissioned and removed in 2023.

Looking Forward

In the next five to ten years, SVP plans to focus its research on the deployment of energy storage projects and to develop localized system integration studies to determine locational nodes in SVP's service territory to alleviate congestion and to manage energy and capacity needs as well as maintaining balance of its grid. Other variables will also impact scalability and the use-case for storage, including, SVP's load growth, increased behind-the-meter customer distributed energy resources, electric vehicles, and building electrification. The deployment of storage will help SVP meet on-going State and City-wide renewable energy and sustainability goals and targets.

SVP plans to research the potential to participate in the CAISO wholesale market, including participating in the non-generator resource, regulation energy market, and proxy demand response participation models, which include not only bidding energy resources, but also ancillary services (frequency regulation, spin, non-spin).

To manage, operate, and monitor performance, SVP intends to research an architecture that integrates each of its pilot programs into a distributed energy resources management platform, tied to additional microgrid sites. The purpose is to enhance coordination amongst DERs, dispatch, and communication across DER assets connected to the grid to optimize reliability, safety and efficiency when operating the distribution grid.

SVP believes that commercially available long-duration technologies tied to clean fuel sources that can be stored on-site will be required to transform adoption at the utility-scale level. SVP and its customers must have confidence that there is no interruption to the electric or gas supply if on-site fuel cannot be achieved, otherwise storage fuel must be dense enough to store on-site. Further, SVP anticipates that more demonstration projects from utilities and utility-customer partnerships will be required to test end-use applications, monitor stacked benefits, and to help scale the technology. Grant funding along with the decrease in energy storage costs will be needed to assist in bringing down the total installed costs of the systems. Additional federal, state, and local incentives and grants can encourage investment to scale the technology and test various end-use applications.

Lastly, SVP will continue to benchmark new storage technologies, assess scalability and cost-effectiveness, and pilot new programs/projects that foster a diverse set of clean, hybrid and long-duration energy storage technologies. Because the City of Santa Clara is approximately 18.4 square miles, new storage technologies sited within the city's boundaries must be energy dense to accommodate space constraints.

5.4. Transportation Electrification

Transportation electrification and zero-emission vehicle (ZEV) policies have been gaining momentum in recent years, both at the state and federal levels. California has been a leader in this movement, with its Zero-Emission Vehicle Program that requires automakers to produce a certain number of EVs each year. The state has also set a goal to have 5 million ZEVs on the road by 2030.

At the federal level, the Biden administration has set a goal of reaching net-zero emissions by 2050 and has proposed investing $174 billion in EV infrastructure, including charging stations and incentives for consumers to buy Evs. The most significant legislation to accelerate transportation electrification in U.S.

history was the Inflation Reduction Act (IRA) of 2022, which was signed into law on August 16. The IRA introduced several significant changes to the tax credit for new Evs and the reforms to the $7,500 tax credit for Evs will evolve considerably over the coming months and years. The IRA also established tax credits for pre-owned clean vehicles and for commercial clean vehicles.

California calls for a 40% reduction in GHG emissions from 1990 levels by 2030 and an 80% reduction by 2050 per Executive Order S-3-05 (2005). Air quality goals include a 90% reduction in emissions of Nox from 2010 levels by 2032. In January 2018, Governor's Executive Order B-48-18 set a goal of 5 million ZEVs on California roads by 2030 and directs state agencies to accelerate deployment of 250,000 chargers (including 10,000 direct current fast chargers (DCFCs) by 2025). SB 350 requires state agencies to identify recommendations on how to increase access to zero-emission and near-zero-emission transportation options to income-qualified customers. In December 2018, CARB passed the "Innovative Clean Transit" policy stating that by 2023, one quarter of purchased transit buses need to be zero emission, and by 2029, 100% of new buses purchased need to be zero emission. Governor's Executive Order B-55-18 directs state agencies to work together to support the deployment of ZEVs in California, including through the development of infrastructure and incentives. Most recently in 2020, Governor's Executive Order N-79-20 set a goal of transitioning all new passenger cars and trucks sold in California to ZEVs with the share of VEZ and plug-in hybrid electric vehicles (PHEV) to reach 100% of new vehicle sales by 2035. CARB codified the Governor's EO N-79-20 for light-duty passenger vehicles with the adoption of the Advanced Clean Cars II rule that established a year-by-year roadmap for the share of VEZ to reach 100% of new vehicle sales by 2035.

One of California's most important policies is the Zero-Emission Vehicle Program, which requires automakers to produce a certain number of ZEVs each year. The program was first implemented in 1990 and has since been updated several times. In 2020, the state adopted new regulations that require automakers to sell an increasing percentage of ZEVs each year. By 2025, automakers must sell enough ZEVs to account for 8% of their total sales in the state. In addition, the Advanced Clean Trucks (ACT) Regulation requires manufacturers of medium- and heavy-duty vehicles to sell a certain percentage of zero-emission trucks in California, starting in 2024. SVP aims to prepare Santa Clara for success as new clean fleet requirements are set by the state. In April 2023, the CARB adopted the Advanced Clean Fleets regulation that requires beginning January 1, 2024, 50% of State and Local Government Agency Fleets annual vehicle purchases per calendar year to be zero-emissions, and beginning January 1, 2027, that 100%of vehicle purchases to be zero-emissions.

California has also implemented several financial incentives to encourage consumers to buy ZEVs. The state offers rebates of up to $7,000 for the purchase or lease of a new EV, and there are also federal tax credits available. Additionally, California allows ZEVs to use carpool lanes regardless of how many passengers are in the vehicle, providing an added incentive for drivers. In 2020, SVP along with other California electric utilities teamed up with CARB to offer the California Clean Fuel Reward, a point-of-sale price reduction of up to $1,500 for the purchase or lease of any eligible new Battery Electric or Plug-in Hybrid vehicle. As of 2023, the reward amount has temporarily been reduced to zero and SVP is engaging with program stakeholders on the future strategy of the program.

To support the increased adoption of ZEVs, California has also invested heavily in charging infrastructure. The AB 2127 Electric Vehicle Charging Infrastructure Assessment found that for passenger vehicle charging in 2030, over 700,000 public and shared private chargers are needed to support 5 million ZEVs, and nearly 1.2 million chargers to support about 8 million ZEVs anticipated under Executive Order N-79-20. An additional 157,000 chargers are needed to support 180,000 medium- and heavy-duty vehicles anticipated for 2030.

Local Government Regulatory Landscape

SVP encourages the use of Evs as a part of our commitment to reduce carbon emissions. With convenient and publicly accessible EV charging stations, residents and business can help accelerate the efforts. Since 2019, Santa Clara has initiated a suite of Council actions, policies, and strategies to be an EV ready community by 2030.

- May 2019 – Adopted a Green Fleet Policy
- June 2019 – Adopted the EV Ready Community Blueprint
- April 2020- City Council approves a Public and Fleet Infrastructure Access Project
- January 2021- City of Santa Clara Fleet Electrification Plan
- September 2022- City Adopted All-Electric Reach Codes

SVP designed and built a robust and accessible EV charging infrastructure that maximizes the number of residents and visitors served. SVP has added over 100 EV charging connectors throughout Santa Clara's 18 square miles in parks, community centers and other public access areas near multifamily housing; providing an amenity that increased park utilization and access to EV charging to residents who may not have access to charging at home.

SVP has also helped Santa Clara reduce its fleet operational costs and environmental impact by replacing Santa Clara-owned old combustion vehicles with all-electric vehicles. SVP purchased 46 all-electric vehicles and an electric forklift to support Police, Fire, Public Works and other City department fleets in fiscal year 2022. Santa Clara will receive the benefits of lower operating and maintenance costs EVs provide as well as a reduction in smog and GHG emissions from operating their vehicle fleet.

In parallel with purchasing cleaner vehicles for Santa Clara, SVP also installed EV charging stations at City facilities to support the new clean fleet. SVP took a holistic approach using design thinking by partnering early with other City departments to select optimal locations and helped streamline the permitting process for future EV charging projects. SVP also explored enhancing projects with faster charging times and additional resiliency by adding renewable solar PVs plus storage. By Q3 2023, SVP energized nearly 50 additional charging ports at 8 locations supporting public and fleet charging and plans the next phase of EV charger installations to prepare for the City's incoming medium and heavy-duty fleet.

Using CARB's Clean Vehicle Rebate Project (CVRP), which began tracking rebates for purchased ZEVs in 2011 through 2022, 2,764 battery-electric, 910 plug-in hybrids, 99 fuel cell, and 5 categorized as other vehicle rebates have been distributed for a total of 3,778 clean vehicle rebates registered within Santa Clara. Note that not all plug-in hybrid, all-battery, and fuel cell EVs sold/leased in the state are captured in this database. Not every eligible vehicle owner applies to the CVRP, and not every clean vehicle is eligible for the rebate. Over the first five years of the program, owners of about 75% of eligible vehicles participated in the rebate project. Department of Motor Vehicle (DMV) registration data is a preferred source for a more accurate estimate of current Plug-in Electric Vehicle (PEV) adoption within a city; that data can also provide information on vehicle class for commercial vehicles. However, neither of these sources forecast vehicle ownership trends or inflow of traffic from surrounding areas. SVP requested registration data from the DMV on a bi-annual basis beginning 2023 to support SVP's energy procurement, transmission, and distribution planning for transportation electrification. In partnership with other northern California municipal utilities, SVP is actively coordinating with the DMV to establish a registration data sharing protocol that would enable data collection on a more frequent cadence. As Californians adopt more hybrid electric and alternative fuel vehicles, we are working on a transportation electrification strategy to prepare their electrical distribution grid for the future demands. SVP is also exploring managed charging programs using vehicle telematics to coordinate the customer side of the meter with the utility's side, optimizing critical assets throughout the distribution network. In addition to shifting charging to times of day when there is more renewable energy supply on the grid, managed charging programs can also defer costly upgrades to distribution grid assets. SVP is also exploring fleet advisory program offerings such as online fleet planning tools and technical assistance for fleet customers in our service territory.

SVP also utilizes CEC new ZEV sales data which is updated on a quarterly basis by examining the DMV Vehicle Registration database to track vehicle adoption in Santa Clara. By the end of June 2023, the CEC reported a cumulative total of 8,824 all-electric vehicles, 2,596 plug-in hybrid EVs, and 140 hydrogen fuel cell vehicles in Santa Clara as shown in Figure 17.

Figure 17. New Zero Emission Vehicle Sales by year: Santa Clara

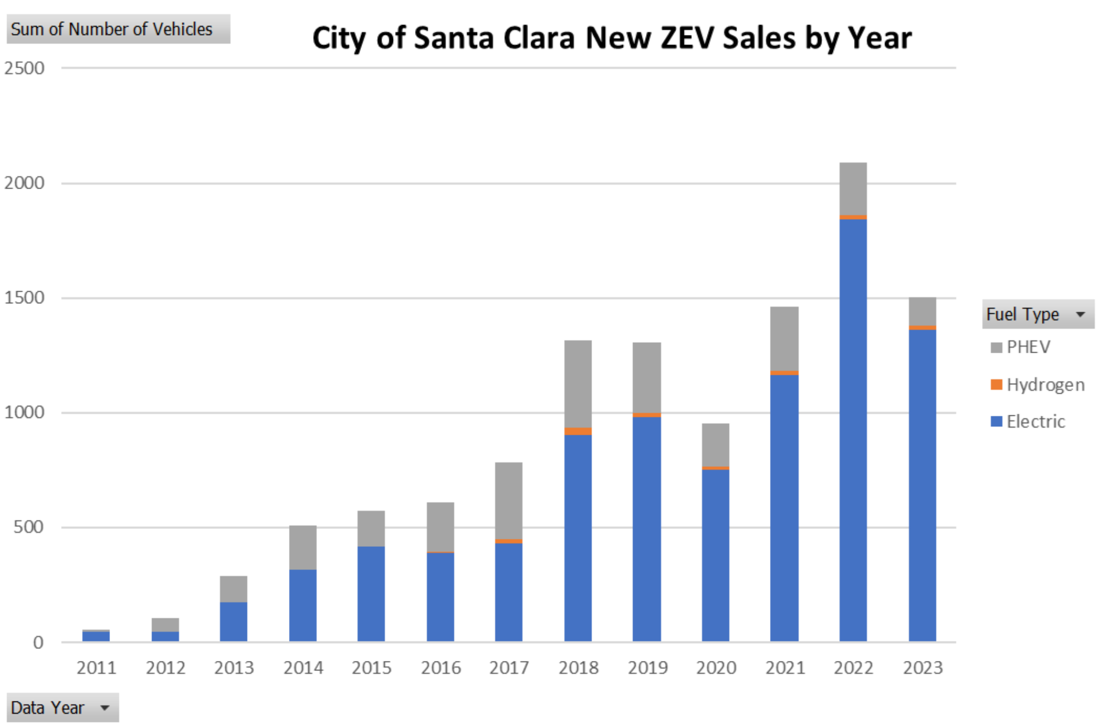


Figure 18 shows the cumulative growth of ZEV rebates dollars distributed though the CVRP program within SVP's service territory, by vehicle type, from 2011-2023. The slight decline in annual rebates in 2019 was due to popular rebate-eligible vehicles. Reaching 200,000 sold in the U.S. and thus no longer qualifying for the federal PEV rebates. The IRA of 2022 changed the rules for the federal tax credit for vehicles purchased from 2023 to 2032 which made certain vehicles eligible again. The decline was further exacerbated by the Covid-19 pandemic which unfolded in early 2020 and imposed global lockdowns leading to an unprecedented drop in car sales. Despite gradual recovery over the following year, the ZEV market also suffered from a rippling effect of global supply chain issues limiting vehicle availability.

Figure 18. CVRP Rebate Dollars in SVP Service Territory by year

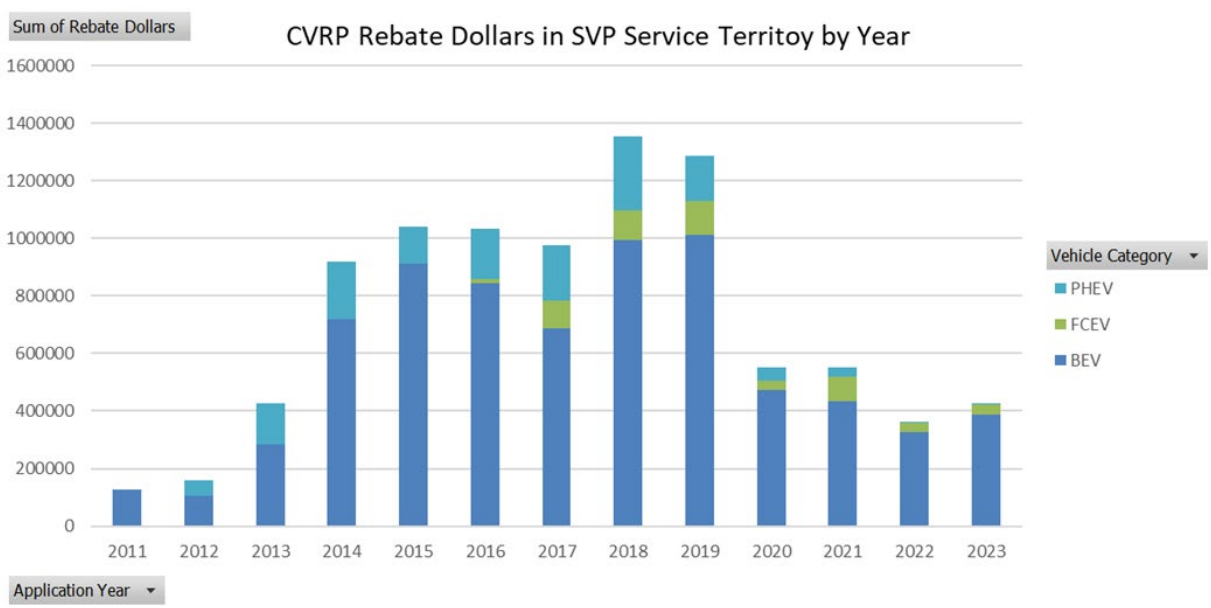
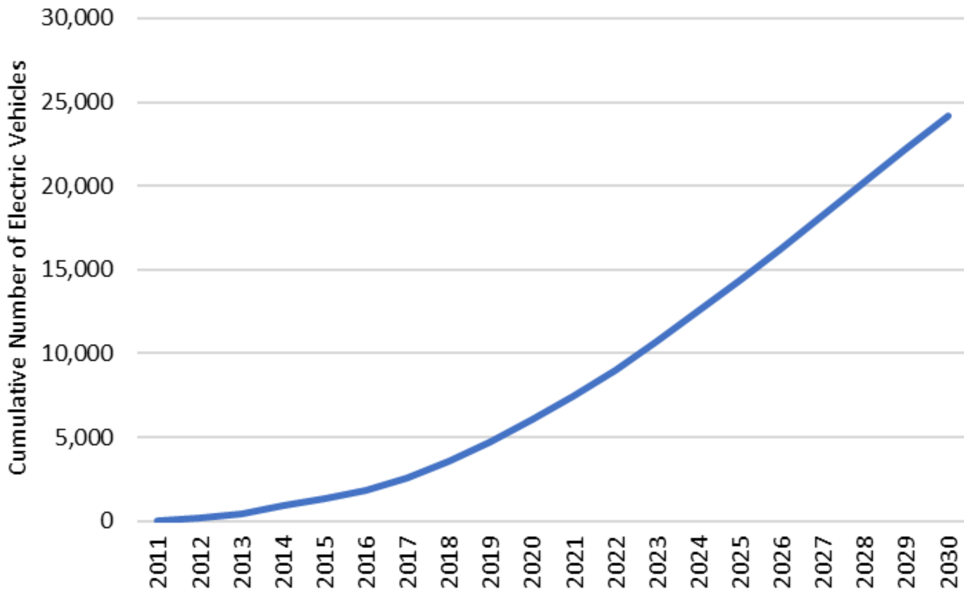


Figure 19. Cumulative SVP ZEV Rebates by ZEV Type, 2011-2018

Rebates and Rebate Funding Issued or Approved to Date		
Battery Electric Vehicle	2,869	$7,304,362
Plug-in Hybrid Electric Vehicle	912	$1388,284
Fuel-cell Electric Vehicle	105	$522,500
Other	5	$4,200
Total	**3891**	**$9,219,346**

For the SVP service area, EV forecast involves a significant increase in the number of vehicles through 2026. Figure 20 shows the cumulative number of EVs, including EVs and PEVs that are projected to increase from approximately 2,200 in 2018 to more than 24,000 by 2030 based on the CEC EV model.

Figure 20. CEC Projected EV Adoption (cumulative)

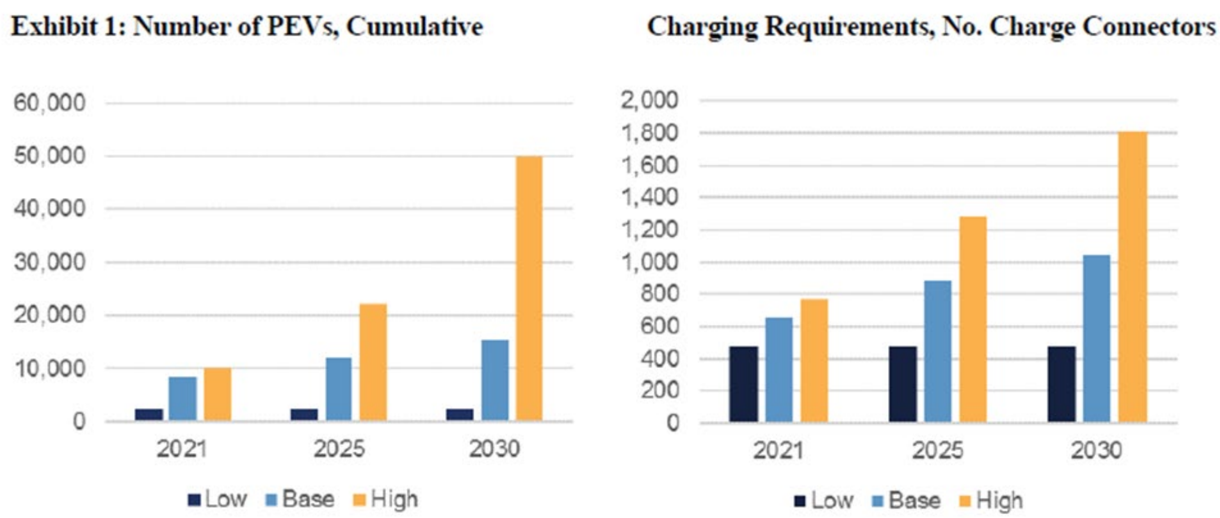


SVP EV Readiness by 2030

In December 2017, the CEC released a Grant Funding Opportunity (GFO-17-604) for EV Ready Communities Challenge Phase I – Blueprint Plan Development.

On May 9, 2018, at the CEC Business Meeting, SVP was officially awarded a grant to develop an EV Ready Communities Blueprint. SVP, along with various Santa Clara city departments and stakeholders, has completed and developed the Electric Vehicle Ready Communities Blueprint (EV Blueprint) for Santa Clara per the grant requirements. The EV Blueprint identifies the actions and milestones needed to proceed toward implementation of an EV ready community through 2030. When the CEC solicited Phase II of the grant funding in 2020, SVP used the EV Blueprint as a submission for the application but unfortunately was not awarded Phase II funding. The EV Blueprint for Santa Clara defined goals and requirements, analyzed target areas, provided technical recommendations, and economic recommendations for charging infrastructure; and evaluated city programs to be implemented. The EV Blueprint also forecasted the number of PEV adoptions which included both person and commercial vehicles. Recognizing the inherent uncertainty in any forecast, and especially in nascent technology, the EV Blueprint Team developed three forecast cases: low, base, and high. The base case was based on SVP's 2018 IRP using the "2017 SB 350 Common Assumptions Guidelines for Transportation Electrification Analysis." To place that forecast in context, the EV Blueprint Team set a low case assuming no further PEV adoption and a high case based on Siemens proprietary PEV adoption forecasting tool, which resulted in adoption rates closely aligned with California's statewide five million ZEV goal by 2030. Figure 21 shows the number of PEVs and required charge connectors forecasted for each of the adoption scenarios.

Figure 21. Forecasted Plug-in Vehicles and Charging Requirements, Cumulative – Santa Clara



Source: SVP 2019 EV Readiness Blueprint

Current Electric Vehicle Charge Connectors

By 2022, Santa Clara and its businesses had installed 753 Level 2 charging connectors and 39 DCFC charging connectors. Note that a typical charging station contains multiple charging connectors to plug into multiple vehicles. In Santa Clara, the average charging station has six charging connectors. Using the Alternative Fuels Data Center (AFDC), Santa Clara tracks installation of public and private charge connectors.[17] This information, as well as ownership type, is detailed in Figure 22.

Figure 22. Current Charger Port Installations by Type and Ownership[18]

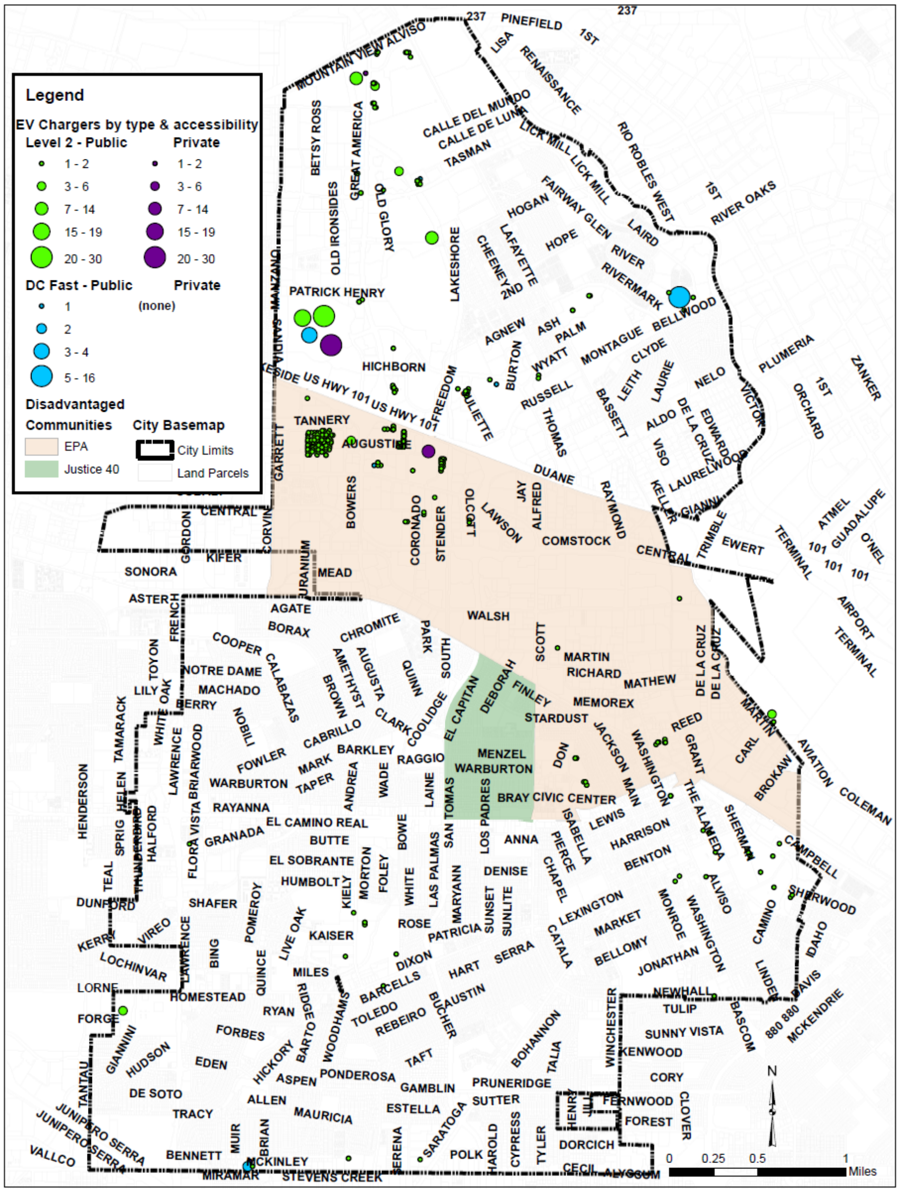
EV Ownership Type	EV Level 2 EVSE	EV DC Fast
Private	47	0
Public	726	39
Total	773	39

The 812 public and private charge ports currently within Santa Clara are found in 340 different locations, for an average of 2.4 charge ports per location. However, specifically for DCFC, there are only one or two charge ports per location. Figure 23 maps where PEV chargers are located within Santa Clara, based on city permitting data. Most of the charging infrastructure is in the northern part of Santa Clara, zip code 95054, with 83% of all charge ports. Figure 24 details the distribution of EV chargers in Santa Clara by ownership, charger level, and location relative to the CalEPA SB 535 designated disadvantaged communities (DAC) area and the Justice 40 Initiative criteria area. Santa Clara currently has a total of 113

[17] U.S. DOE, “Electric Vehicle Charging Station Locations,” U.S. Department of Energy, Alternative Fuels Data Center, 2023, https://afdc.energy.gov/fuels/electricity_locations.html#/find/nearest?fuel=ELEC.
18 U.S. DOE.

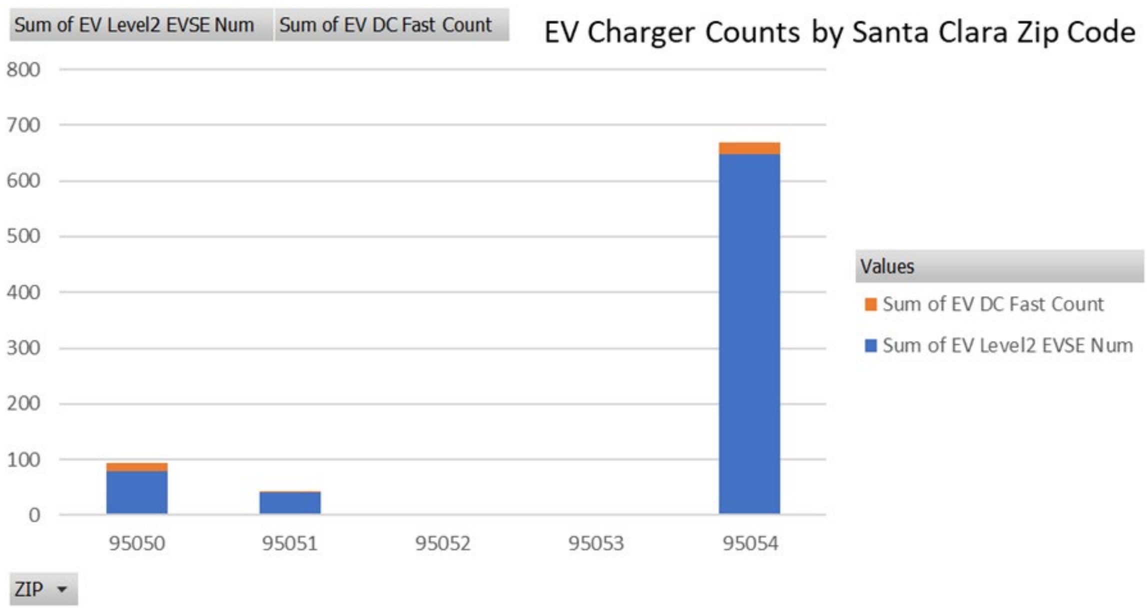
city-installed Level 2 public charging ports located at Libraries, Community Recreation Centers, Santa Clara Convention Center, Tasman Garage, City Hall, and Parks. Two DCFC ports at the Central Park Library and the Santa Clara Convention Center have been identified for replacement. Figure 23 maps where PEV chargers are located within Santa Clara, based on city permitting data.

Figure 23. Map of PEV known Chargers within Santa Clara [19]



19 Source: SVP Geographic Information Systems Team

Figure 24. EV Charger Distributions by Santa Clara Zip Codes



Grid Impacts of EV Adoption

SVP's primary responsibility is to provide safe, reliable power, while limiting future cost increases and complying with city core values. PEV adoption poses both risks and opportunities to utilities as summarized in Figure 25. Since SVP's electricity sales are primarily commercial/industrial, its energy use and peak demand profile is relatively flat monthly. However, SVP has historically experienced sudden increases in electricity demand at times, as customers move into new facilities. Data center loading can cause SVP's load growth profile to be "lumpy", due to new connections of substantial blocks of power-consuming facilities or equipment by industrial customers. This profile is reflective of the high intensity of industrial energy use in SVP's service area, which is heavily weighted toward high-technology manufacturing and data management facilities. To accurately plan impacts of PEV adoption on the grid, the SVP EV Blueprint Team first gathered data on The City forecasted energy demand for electricity then identified the utility risks and opportunities from PEV adoption.

Figure 25. Utility Risks and Opportunities from PEV Adoption[20]

Increased Planning Cost and Decreased Effectiveness	Waiting to plan for inevitable Plug-in Electric Vehicle (PEV) growth will result in reactive uncoordinated efforts to study and upgrade systems to meet system/circuit stresses caused by local charging. Such ad hoc efforts will prove more costly and less effective than a planned systemic business approach to prepare the grid for PEVs.
Scramble to Keep Pace with Other Agendas	The current reactive approach to transport electrification allows interveners and new market entrants to drive the public debate and steer political responses resulting in utilities trying to catch-up with state regulators.
Missed Load and Business Opportunities	The PEV market will grow and affect utilities whether they want it to or not. Active engagement provides opportunities to counter declining load, test new business models, and reduce negative grid impacts. However, without a strategy, utilities have been ceding these opportunities to new market entrants, which are taking the low hanging fruit.
Precedents and Funding Available	While the PEV market is new, the risk that growth will slow or stop is lower than many think. With state policymakers funding charging infrastructure and another $2.4 billion in Volkswagen settlement funds available, the lack of available charging infrastructure will cease being a barrier to consumers considering PEVs.

Unlike many cities, which experienced lower than expected load growth due to energy efficiency programs, and DER, Santa Clara is experiencing consistent growth in energy and peak demand. Both energy and peak demand have been consistently increasing over the years and this trend is forecasted to continue going forward. The current forecast for PEV energy demand by 2030 is an additional 52 GWh to 143 GWh based on preliminary modeling. Overall, anywhere from a 0.70% to 2.61% of SVP's total load demand.

SVP conducts Forward System Planning on an annual basis through a System Impact Study process, where load estimation from various SVP departments is incorporated into a set of unified planning input assumptions and studied under a variety of Planning Scenarios. The outcomes of the System Impact Study process are the determination of system constraints along with an assessment of mitigation options (Operationally, or Capital Improvement Project – CIP based) and associated costs. The Public Facing case is submitted annually to the CEC IEPR and CAISO Transmission Planning Process (TPP). For CY2023 TPP 24/25 SVP System EV Load Impacts will be studied as part of our annual System Impact Study process for the first time internally under a sensitivity scenario.

SVP also plans to conduct a 20-Year Forecast beginning Q3-Q4 2023 that will include a Spatial Analysis of Light, Medium and Heavy EVs and identify where the load will materialize on SVP's system via Santa Clara city geographic information system (GIS) parcel map (each parcel assigned to a feeder). SVP will also identify requirements to manage EV growth (including sensitivities for both known & unknown load growth). In addition, SVP plans to update its 2019 EV Readiness Community Blueprint and develop a comprehensive Equity Focused Transportation and Building Electrification Plan. The primary purpose of the EV Blueprint was to develop a program of initiatives the City of Santa Clara could lead to support increased EV adoption and the many benefits which derive from that adoption. The plan update should

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20 Source: SVP EV Ready Communities Blueprint 2019

expand on that initiative to include the equitable transition to electrify both transportation and built environment. The Equity Focused Transportation and Building Electrification Plan development process should establish a firm planning foundation that involves engaging internal and external stakeholders, analyzing the current state of transportation and building electrification, forecast long-term impacts of Plug-in Electric Vehicle (PEV) and building electrification adoption, and prioritize key requirements to help Santa Clara meet greenhouse gas emissions reduction targets as identified in the City's 2022 Climate Action Plan. The plan shall develop supporting analysis for multiple electrification scenarios in its forecasting and provide recommendations that provide Santa Clara with a clear understanding of the technical and economical requirements to support EV and building electrification adoption specific to the City's ecosystem and its clean energy goals. The study aims to determine SVP's incremental resource needs by comparing SVP's load and resource forecast against key Integrated Resource Plan constraints (including resource adequacy requirements, Clean Energy and Climate Act targets); identify gaps for meeting the constraints; identify cost-saving opportunities under existing arrangements; and propose resource solutions. The plan should develop a strategy to connect resource planning and beneficial electrification to form a cohesive decarbonization strategy.

Low Carbon Fuel Standard

In October of 2016, SVP entered a voluntary CARB program called the Low Carbon Fuel Standard (LCFS) Program. The LCFS Program was created through AB 32, California Global Warming Solutions Act of 2006 and Governor's Executive Order S-01-07. The LCFS Program is a key part of a comprehensive set of programs in California to cut GHG emissions and other smog-forming and toxic air pollutants by improving vehicle technology, reducing fuel consumption, and increasing transportation mobility options. The LCFS Program is designed to decrease the carbon intensity of California's transportation fuel pool and provide an increasing range of low-carbon and renewable-powered alternatives. The goal of this program is to reduce by at least 20% the carbon intensity of California's transportation fuels by 2030.

Through compliance with the LCFS Program, SVP receives LCFS credits. These credits are sold in an exchange and these funds are to be used to comply with Title 17 of the California Code of Regulations Section 95483I (1) (A-D), LCFS program proceeds may only be used in accordance with the following requirements.

Regulated Parties for Electricity

For electricity used as a transportation fuel, the party who is eligible to generate credits is determined as specified below:

For on-road transportation fuel supplied through EV charging in a single- or multi-family residence, the Electrical Distribution Utility is eligible to generate credits in its service territory. To receive such credits, the Electrical Distribution Utility SVP must:

- Use all credit proceeds to benefit current or future EV customers;
- Educate the public on the benefits of EV transportation (including environmental benefits and costs of EV charging, or total cost of ownership, as compared to gasoline);

- Provide rate options that encourage off-peak charging and minimize adverse impacts to the electrical grid; and
- Include in annual compliance reporting the following supplemental information: an itemized summary of efforts to meet requirements (A) through (C) above and costs associated with meeting the requirements.

The LCFS combined with other programs, enables SVP to create an EV program that includes the following initiating activities in fiscal year 2021/22. SVP used LCFS proceeds to fund a residential electric bicycle rebate program where customers could receive a 10% rebate on the purchase price of a new e-bike, up to $300. Income-qualified customers were eligible to receive an additional rebate up to $200. SVP also funded an EV charging station rebate program to residents (up to $550), multi-family properties (up to $3,000), schools and non-profits (up to $5,000). We also offered an additional grant of up to $1,000 for the purchase and installation of qualified Level 2 EV Charging Stations to income-qualified multi-family properties. Beginning January 1, 2023, SVP increased the rebate amounts for the multifamily and commercial EV charging station rebate program that provided increased per port incentives (up to $8,000) for projects that installed 8+ charging connections. SVP’s rebate program offers up to $150,000 per site for Multifamily Residential Properties and Commercial Properties to help lower the upfront costs of Level 1 and Level 2 EV charging station projects. Increased incentives are available for projects that meet equity eligibility criteria.

In addition to offering rebates on the EV chargers, SVP also funded a income-qualified EV rebate up to $1,500 to qualifying customers who purchased a new or used EV or plug-in hybrid vehicle. In July 2023, this program transitioned to an income-qualified rebate up to $3,500 for the purchase of a pre-owned EV or plug-in hybrid vehicle. Income qualified customers can receive $1,500 for a fully electric vehicle or $1,000 for a plug-in hybrid vehicle. Customers who meet the Low-Income Home Energy Assistance Program eligibility requirements may be eligible for a bonus rebate of $1,000. Vehicles with a miles per gallon gasoline equivalent of 117 or greater may be eligible for a bonus rebate of $1,000.

LCFS proceeds were also used to fund the Electric Vehicle Charging Access Project that furnished and installed Santa Clara-owned Level 2 EV chargers at 16 public locations, libraries, parks, and community centers, near multi-family properties and 6 city locations to jumpstart the implementation of the city’s Fleet Electrification Plan. LCFS funds were also spent to fund the California Clean Fuel Reward and the Peninsula-Silicon Valley California Electric Vehicle Infrastructure Project 1.0 program. In 2021 and 2022, as a medium-sized POUs, SVP was required to transfer funds to the CFR Program equal to 20% of proceeds generated from base credits from the LCFS program. Beginning 2023, the CFR requirement increased to 25%. The Peninsula-Silicon Valley Incentive Project is no longer accepting applications as of June 2023.

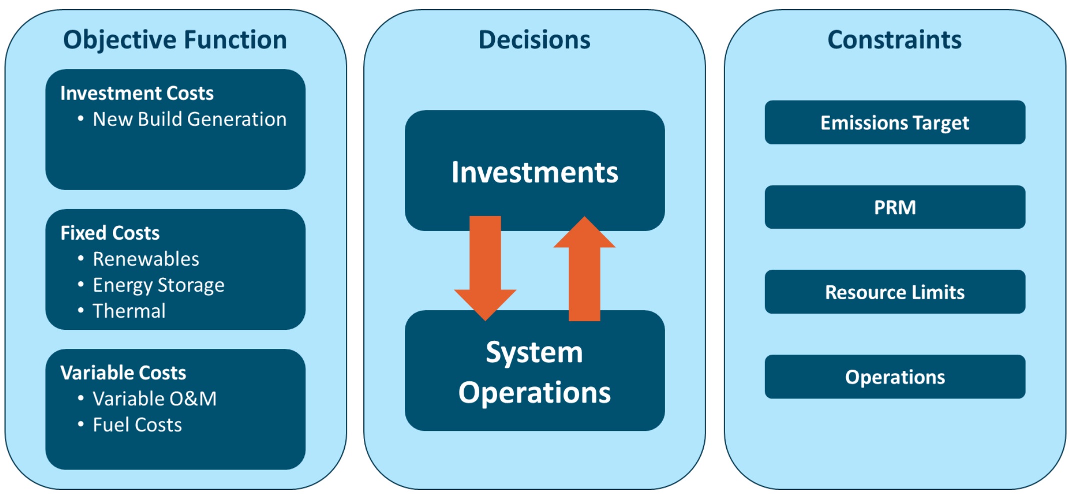
6. SVP System Modeling Approach

6.1. PLEXOS LT Overview

E3 performed resource portfolio optimization in this study using PLEXOS LT, an electricity system capacity expansion model that identifies the least-cost long-term combination of generation investments subject to reliability, policy, and operational constraints.[21] PLEXOS LT considers investment costs, fixed costs, and production costs to simultaneously optimize long-term capacity expansion and dispatch decisions. This allows the model to directly capture dynamic trade-offs between investments and dispatch, such as energy storage investments versus renewable curtailment and/or overbuild. PLEXOS LT also captures the reliability contributions of all resources to the system towards satisfying its reliability constraint.

Figure 26 provides an overview of the PLEXOS LT model including the objective function, key model decisions, and key constraints.

Figure 26. Overview of the PLEXOS LT Model



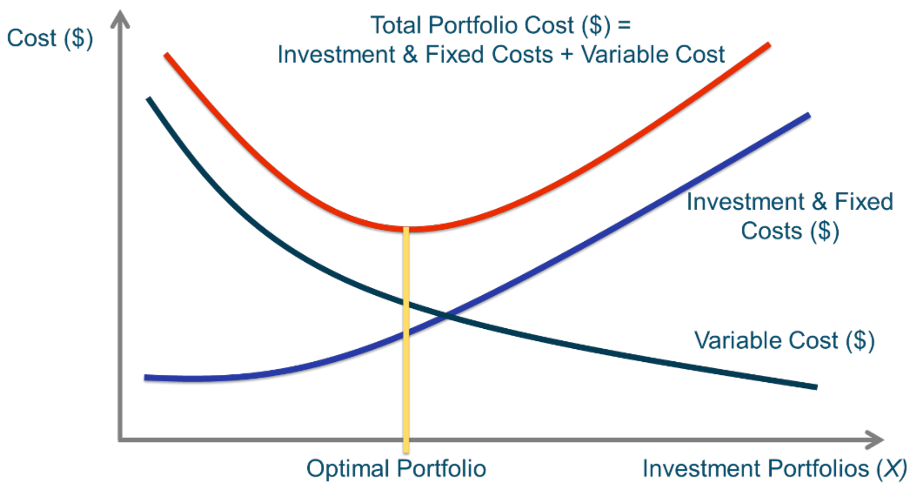
6.2. Objective Function

The objective function minimizes the net present value (NPV) of electricity system forward looking costs over the planning horizon subject to constraints. Forward-looking costs include investment costs, fixed costs, and production costs. Investment costs include the capital costs of new generation and storage resources. Fixed costs include fixed operations and maintenance (FO&M) costs of existing and new resources. Finally, production costs include variable operation and maintenance (VO&M) costs of existing

[21] PLEXOS is a widely-used commercially available software package from Energy Exemplar for electricity system modeling. PLEXOS LT is the Long-term plan phase of PLEXOS used for capacity expansion modeling.

and new resources, fuel costs, and the costs of imported power (offset by any exported power revenues). Figure 27 depicts an example optimal portfolio for a capacity expansion problem's objective function.

Figure 27. Objective Function of Capacity Expansion Problem

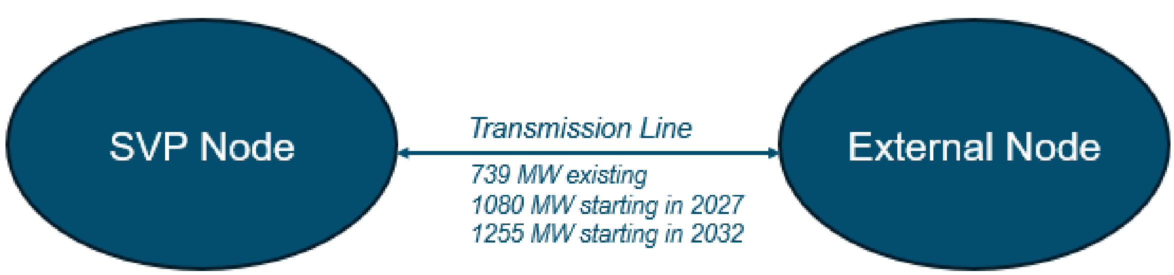


The objective function is also subject to investment and operational constraints (see next section). Investment constraints include maximum resource potential for addition/retirement candidates (max/min units built/retired), and other potential policy-related constraints, such as minimum RPS and SB 100 procurement requirements, emissions reductions requirements, and minimum reliability requirements. Operationally, the model is constrained by the hourly energy balance in each modeled period, resource limits set by energy, fuel, emissions, and other limits of generation and storage.

6.3. SVP System Representation

In E3's modeling approach, SVP's system is represented with a simplified zonal topology consisting of two nodes ("SVP" and "External") and a single transmission connection. The SVP node contains SVP's load and local existing and planned resources (DVR, Cogen, Gianera, and the planned BESS project). The External node contains SVP's other existing and planned resources, candidate expansion resources, and the CAISO market, with which SVP can buy and sell electricity. Figure 28 illustrates SVP's simplified topology used in the capacity expansion model.

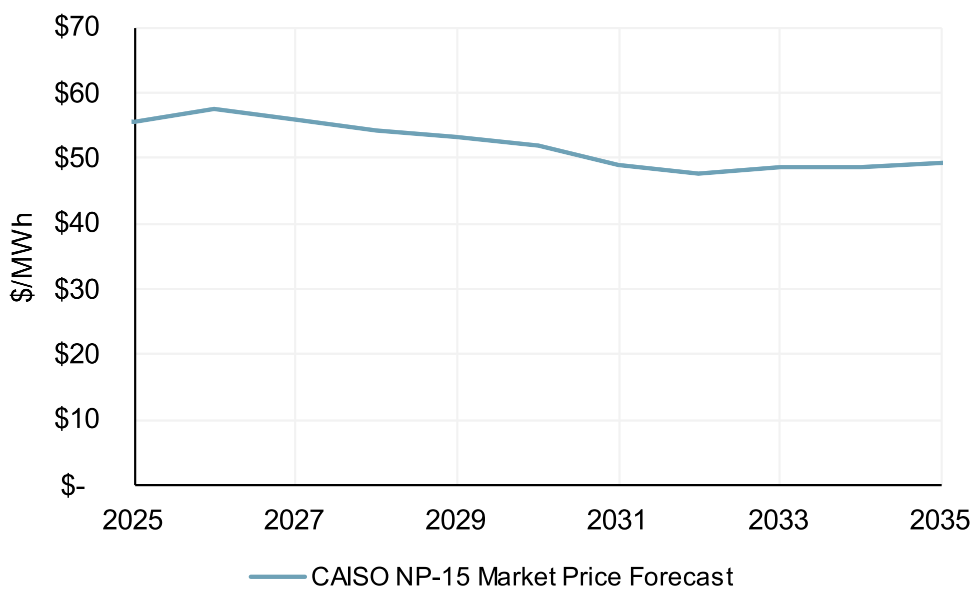
Figure 28. Simplified Topology for Capacity Expansion Model



In addition to their contracted resources, SVP can execute market transactions with other CAISO entities for energy, RECs, and RA attributes. For the IRP, only the energy market interactions are modeled. In every hour of the modeling horizon, SVP has the option to either purchase electricity from the market to serve load or to sell generation from its owned/contracted portfolio to the market. These interactions include both the cost/value of imports/exports as well as the associated carbon emissions. In the SVP system topology (Figure 28), the CAISO Market is in the External Node, and any purchases must flow over the transmission line to serve SVP's load.

The hourly market price forecast used to Inform SVP's market decisions is derived from E3's CAISO Market Price Forecast dataset.[22] Annual averages of the hourly price forecast are provided in Figure 29. Average market prices over the 2025-2035 horizon are primarily influenced by near-term solar build-out and transmission flow constraints between Northern and Southern California. The hourly market prices are correlated to the market emissions rate, discussed in Section 6.4. E3's price forecasts represent a fundamentals-based view of the CAISO market, including long-run portfolio changes to meet the energy, reliability, and policy requirements of the region.

Figure 29. CAISO Market Average Annual Price Forecast, $/MWh



Price forecasts used in capacity expansion modeling are typically an hourly-varying input price stream that does not change with system dynamics. While these price streams are useful to approximate the complicated dynamics that occur outside the area of interest, they can, in many instances, overstate the arbitrage opportunities that may exist between external resources and resources within the area of interest (i.e., SVP's territory). To the extent that unrealistic arbitrage opportunities exist for these transactions, the result may be a portfolio that is too reliant on external transactions relative to what will be realized in practice. It is therefore prudent for modeling and planning to restrict market transactions

[22] Purchase required. https://shop.ethree.com/product/caiso-price-forecast-2022-edition-core-case/.

in capacity expansion simulations to minimize the impact that these transactions may have on the resource portfolio.

To limit speculation on external market revenues from biasing SVP's portfolio economics, for IRP modeling in PLEXOS, sales to the CAISO Market are capped at 20% of SVP's load in each hour, and 5% of SVP's annual load in each year. These values were determined based on SVP's historical market activity and risk tolerance to market exposure. These constraints prevent the over-procurement of resources for energy trading and limit any model behavior associated with a potential disequilibrium between the market price forecast and the SVP IRP inputs. These constraints only impact market interactions and do not limit the availability of SVP-contracted resources in the External node (Section 4, Section 7) to utilize SVP's dedicated transmission lines.

In Scenario 3: Zero Emissions with Emerging Technology (Zero Emissions Scenario), market activity is restricted to obey the zero hourly emissions rule, whereby emissions are only allowed during hours with 0 MT CO2/MWh emissions factors (i.e., when excess renewable energy in the CAISO would have otherwise been curtailed). This is discussed in detail in Section 6.4.

6.4. Model Constraints

Resource Adequacy Modeling Approach

Traditionally, for near term local resource adequacy the CEC published a monthly Coincident Peak for all CAISO load serving entities (LSEs), including SVP, based on their respective load forecasts for the following year. Per CAISO Tarif Section 40 From the coincident peak number the CEC and CAISO required LSEs to provide sufficient capacity to meet each LSE's needs (115% of the coincident peak), through Local and System requirements for the upcoming year. The Local Requirement is the amount of capacity required to be satisfied by local resources classified as being able to meet that LSE's local Requirement, and the remaining amount can be satisfied by system resources not tied to a specific location.[23]

However, the long-term RA requirements and future input data for SVP (PRM, resource accreditation, etc.) are uncertain as the California Public Utilities Commission (CPUC) moves towards the "slice-of-day" approach for resource adequacy.[24] Once slice-of-day is implemented, CPUC jurisdictional LSE resource accreditation will be done within a spreadsheet model using LSE specific loads; no resource level accreditation metrics (like the average ELCCs published for solar and wind historically) will be available for POUs to utilize. Even if the historical approach were to be maintained, there are no public CAISO system level forecasts of average ELCCs for solar, wind, and storage, which form the bulk of forecasted SVP capacity additions. For these reasons, SVP has opted to follow the long-term planning method for system reliability needs consistent with the CPUC's approach for its jurisdictional LSEs utilized in the current 2022-

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[23] SVP Local Area Requirements can be satisfied by resources within the local areas of Humbolt, North Coast/North Bay, Stockton, Greater Bay, Greater Fresno, Kern, Bid Creek/Ventura, LA Basin, San Diego/Imperial Valley

[24] CPUC, "Resource Adequacy Homepage," California Public Utilities Commission, 2023, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage.

2023 CPUC IRP cycle. This approach, as described in the following section, plans for the "marginal reliability need" using marginal effective load carrying capability (ELCC) accreditation for all resource types.

Local reliability needs are not explicitly optimized in SVP's IRP, as SVP's procurement approach for their slice of the PG&E transmission territory local resource needs is to primarily rely on short-term market purchases and sales to balance their local reliability position. SVP's plan also relies on significant growth of remote solar, wind, storage, and geothermal resources; some of these could be sited in locally constrained areas. SVP will rely on resource adequacy market purchases to fill any residual local reliability needs.

System Reliability Constraints

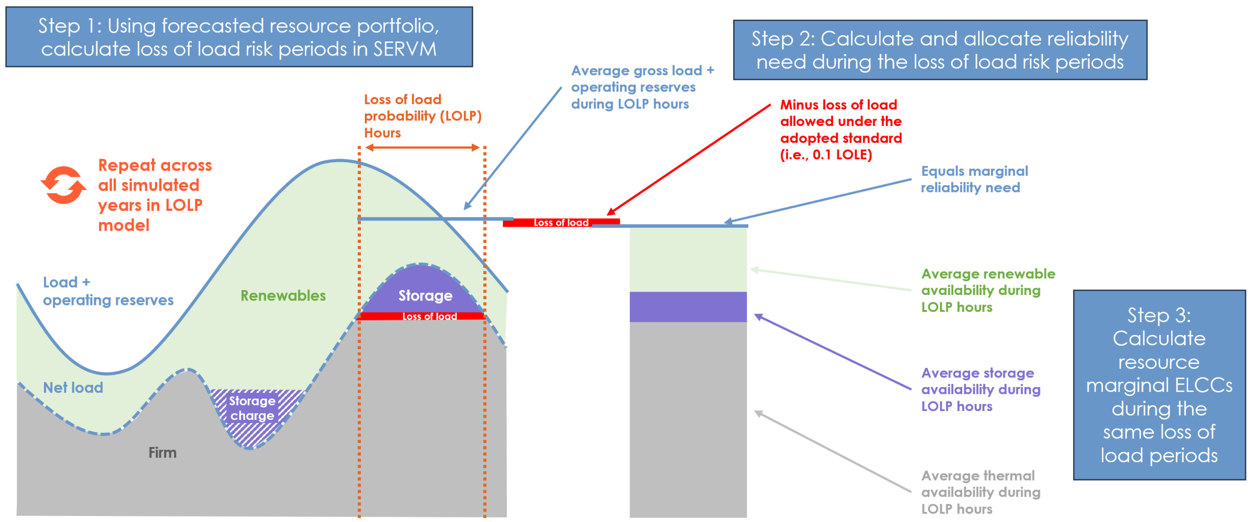
Meeting reliability needs is a critical component of utility integrated resource planning. Amongst utilities, SVP – and other CAISO LSEs – face a unique reliability planning situation, whereby 1) system reliability needs are measured at the CAISO level, 2) LSEs have their own bilateral RA obligations, and 3) the long-term system reliability value of LSE resources is dependent upon the resource decisions of all LSEs. Using inputs developed by the CPUC for use in CPUC jurisdictional LSE IRPs, the reliability constraints in PLEXOS are set up to reflect this unique situation.

For their 2022 IRPs, the CPUC directed LSEs to plan for their share of the "marginal reliability need" using marginal ELCC accreditation for all resource types. This represents a departure from the historical paradigm in the CPUC RA process to rely on "average" ELCCs, but provides a more accurate – and therefore economically efficient – long-term forecast of the marginal system reliability value of incremental resource changes on top of the larger CAISO fleet. It therefore represents a robust set of reliability planning inputs for SVP's IRP process, consistent with the latest long-term planning guidance available from a California state agency.

Figure 30 illustrates the key steps for a marginal reliability planning process: 1) determining the periods of future loss of load risk under a forecasted system-level portfolio, 2) calculating and allocating the marginal reliability need during those same periods, and 3) measuring the resource contributions during those risk periods using marginal ELCC.[25]

[25] Note: The marginal reliability need can be calculated in two ways to arrive at the same value: 1) as shown in this diagram, it can be calculated as the gross load plus operating reserves minus allowed loss of load under the adopted reliability standard, or 2) as the sum of the marginal ELCCs of the resource portfolio that is tuned to the adopted reliability standard.

Figure 30. Schematic of the Marginal Reliability Planning Process



The following process was used by the CPUC to develop their marginal reliability planning inputs, used for the IRPs of the CPUC jurisdictional LSEs as well as for SVP's IRP:

1. **Data Development**: A loss of load probability model and dataset were developed. The CPUC uses Astrapé's SERVM model for this purpose, considering weather, load, and renewable variability over 23 historical years of weather conditions (1998-2020) as well as stochastic draws for forced outages and economic load uncertainty.

2. **System-level Need Determination**: Using the loss of load probability model, the Total Reliability Need was be calculated by measuring the total effective capacity (i.e., ELCC MW or perfect capacity (PCAP) equivalent MW) needed to reach the CPUC's 1-day-in-10-years loss of load expectation (LOLE) standard (also described as reaching 0.1 days/year LOLE).

3. **CAISO level resource portfolio forecast**: a forecasted resource portfolio for the entire CAISO was developed based on the CPUC's 2021 Preferred System Plan, tuning that resource portfolio to the 0.1 days/year LOLE standard each year.

4. **Marginal ELCC forecast**: the marginal ELCC for each resource type in the forecasted portfolio was calculated for key years (with between years using interpolation) to produce an annual forecast of marginal ELCCs by resource type. Marginal ELCCs are calculated as removing a small increment (e.g., 100 MW) of each resource type from the portfolio and calculating the perfect capacity equivalent, measuring the marginal value of each resource type to reduce loss of load risk.

5. **Translation of the total need into the marginal reliability need for use in LSE IRPs:** when accrediting against the total ELCC required to reach 0.1 LOLE in all hours, "average ELCCs" are used. For a system at the reliability criteria, the sum of average ELCCs for all resources equals the Total Reliability Need MW to reach the reliability criteria. However, when accrediting using

marginal ELCCs, which produce a more economically efficient signal of the marginal reliability value of each resource, the sum of the marginal ELCCs produces a lower MW value than the Total Reliability Need. This lower MW value is the marginal reliability need. For a system at the reliability criteria, the sum of marginal ELCCs for all resources equals the marginal reliability need MW to reach the reliability criteria. The CAISO's marginal reliability need was calculated by the CPUC for each year based on the sum of the marginal ELCCs for the resource portfolio tuned to the reliability criteria.

6. **Allocation of the marginal reliability need to each LSE**: the CPUC allocates the system level marginal reliability need to each LSE based on their share of the IEPR's coincident managed peak. While this does not fully capture LSE contributions during the multiple hours where loss of load risk may occur, it used existing available data and – due to the large behind the meter PV peak shift captured in the managed peak – is a reasonable initial proxy for LSE contributions during the net peak.[26]

The resulting marginal ELCCs by resource and the marginal reliability need published by the CPUC for use by their jurisdictional LSEs are shown in Figure 31. These values come from the "38 MMT by 2030" modeling scenario from the 2021 Preferred System Plan.[27]

[26] Gross peak = the consumption peak prior to behind the meter (PV, storage, etc.) resource output. Managed peak = the metered peak after behind the meter resource output. Net peak = the resulting system load after the output from supply side renewable resources. The net peak can also be defined as the remaining system load after all variable and use limited resources are dispatched (including storage, hydro, DR, etc. and not just solar and wind), which would align it more critically with the hours of loss of load risk for a system with increasing battery storage penetrations.

[27] Slide 42, "Reliability Filing Requirements for Load Serving Entities' 2022 Integrated Resource Plans – Results of PRM and ELCC Studies." https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/20220729-updated-fr-and-reliability-mag-slides.pdf.

Figure 31. Marginal ELCCs by Resource Type from the CPUC 38MMT Scenario

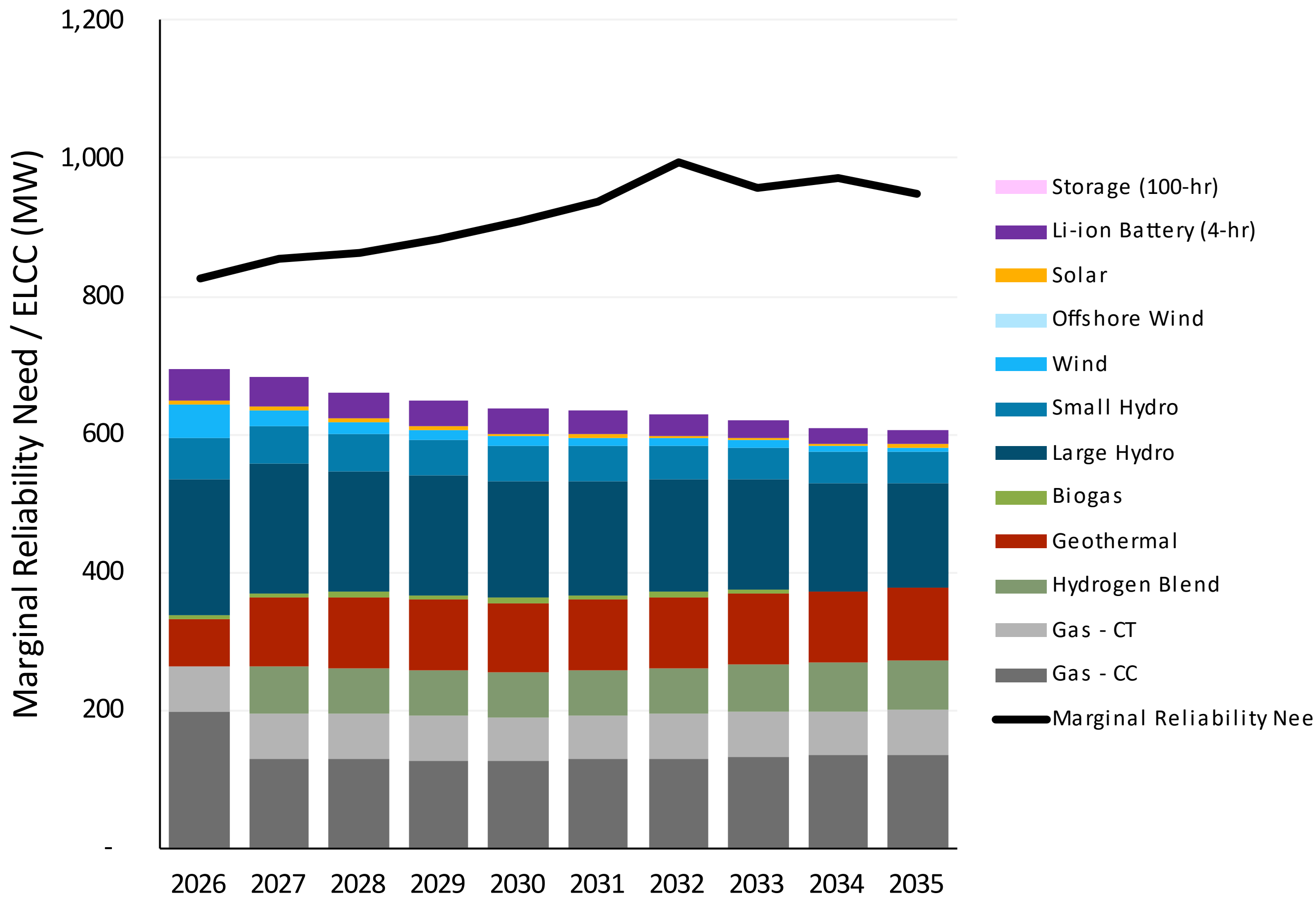
Modeled Year (results complete) | Interpolated Year

Resource Class	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
In-state Wind (SoCal)	15%	15%	15%	12%	8%	8%	8%	7%	7%	6%	5%	4%
In-state Wind (NorCal)	30%	30%	31%	24%	17%	17%	16%	15%	13%	12%	10%	9%
Out-of-state Wind (WY/ID)	43%	39%	36%	37%	39%	31%	24%	25%	26%	27%	29%	30%
Out-of-state Wind (WA/OR)	26%	24%	22%	23%	24%	19%	14%	15%	16%	17%	18%	18%
Out-of-state Wind (AZ/NM)	38%	35%	32%	34%	35%	28%	21%	22%	24%	25%	26%	27%
Offshore Wind	55%	51%	46%	49%	51%	47%	43%	40%	38%	36%	34%	32%
Utility PV	10%	10%	11%	10%	9%	8%	6%	6%	6%	6%	6%	6%
BTM PV	9%	9%	10%	8%	7%	6%	5%	5%	5%	5%	5%	6%
4-hr Battery Storage	89%	90%	92%	85%	77%	76%	75%	68%	61%	54%	47%	40%
8-hr Battery Storage	89%	91%	93%	90%	87%	86%	85%	82%	79%	76%	73%	70%
Pumped Hydro Storage	89%	91%	93%	91%	89%	89%	89%	86%	83%	80%	76%	73%
Demand Response	89%	91%	92%	77%	62%	61%	59%	50%	41%	32%	23%	14%
Hydro (large)	57%	56%	56%	53%	50%	49%	48%	47%	46%	45%	44%	43%
Hydro (small)	41%	40%	40%	38%	36%	35%	35%	34%	33%	32%	32%	31%
Firm												
Geothermal	86%	88%	89%	91%	93%	92%	92%	93%	93%	94%	95%	95%
Biomass/wood	79%	81%	83%	83%	83%	82%	82%	83%	85%	86%	88%	89%
Biogas	76%	78%	80%	80%	79%	78%	77%	79%	81%	83%	85%	87%
Nuclear	93%	94%	95%	94%	94%	94%	93%	94%	95%	95%	96%	96%
Gas CC	85%	86%	88%	87%	87%	86%	85%	86%	88%	89%	90%	91%
Gas CT	80%	82%	83%	83%	82%	81%	79%	80%	81%	82%	83%	84%
Cogen	90%	92%	95%	92%	89%	89%	89%	90%	90%	91%	92%	93%
ICE	93%	90%	87%	90%	92%	92%	91%	90%	89%	88%	87%	86%
Coal	69%	72%	74%	74%	73%	71%	69%	72%	74%	77%	80%	83%
Steam	78%	80%	82%	81%	81%	79%	78%	80%	82%	84%	86%	88%

The inputs used for the CPUC IRP process were also utilized as the key inputs for the reliability constraint in the SVP IRP. SVP's marginal reliability need was calculated using its forecasted share of the CAISO coincident managed peak in the 2022 IEPR. The SVP managed peak MW was divided by the CAISO managed peak MW; this ratio was then multiplied by the CPUC's marginal reliability need to obtain the SVP-level need. This marginal reliability need represents SVP's share of the system need during hours with loss of load risk as measured in ELCC MW. All existing and new candidate resource options in PLEXOS's optimization that provide system RA attributes are also counted in ELCC MW, using the marginal ELCC percentages reported above. This approach puts all resources on a level playing field by measuring their reliability contributions consistently using marginal ELCC, which accounts for the operational limitations of all resource types, including variable renewables, use-limited hydro, use-limited energy storage, and thermal units subject to forced outages.

Figure 32 shows the contributions of SVP's existing and planned resources towards its forecasted marginal reliability need. The shortfall between the existing portfolio ELCC MW and SVP's marginal reliability need must be satisfied via candidate resource builds. Due to constraints on candidate resource availability (see Section 7.1), the reliability constraint will not be enforced until 2026.

Figure 32. Existing and Planned Resource Marginal ELCC and SVP's Reliability Need, 2026-35[28]



Clean Energy and Emissions Reduction Requirements

SVP must satisfy three key policy criteria in its IRP. SB 100 and SB1020 set targets for the RPS and Clean Energy Standard (CES) annually through 2045, and the CARB has also stipulated a GHG reduction target for 2030.

+ **RPS** targets stipulated in legislation are 44% of retail electricity sales by 2024, 52% by 2027, and 60% by 2030.[29] Only eligible renewable energy resources qualify for the RPS, including solar, wind, geothermal, and small hydroelectric units.
+ **CES** policy goals are 90% by 2035, 95% by 2040, and 100% by 2045. Resource qualification for the CES is expanded to include all zero-carbon resources, including nuclear, large hydro, and emerging

[28] The marginal reliability constraint is only enforced in the model beginning in 2026, which is the first year when SVP expects to be able to sign new long-term contracts as discussed in Section 7. In the intervening years, it is assumed that SVP will sign short-term capacity contracts to meet their reliability need if there is any capacity shortage.

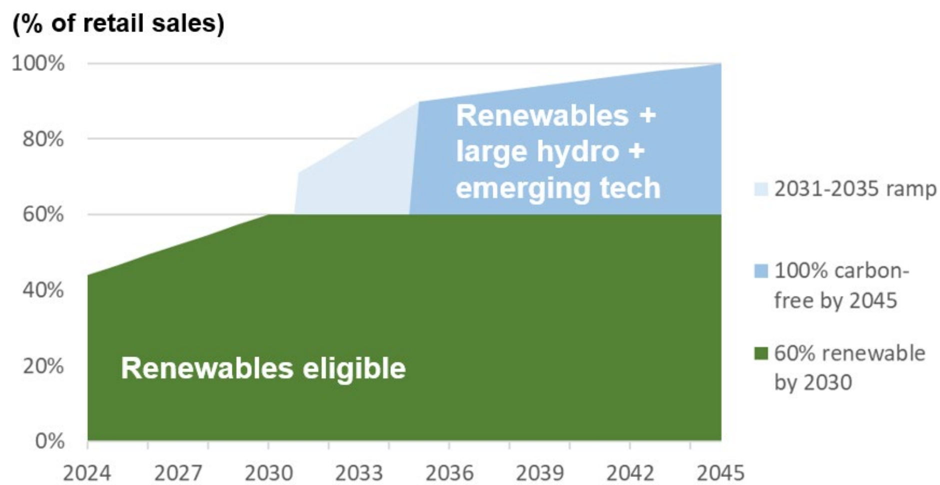
[29] The RPS constraint is only enforced in the model beginning in 2026, which is the first year when SVP expects to be able to sign new long-term contracts as discussed in Section 7. In the intervening years, it is assumed that SVP will buy RECs if there is any REC shortage.

technologies such as hydrogen and Carbon Capture and Storage (CCS). In the intervening years between the expiration of the RPS (2030) and the enforcement of the CES (2035), a ramp-up is modeled to smooth policy compliance in the model (Figure 33).

+ **GHG** reductions target the electric sector's share of a 40% economy-wide reduction of GHG emissions from 1990 levels by 2030. For SVP, this amounts to 485,000 MMT CO_2e, as published in the SB 350 Final Report.[30] This value represents the high end of the GHG target range published by CARB and hence the minimum requirement for SVP. Scenarios of more aggressive carbon reduction were modeled focused on the year 2035, as described below.

The schematic outlined in Figure 33 shows the compliance targets for the RPS and CES, expressed as percentages of retail sales.

Figure 33. RPS (Green) and CES (Blue) Compliance Targets



All of SVP's existing and planned renewable resources, including solar, wind, geothermal, biogas, and small hydro generators, are assumed to be REC-producing and qualify towards RPS compliance. Additionally, all candidate wind, solar, and geothermal resources selected in the capacity expansion model are assumed to provide RECs to SVP.

In addition to renewable resources, SVP's portfolio of large hydro generators is assumed to qualify for the CES and provide credits to SVP. Candidate renewables and zero-emission emerging technologies are assumed to qualify for the CES as well.

The GHG constraint is enforced starting in 2030. Gas-fired thermal generators are assumed to generate carbon emissions at a rate of 117 pounds CO_2 per MMBtu of fuel consumption. When LEC undergoes its planned conversion to 45% hydrogen fuel blending in 2027, its emissions factor reduces to 92.2 pounds per MMBtu of blended fuel (see Emerging Technology in Section 7.1). The Allam Cycle CCS resource modeled in Scenario 3: Zero Emissions with Emerging Technology (Zero Emissions Scenario) has a 100%

[30] CARB, "Senate Bill 350 - Integrated Resource Planning Electricity Sector Greenhouse Gas Planning Targets: 2020 Update" (Sacramento, CA: California Air Resource Board (CARB), 2020), https://ww2.arb.ca.gov/sites/default/files/2021-04/sb350-final-report-2020.pdf.

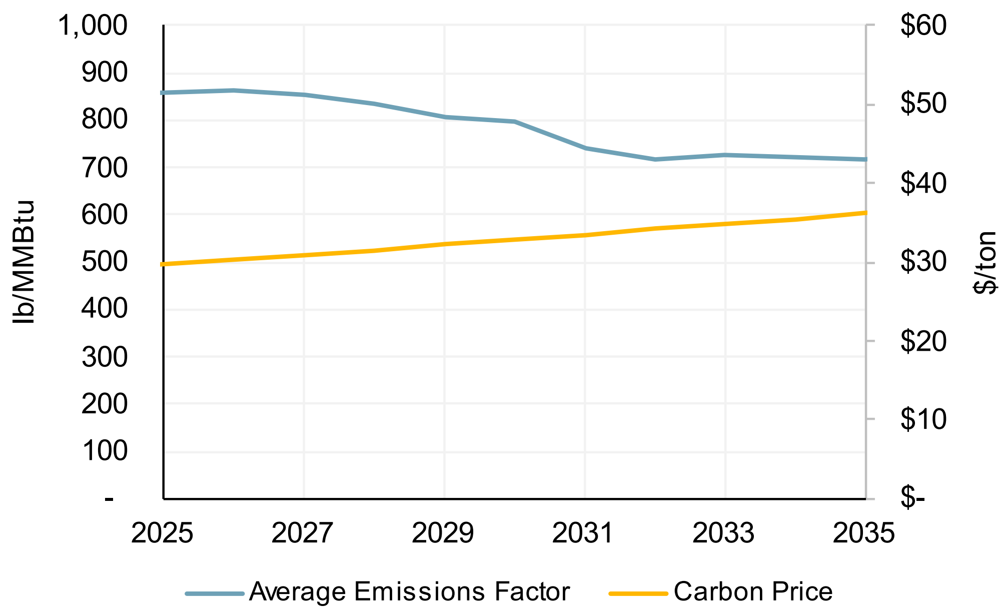
carbon capture efficiency, and consequently is not modeled as producing emissions. When Gianera 1 and 2 convert to renewable natural gas (RNG) in the Zero Emissions Scenario, the lifecycle carbon emissions of RNG are assumed to be zero. For more information on the emerging technologies under consideration, refer to Section 7.1.

Market interactions also contribute to the carbon emissions constraint. The hourly market emissions factors used for purchases and sales are equal to the average hourly emission factors from the CAISO-wide thermal generator fleet that dispatches in each hour, as calculated from the E3 CAISO Market Price forecast dataset.[31] Purchases in each hour from the market incur a carbon penalty at the hourly market emissions factor, while market sales offset SVP's carbon emissions at that same rate. This representation is consistent with the emissions accounting approach used in the CPUC IRP and reflects SVP's continuous participation in the CAISO market.

A volumetric cost is modeled for every ton of carbon produced by SVP. These costs are also taken from the E3 CAISO Market Price Forecast. Market prices, emission factors, and carbon prices are all correlated in this dataset.

The CAISO average annual emission factors and annual carbon price forecasts are shown in Figure 34.

Figure 34. CAISO Average Annual Emissions Factor and Carbon Price



In the Zero Emissions Scenario, the GHG constraint is modified such that no emissions are permitted in all hours of the year, beginning in 2035. Under this scenario, market sales do not offset SVP emissions, and

[31] E3, "California ISO Market Price Forecast E3 Core Case 2022," Energy + Environmental Economics (E3), 2022, https://shop.ethree.com/wp-content/uploads/2022/11/Market-Summary_CAISO_2022-edition_SAMPLE.pdf.

market purchases are only allowed in hours where the average market emissions factor is zero. For more information, refer to Section 6.6.

6.5. Capacity Expansion Model Configuration

To identify a least-cost capacity expansion and system operations portfolio, PLEXOS LT optimizes across the entire planning horizon from 2024 to 2035 (11 years) in a single step, resulting in a computationally intensive optimization problem. To ensure the capacity expansion problem is computationally tractable while still providing accurate and actionable results, PLEXOS performs several modifications to the system's representation to make the model more tractable. These modifications are described in the following sections.

Day Sampling

Regarding the chronology or level of detail in representing the planning horizon, day sampling ensures that the model captures intra-month and monthly variations in load and resources annually while reducing the size of the simulation. Instead of modeling every day of the modeling horizon, a sample set of three days per month are studied. A statistical sampling algorithm within PLEXOS LT extracts similar periods (such as days, weeks, months) with a focus on highly variable data (such as load, solar and wind profiles), leaving a sample set of days that, together, have characteristics that are representative of conditions on the electricity system over the course of multiple years. After sampling, PLEXOS LT rescales the results to ensure that the total energy equals the original input values.

Expansion Decisions

The capacity expansion algorithm in PLEXOS LT can be programmed to select new generator builds using integer decision variables or linearized variables. In the integer representation, each generator must be built at its full nameplate capacity, or not at all. In the linear representation, partial builds are allowed. In general, integer/discrete problems are much harder for PLEXOS to solve than linear problems. In this study, the model is permitted to make linear expansion decisions, which significantly reduces the computational time required to solve the problem while still providing sufficient information on the magnitude and diversity of new builds to support decision making.

Operation Decisions

Operations unit commitment optimality determines how unit commitment decision variables are treated in the optimization problem. Operations in PLEXOS LT are simulated through economic dispatch of existing and new resources to meet load in each hour. The dispatch logic depends on the type of resource. Solar and wind resources have fixed generation profiles (input as hourly capacity factors) based on the resource location and can be curtailed when total generation exceeds load. Thermal resources (such as natural gas turbines) are operated flexibly while meeting operating constraints such as maximum capacity rating and minimum generation level. Must-run resources are operated at their rated capacity in all hours except for planned outages. Market purchases and demand response resources are configured similarly to generation and can be operated flexibly while also meeting operating constraints. Energy storage resources (such as batteries and pumped hydropower) increase load when charging and can serve load when discharging.

6.6. Scenarios and Sensitivities Considered

Three modeling scenarios and one modeling sensitivity were considered for the SVP IRP. Scenario 1: Base SB 100 (Base Scenario) consists of the default inputs and assumptions regarding load growth, resource availability, policy targets, and market activity. Under Scenario 2: Accelerated SB 100 (Accelerated SB 100 Scenario), the compliance targets are accelerated from 60% RPS to 70% carbon-free energy (60 % still needs to come from renewable resources) by 2030, and from 90% carbon-free energy to 100% by 2035. Finally, Scenario 3: Zero Emissions with Emerging Technology (Zero Emissions Scenario) restricts SVP from producing any carbon emissions in all hours starting in 2035, enables the selection of certain zero-emitting emerging technologies beginning in 2035, and includes conversion of LEC, DVR, and Gianera 1 and 2 to zero-carbon fuels by 2035. The emissions restrictions in this Scenario extend to market activity, where purchases are only allowed during hours where the market average emissions rate is zero, and sales are not permitted to provide negative emissions "credits" during hours when market average emissions rates are non-zero.

The Geothermal Limitations and Hydrogen Challenges Sensitivity (Hydrogen Sensitivity) represents a variation of the Zero Emissions Scenario where the geothermal resource potential available to SVP is capped to 50 MW and the costs of hydrogen retrofits, new hydrogen turbines, and hydrogen fuel are increased due to uncertainty over a future hydrogen economy.

A summary of the key changes by Scenario are shown in Figure 35 below.

Figure 35. Modeling Parameters that Vary by Scenario or Sensitivity

Parameter	**Scenario 1:** Base SB 100	**Scenario 2:** Accelerated SB 100	**Scenario 3:** Zero Emissions with Emerging Technology	**Sensitivity:** Geothermal Limitations and Hydrogen Challenges
SB 100 CES Targets	90% by 2035 100% by 2045	70% by 2030 100% by 2035	70% by 2030 100% by 2035	70% by 2030 100% by 2035
Carbon Emission Reduction Targets	485,000 MT by 2030	485,000 MT by 2030	485,000 MT by 2030 Zero hourly emissions beginning in 2035	485,000 MT by 2030 Zero hourly emissions beginning in 2035

Zero-carbon Emerging Technologies	Not included	Not included	Included	Included
Gas Plant Conversions*	LEC 45% (volumetric) Hydrogen in 2027	LEC 45% (volumetric) Hydrogen in 2027	All gas plants are converted to 100% zero-carbon fuels by 2035	All gas plants are converted to 100% zero-carbon fuels by 2035
Market Purchases	Allowed	Allowed	Allowed before 2035 Restricted in 2035 to hours where market emission factor is zero	Allowed before 2035 Restricted in 2035 to hours where market emission factor is zero
Carbon Credits via Market Sales	Allowed	Allowed	Allowed before 2035 Not allowed in 2035	Allowed before 2035 Not allowed in 2035
Geothermal Resource Potential	Default	Default	Default	Reduced to 50 MW in 2028
Hydrogen Retrofit, New Build, and Fuel Costs	Default	Default	Default	High

**Gas plant conversions are discussed in Section 7.1.*

6.7. Model Inputs

The inputs to the PLEXOS model, discussed in Sections 3, 4, 6, and 7, are organized into the following topics:

+ **Load Forecast** – The load forecast was developed using a combination of a baseline load forecast provided by SVP and load modifiers to form a Reference Scenario forecast. This load forecast was used in all scenarios. See Section 3.
+ **Existing and Planned Resources** – Inputs were provided by SVP and are discussed in Section 4:

  - **Online and retirement dates** – As a PLEXOS modeling assumption, all of SVP's small and large hydro generators are retained over the planning horizon, irrespective of contract status.
  - **Nameplate capacity**
  - **Variable O&M**
  - **Thermal operating parameters**
  - **Generation profiles & capacity factors** – Geothermal and hydro energy budgets were provided by SVP. Renewable solar and wind profiles were collected from the CPUC IRP 2023 Inputs and Assumptions (I&A) supporting information.
- **Candidate Resources** – Inputs were developed by E3 and are discussed in Section 7:
  - **Resource costs** – Resource costs for candidate resources were derived from the National Renewable Energy Laboratory (NREL) 2023 Annual Technology Baseline (ATB).[32] Emerging technology cost assumptions were collected via E3 literature review.
  - **Resource Potential & Availability** – The availability and build limits for candidate resources were collected from the CPUC IRP 2023 I&A document, with modifications to reflect SVP's market share and procurement risk.[33]
  - **Generation Profiles & Capacity Factors** – Profiles were collected from the CPUC IRP 2023 I&A supporting information.
  - **Thermal Operating Parameters** – Data was taken from the CPUC IRP 2023 Resource Cost and Build workbook.
- **Reliability Need** – Inputs were developed by E3 and are discussed in Section 6.4:
  - **Reliability Need** – Developed using the CPUC data and SVP's coincident peak demand to derive the SVP marginal reliability need.
  - **Resource Capacity Contributions –** The marginal ELCCs for candidate renewable resources were adopted from CPUC data, using a marginal reliability need framework.
- **Fuel Prices** – These trajectories were derived from several data sources. More information can be found in Section 7.4, including:

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[32] https://atb.nrel.gov/electricity/2023/index

[33] Resource potential and availability limits were reduced from the CAISO-wide potentials to represent what would be available to SVP for procurement. Further discussion can be found in Section 7.1.

- **Natural Gas** – The gas forecast was derived from the Energy Information Administration 2022 Annual Energy Outlook, with the trajectory regionalized to the settlement node of SVP's contracted gas supply.
- **Hydrogen** – Green hydrogen price forecasts were developed by E3. The forecast assumes electrolysis of hydrogen using an alkaline electrolyzer that is powered by solar energy. Hydrogen electrolyzer costs are derived from the CEC publication on hydrogen production costs.[34] Hydrogen storage costs are derived from Department of Energy (DOE) project ST-001 costs.[35] Hydrogen transport costs are derived using Argonne's Hydrogen Delivery Scenario Analysis Model (HDSAM).[36] A $3/kg Production Tax Credit (PTC) from the IRA is applied to units brought online by 2035.[37]
- **Renewable Natural Gas** – Fuel cost provided by SVP.
- **Uranium** – Fuel cost taken from the CPUC IRP 2023 Resource Cost and Build Workbook.

6.8. Model Outputs

The following outputs are produced by PLEXOS and are the subject of discussion and interpretation in this report. All fields are reported annually for each generator, except for the Constraint outputs which are single-defined values for each year of the modeling horizon. The key model outputs for this IRP are reported in Figure 36.

Figure 36. Key Model Outputs

PLEXOS Output	Description	Output Units
Installed Capacity	Installed capacity of Generation and Battery Storage.	MW
Generation	Total annual generation of Generation and Battery Storage.	GWh
Annualized Build Cost	Total fixed costs of candidate resources, including levelized capital costs and FO&M costs.	Nominal $'000
VO&M Cost	Total VO&M cost.	Nominal $'000
Fuel Cost	Total annual fuel bill.	Nominal $'000
Market Net Purchases	Energy purchases from the market, net of sales to market.	GWh
Market Cost	Cost of market purchases.	Nominal $'000
Market Revenue	Revenue (negative cost) collected from market sales.	Nominal $'000
Emission Production	Total production of carbon emissions, including from generation and market activity.	Short tons
Emission Cost	Total cost of emissions, equal to the emission price times production.	Nominal $'000

[34] https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-F.pdf.
[35] https://www.hydrogen.energy.gov/pdfs/review22/st001_ahluwalia_2022_p.pdf.
[36] https://hdsam.es.anl.gov/index.php?content=hdsam.
[37] Qualification of hydrogen generators for the Hydrogen PTC under the IRA assumes a three-year safe harboring following the expiration of the IRA tax credits in 2032. The PTC applies to the first ten years of plant operations. This credit is levelized over the useful life of the hydrogen generator and is bundled into the fuel price forecast.

7. Portfolio Expansion Resource Options

7.1. Candidate Resource Assumptions

When planning for capacity expansion, SVP can select from a range of candidate resource options to meet growing load, reliability requirements, GHG policy targets, and additional policy goals. These resources are grouped into the following categories:

- **Candidate Renewable Resources**
- **Candidate Storage Resources**
- **Candidate Thermal Resources**
- **Candidate Emerging Technology Resources**

For resource cost assumptions, see to Section 7.2.

Candidate Renewable Resources

Candidate renewable resources include the renewable energy resources available to SVP under all modeling scenarios. These are established and commercially viable technologies, including solar PV, in-state wind, out-of-state wind, offshore wind, and geothermal.

The candidate renewable resources available to SVP are aggregations of the resources reported in the CPUC IRP I&A document.[38] For solar and in-state wind, the resource potentials were aggregated into Northern, Central, and Southern regions according to the region boundaries used by the CPUC. Geothermal is represented as a single resource encompassing all in-state geothermal resource potential in the CPUC model. Details of the aggregation are summarized in Figure 37.

Figure 37. SVP Candidate Renewable Resources Mapping to CPUC Aggregation

SVP Resource Name	CPUC Aggregation
Northern California Solar	Northern California
Central California Solar	Southern PGAE, Greater Kramer, Tehachapi, Southern NV Eldorado
Southern California Solar	Greater LA, Riverside, Greater Imperial, Arizona
Northern California Wind	Northern California, Solano
Central California Wind	Central Valley North Los Banos, Tehachapi, Southern NV Eldorado
Baja California Wind	Baja California
Geothermal	All in-state geothermal resources

The resource potentials available to SVP are indexed to the corresponding potentials from the CPUC IRP I&A document. Specifically, the solar resource potential is assumed to be sufficiently large to capture all of SVP's potential needs, and no resource potential limit is modeled. For in-state wind, out-of-state wind,

[38] CPUC 2022-23 IRP Cycle Events and Materials. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials.

and offshore wind, the portion of the CPUC resource potentials available to SVP is assumed to be 5% of the reported totals, reflecting SVP's market share and ability to procure wind generation. For Baja California Wind, the available potential reported by the CPUC is also reduced to account for Cimarron Wind, for which SVP is already under contract. For geothermal, it is understood that, of the 3.3 GW of resource potential modeled in the CPUC IRP, 1 GW of this resource must be earmarked for the CPUC Mid-Term Reliability Clean Firm order. As such, SVP's portion of the CPUC resource potential for geothermal is represented as 15% of the net remaining statewide potential of 2.3 GW.

Each candidate renewable resource's first available year reflects feasible timelines for bringing resources online based on the CAISO interconnection queue and typical development lead times. Additionally, no resources are made available for selection in the capacity expansion model until 2026 at the earliest, reflecting SVP's near-term procurement decisions.

For candidate solar and wind resources, the renewable profiles and capacity factors were adopted from the profiles used in the CPUC IRP model.[39] A single weather year (2020) was sampled to create the profiles. Weather stations were selected for candidate renewable resources that align with the geographic extent of the resource potential.

Key metrics for the candidate renewable resources available to SVP are summarized in Figure 38. The resource potential totals represent the total amounts available to the model by 2035; for wind and geothermal resources, the available potential is staggered between 2026-2030 to reflect construction lead time, projects in the CAISO interconnection queue, and commercial interest.

Figure 38. Candidate Renewable Resource Options

Technology	Resource Name	First Year Available	Resource Potential	Lifetime (years)	Capacity Factor
Solar	Northern California Solar	2026	Uncapped	30	29.9%
Solar	Central California Solar	2026	Uncapped	30	32.5%
Solar	Southern California Solar	2026	Uncapped	30	33.7%
In-State Wind	Northern California Wind	2026	142 MW	30	21.2%
In-State Wind	Central California Wind	2026	478 MW	30	33.2%
In-State Wind*	Baja California Wind	2026	109 MW	30	30.4%
Out-of-State Wind	New Mexico Wind	2026	275 MW	30	48.1%
Out-of-State Wind	Wyoming Wind	2027	200 MW	30	51.2%
Offshore Wind	Humboldt Bay Offshore Wind	2034	134 MW	25	57.1%
Offshore Wind	Morro Bay Offshore Wind	2034	244 MW	25	47.6%
Geothermal	Geothermal	2028	347 MW	25	-

** Baja California Wind interconnects directly to the CAISO system and is considered in-state*

[39] CPUC System Reliability Modeling Datasets 2023. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/system-reliability-modeling-datasets-2023.

"I think we should continue to explore the viability of other energy options, such as hydrogen or even nuclear." -Santa Clara resident survey response

Distributed Energy Resources

DER—including residential rooftop solar and commercial solar—are additional renewable resource options that may be considered within long-term planning. DER is not included as a candidate resource within SVP's IRP model. The IEPR load forecasts (Section 3) include projections of residential rooftop solar adoption in SVP's service territory. Residential solar is modeled in the IRP as a load modifier, reducing SVP's net load. Estimates of the actual market for DERs within the City of Santa Clara are not available currently, and the potential impacts of significant DER deployment on the local distribution system upgrades are not available.

The distributed, smaller-scale nature of DERs generally results in higher capital costs and have lower energy outputs than utility-scale assets, resulting in these resources being less attractive in capacity expansion modeling. Additionally, the effort required by SVP to contract/deploy a comparable portfolio of DER capacity in place of a utility-scale resource would likely be significant. However, siting DER within the City of Santa Clara does offer benefits for SVP as any resources developed locally would reduce SVP's net load and reduce the transmission access charge (TAC) paid to CAISO (see Section 7.5). Recognizing the potential benefits of developing resources within the City Santa Clara, SVP will continue to explore DER as local opportunities for deployment become available.

Monthly Capacity Factors

Breakdowns of the average solar and wind capacity factors by month, as calculated from the CPUC weather profiles, are provided in Figure 39 and Figure 40.

Figure 39. Candidate Solar Monthly Capacity Factor

Month	Central California Solar	Northern California Solar	Southern California Solar
January	20%	14%	24%
February	29%	29%	29%
March	28%	25%	31%
April	36%	35%	40%
May	44%	35%	43%
June	44%	43%	44%
July	45%	46%	40%
August	38%	36%	38%
September	33%	29%	35%
October	27%	29%	31%
November	24%	21%	26%
December	21%	16%	23%
Annual	**32%**	**30%**	**34%**

Figure 40. Candidate Wind Monthly Capacity Factor

Month	Baja CA Wind	Central CA Wind	New Mexico Wind	Northern CA Wind	Wyoming Wind	Humboldt Bay Offshore Wind	Morro Bay Offshore Wind
January	18%	37%	59%	22%	72%	56%	51%
February	19%	39%	56%	27%	63%	69%	48%
March	32%	31%	62%	27%	54%	44%	29%
April	38%	28%	60%	17%	47%	45%	61%
May	43%	39%	51%	24%	42%	60%	56%
June	47%	34%	46%	16%	40%	65%	51%
July	44%	29%	27%	14%	37%	83%	48%
August	34%	21%	23%	12%	33%	70%	49%
September	22%	24%	35%	21%	46%	37%	42%
October	29%	28%	47%	25%	54%	68%	34%
November	21%	39%	55%	23%	60%	43%	50%
December	19%	48%	56%	26%	68%	47%	52%
Annual	**30%**	**33%**	**48%**	**21%**	**51%**	**57%**	**48%**

Candidate Storage Resources

To complement candidate renewables, candidate energy storage resources are represented in SVP's capacity expansion model. Energy storage resources can shift the generation from variable renewable resources to serve load during critical system hours when renewables might otherwise not be producing electricity. Four energy storage resources are modeled, including both conventional technologies (Li-ion batteries, Pumped Hydro Storage) and a generic emerging energy storage technology. The four energy storage resources each have a different storage duration, allowing the model to select the optimal mix of storage capacity and duration.

Li-ion batteries are modeled in two durations (4- and 8-hr) and are available for selection immediately in 2026. Pumped Storage is modeled with a 12-hr duration and is the only energy storage resource modeled with limits on the available resource potential. The resource potential for Pumped Storage is taken from the CPUC IRP I&A document.[40] This resource is an aggregation of several project sites that have been identified as suitable for development, the first of which could be developed as early as 2027. Finally, the Generic Energy Storage (100-hr) resource is only available for selection in scenarios where emerging technologies are allowed, starting in 2036.

Key metrics for the candidate storage resources available to SVP are summarized in Figure 41.

Figure 41. Candidate Storage Resource Options

Resource Name	Duration (hr)	First Available Year	Cumulative Build Limit	Lifetime (years)	Round-Trip Efficiency
Li Battery 4hr	4	2026	Uncapped	20	85%
Li Battery 8hr	8	2026	Uncapped	20	85%
Pumped Storage 12hr	12	2027	3.2 GW	50	70%
Generic Energy Storage 100hr	100	2036	Uncapped	20	45%

Candidate Thermal Resources

Candidate thermal resources are also made available to SVP in scenarios where new emitting resources are allowed to be procured. These include new combined cycle gas turbines (CCGTs), CTs, and reciprocating engine units. The first available year for all new thermal units is 2027. New thermal units are assumed to be procured from outside the SVP system.

Key metrics for the candidate thermal resources available to SVP are summarized in Figure 42 and Figure 43.

[40] CPUC 2022-23 IRP Cycle Events and Materials. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials.

Figure 42. Candidate Thermal Resource Options

Resource Name	First Available Year	Cumulative Build Limit[2]	Lifetime (years)
Advanced CCGT	2027	Uncapped	25
Aero CT	2027	Uncapped	25
Reciprocating Engine	2027	Uncapped	25

Figure 43. Candidate Thermal Operating Parameters

Resource Name	Heat Rate Curve		VO&M ($/MWh)	Fuel Type
	Intercept (MMBtu)	Slope (MMBtu/MWh)		
Advanced CCGT	500	6.0	2.12	Spot Gas
Aero CT	346	6.0	6.96	Spot Gas
Reciprocating Engine	4.9	9.2	6.96	Spot Gas

Emerging Technology Resources

Emerging technology resources include zero-carbon technologies that have not yet reached full commercialization. These resources are not included in core portfolios that are considered for adoption in SVP's IRP; they are only considered in Scenario 3: Zero Emissions with Emerging Technology (Zero Emissions Scenario) and the Geothermal Limitations and Hydrogen Challenges Sensitivity (Hydrogen Sensitivity). Emerging technologies under consideration include both candidate emerging technology resources, which are subject to optimization decisions in the PLEXOS capacity expansion model; and planned emerging technology conversions, which include retrofits and fuel conversions of specific thermal generators for the combustion of zero-carbon fuels. While emerging technologies are generally more expensive to build and operate than conventional renewable resources, their chief advantage is that they are firm, non-emitting resources capable of serving peak load.

Candidate emerging technology resources under consideration in the IRP are Allam Cycle CCS with 100% carbon capture efficiency, Nuclear small module reactor (SMR), and Hydrogen CT. The candidate hydrogen resource modeled in the IRP represents the procurement of new hydrogen CTs. Other components required for the hydrogen economy, including pipelines, storage reservoirs, electrolyzers, and dedicated renewable electricity to run the electrolyzers, are bundled into the hydrogen fuel cost, discussion in the Fuel Prices section.

SVP's portfolio of existing thermal units is assumed to undergo retrofits or conversions to zero-emission fuels in the emerging technology scenarios:

+ **Lodi Energy Center (LEC)** – LEC is assumed to undergo a two-phase retrofit to transition from natural gas to hydrogen by 2035. The first phase occurs in 2027 where a 45% hydrogen fuel blend is assumed. This first phase occurs in all model scenarios, not just the Zero Emissions Scenario. In the second phase, the system is assumed to switch to 100% hydrogen combustion beginning in 2032. Since this is a planned conversion, no costs are modeled for this retrofit.
+ **Alameda CT 1 and 2** – These units are assumed to retrofit to 100% hydrogen starting in 2030. The conversion is a forced-in decision, and the costs of the retrofit are included in the total system cost.

- **Lodi CT** – Lodi CT is assumed to retrofit to 100% hydrogen in 2032. The conversion is a forced-in decision, and the costs of the retrofit are included in the total system cost.
- **DVR Hydrogen** – DVR is assumed to undergo a retrofit for hydrogen fuel combustion in 2035. The conversion is represented as a forced-in decision, and the costs of the retrofit are included in the total system cost.
- **Gianera 1 and 2** – These units are assumed to switch fuels from natural gas to RNG, beginning in 2035. Apart from an increased fuel price and the ending of carbon emissions, no other costs or impacts of the fuel switch are modeled.

Key metrics for the emerging technology resources available to SVP are summarized in Figure 44 and Figure 45.

Figure 44. Emerging Technology Resource Options

Resource Name	First Available Year	Cumulative Build Limit	Lifetime (years)
Allam Cycle 100% CCS	2036	Uncapped	25
Nuclear SMR	2036	Uncapped	25
Hydrogen CT	2035	Uncapped	25
Lodi Energy Center (LEC)	2027 – 45% Fuel Blend (modeled in all scenarios) 2032 – 100% Hydrogen (Zero Emissions Scenario and Hydrogen Sensitivity only)	--	--
Alameda CT 1 Hydrogen	2030 – Retrofit	--	25
Alameda CT 2 Hydrogen	2030 – Retrofit	--	25
Lodi CT Hydrogen	2032 – Retrofit	--	25
DVR Hydrogen	2035 – Retrofit	--	25
Gianera 1 RNG	2035 – Fuel Switch	--	--
Gianera 2 RNG	2035 – Fuel Switch	--	--

Figure 45. Emerging Technology Operating Parameters

Resource Name	Heat Rate Curve Intercept (MMBtu)	Heat Rate Curve Slope (MMBtu/MWh)	VO&M ($/MWh)	Fuel Type	Pmin
Allam Cycle 100% CCS	1,624	6.3	5.09	Spot Gas	50%
Nuclear SMR	0	10.0	3.38	Uranium	40%
Hydrogen CT	346	6.1	6.96	Hydrogen	--
Lodi Energy Center (LEC)	Load points provided by SVP	Load points provided by SVP	3.66	Spot Gas (2024-26) Hydrogen 45% Blend (2027-2031) Hydrogen (2032+)	--
Alameda CT 1 Hydrogen	Load points provided by SVP	Load points provided by SVP	1.52	Spot Gas (2024-2029) Hydrogen (2030+)	--
Alameda CT 2 Hydrogen	Load points provided by SVP	Load points provided by SVP	1.52	Spot Gas (2024-2029) Hydrogen (2030+)	--
Lodi CT Hydrogen	Load points provided by SVP	Load points provided by SVP	1.52	Spot Gas (2024-2031) Hydrogen (2032+)	--
DVR Hydrogen	Load points provided by SVP	Load points provided by SVP	3.00	Spot Gas (2024-2034) Hydrogen (2035+)	--
Gianera 1	Load points provided by SVP	Load points provided by SVP	3.00	Spot Gas (2024-2034) RNG (2035+)	--
Gianera 2	Load points provided by SVP	Load points provided by SVP	3.00	Spot Gas (2024-2034) RNG (2035+)	--

7.2. Candidate Resource Costs

The total fixed costs of candidate resources, including capital cost, FO&M costs, interconnection, investment tax credits (ITCs), property taxes, and warranty and augmentation costs, if any, were derived from the 2023 NREL ATB Electricity report.[41] These costs on a $/kW basis were then levelized using a nominal developer weighted average cost of capital (WACC) over the resource's economic life. Additionally, transmission cost adders for out-of-state resources, discussed in the Transmission section, are added to this value to determine the Levelized Fixed Cost (LFC). In PLEXOS, the Build Cost parameter represents the levelized cost inputs from NREL ATB plus any transmission deliverability cost adders. The sum of these values yields LFC for each candidate resource.

The IRA is expected to impact the costs of candidate clean energy resources. These impacts are largely due to existing tax credits extending beyond 2024 and new technology-neutral tax credits that will begin in 2025. Due to the IRA, solar PV can elect to receive a PTC instead of the ITC. Early analysis suggests that the PTC will outperform the ITC for utility-scale solar projects. Therefore, new candidate solar resources are assumed to elect the PTC. In addition, standalone storage projects are now eligible for the ITC under the IRA. Projects are eligible for the full "Bonus" tax credit amounts (30% of qualifying capital expenditure for the ITC or $26/MWh of electricity generation for the PTC) if specific prevailing wage and apprenticeship requirements are met. If these requirements are not met, the project is eligible for one-fifth of the full tax credit amount. The full "Bonus" IRA tax credits will be used to calculate resource costs.

Emerging clean energy technologies such as hydrogen and CCS are eligible for new tax credits under the IRA for systems that produce green electrofuels and thermal generators equipped with CCS technologies. Systems are eligible for these PTCs until 2032, which can be extended to 2035 using a three-year assumption for Continuity Safe Harbor. The PTC for hydrogen CTs and retrofits built in 2035 is factored into the hydrogen fuel price, discussed in a later section. For Allam Cycle 100% CCS, since the resource is not available until 2036, no PTC is modeled.

Inflationary pressures and supply chain issues have caused price increases for certain metals and other raw materials which may drive up the costs for some technologies. Studies have shown that since 2020, renewable technologies such as wind, solar, and lithium-ion batteries have seen increases in Levelized Cost of Energy (LCOE) and overnight capital expenditure (CAPEX). Modifications to the NREL ATB cost trajectory for utility-scale solar, onshore wind, offshore wind, and Li-ion batteries were made to reflect current market conditions and substantial impacts to the supply chain.

Although new emitting thermal generation is not allowed in the scenarios considered, the LFCs for candidate thermal resources are summarized in Figure 46 for reference.

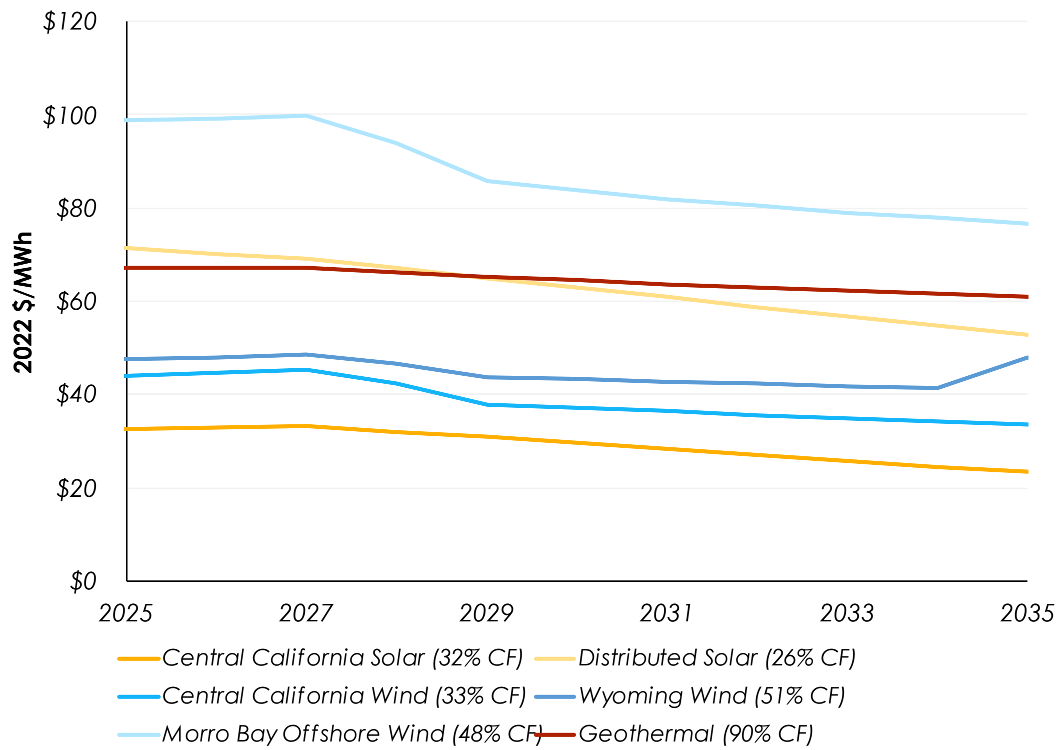
[41] https://atb.nrel.gov/electricity/2023/index

Figure 46. Candidate Thermal Resource Levelized Fixed Costs, 2022 $/kW-yr

Resource Name	2026	2028	2030	2032	2035
Advanced CCGT	$187.37	$184.31	$181.24	$178.16	$173.43
Aero CT	$187.14	$184.64	$182.00	$179.36	$175.60
Reciprocating Engine	$187.14	$184.64	$182.00	$179.36	$175.60

For candidate renewable resources, the LCOE is derived from the LFC using the annual capacity factor, plus any VO&M cost, fuel cost, and PTCs, if applicable. The LCOE represents the volumetric cost of electricity required for the candidate resource to recover its variable and fixed costs. The LCOEs of candidate renewable resources are summarized in Figure 47.

Figure 47. Levelized Cost of Electricity by Candidate Renewable Technology, 2022 $/MWh



LFCs for candidate energy storage and emerging technologies are derived from NREL ATB and the CPUC IRP I&A documentation. LFCs are provided in Figure 48 and Figure 49 for storage and emerging technologies, respectively. Note that in the Geothermal Limitations and Hydrogen Challenges Sensitivity, the cost of hydrogen retrofits are doubled relative to what is presented in Figure 49.

Figure 48 Candidate Storage Resource Levelized Fixed Costs, 2022 $/kW-yr

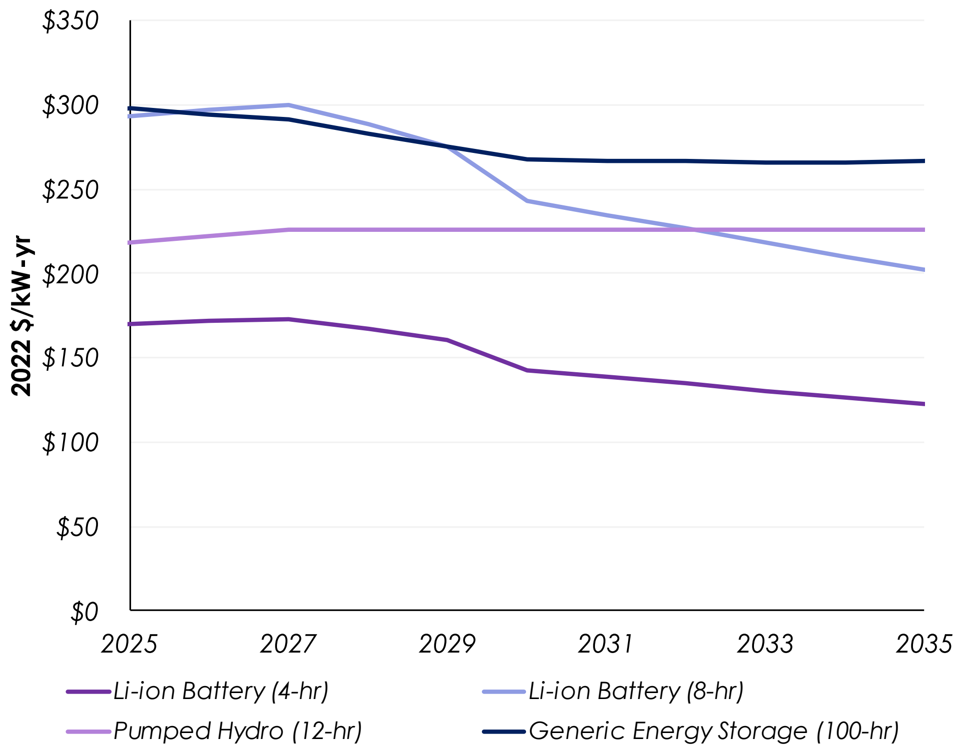
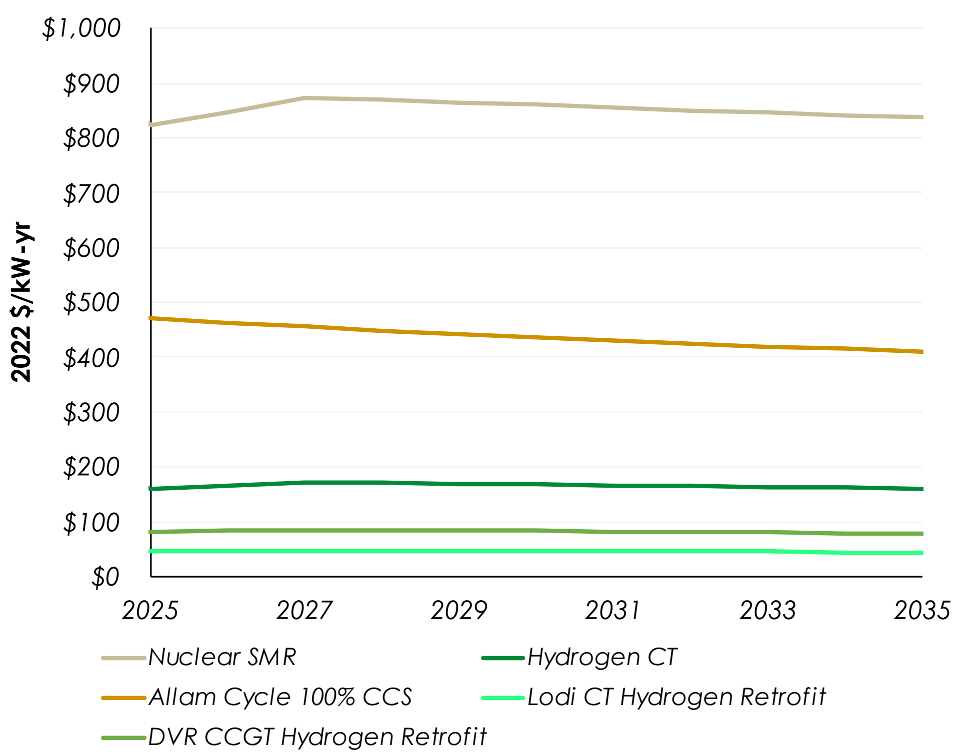


Figure 49. Candidate Emerging Technology Levelized Fixed Cost, 2022 $/kW-yr



7.3. Reliability Requirement Assumptions

The reliability contribution from candidate resources was determined using a marginal ELCC accounting framework as discussed in Section 6.4. The marginal ELCCs by technology and year are provided in Figure 31 of Section 6.4.

7.4. Fuel Prices

Several fuels are modeled for the thermal resources in SVP's existing and planned resource portfolio, as well as for candidate and planned emerging technology resources in Scenario 3: Zero Emissions with Emerging Technology (Zero Emissions Scenario) and the Geothermal Limitations and Hydrogen Challenges Sensitivity (Hydrogen Sensitivity). These fuels include natural gas, RNG, hydrogen, and uranium, shown in Figure 50. See Appendix C for hydrogen fuel price assumptions.

Figure 50. Fuels Included in the SVP IRP Model

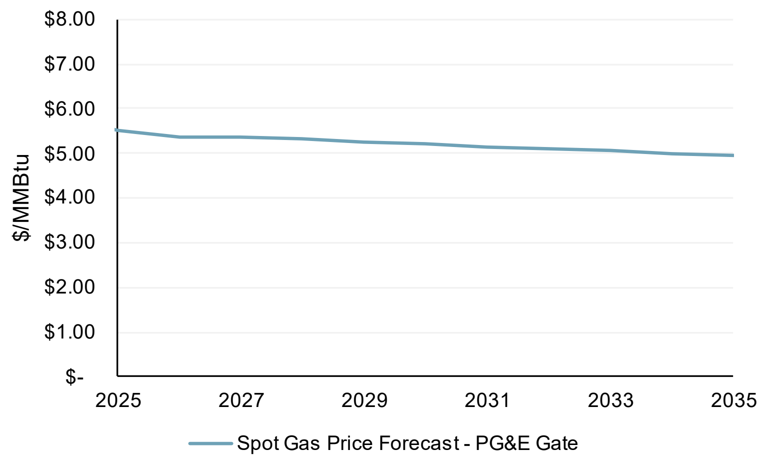
Fuel	Generators	Data Source
Natural Gas	Existing thermal fleet Candidate thermal resources	E3 Gas Price Forecast
Hydrogen Blend	Lodi Energy Center (from 2027)	45%/55% Blend of Natural Gas and Hydrogen fuel prices
Hydrogen*	Candidate Hydrogen CT Alameda CT 1 and 2 (from 2030) Lodi CT (from 2032) Lodi Energy Center (from 2032) DVR (from 2035)	E3 Electrofuels Calculator
Renewable Natural Gas*	Gianera 1 and 2 (from 2035)	SVP price estimate
Uranium*	Candidate Nuclear SMR	CPUC IRP Inputs & Assumptions

** Only modeled in the Zero Emissions Scenario and Hydrogen Sensitivity*

SVP's existing portfolio of thermal-fired units are assumed to use natural gas settled at the PG&E City Gate spot gas price. The price forecast was developed by E3 using a combination of forward prices in the near-term[42] and Energy Information Administration Annual Energy Outlook fundamentals-based forecasts for the longer term.[43] The price forecasts were localized to the PG&E Gate using projections of monthly basis differentials from the near-term forward prices. The resulting spot gas price forecast is shown in Figure 51.

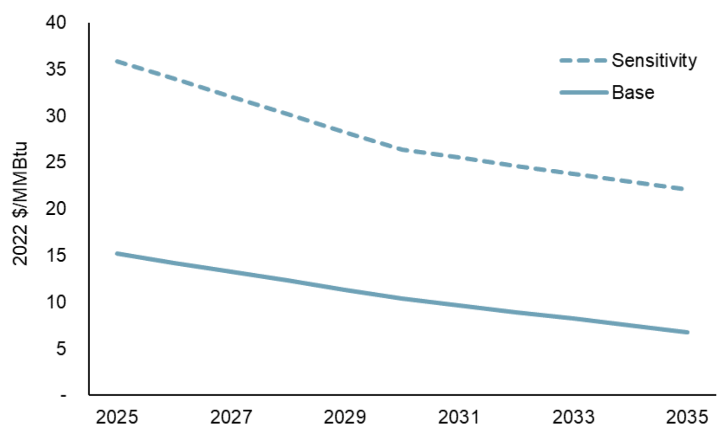
[42] Henry Hub forwards from S&P Global Market Intelligence, https://www.spglobal.com/marketintelligence/en/.
[43] https://www.eia.gov/outlooks/aeo/.

Figure 51. Natural Gas Price Forecast, 2022 $/MMBtu



The hydrogen fuel price forecast, shown in Figure 52, was calculated using E3's Hydrogen Calculator. Hydrogen fuel prices are levelized and vintaged by generator construction year due to the hydrogen PTC. In the Geothermal Limitations and Hydrogen Challenges Sensitivity, hydrogen fuel prices are increased to reflect an upper bound of uncertainty over future fuel prices. For details on hydrogen forecast assumptions, see Appendix C.

Figure 52. Hydrogen Price Forecast, 2022 $/MMBtu



A RNG price assumption of $30/MMBtu in 2035 was provided by SVP for Gianera 1 and 2.

A uranium fuel price of $0.71/MMBtu in real 2022 dollars was adopted from the CPUC IRP Inputs and Assumptions document.[44]

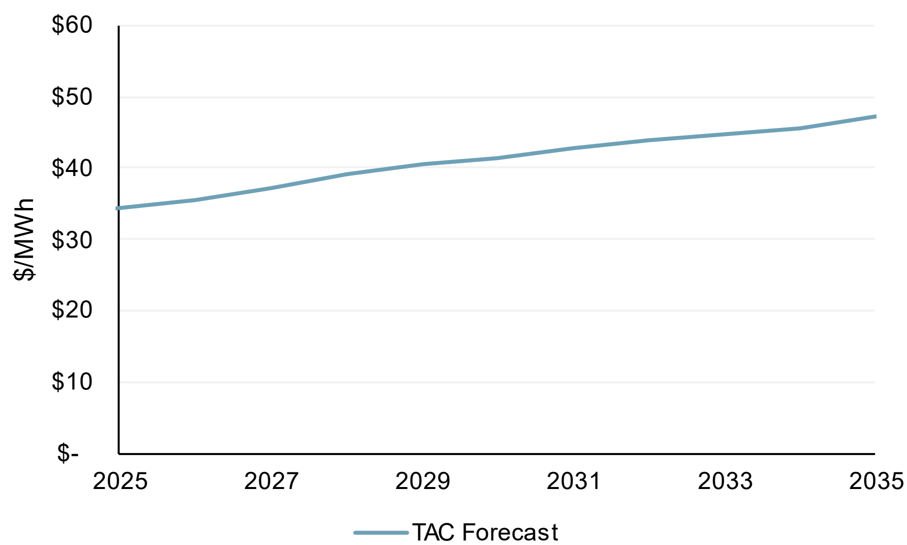
[44] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials

7.5. Transmission

As discussed in Section 6, the two regions in the SVP IRP model represent the SVP MSSA and the rest of CAISO. These two nodes are connected by a transmission line that represents SVP's tie-ins to the bulk CAISO system. Per SVP's MSSA, SVP must pay a TAC on net imports over this line. In PLEXOS, this consideration is instead implemented by applying a discount, equal to the TAC, on DVR and Gianera 1 and 2, such that these resources are incentivized to dispatch as resources that reduce SVP's net load. The TAC is then added back in as a post-processing step to calculate total system costs. Here, the TAC is applied to SVP's total load.

The forecast of high-voltage and low-voltage TAC was provided by a consultant supporting SVP and is provided in Figure 53.

Figure 53. TAC Forecast, 2022 $/MWh



Two out-of-state resources, Wyoming Wind and New Mexico Wind, are located external to the CAISO system. Instead of modeling these remote candidate resources in separate zones within PLEXOS to simulate the full transmission network, the transmission considerations have been modeled implicitly:

+ The availability of remote candidate resources is delayed reflecting the expected timelines for additional capability to be made available on specific transmission lines, aligned with the latest assumptions from the CPUC IRP Inputs and Assumptions document.[45]
+ Cost adders have been assigned to specific candidate resources based on the need for line upgrades to accommodate additional transmission capability. These are included in the resource "Build Cost" in the PLEXOS model.

[45] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials

Out-of-state resources are assumed to require new transmission connections to the CAISO system. These connections incur out-of-state transmission deliverability costs which include transmission upgrade costs and wheeling charges. Transmission cost data for these remote wind generators are summarized in Figure 54.

Figure 54. Transmission Deliverability Costs, 2022 $/kW-yr

Resource Name	Upgrade Cost	Wheeling Charge	Notes
New Mexico Wind	$71.20	$30.78	SunZia[46] + SRP Wheeling[47]
Wyoming Wind	$118.80	N/A	TransWest[48]

46 https://nmfwri.org/wp-content/uploads/2022/02/Mountainair-Collaborative_SunZia-Update-1-27-2022.pdf.
47 http://www.oasis.oati.com/woa/docs/SRP/SRPdocs/SRP_OATT_08-01-2022_Final.pdf.
48 https://www.energy.ca.gov/reti/.

8. Results and Discussion

This section presents the SVP system resource portfolios in three scenarios with varying clean energy requirements from 2026, the first year when new resource additions are allowed, to 2035, the end of the planning horizon. The three scenarios are listed in order of least to most stringent clean energy requirements:

+ Scenario 1: Base SB 100
+ Scenario 2: Accelerated SB 100
+ Scenario 3: Zero Emissions with Emerging Technology

Scenario 1: Base SB 100 (Base Scenario) identifies the optimal least-cost portfolio that meets the current state policies. Scenario 2: Accelerated SB 100 (Accelerated SB 100 Scenario) advances the statewide SB 100 targets from the Base Scenario to reach 100% of retail sales clean by 2035. Scenario 3: Zero Emissions with Emerging Technology (Zero Emissions Scenario) achieves zero hourly emissions in 2035 with emerging technologies. For detailed scenario assumptions, please refer to Section 6.6.

The following Sections 8.1, 8.2, and 8.3 summarize results in each of the scenarios. Section 8.4 compares the three scenarios to identify the impacts of more aggressive clean energy policies.

The accompanying CEC Standardized Tables (CRAT, EBT, RPT, and GEAT) for the three scenarios are included in Appendix A.

8.1. Scenario 1: Base SB 100

Figure 55 shows the cumulative resource additions through 2035 in Scenario 1: Base SB 100 (Base Scenario). In the period 2026-2027, SVP is modeled to add 180 MW wind, 150 MW solar, and 110 MW battery storage capacity to meet load growth and reliability requirements. Starting in 2028, geothermal becomes available and is added to the system (as well as wind capacity) as geothermal, though higher cost per MWh than wind, provides both clean energy generation and firm capacity that carries a higher reliability contribution. The baseload operating characteristics of geothermal also align with the relatively high 80% load factor (or average load divided by peak load) of the SVP system. A high load factor means that the system demand is relatively constant. Due to the large share of industrial load on SVP's system and forecasted data center load growth, there is less ability to shape loads to take advantage of certain resource production, such as low-cost solar. By 2035, the total resource additions include 290 MW geothermal, 590 MW wind, 150 MW solar, and 110 MW storage capacity to meet load growth and the increasing clean energy requirement.

Figure 55. Base Scenario Cumulative New Build Capacity

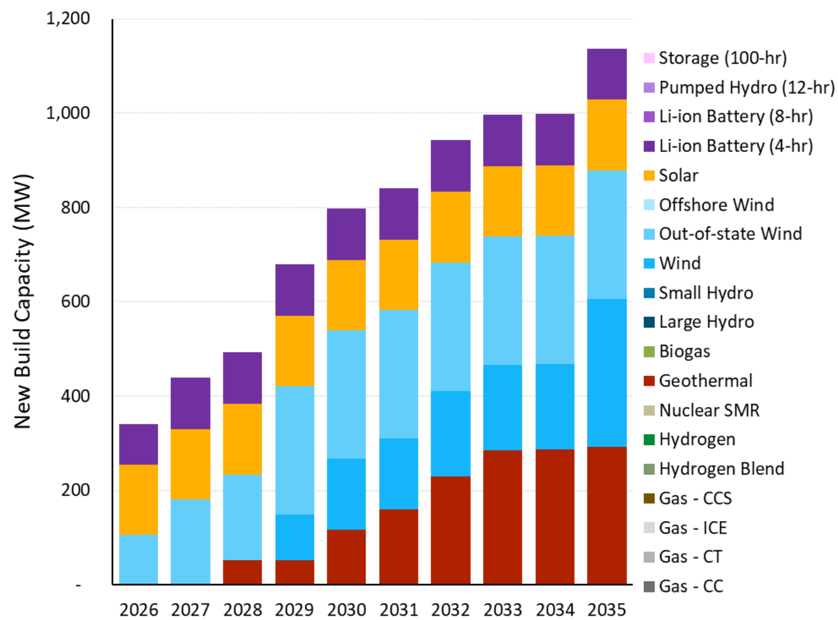


Figure 56 shows the total capacity through 2035 in the Base Scenario. In addition to resource additions in the new build capacity, this figure includes SVP's existing and planned resources. Renewable and zero-carbon resources make up an increasing share of the total system capacity as no new emitting fossil fuel resources can be added to the system. One of the existing gas resources, LEC (78 MW), also transitions from 100% natural gas to 45% (volumetric) hydrogen blending. For detailed assumptions on existing and planned resources, please refer to Section 4 Existing and Planned System and Resources.

Figure 56. Base Scenario Total Capacity

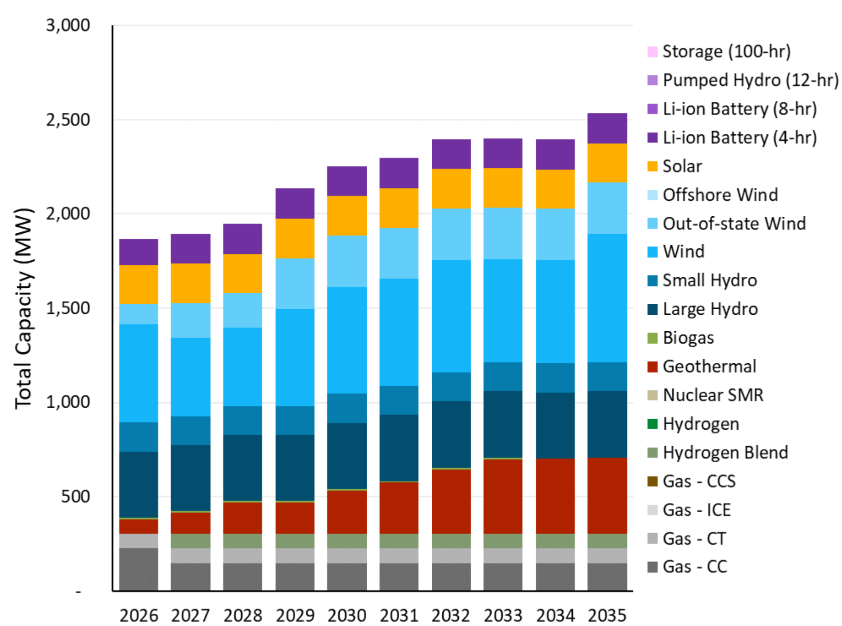
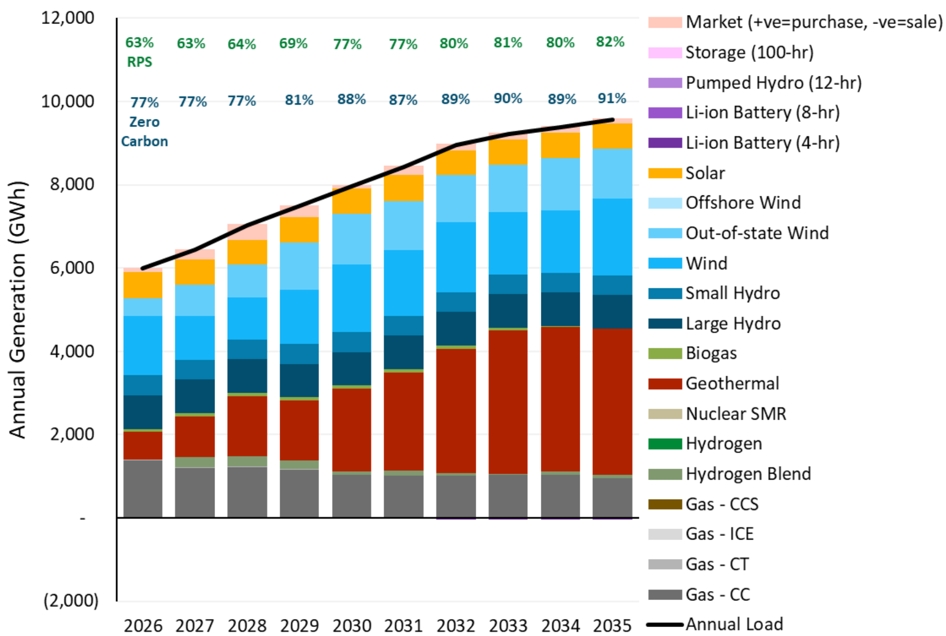


Figure 57 shows the annual generation by resource type through 2035 in the Base Scenario. With existing, planned, and new build renewable resources, RPS (as a % of retail sales) reaches slightly over 60% in 2026, four years ahead of the 60% by 2030 SB 100 target and increases to around 80% by 2035. Zero-carbon resource generation (as a percentage of retail sales) reaches an estimated 77% in 2026 and increases to 90% in 2035, meeting SB 100 interim targets. Despite significant load growth forecasted over the planning period, gas-based generation gradually reduces and stays relatively consistent in later years, as clean energy generation is selected to meet new loads.

Figure 57. Base Scenario Annual Generation



Note: RPS and Zero Carbon percentages are based on retail sales and on the accounting framework of annual targets in SB 100

Figure 58 details the annual energy balance of loads and resources.

Figure 58. Base Scenario Annual Energy Balance of Loads and Resources

Annual Energy Balance of Loads and Resources Silicon Valley Power												
Description		Technology	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
System Annual Energy Demand (GWh)			5,983	6,436	7,037	7,492	7,964	8,428	8,953	9,210	9,387	9,559
SVP Owned Units - Generation (GWh)												
SVP Owned Units (Non-RPS Eligible)	DVR	Gas - CC	1,103	1,195	1,214	1,163	1,036	1,012	1,005	1,034	1,041	946
	Gianera 1	Gas - CT	10	10	10	7	3	7	5	-	0	1
	Gianera 2	Gas - CT	10	10	10	5	4	4	5	-	-	0
	Alameda CT 1	Gas - CT	-	-	-	-	-	-	-	-	-	-
	Alameda CT 2	Gas - CT	-	-	-	-	-	-	-	-	-	-
	Lodi CT	Gas - CT	-	-	-	-	-	-	-	-	-	-
	LEC	Gas - CC	284	-	-	-	-	-	-	-	-	-
	LEC Hydrogen 45 Blend	Hydrogen Blend	-	254	257	214	76	108	67	16	78	93
	Collierville	Large Hydro	158	158	158	158	158	158	158	158	158	158
	BESS 50MW 200MWh	Li-ion Battery (4-hr)	(7)	(6)	(7)	(7)	(10)	(11)	(13)	(13)	(11)	(13)
SVP Owned Units (RPS Eligible)	Black Butte	Small Hydro	8	8	8	8	8	8	8	8	8	8
	Stony Gorge	Small Hydro	6	7	7	7	7	7	7	7	7	7
	Grizzly Hydro	Small Hydro	43	43	43	43	43	43	43	43	43	43
	Big Horn 1	Wind	209	-	-	-	-	-	-	-	-	-
	Big Horn 2	Wind	41	40	42	37	37	42	36	35	37	28
	Geo Plant 1 Unit 1	Geothermal	105	105	105	105	105	105	105	105	105	105
	Geo Plant 1 Unit 2	Geothermal	105	105	105	105	105	105	105	105	105	105
	Geo Plant 2 Unit 4	Geothermal	140	140	141	140	140	140	141	140	140	140
	Spicer	Small Hydro	5	5	5	5	5	5	5	5	5	5
Total SVP Owned Units (GWh)			*2,221*	*2,074*	*2,098*	*1,990*	*1,716*	*1,733*	*1,678*	*1,644*	*1,717*	*1,626*
Long-Term Contracts - Generation (GWh)												
Long-term Contracts (Non-RPS Eligible)	Tri-Dam Donnells	Large Hydro	243	243	243	243	243	243	243	243	243	243
	WAPA Base Resource	Large Hydro	250	250	250	250	250	250	250	250	250	250
	South Feather - Forbstown	Large Hydro	59	60	59	57	58	60	58	59	60	57
	South Feather - Woodleaf	Large Hydro	99	100	99	98	95	99	100	98	95	95
Long-term Contracts (RPS Eligible)	Ameresco Forward	Biogas	37	37	37	37	36	37	36	36	6	-
	Ameresco Vasco	Biogas	38	38	38	38	37	37	37	37	6	-
	G2 Landfill	Biogas	-	-	-	-	-	-	-	-	-	-
	Tri-Dam Beardsley	Small Hydro	43	44	45	45	44	45	44	44	43	43
	Tri-Dam Sand Bar	Small Hydro	71	74	73	75	73	75	74	73	70	70
	Tri-Dam Tulloch	Small Hydro	111	109	108	108	108	110	110	108	106	106
	Friant 1	Small Hydro	66	67	66	66	65	66	66	66	65	65
	Friant 2 (Quinten)	Small Hydro	39	39	39	39	39	40	39	39	38	38
	Rio Bravo (Index+)	Small Hydro	15	15	14	14	14	15	14	13	15	14
	Camp Far West Hydro (Index+)	Small Hydro	26	26	24	26	25	25	25	26	25	26
	South Feather - Kelly Ridge	Small Hydro	27	27	27	28	27	27	27	27	27	27
	South Feather - Sly Creek	Small Hydro	14	14	14	14	14	14	14	14	14	14
	Central 40 Solar	Solar	113	113	110	111	112	113	107	109	111	110
	Rosamond Solar	Solar	63	63	61	62	62	62	60	61	63	60
	Aquamarine Westside (Index+)	Solar	-	-	-	-	-	-	-	-	-	-
	Manzana Wind	Wind	132	125	116	119	128	126	125	-	-	-
	Cimmaron Wind	Wind	930	786	742	783	886	820	855	786	797	761
	Calpine Geo	Geothermal	307	613	615	613	613	613	615	613	613	613
	Sand Hill A	Wind	30	28	29	28	28	29	30	26	27	30
	Sand Hill B	Wind	41	38	39	38	37	39	40	36	37	40
	Rooney Ranch	Wind	44	41	43	41	41	42	43	39	40	43
Total Long-term Contracts (GWh)			*2,795*	*2,949*	*2,891*	*2,931*	*3,034*	*2,986*	*3,012*	*2,804*	*2,751*	*2,705*
New Resource Additions - Generation (GWh)												
New Resources (Non-RPS Eligible)	Li_Battery_4hr	Li-ion Battery (4-hr)	(10)	(10)	(12)	(13)	(17)	(19)	(23)	(20)	(21)	(22)
New Resources (RPS Eligible)	Central_California_Wind	Wind	-	-	-	256	471	471	560	561	569	948
	Geothermal	Geothermal	-	-	466	465	1,026	1,397	2,012	2,482	2,508	2,541
	New_Mexico_Wind	Out-of-state Wind	432	415	437	514	525	505	484	486	562	500
	Southern_California_Solar	Solar	438	442	426	438	442	450	426	440	443	424
	Wyoming_Wind	Out-of-state Wind	-	328	354	615	683	674	640	662	695	703
Total New Resource Additions (GWh)			*860*	*1,176*	*1,672*	*2,275*	*3,130*	*3,479*	*4,098*	*4,610*	*4,756*	*5,096*
Market Purchases and Sales (GWh)												
Market Purchases (GWh)			407	560	728	671	483	653	612	613	633	609
Market Sales (GWh)			(300)	(322)	(352)	(375)	(399)	(422)	(448)	(461)	(470)	(478)
Net Market Purchases (GWh)			*107*	*237*	*376*	*296*	*84*	*231*	*164*	*152*	*163*	*131*
Net System Energy (GWh)			*5,983*	*6,436*	*7,037*	*7,492*	*7,964*	*8,428*	*8,953*	*9,210*	*9,387*	*9,559*

Figure 59 shows the system reliability modeling results through 2035 in the Base Scenario, using SVP's marginal reliability need and marginal ELCC MW values. While the marginal ELCC per nameplate capacity of some resources such as gas and geothermal remains high, that of other resources such as wind, solar, and battery storage is lower and declines over the planning horizon as large volumes of these resources are added by other CAISO LSEs. Therefore, even with a relatively large share of the total nameplate capacity, solar, wind, and battery storage only contribute to a small share of the total effective capacity need. Geothermal, existing gas and hydro remain important for system reliability throughout the planning horizon.

The marginal reliability need shown in Figure 59 is not as high as peak load plus a margin as in the traditional PRM approach and it does not necessarily increase. However, it should not be directly interpreted as meaning there are lower capacity needs for the system, because the corresponding marginal ELCCs used for resource accreditation are also lower than the average ELCCs used in the traditional PRM approach. Hence, relative to the traditional PRM planning approach, the need declines but the resource contributions also decline accordingly. Although not directly used in modeling, the estimated total reliability need, using the traditional framework, and the difference in resource capacity accreditation ("CAISO Portfolio Effects") is included in the reliability figure for illustrative purposes.[49] For more details on the marginal reliability framework, please refer to Section 6.4 Model Constraints.

Figure 59. Base Scenario Marginal Reliability Need and Marginal Effective Capacity

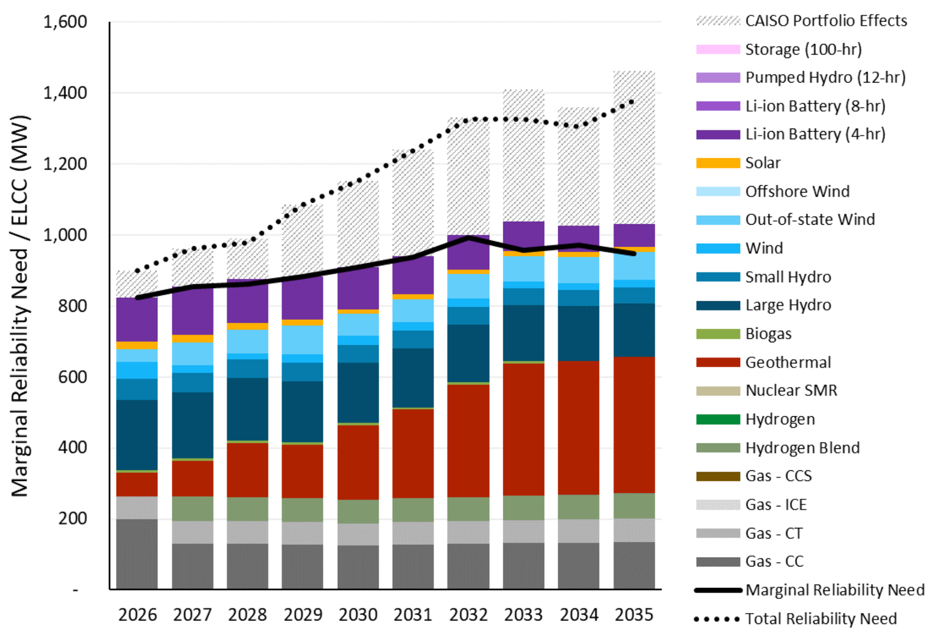


Figure 60 details the annual marginal reliability need and resource capacity.

[49] The total reliability need is estimated based on SVP's coincident load with CAISO's gross peak in the 2022 IEPR forecast and a perfect capacity (PCAP)-based PRM of 14%. Gross peak is CAISO's managed net peak with all BTM PV's load-reducing impacts added back. The 14% PCAP PRM translates to about 22% ICAP PRM and is a more stringent target than previous CAISO studies to ensure a 1-day-in-10-years LOLE target.

Figure 60. Base Scenario Marginal Reliability Need and Resource Capacity Accreditation

Marginal Reliability Need and Resource Capacity Accreditation Silicon Valley Power												
Description		Technology	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
System Coincident Peak (Coincident with 2022 IEPR CAISO Gross Peak)			798	850	866	960	1,018	1,093	1,171	1,171	1,152	1,219
PCAP PRM (%)			14%	14%	14%	14%	14%	14%	14%	14%	14%	14%
System Total Reliability Need (MW)			909	970	987	1,094	1,160	1,246	1,335	1,335	1,314	1,389
CAISO Portfolio Effects (MW)			85	116	125	212	251	309	342	379	343	442
System Marginal Reliability Need (MW)			*825*	*853*	*863*	*882*	*909*	*937*	*993*	*956*	*970*	*947*
SVP Owned Units - Marginal Effective Load Carrying Capability, ELCC (MW)												
SVP Owned Units (Non-RPS Eligible)	DVR	Gas - CC	130	129	129	127	126	128	129	131	133	135
	Gianera 1	Gas - CT	21	20	20	20	20	20	20	20	21	21
	Gianera 2	Gas - CT	21	20	20	20	20	20	20	20	21	21
	Alameda CT 1	Gas - CT	8	8	8	8	8	8	8	8	8	8
	Alameda CT 2	Gas - CT	8	8	8	8	8	8	8	8	8	8
	Lodi CT	Gas - CT	8	8	8	8	8	8	8	8	8	8
	LEC	Gas - CC	68	-	-	-	-	-	-	-	-	-
	LEC Hydrogen 45 Blend	Hydrogen Blend	-	68	68	67	66	67	68	69	70	71
	Collierville	Large Hydro	51	49	46	45	44	43	42	41	40	39
	BESS 50MW 200MWh	Li-ion Battery (4-hr)	46	42	39	38	37	34	30	27	23	20
SVP Owned Units (RPS Eligible)	Black Butte	Small Hydro	2	2	2	2	2	2	2	2	2	2
	Stony Gorge	Small Hydro	2	2	2	2	2	2	2	2	2	2
	Grizzly Hydro	Small Hydro	7	7	6	6	6	6	6	6	6	5
	Big Horn 1	Wind	23	-	-	-	-	-	-	-	-	-
	Big Horn 2	Wind	4	4	4	3	3	3	3	3	3	3
	Geo Plant 1 Unit 1	Geothermal	11	11	11	11	11	11	11	11	11	11
	Geo Plant 1 Unit 2	Geothermal	11	11	11	11	11	11	11	11	11	11
	Geo Plant 2 Unit 4	Geothermal	14	15	15	15	15	15	15	15	15	15
	Spicer	Small Hydro	1	1	1	1	1	1	1	1	1	1
Total SVP Owned Units (MW)			*436*	*406*	*399*	*392*	*386*	*385*	*384*	*384*	*383*	*382*
Long-Term Contracts - Marginal Effective Load Carrying Capability, ELCC (MW)												
Long-term Contracts (Non-RPS Eligible)	Tri-Dam Donnells	Large Hydro	40	38	36	35	35	34	33	32	32	31
	WAPA Base Resource	Large Hydro	71	67	63	62	61	59	58	57	55	54
	South Feather - Forbstown	Large Hydro	13	13	12	12	12	11	11	11	11	10
	South Feather - Woodleaf	Large Hydro	22	20	19	19	19	18	18	17	17	17
Long-term Contracts (RPS Eligible)	Ameresco Forward	Biogas	3	3	3	3	3	3	3	3	-	-
	Ameresco Vasco	Biogas	3	3	3	3	3	3	3	4	-	-
	G2 Landfill	Biogas	-	-	-	-	-	-	-	-	-	-
	Tri-Dam Beardsley	Small Hydro	5	4	4	4	4	4	4	4	4	4
	Tri-Dam Sand Bar	Small Hydro	7	6	6	6	6	5	5	5	5	5
	Tri-Dam Tulloch	Small Hydro	10	10	9	9	9	9	9	8	8	8
	Friant 1	Small Hydro	10	10	9	9	9	8	8	8	8	8
	Friant 2 (Quinten)	Small Hydro	-	-	-	-	-	-	-	-	-	-
	Rio Bravo (Index+)	Small Hydro	6	5	5	5	5	5	5	5	4	4
	Camp Far West Hydro (Index+)	Small Hydro	3	3	2	2	2	2	2	2	2	2
	South Feather - Kelly Ridge	Small Hydro	3	3	3	2	2	2	2	2	2	2
	South Feather - Sly Creek	Small Hydro	3	3	3	3	3	3	3	3	3	3
	Central 40 Solar	Solar	4	4	4	3	2	2	2	2	3	3
	Rosamond Solar	Solar	2	2	2	2	1	1	1	1	1	1
	Aquamarine Westside (Index+)	Solar	-	-	-	-	-	-	-	-	-	-
	Manzana Wind	Wind	8	6	4	4	4	4	3	-	-	-
	Cimmaron Wind	Wind	-	-	-	-	-	-	-	-	-	-
	Calpine Geo	Geothermal	31	64	65	65	64	65	65	66	66	67
	Sand Hill A	Wind	4	3	2	2	2	2	2	2	1	1
	Sand Hill B	Wind	5	4	3	3	3	3	2	2	2	2
	Rooney Ranch	Wind	6	5	3	3	3	3	3	2	2	2
Total Long-term Contracts (MW)			*260*	*277*	*262*	*257*	*252*	*248*	*244*	*237*	*226*	*222*
New Resource Additions - Marginal Effective Load Carrying Capability, ELCC (MW)												
New Resources (Non-RPS Eligible)	Li_Battery_4hr	Li-ion Battery (4-hr)	79	92	84	83	81	74	66	59	51	44
New Resources (RPS Eligible)	Central_California_Wind	Wind	-	-	-	8	12	11	12	11	9	14
	Geothermal	Geothermal	-	-	49	49	108	148	215	268	272	279
	New_Mexico_Wind	Out-of-state Wind	34	36	37	34	26	27	29	30	32	33
	Southern_California_Solar	Solar	16	15	14	12	9	9	9	9	9	10
	Wyoming_Wind	Out-of-state Wind	-	28	29	47	35	37	39	41	43	45
Total New Resource Additions (MW)			*129*	*171*	*214*	*233*	*271*	*307*	*370*	*418*	*417*	*425*
Total System Marginal ELCC Capacity (MW)			*825*	*853*	*875*	*882*	*909*	*940*	*999*	*1,039*	*1,026*	*1,030*

8.2. Scenario 2: Accelerated SB 100

The Accelerated SB 100 Scenario builds on top of Scenario 1: Base SB 100 (Base Scenario) to accelerate the SB 100 targets from 60% RPS to 70% carbon-free energy (60% still needs to come from renewable resources) by 2030, and from 90% carbon-free energy to 100% by 2035.

Figure 61 shows the cumulative resource additions through 2035 in the Accelerated SB 100 Scenario. Near-term additions are similar to those in the Base Scenario prior to the accelerated clean energy targets driving decisions later in the horizon. By 2035, the total resource additions include 330 MW geothermal, 740 MW wind, 180 MW solar, and 100 MW battery storage. 40 MW more geothermal, 150 MW more wind, and 30 MW more solar are selected compared to the Base Scenario to meet the higher clean energy requirement. Figure 62 shows the total capacity, including existing and planned resources, through 2035.

Figure 61. Accelerated SB 100 Scenario Cumulative New Build Capacity

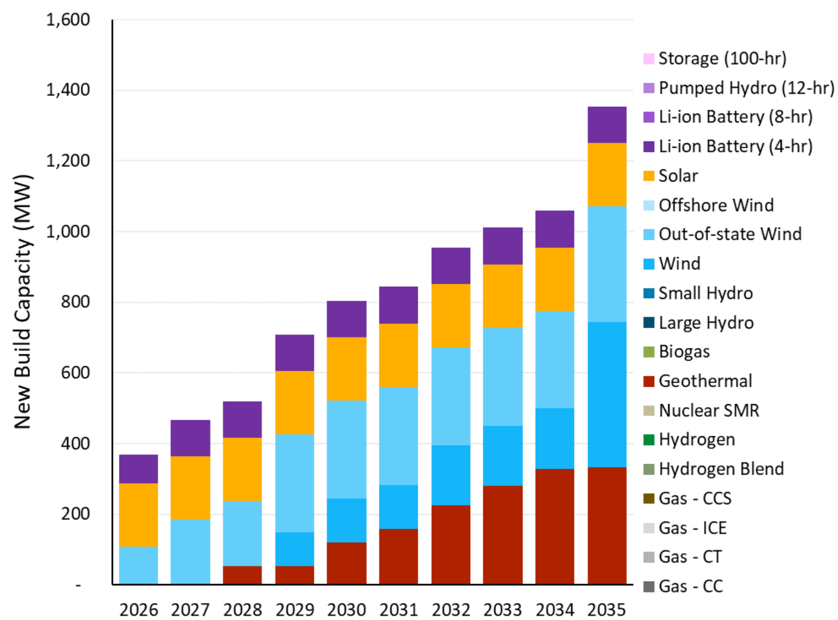


Figure 62. Accelerated SB 100 Scenario Total Capacity

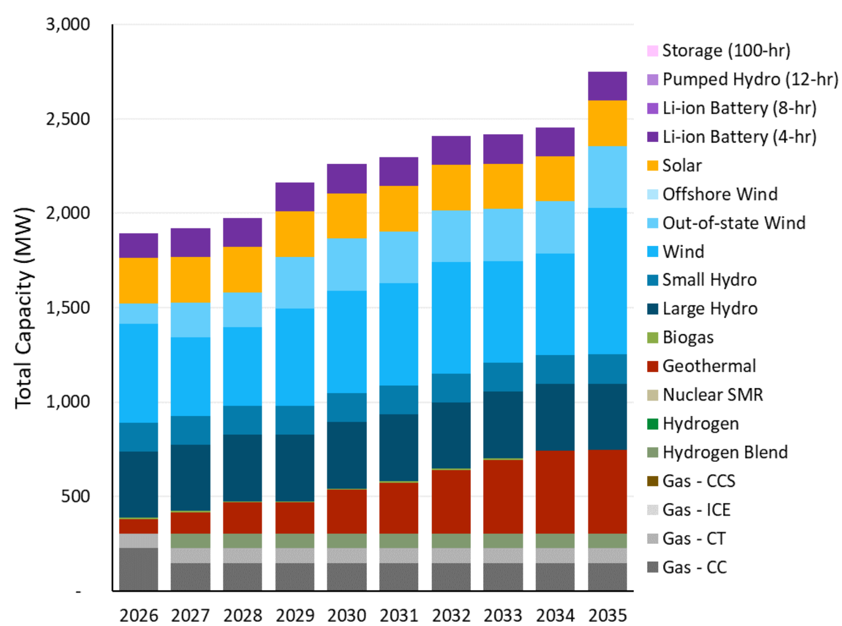
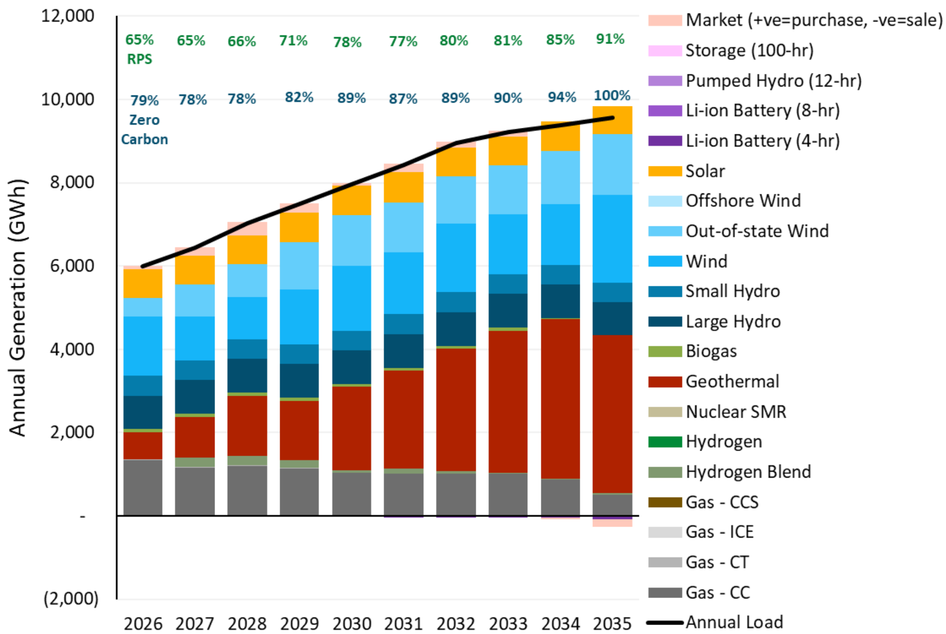


Figure 63 shows the annual generation by resource type through 2035 in the Accelerated SB 100 Scenario. With existing, planned, and new build resources, carbon-free resource generation (as a percentage of retail sales) surpasses the 70% target in 2030, as clean energy generation is selected to meet SVP's large increase in retail sales, and increases to 100%, meeting the accelerated 2035 target. Gas-based generation is lower than that in the Base Scenario, but still present as the clean energy requirement is based on the accounting framework of SB 100, which requires 100% clean energy generation of retail sales, not total generation.

Figure 63. Accelerated SB 100 Scenario Annual Generation



Note: RPS and Zero Carbon percentages are based on retail sales and based on the accounting framework of annual targets in SB 100

Figure 64 details the annual energy balance of loads and resources.

Figure 64. Accelerated SB 100 Scenario Annual Energy Balance of Loads and Resources

Annual Energy Balance of Loads and Resources Silicon Valley Power												
Description		Technology	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
System Annual Energy Demand (GWh)			5,983	6,436	7,037	7,492	7,964	8,428	8,953	9,210	9,387	9,559
SVP Owned Units - Generation (GWh)												
SVP Owned Units (Non-RPS Eligible)	DVR	Gas - CC	1,056	1,152	1,193	1,139	1,026	1,007	1,005	1,020	876	508
	Gianera 1	Gas - CT	10	10	10	6	1	5	5	-	-	-
	Gianera 2	Gas - CT	10	10	10	4	3	5	5	-	-	-
	Alameda CT 1	Gas - CT	-	-	-	-	-	-	-	-	-	-
	Alameda CT 2	Gas - CT	-	-	-	-	-	-	-	-	-	-
	Lodi CT	Gas - CT	-	-	-	-	-	-	-	-	-	-
	LEC	Gas - CC	274	-	-	-	-	-	-	-	-	-
	LEC Hydrogen 45 Blend	Hydrogen Blend	-	237	236	188	57	111	65	15	22	38
	Collierville	Large Hydro	158	158	158	158	158	158	158	158	158	158
	BESS 50MW 200MWh	Li-ion Battery (4-hr)	(8)	(6)	(7)	(8)	(11)	(12)	(13)	(12)	(13)	(38)
SVP Owned Units (RPS Eligible)	Black Butte	Small Hydro	8	8	8	8	8	8	8	8	8	8
	Stony Gorge	Small Hydro	6	7	7	7	7	7	7	7	7	7
	Grizzly Hydro	Small Hydro	43	43	43	43	43	43	43	43	43	43
	Big Horn 1	Wind	208	-	-	-	-	-	-	-	-	-
	Big Horn 2	Wind	41	40	42	37	37	42	36	35	37	27
	Geo Plant 1 Unit 1	Geothermal	105	105	105	105	105	105	105	105	105	105
	Geo Plant 1 Unit 2	Geothermal	105	105	105	105	105	105	105	105	105	105
	Geo Plant 2 Unit 4	Geothermal	140	140	141	140	140	140	141	140	140	140
	Spicer	Small Hydro	5	5	5	5	5	5	5	5	5	5
Total SVP Owned Units (GWh)			*2,163*	*2,014*	*2,056*	*1,938*	*1,686*	*1,729*	*1,676*	*1,630*	*1,493*	*1,107*
Long-Term Contracts - Generation (GWh)												
Long-term Contracts (Non-RPS Eligible)	Tri-Dam Donnells	Large Hydro	243	243	243	243	243	243	243	243	243	243
	WAPA Base Resource	Large Hydro	250	250	250	250	250	250	250	250	250	250
	South Feather - Forbstown	Large Hydro	59	60	59	57	59	60	58	59	60	57
	South Feather - Woodleaf	Large Hydro	99	100	99	98	97	99	101	98	95	94
Long-term Contracts (RPS Eligible)	Ameresco Forward	Biogas	37	37	37	37	37	37	36	36	6	-
	Ameresco Vasco	Biogas	38	38	38	38	37	37	37	37	6	-
	G2 Landfill	Biogas	-	-	-	-	-	-	-	-	-	-
	Tri-Dam Beardsley	Small Hydro	43	44	45	45	44	45	44	44	43	43
	Tri-Dam Sand Bar	Small Hydro	71	74	73	75	73	75	74	73	70	70
	Tri-Dam Tulloch	Small Hydro	111	109	108	108	108	110	110	108	106	106
	Friant 1	Small Hydro	66	67	66	66	65	66	66	66	65	65
	Friant 2 (Quinten)	Small Hydro	39	39	39	39	39	40	39	39	38	38
	Rio Bravo (Index+)	Small Hydro	15	15	14	14	14	15	14	13	15	14
	Camp Far West Hydro (Index+)	Small Hydro	26	26	24	26	25	25	25	26	25	26
	South Feather - Kelly Ridge	Small Hydro	26	27	27	28	27	27	27	27	27	26
	South Feather - Sly Creek	Small Hydro	14	14	14	14	14	14	14	14	14	13
	Central 40 Solar	Solar	113	113	110	111	112	113	107	107	110	103
	Rosamond Solar	Solar	62	63	61	62	62	62	59	61	62	55
	Aquamarine Westside (Index+)	Solar	-	-	-	-	-	-	-	-	-	-
	Manzana Wind	Wind	131	125	116	119	128	127	123	-	-	-
	Cimmaron Wind	Wind	930	786	742	783	886	822	851	777	794	732
	Calpine Geo	Geothermal	307	613	615	613	613	613	615	613	613	613
	Sand Hill A	Wind	30	28	29	28	28	29	29	26	27	28
	Sand Hill B	Wind	41	38	39	38	38	39	40	36	37	37
	Rooney Ranch	Wind	44	41	43	41	41	42	43	39	40	41
Total Long-term Contracts (GWh)			*2,792*	*2,949*	*2,891*	*2,931*	*3,039*	*2,988*	*3,005*	*2,792*	*2,747*	*2,654*
New Resource Additions - Generation (GWh)												
New Resources (Non-RPS Eligible)	Li_Battery_4hr	Li-ion Battery (4-hr)	(11)	(10)	(12)	(13)	(17)	(20)	(21)	(20)	(21)	(33)
New Resources (RPS Eligible)	Central_California_Wind	Wind	-	-	-	256	389	390	526	527	534	1,242
	Geothermal	Geothermal	-	-	466	465	1,045	1,389	1,961	2,447	2,869	2,821
	New_Mexico_Wind	Out-of-state Wind	445	427	450	534	545	524	502	505	584	520
	Southern_California_Solar	Solar	525	529	511	524	530	539	510	528	531	508
	Wyoming_Wind	Out-of-state Wind	-	328	354	615	683	674	640	662	695	938
Total New Resource Additions (GWh)			*959*	*1,275*	*1,769*	*2,382*	*3,176*	*3,497*	*4,118*	*4,649*	*5,193*	*5,995*
Market Purchases and Sales (GWh)												
Market Purchases (GWh)			369	520	674	616	463	637	601	601	425	281
Market Sales (GWh)			(300)	(322)	(352)	(375)	(399)	(422)	(448)	(461)	(470)	(478)
Net Market Purchases (GWh)			*69*	*198*	*322*	*241*	*64*	*214*	*153*	*140*	*(45)*	*(198)*
Net System Energy (GWh)			*5,983*	*6,436*	*7,037*	*7,492*	*7,964*	*8,428*	*8,953*	*9,210*	*9,387*	*9,559*

Figure 65 shows the system reliability modeling results through 2035 in the Accelerated SB 100 Scenario. As more capacity is added to meet the clean energy target in this scenario, the total system marginal ELCC MW is higher than that in the Base Scenario and is above the marginal reliability need towards the end of the planning horizon, which illustrates that the clean energy target is the more stringent requirement to meet.

Figure 65. Accelerated SB 100 Scenario Marginal Reliability Need and Marginal Effective Capacity

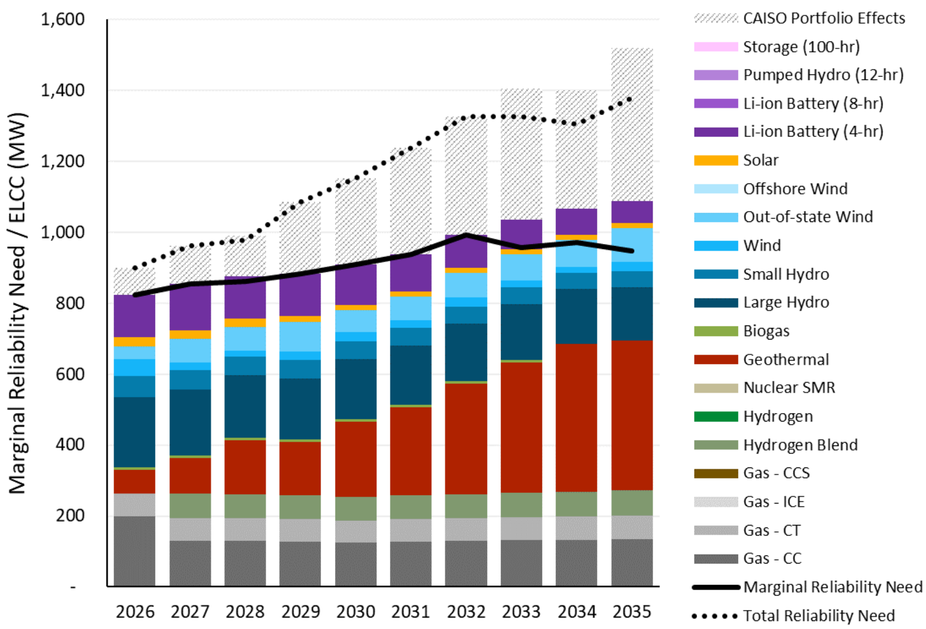


Figure 66 details the annual marginal reliability need and resource capacity.

Figure 66. Accelerated SB 100 Scenario Marginal Reliability Need and Resource Capacity Accreditation

Marginal Reliability Need and Resource Capacity Accreditation Silicon Valley Power												
Description		Technology	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
System Coincident Peak (Coincident with 2022 IEPR CAISO Gross Peak)			798	850	866	960	1,018	1,093	1,171	1,171	1,152	1,219
PCAP PRM (%)			14%	14%	14%	14%	14%	14%	14%	14%	14%	14%
System Total Reliability Need (MW)			909	970	987	1,094	1,160	1,246	1,335	1,335	1,314	1,389
CAISO Portfolio Effects (MW)			85	116	125	212	251	309	342	379	343	442
System Marginal Reliability Need (MW)			*825*	*853*	*863*	*882*	*909*	*937*	*993*	*956*	*970*	*947*
SVP Owned Units - Marginal Effective Load Carrying Capability, ELCC (MW)												
SVP Owned Units (Non-RPS Eligible)	DVR	Gas - CC	130	129	129	127	126	128	129	131	133	135
	Gianera 1	Gas - CT	21	20	20	20	20	20	20	20	21	21
	Gianera 2	Gas - CT	21	20	20	20	20	20	20	20	21	21
	Alameda CT 1	Gas - CT	8	8	8	8	8	8	8	8	8	8
	Alameda CT 2	Gas - CT	8	8	8	8	8	8	8	8	8	8
	Lodi CT	Gas - CT	8	8	8	8	8	8	8	8	8	8
	LEC	Gas - CC	68	-	-	-	-	-	-	-	-	-
	LEC Hydrogen 45 Blend	Hydrogen Blend	-	68	68	67	66	67	68	69	70	71
	Collierville	Large Hydro	51	49	46	45	44	43	42	41	40	39
	BESS 50MW 200MWh	Li-ion Battery (4-hr)	46	42	39	38	37	34	30	27	23	20
SVP Owned Units (RPS Eligible)	Black Butte	Small Hydro	2	2	2	2	2	2	2	2	2	2
	Stony Gorge	Small Hydro	2	2	2	2	2	2	2	2	2	2
	Grizzly Hydro	Small Hydro	7	7	6	6	6	6	6	6	6	5
	Big Horn 1	Wind	23	-	-	-	-	-	-	-	-	-
	Big Horn 2	Wind	4	4	4	3	3	3	3	3	3	3
	Geo Plant 1 Unit 1	Geothermal	11	11	11	11	11	11	11	11	11	11
	Geo Plant 1 Unit 2	Geothermal	11	11	11	11	11	11	11	11	11	11
	Geo Plant 2 Unit 4	Geothermal	14	15	15	15	15	15	15	15	15	15
	Spicer	Small Hydro	1	1	1	1	1	1	1	1	1	1
Total SVP Owned Units (MW)			*436*	*406*	*399*	*392*	*386*	*385*	*384*	*384*	*383*	*382*
Long-Term Contracts - Marginal Effective Load Carrying Capability, ELCC (MW)												
Long-term Contracts (Non-RPS Eligible)	Tri-Dam Donnells	Large Hydro	40	38	36	35	35	34	33	32	32	31
	WAPA Base Resource	Large Hydro	71	67	63	62	61	59	58	57	55	54
	South Feather - Forbstown	Large Hydro	13	13	12	12	12	11	11	11	11	10
	South Feather - Woodleaf	Large Hydro	22	20	19	19	19	18	18	17	17	17
Long-term Contracts (RPS Eligible)	Ameresco Forward	Biogas	3	3	3	3	3	3	3	3	-	-
	Ameresco Vasco	Biogas	3	3	3	3	3	3	3	4	-	-
	G2 Landfill	Biogas	-	-	-	-	-	-	-	-	-	-
	Tri-Dam Beardsley	Small Hydro	5	4	4	4	4	4	4	4	4	4
	Tri-Dam Sand Bar	Small Hydro	7	6	6	6	6	5	5	5	5	5
	Tri-Dam Tulloch	Small Hydro	10	10	9	9	9	9	9	8	8	8
	Friant 1	Small Hydro	10	10	9	9	9	8	8	8	8	8
	Friant 2 (Quinten)	Small Hydro	-	-	-	-	-	-	-	-	-	-
	Rio Bravo (Index+)	Small Hydro	6	5	5	5	5	5	5	5	4	4
	Camp Far West Hydro (Index+)	Small Hydro	3	3	2	2	2	2	2	2	2	2
	South Feather - Kelly Ridge	Small Hydro	3	3	3	2	2	2	2	2	2	2
	South Feather - Sly Creek	Small Hydro	3	3	3	3	3	3	3	3	3	3
	Central 40 Solar	Solar	4	4	4	3	2	2	2	2	3	3
	Rosamond Solar	Solar	2	2	2	2	1	1	1	1	1	1
	Aquamarine Westside (Index+)	Solar	-	-	-	-	-	-	-	-	-	-
	Manzana Wind	Wind	8	6	4	4	4	4	3	-	-	-
	Cimmaron Wind	Wind	-	-	-	-	-	-	-	-	-	-
	Calpine Geo	Geothermal	31	64	65	65	64	65	65	66	66	67
	Sand Hill A	Wind	4	3	2	2	2	2	2	2	1	1
	Sand Hill B	Wind	5	4	3	3	3	3	2	2	2	2
	Rooney Ranch	Wind	6	5	3	3	3	3	3	2	2	2
Total Long-term Contracts (MW)			*260*	*277*	*262*	*257*	*252*	*248*	*244*	*237*	*226*	*222*
New Resource Additions - Marginal Effective Load Carrying Capability, ELCC (MW)												
New Resources (Non-RPS Eligible)	Li_Battery_4hr	Li-ion Battery (4-hr)	74	88	81	79	78	70	63	56	49	42
New Resources (RPS Eligible)	Central_California_Wind	Wind	-	-	-	8	10	9	11	10	9	18
	Geothermal	Geothermal	-	-	49	49	110	148	210	264	312	317
	New_Mexico_Wind	Out-of-state Wind	35	37	38	36	27	28	30	31	33	34
	Southern_California_Solar	Solar	19	18	17	14	11	11	11	11	11	11
	Wyoming_Wind	Out-of-state Wind	-	28	29	47	35	37	39	41	43	60
Total New Resource Additions (MW)			*129*	*171*	*214*	*233*	*271*	*304*	*365*	*414*	*457*	*484*
Total System Marginal ELCC Capacity (MW)			*825*	*853*	*875*	*882*	*909*	*937*	*993*	*1,035*	*1,066*	*1,088*

8.3. Scenario 3: Zero Emissions with Emerging Technology

This scenario represents the most stringent clean energy target modeled in this IRP. Scenario 3: Zero Emissions with Emerging Technology (Zero Emissions Scenario) builds on top of Scenario 2: Accelerated SB 100 and limits emission to zero in every hour in 2035.

As gas plants cannot be dispatched to serve load or meet reliability requirements without resulting in carbon emissions in this scenario, they must either retire or convert to zero-carbon fuels by 2035. Additionally, market purchases are only allowed in hours when the market emission factors are zero. However, emerging technologies are assumed to be available to help achieve zero emissions in this scenario. As many studies have shown, “clean firm” resources that can provide zero-carbon generation on demand to fill in gaps in variable resource output are a critical component of reaching a zero-emissions power system. The “clean firm” technologies considered include building new green hydrogen power plants, CCS (Allam cycle with 100% capture and storage) plants, and long-duration storage. In addition to the ability to build new clean firm resources, retrofits of SVP’s existing thermal portfolio to zero-emission fuels are assumed:

- LEC transitions from 45% (volumetric) hydrogen blending (2027) to 100% hydrogen starting in 2032 [50]
- Alameda CT 1 and 2 run on 100% hydrogen starting in 2030
- Lodi CT runs on 100% hydrogen starting in 2032
- DVR runs on 100% hydrogen starting in 2035
- Gianera 1 and 2 run on 100% biogas starting in 2035

DVR and Gianera are two significant local SVP resources, and the transition of these resources to zero-emission fuels in 2035 in this scenario is partly driven by transmission limitations between SVP and CAISO. If local resources aren’t available, SVP may be completely dependent on electricity delivered via transmission from CAISO to meet load. However, the existing and planned transmission capacity would have insufficient capacity and is about 90 MW below SVP’s forecasted peak load in 2035. Therefore, it is not feasible under current and planned transmission additions to reach zero-emissions without retrofitting local gas generating resources to run on zero-emission fuel and allow them to be dispatched to meet SVP’s load.

Figure 67 shows the cumulative resource additions through 2035 in the Zero Emissions Scenario. The figure includes the above existing resources’ assumed transitions to zero-emission fuels. Near-term additions are similar to the Accelerated SB 100 Scenario’s additions as the zero-emission limit is not applied until 2035. By 2035, the total resource additions include 280 MW hydrogen (250 MW comes from assumed transitions of DVR and LEC and 30 MW comes from building new hydrogen plants), 350 MW geothermal, 50 MW biogas (assumed transition of Gianera), 530 MW wind, 150 MW solar, and 100 MW

[50] The 2032 start year is assumed based on information provided to SVP in communications with NCPA.

battery storage. Other emerging technologies, such as CCS and long-duration storage are not selected due to economics. See Figure 68 for the total system capacity, including other existing resources, through 2035.

Figure 67. Zero Emissions Scenario Cumulative New Build Capacity

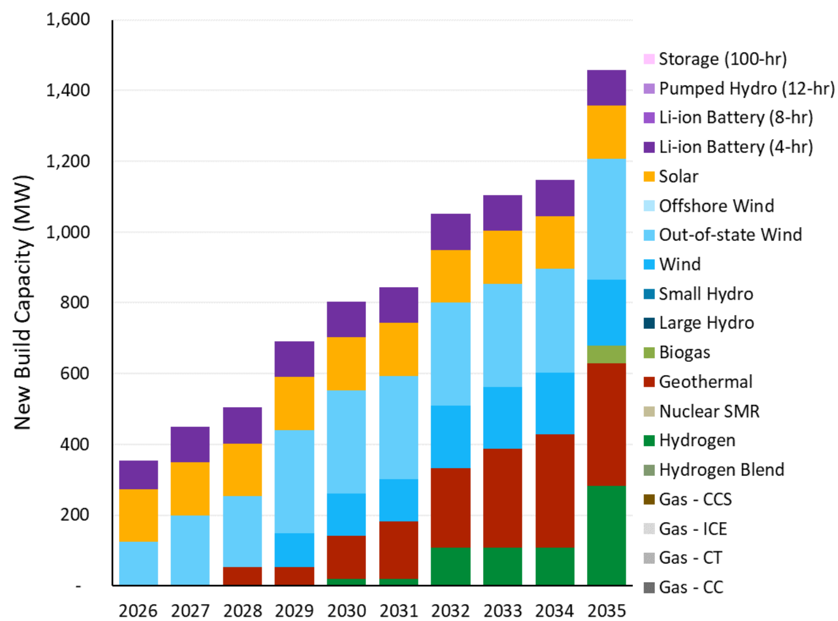
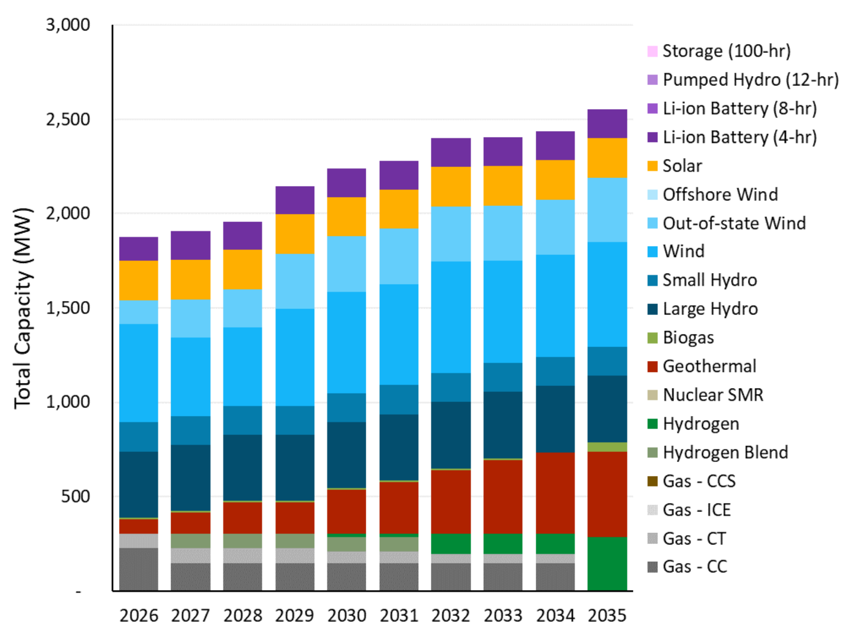
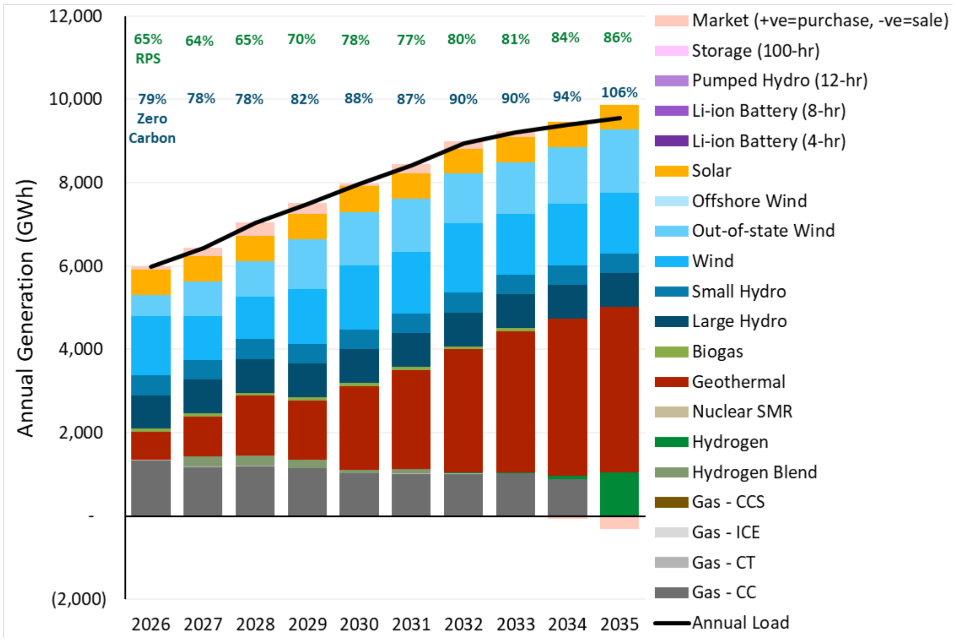


Figure 68. Zero Emissions Scenario Total Capacity



See Figure 69 for the annual generation by resource type through 2035 in the Zero Emissions Scenario. Generation mix follows similar trends as seen in the Accelerated SB 100 Scenario in the near term. In 2035 when the zero-emission limit is applied, no gas generation is allowed and all generation comes from renewable and carbon-free resources, and zero-emission market purchases. The reason that the zero-carbon percentage exceeds 100% in 2035 is because it is calculated based on the accounting framework of SB 100, which is different from total system generation.

Figure 69. Zero Emissions Scenario Annual Generation



Note: RPS and Zero Carbon percentages are based on retail sales and based on the accounting framework of annual targets in SB 100

Figure 70 details the annual energy balance of loads and resources.

Figure 70. Zero Emissions Scenario Annual Energy Balance of Loads and Resources

Annual Energy Balance of Loads and Resources												
Silicon Valley Power												
Description		Technology	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
System Annual Energy Demand (GWh)			5,983	6,436	7,037	7,492	7,964	8,428	8,953	9,210	9,387	9,559
SVP Owned Units - Generation (GWh)												
SVP Owned Units (Non-RPS Eligible)	DVR	Gas - CC	1,067	1,160	1,196	1,141	1,027	1,007	1,006	1,027	891	-
	Gianera 1	Gas - CT	10	10	10	6	2	5	5	-	-	-
	Gianera 2	Gas - CT	10	10	10	4	3	5	5	-	-	-
	Alameda CT 1	Gas - CT	-	-	-	-	-	-	-	-	-	-
	Alameda CT 2	Gas - CT	-	-	-	-	-	-	-	-	-	-
	Lodi CT	Gas - CT	-	-	-	-	-	-	-	-	-	-
	LEC	Gas - CC	273	-	-	-	-	-	-	-	-	-
	LEC Hydrogen 45 Blend	Hydrogen Blend	-	242	240	198	67	113	-	-	-	-
	Collierville	Large Hydro	158	158	158	158	158	158	158	158	158	158
	BESS 50MW 200MWh	Li-ion Battery (4-hr)	(7)	(6)	(7)	(7)	(11)	(11)	(14)	(13)	(13)	(15)
SVP Owned Units (RPS Eligible)	Black Butte	Small Hydro	8	8	8	8	8	8	8	8	8	8
	Stony Gorge	Small Hydro	6	7	7	7	7	7	7	7	7	7
	Grizzly Hydro	Small Hydro	43	43	43	43	43	43	43	43	43	43
	Big Horn 1	Wind	209	-	-	-	-	-	-	-	-	-
	Big Horn 2	Wind	41	40	42	37	37	42	36	35	37	28
	Geo Plant 1 Unit 1	Geothermal	105	105	105	105	105	105	105	105	105	105
	Geo Plant 1 Unit 2	Geothermal	105	105	105	105	105	105	105	105	105	105
	Geo Plant 2 Unit 4	Geothermal	140	140	141	140	140	140	141	140	140	140
	Spicer	Small Hydro	5	5	5	5	5	5	5	5	5	5
Total SVP Owned Units (GWh)			*2,174*	*2,028*	*2,063*	*1,951*	*1,696*	*1,732*	*1,612*	*1,621*	*1,486*	*584*
Long-Term Contracts - Generation (GWh)												
Long-term Contracts (Non-RPS Eligible)	Tri-Dam Donnells	Large Hydro	243	243	243	243	243	243	243	243	243	243
	WAPA Base Resource	Large Hydro	250	250	250	250	250	250	250	250	250	250
	South Feather - Forbstown	Large Hydro	59	60	59	57	59	60	58	59	59	57
	South Feather - Woodleaf	Large Hydro	99	100	99	98	97	99	100	98	95	94
Long-term Contracts (RPS Eligible)	Ameresco Forward	Biogas	37	37	37	37	37	37	36	36	6	-
	Ameresco Vasco	Biogas	38	38	38	38	37	37	37	37	6	-
	G2 Landfill	Biogas	-	-	-	-	-	-	-	-	-	-
	Tri-Dam Beardsley	Small Hydro	43	44	45	45	44	45	44	44	43	43
	Tri-Dam Sand Bar	Small Hydro	71	74	73	75	73	75	74	73	70	70
	Tri-Dam Tulloch	Small Hydro	111	109	108	108	108	110	110	108	106	106
	Friant 1	Small Hydro	66	67	66	66	65	66	66	66	65	65
	Friant 2 (Quinten)	Small Hydro	39	39	39	39	39	40	39	39	38	38
	Rio Bravo (Index+)	Small Hydro	15	15	14	14	14	15	14	13	15	14
	Camp Far West Hydro (Index+)	Small Hydro	26	26	24	26	25	25	25	26	25	26
	South Feather - Kelly Ridge	Small Hydro	26	27	27	28	27	27	27	27	27	27
	South Feather - Sly Creek	Small Hydro	14	14	14	14	14	14	14	14	14	13
	Central 40 Solar	Solar	113	113	110	111	113	113	106	108	110	108
	Rosamond Solar	Solar	62	63	61	62	63	62	59	60	62	59
	Aquamarine Westside (Index+)	Solar	-	-	-	-	-	-	-	-	-	-
	Manzana Wind	Wind	132	125	116	119	128	126	123	-	-	-
	Cimmaron Wind	Wind	930	786	742	783	887	821	854	783	794	752
	Calpine Geo	Geothermal	307	613	615	613	613	613	615	613	613	613
	Sand Hill A	Wind	30	28	29	28	28	29	30	27	27	29
	Sand Hill B	Wind	41	38	39	38	38	39	40	36	37	40
	Rooney Ranch	Wind	44	41	43	41	41	42	43	39	40	43
Total Long-term Contracts (GWh)			*2,794*	*2,949*	*2,891*	*2,931*	*3,042*	*2,987*	*3,006*	*2,799*	*2,745*	*2,691*
New Resource Additions - Generation (GWh)												
New Resources (Non-RPS Eligible)	Hydrogen_Aero_CT_2035	Hydrogen	-	-	-	-	-	-	-	-	-	25
	Li_Battery_4hr	Li-ion Battery (4-hr)	(9)	(9)	(11)	(12)	(17)	(17)	(20)	(19)	(18)	(15)
	DVR Hydrogen	Hydrogen	-	-	-	-	-	-	-	-	-	856
	Alameda CT 1 Hydrogen	Hydrogen	-	-	-	-	-	-	-	-	-	-
	Alameda CT 2 Hydrogen	Hydrogen	-	-	-	-	-	-	-	-	-	5
	Lodi CT Hydrogen	Hydrogen	-	-	-	-	-	-	-	-	-	5
	LEC Hydrogen 100 Blend	Hydrogen	-	-	-	-	-	-	38	14	75	158
New Resources (RPS Eligible)	Central_California_Wind	Wind	-	-	-	256	378	378	541	542	550	563
	Geothermal	Geothermal	-	-	466	465	1,055	1,413	1,977	2,432	2,802	3,000
	New_Mexico_Wind	Out-of-state Wind	509	489	515	599	612	588	564	566	655	583
	Southern_California_Solar	Solar	437	441	425	437	441	449	425	439	442	423
	Wyoming_Wind	Out-of-state Wind	-	328	354	615	683	674	640	662	695	938
	Gianera 1 RNG	Biogas	-	-	-	-	-	-	-	-	-	10
	Gianera 2 RNG	Biogas	-	-	-	-	-	-	-	-	-	8
Total New Resource Additions (GWh)			*937*	*1,250*	*1,750*	*2,360*	*3,152*	*3,485*	*4,165*	*4,637*	*5,201*	*6,558*
Market Purchases and Sales (GWh)												
Market Purchases (GWh)			379	532	685	625	472	646	617	614	424	204
Market Sales (GWh)			(300)	(322)	(352)	(375)	(399)	(422)	(448)	(461)	(470)	(478)
Net Market Purchases (GWh)			*79*	*209*	*333*	*250*	*73*	*224*	*169*	*153*	*(46)*	*(274)*
Net System Energy (GWh)			*5,983*	*6,436*	*7,037*	*7,492*	*7,964*	*8,428*	*8,953*	*9,210*	*9,387*	*9,559*

Figure 71 shows the system reliability modeling results through 2035 in the Zero Emissions Scenario. Resource capacity contribution is similar to the Accelerated SB 100 Scenario before 2035. In 2035, more clean resources are added to the system due to the stringent emission target and surpass the marginal reliability need, meaning the marginal reliability requirement is not the primary driver of resource builds by 2035.

Figure 71. Zero Emissions Scenario Marginal Reliability Need and Marginal Effective Capacity

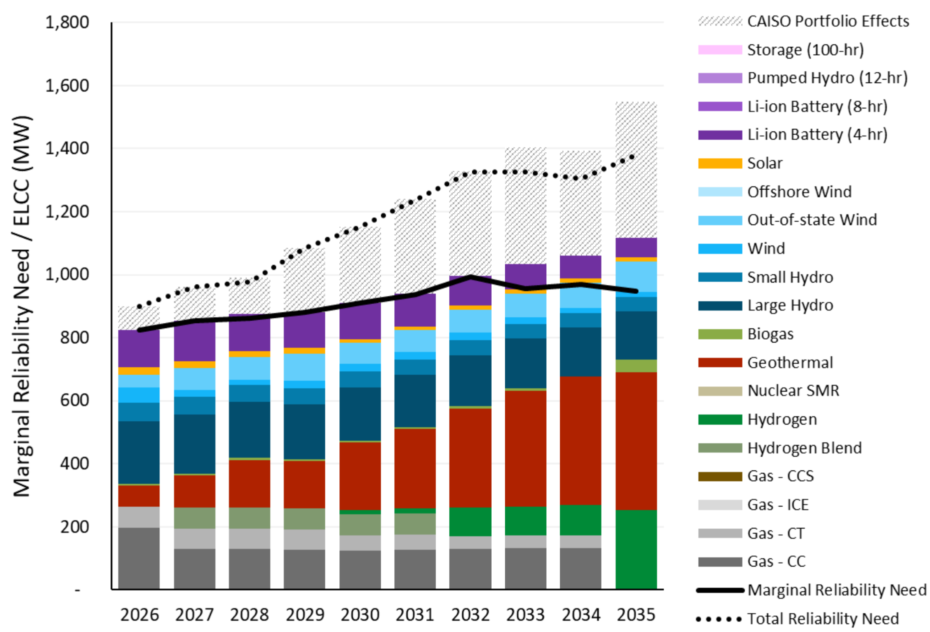


Figure 72 details the annual marginal reliability need and resource capacity.

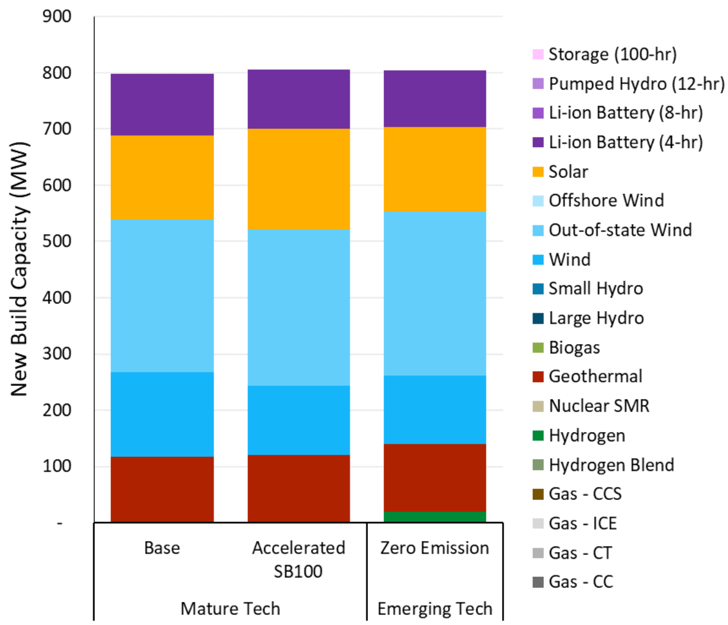
Figure 72. Zero Emissions Scenario Marginal Reliability Need and Resource Capacity Accreditation

Marginal Reliability Need and Resource Capacity Accreditation												
Silicon Valley Power												
Description		Technology	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
System Coincident Peak (Coincident with 2022 IEPR CAISO Gross Peak)			798	850	866	960	1,018	1,093	1,171	1,171	1,152	1,219
PCAP PRM (%)			14%	14%	14%	14%	14%	14%	14%	14%	14%	14%
System Total Reliability Need (MW)			909	970	987	1,094	1,160	1,246	1,335	1,335	1,314	1,389
CAISO Portfolio Effects (MW)			85	116	125	212	251	309	342	379	343	442
System Marginal Reliability Need (MW)			*825*	*853*	*863*	*882*	*909*	*937*	*993*	*956*	*970*	*947*
SVP Owned Units - Marginal Effective Load Carrying Capability, ELCC (MW)												
SVP Owned Units (Non-RPS Eligible)	DVR	Gas - CC	130	129	129	127	126	128	129	131	133	-
	Gianera 1	Gas - CT	21	20	20	20	20	20	20	20	21	-
	Gianera 2	Gas - CT	21	20	20	20	20	20	20	20	21	-
	Alameda CT 1	Gas - CT	8	8	8	8	-	-	-	-	-	-
	Alameda CT 2	Gas - CT	8	8	8	8	-	-	-	-	-	-
	Lodi CT	Gas - CT	8	8	8	8	8	8	-	-	-	-
	LEC	Gas - CC	68	-	-	-	-	-	-	-	-	-
	LEC Hydrogen 45 Blend	Hydrogen Blend	-	68	68	67	66	67	-	-	-	-
	Collierville	Large Hydro	51	49	46	45	44	43	42	41	40	39
	BESS 50MW 200MWh	Li-ion Battery (4-hr)	46	42	39	38	37	34	30	27	23	20
SVP Owned Units (RPS Eligible)	Black Butte	Small Hydro	2	2	2	2	2	2	2	2	2	2
	Stony Gorge	Small Hydro	2	2	2	2	2	2	2	2	2	2
	Grizzly Hydro	Small Hydro	7	7	6	6	6	6	6	6	6	5
	Big Horn 1	Wind	23	-	-	-	-	-	-	-	-	-
	Big Horn 2	Wind	4	4	4	3	3	3	3	3	3	3
	Geo Plant 1 Unit 1	Geothermal	11	11	11	11	11	11	11	11	11	11
	Geo Plant 1 Unit 2	Geothermal	11	11	11	11	11	11	11	11	11	11
	Geo Plant 2 Unit 4	Geothermal	14	15	15	15	15	15	15	15	15	15
	Spicer	Small Hydro	1	1	1	1	1	1	1	1	1	1
Total SVP Owned Units (MW)			*436*	*406*	*399*	*392*	*370*	*369*	*292*	*290*	*289*	*110*
Long-Term Contracts - Marginal Effective Load Carrying Capability, ELCC (MW)												
Long-term Contracts (Non-RPS Eligible)	Tri-Dam Donnells	Large Hydro	40	38	36	35	35	34	33	32	32	31
	WAPA Base Resource	Large Hydro	71	67	63	62	61	59	58	57	55	54
	South Feather - Forbstown	Large Hydro	13	13	12	12	12	11	11	11	11	10
	South Feather - Woodleaf	Large Hydro	22	20	19	19	19	18	18	17	17	17
Long-term Contracts (RPS Eligible)	Ameresco Forward	Biogas	3	3	3	3	3	3	3	3	-	-
	Ameresco Vasco	Biogas	3	3	3	3	3	3	3	4	-	-
	G2 Landfill	Biogas	-	-	-	-	-	-	-	-	-	-
	Tri-Dam Beardsley	Small Hydro	5	4	4	4	4	4	4	4	4	4
	Tri-Dam Sand Bar	Small Hydro	7	6	6	6	6	5	5	5	5	5
	Tri-Dam Tulloch	Small Hydro	10	10	9	9	9	9	9	8	8	8
	Friant 1	Small Hydro	10	10	9	9	9	8	8	8	8	8
	Friant 2 (Quinten)	Small Hydro	-	-	-	-	-	-	-	-	-	-
	Rio Bravo (Index+)	Small Hydro	6	5	5	5	5	5	5	5	4	4
	Camp Far West Hydro (Index+)	Small Hydro	3	3	2	2	2	2	2	2	2	2
	South Feather - Kelly Ridge	Small Hydro	3	3	3	2	2	2	2	2	2	2
	South Feather - Sly Creek	Small Hydro	3	3	3	3	3	3	3	3	3	3
	Central 40 Solar	Solar	4	4	4	3	2	2	2	2	3	3
	Rosamond Solar	Solar	2	2	2	2	1	1	1	1	1	1
	Aquamarine Westside (Index+)	Solar	-	-	-	-	-	-	-	-	-	-
	Manzana Wind	Wind	8	6	4	4	4	4	3	-	-	-
	Cimmaron Wind	Wind	-	-	-	-	-	-	-	-	-	-
	Calpine Geo	Geothermal	31	64	65	65	64	65	65	66	66	67
	Sand Hill A	Wind	4	3	2	2	2	2	2	2	1	1
	Sand Hill B	Wind	5	4	3	3	3	3	2	2	2	2
	Rooney Ranch	Wind	6	5	3	3	3	3	3	2	2	2
Total Long-term Contracts (MW)			*260*	*277*	*262*	*257*	*252*	*248*	*244*	*237*	*226*	*222*
New Resource Additions - Marginal Effective Load Carrying Capability, ELCC (MW)												
New Resources (Non-RPS Eligible)	Hydrogen_Aero_CT_2035	Hydrogen	-	-	-	-	-	-	-	-	-	24
	Li_Battery_4hr	Li-ion Battery (4-hr)	73	86	79	77	76	69	62	55	48	41
	DVR Hydrogen	Hydrogen	-	-	-	-	-	-	-	-	-	135
	Alameda CT 1 Hydrogen	Hydrogen	-	-	-	-	8	8	8	8	8	8
	Alameda CT 2 Hydrogen	Hydrogen	-	-	-	-	8	8	8	8	8	8
	Lodi CT Hydrogen	Hydrogen	-	-	-	-	-	-	8	8	8	8
	LEC Hydrogen 100 Blend	Hydrogen	-	-	-	-	-	-	68	69	70	71
New Resources (RPS Eligible)	Central_California_Wind	Wind	-	-	-	8	10	9	12	10	9	8
	Geothermal	Geothermal	-	-	49	49	111	150	211	263	304	331
	New_Mexico_Wind	Out-of-state Wind	40	42	44	40	30	32	34	35	37	39
	Southern_California_Solar	Solar	16	15	14	12	9	9	9	9	9	10
	Wyoming_Wind	Out-of-state Wind	-	28	29	47	35	37	39	41	43	60
	Gianera 1 RNG	Biogas	-	-	-	-	-	-	-	-	-	21
	Gianera 2 RNG	Biogas	-	-	-	-	-	-	-	-	-	21
Total New Resource Additions (MW)			*129*	*171*	*215*	*233*	*287*	*321*	*459*	*507*	*545*	*784*
Total System Marginal ELCC Capacity (MW)			*825*	*853*	*876*	*882*	*909*	*939*	*995*	*1,035*	*1,059*	*1,117*

8.4. Scenario Comparison

In 2030, the three scenarios have similar resource additions. At least 120 MW geothermal, 400 MW wind, 150 MW solar, and 100 MW battery are selected across the scenarios, indicating that these resources are fairly robust and likely low-regret decisions for SVP in the near term, given the assumptions in this study.

Figure 73. Scenario Comparison – 2030 Cumulative New Build Capacity



While the three scenarios have similar resource additions in the near-term, they begin to diverge towards the end of the planning horizon as more aggressive clean energy targets are applied in Scenario 2: Accelerated SB 100 (Accelerated SB 100 Scenario) and Scenario 3: Zero Emissions with Emerging Technology (Zero Emissions Scenario). Figure 74 compares the cumulative resource additions between the scenarios by 2035. The resource capacities in the Zero Emissions Scenario include the assumed retrofit of some existing SVP natural gas resources (DVR, Gianera, and LEC) to zero-emission fuels.

Compared to Scenario 1: Base SB 100 (Base Scenario), the Accelerated SB 100 Scenario adds about 40 MW more geothermal, 150 MW more wind, and 30 MW more solar capacities to achieve the accelerated 100% carbon free of retail sales by 2035 based on SB 100's annual accounting framework.

Compared to the Base Scenario, the Zero Emissions Scenario assumes 300 MW of existing gas resources are converted to zero-emission fuel by 2035 and adds about 30 MW more hydrogen and 50 MW more geothermal resources to the portfolio. While solar and battery storage capacities are similar, wind capacity is 60 MW less than the Base Scenario due to the availability of emerging technologies and additional geothermal capacity selected. Clean firm resources, such as hydrogen and geothermal considered in this IRP, are favored in this scenario as it is difficult to meet SVP's load profile with no emissions in every hour without firm and dispatchable resource options. The critical role of "clean firm" resources in deep-decarbonized and zero-emission systems has been highlighted and discussed in the industry.[51]

Figure 74. Scenario Comparison – 2035 Cumulative New Build Capacity

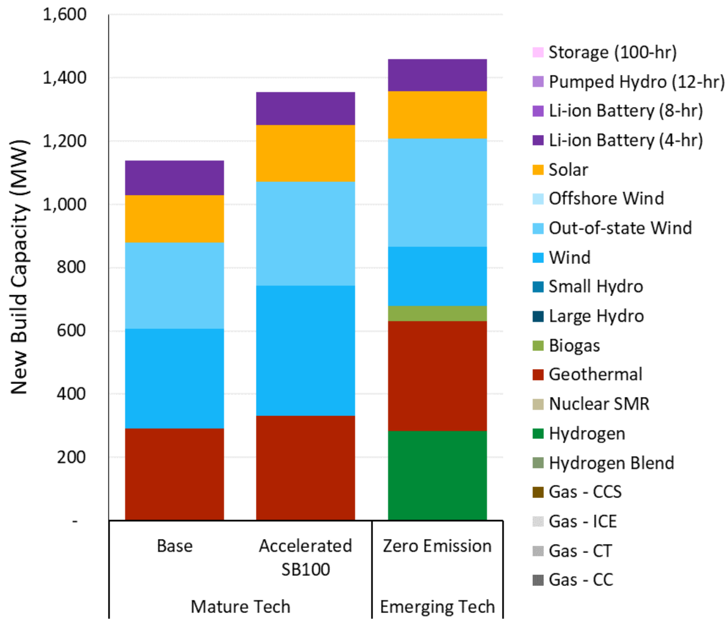


Figure 75 shows a comparison of total capacity between the three scenarios in 2035. The total capacity of the Zero Emissions Scenario is similar to the Base Scenario and lower than the Accelerated SB 100 Scenario because it includes the zero-emission fuel conversion of some of the existing gas resources and other emerging technologies. However, there are uncertainties in these assumptions. If emerging technologies and zero-emission fuels are not available to SVP by 2035, SVP would need to procure higher amounts of existing mature technologies, such as solar, wind, and battery storage resources to achieve zero emission in every hour. The total nameplate capacity of those resources is likely higher than the system load and the three scenarios explored here. Because they have low and marginally decreasing reliability value, more capacity would be needed to cover the most critical hours, even though there might be high curtailment in other normal and/or low load hours. Emerging technology options, such as new hydrogen plants and retrofit of existing gas plants to hydrogen or biogas, offer the "clean firm" attributes and significantly reduces the potential for "overbuilding" existing mature technologies. Thus, reaching a zero-emissions SVP system at reasonable costs by 2035 requires reliance on "clean firm" emerging technologies that are not available commercially at scale today.

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[51] Burdick et al, 2022. "Lighting a Reliable Path to 100% Clean Electricity. Evolving Resource Adequacy Practices for a Decarbonizing Grid." IEEE Power & Energy Magazine. July/August 2022
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E3. "Resource Adequacy in the Pacific Northwest." 2019. https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf

Figure 75. Scenario Comparison – 2035 Total Capacity

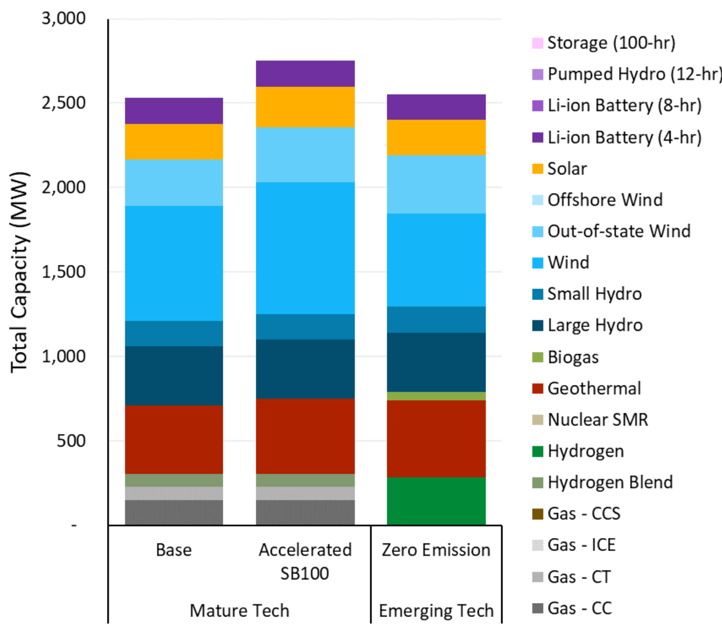


Figure 76 shows the comparison of annual generation between the three scenarios in 2035. Gas generation reduces from Base to Accelerated SB 100 Scenario as the clean energy target increases and becomes zero in the Zero Emissions Scenario. Market purchases also reduce, and the annual net market transaction becomes net sales to market in the latter two scenarios as more energy needs to come from specified renewable and carbon-free resources, and market purchases can only occur in periods when the market is also "clean" (i.e., the emission factor is zero) in the most stringent scenario.

Figure 76. Scenario Comparison – 2035 Annual Generation

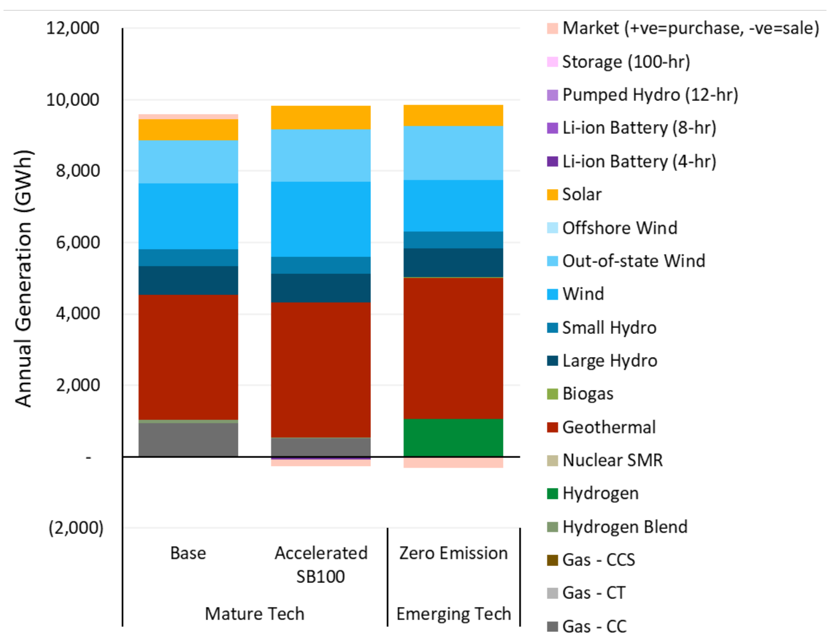
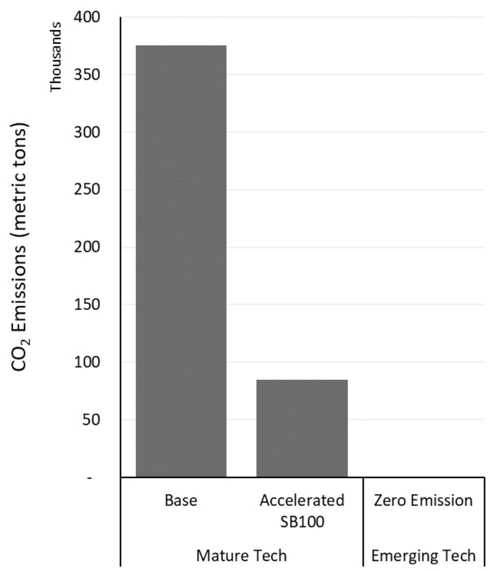


Figure 77 shows the comparison of annual CO_2 emissions between the three scenarios in 2035. This includes emissions from SVP's resources and market purchases. It also includes emission offset credits from market sales when applicable in the Base and Accelerated SB 100 Scenarios (see Section 6.4 for the detailed emission accounting methodology). The 2035 annual emissions are approximately 380,000 metric tons, 85,000 metric tons in the Accelerated SB 100 Scenario, and zero in the Zero Emissions Scenario. System emission reduces following the generation mix trends discussed above.

Figure 77. Scenario Comparison – 2035 Annual CO_2 Emission

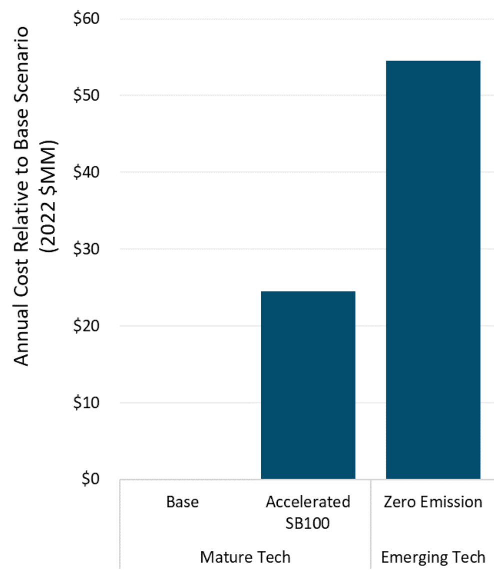


Note: Annual CO_2 emission includes emission from SVP's resources and market purchases. In the Base and Accelerated SB 100 Scenarios, it also includes emission offset credits from market sales when applicable.

See Figure 78 for the comparison of annual modeled cost between the three scenarios in 2035. This only represents the cost components modeled and does not represent SVP's total revenue requirement. Modeled cost includes the operational cost (e.g., variable O&M, fuel costs) of existing and planned capacity, and the capital cost and operational cost of new build capacity. Capital and fixed costs (including PPA cost) of existing and planned capacity are not included. Transmission and distribution costs are also not included.

Compared to the annual modeled cost in the Base Scenario, which reaches $250 million (2022 $; TAC costs and non-modeled system costs are excluded) in 2035, the annual modeled cost increases by about $25 million (2022 $) in the Accelerated SB 100 Scenario and increases by $55 million (2022 $) in the Zero Emissions Scenario. However, it is important to note that there are large uncertainties in the availability and cost of emerging technologies and zero-emission fuels by 2035. As discussed above, without the clean firm emerging technologies modeled in this study, achieving zero emissions with only commercially available resources will likely require significant "overbuilding" of those resources to maintain reliability and the system cost can be much higher. Furthermore, the cost of converting some of the existing gas resources to zero-emission fuels is potentially underestimated due to uncertainties in conversion technologies and limited data at the time of this IRP study. Resource cost and availability uncertainties can have large impacts to the resulting portfolio and system cost, and they should continue to be monitored by SVP in future IRPs.

Figure 78. Scenario Comparison – 2035 Annual Cost Relative to Base Scenario (2022 $MM)



Note: Annual modeled cost includes the operational cost of existing/planned capacity and the capital cost and operational cost of new build capacity. Capital and fixed costs (incl. PPA cost) of existing/planned capacity are not included. Transmission and distribution costs are not included.

8.5. Sensitivity: Geothermal Limitations and Hydrogen Challenges

The Geothermal Limitations and Hydrogen Challenges Sensitivity (Hydrogen Sensitivity) represents an additional modification to Scenario 3: Zero Emissions with Emerging Technology (Zero Emissions Scenario), designed to explore uncertainty over future hydrogen prices and resource availability. Like the Zero Emissions Scenario, this sensitivity includes the most stringent clean energy target modeled in this IRP, limiting emission to zero in every hour in 2035.

The cost of hydrogen retrofits and hydrogen fuel prices are uncertain in a future scenario with deep decarbonization. In this sensitivity, hydrogen costs have been increased relative to the Zero Emissions Scenario to reflect an upper bound to this uncertainty. Hydrogen retrofits costs for SVP's existing gas fleet have been doubled, and fuel prices have been increased by making more conservative assumptions for electrolyzer technology, process electricity costs, and pipeline capacity factor. See Figure 52 and Appendix C for details on hydrogen price forecast.

Finally, this sensitivity explores scarcity of conventional clean firm resources by limiting SVP's geothermal resource potential to 50 MW, first available in 2028.

Figure 74 shows the cumulative resource additions through 2035 in the Hydrogen Sensitivity. The figure includes the above existing resources' assumed transitions to zero-emission fuels. By 2035, the total resource additions include 163 MW of CCS, 255 MW hydrogen (all coming from assumed transitions SVP's existing thermal fleet), 50 MW geothermal, 50 MW biogas (assumed transition of Gianera), 1,262 MW wind, 62 MW offshore wind, 905 MW solar, and 276 MW battery storage. Other emerging technologies, such as nuclear and long-duration storage, are not selected due to economics. See Figure 80 for the total system capacity, including other existing resources, through 2035.

Figure 79. Hydrogen Sensitivity Cumulative New Build Capacity

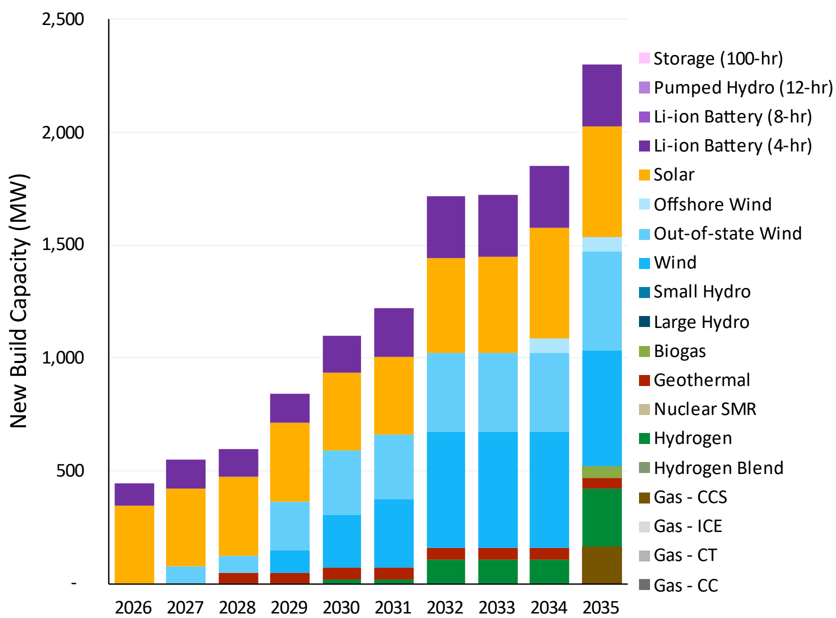
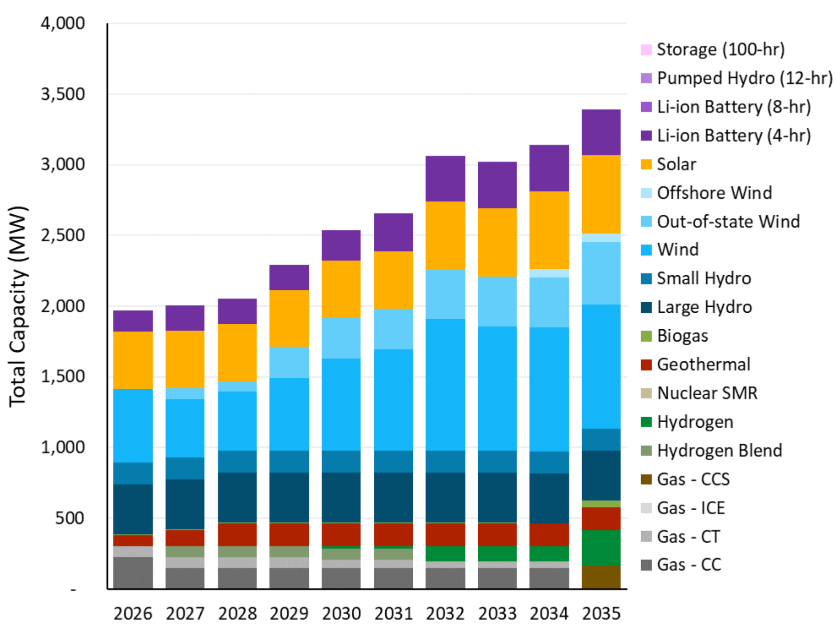
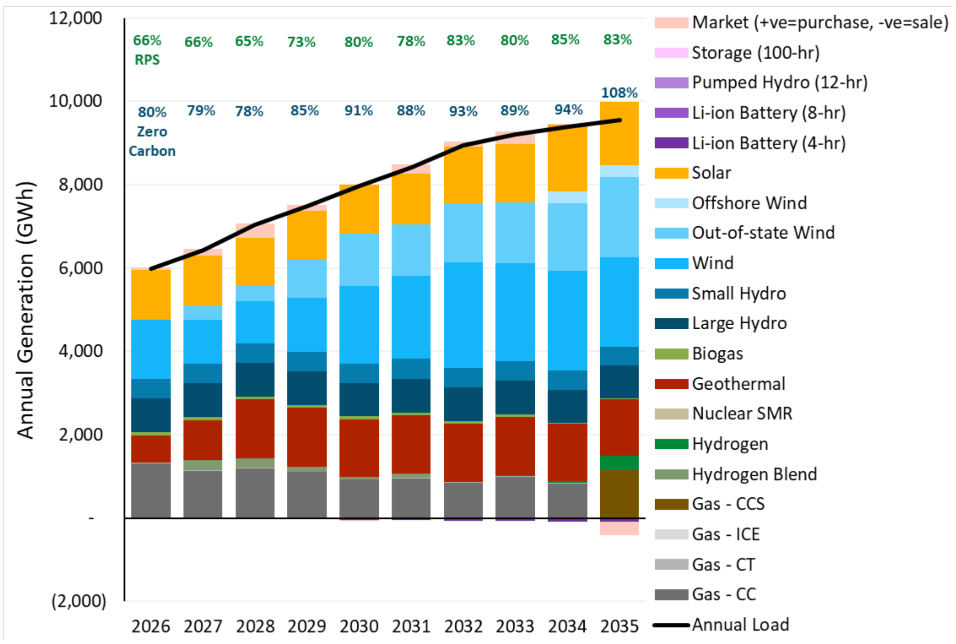


Figure 80. Hydrogen Sensitivity Total Capacity



See Figure 81 for the annual generation by resource type through 2035 in the Hydrogen Sensitivity. In 2035, when the zero-emission limit is applied, no gas generation is allowed and all generation comes from renewable and carbon-free resources, and zero-emission market purchases. The reason that the zero-carbon percentage exceeds 100% in 2035 is because it is calculated based on the accounting framework of SB 100, which is different from total system generation.

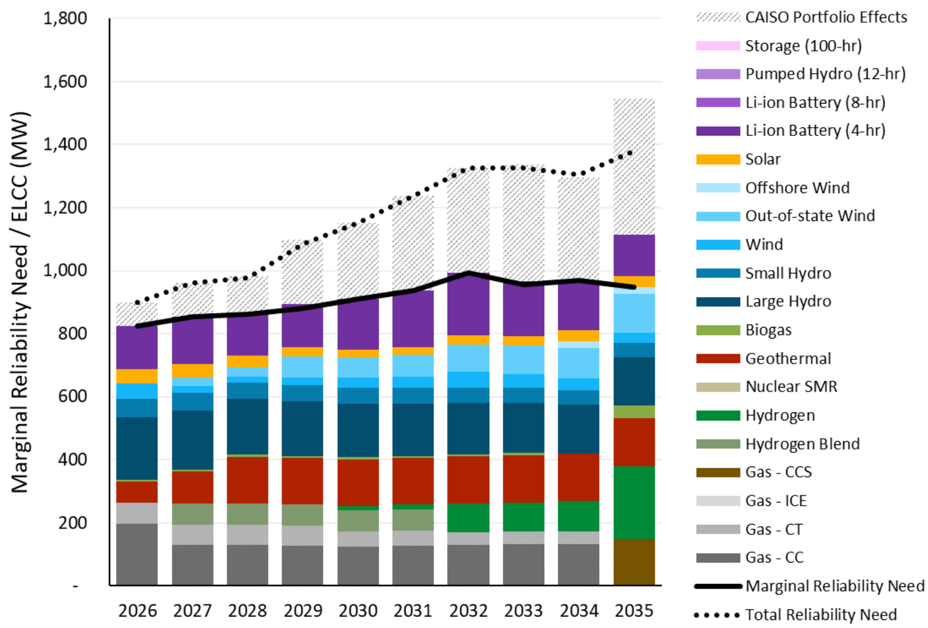
Figure 81. Hydrogen Sensitivity Annual Generation



Note: RPS and Zero Carbon percentages are based on retail sales and based on the accounting framework of annual targets in SB 100

Figure 82 shows the system reliability modeling results through 2035 in the Hydrogen Sensitivity. Unlike previous scenarios, the reliability constraint binds in 2033-34 due to the reduced geothermal resource potential before emerging technologies are available for selection. In 2035, more clean resources are added to the system due to the stringent emission target and surpass the marginal reliability need, meaning the marginal reliability requirement is not the primary driver of resource builds in 2035.

Figure 82. Hydrogen Sensitivity Marginal Reliability Need and Marginal Effective Capacity



8.6. Challenges Ahead to Meet IRP Goals

Through studying Scenario 1: Base SB 100 (Base Scenario) that meets the current state policies, and two additional scenarios with more aggressive clean energy requirements in this IRP, multiple challenges are identified as SVP continues to provide affordable, clean, and reliable power to its growing customer load.

- **SVP's load, primarily data center load, is expected to grow substantially throughout the planning horizon.** The forecasted annual load in 2035 almost doubles the current system load, and significant resource additions are needed to meet this growing load. Also, unlike other utilities, SVP's current and forecasted load is dominated by industrial (datacenter) load, which has a high load factor (or average load divided by peak load) of 80%, meaning that the system demand is relatively constant and there is less ability to shape loads to take advantage of certain resource production, such as low-cost solar. Therefore, SVP's future portfolio requires both clean resources and firm resources that can ensure there is enough energy to meet system load in all hours.
- **SVP will need clean firm resources, such as geothermal, to meet future needs in a deep decarbonized system.** SVP faces a common challenge of deeply decarbonized systems, which is the ability to provide power reliably without firm dispatchable (emitting) thermal plants. Clean firm resources not only provide clean energy, but also firm capacity to help ensure system reliability. The clean, firm, and baseload characteristics of geothermal align well with SVP's forecasted load growth and load shape and could provide a key clean firm option.

- **Competition for limited resources in California can add difficulties for SVP to procure some of cost-effective resources for its system.** For example, only a limited amount, about 3,400 MW, of geothermal may be available to California. Furthermore, the CPUC Mid-Term Reliability order requires CPUC-jurisdictional LSEs to procure approximately 1,000 MW long lead-time clean firm resources by 2028, and geothermal is one of the best available candidates to meet that order. An assumption of this IRP is that SVP may not be able to procure that 1,000 MW tranche. SVP would then be limited to a maximum of about 350 MW, which is approximately 15% of the remaining potential. The three scenarios in this IRP build to, or slightly below that limit. However, with the recent IRA including additional incentives for geothermal resources, and with all LSEs in California transitioning to a cleaner portfolio, there is a growing need for clean and firm resources, further driving competition for limited resources, such as geothermal, and adding challenges (and potentially costs) to cost-effective resource procurement.
- **SVP faces uncertainties in project delivery timelines.** To keep pace with near-term load growth to 2030 and longer-term load growth and policy objectives, SVP will need to bring significant quantities of new resources online over the next several years. As development for new resources in California increases to unprecedented rates, SVP may face challenges including, but not limited to supply chain delays, labor shortage, as well as permitting and lengthy interconnection queue processes. To build and begin utilizing new resources, the cost and schedule uncertainty of a complex, multi-step, multi-year interconnection process can significantly complicate other parts of the development process, including financing and project costs.
- **There are uncertainties in long-term resource cost forecasts.** This IRP uses the long-term resource cost forecast from the industry standard public data source, the NREL Annual Technology Baseline (ATB). However, recent market trends have shown that international trade policies and supply chain issues can significantly impact resource costs during procurement. Furthermore, market competition and developer profit markup are difficult to forecast and model but do influence resource costs. While many cost uncertainties are not explicitly studied in this IRP, they can impact the resulting portfolio choices and system costs. SVP should continue to monitor resource costs in future IRPs and resource procurement activities.
- **Achieving zero emission in every hour will likely require a combination of commercially available resources and new emerging technologies to be cost-effective and affordable.** To meet the hourly zero-emission target, all generation needs come from renewable, carbon-free resources, and/or market purchases (also when market emissions are zero) in every hour. If emerging technologies and emerging zero-emission fuels are not available, SVP would need to add much higher amounts of existing commercially available technologies, such as solar, wind, and battery storage resources. The total nameplate capacity of those resources is likely higher than the system load and the three scenarios presented here. Because they have low and

marginally decreasing reliability value, more capacity is needed to cover the most critical hours, even though there might be high curtailment occurring in other normal and/or low load hours. The emerging technologies, such as building new hydrogen plants and converting existing gas plants to burn on hydrogen or biogas, modeled in this IRP offer both clean and “firm capacity” attributes, and reduces the potential for “overbuilding” existing mature technologies.

+ **There are large uncertainties and risks in emerging technologies.** The emerging technologies modeled in this IRP are developed based on various assumptions and limited data. Many of the emerging technologies are still in their research and development and/or piloting phases, and it is difficult to predict when they will be commercially available at scale. Additionally, some emerging technologies, such as green hydrogen, require significant infrastructure development, such as electrolyzers, renewables for electrolyzers, pipelines, and storage. The costs and infrastructure required to support emerging technologies are uncertain and can impact the resulting portfolio feasibility and cost. The development of emerging technologies should continue to be monitored and studied by SVP in future IRPs and resource procurement.
+ **SVP’s transmission capabilities with CAISO can have an impact on how much emission reduction SVP can achieve.** DVR and Gianera are the only two resources, both natural gas plants, located within SVP’s local zone. When trying to meet more aggressive clean energy goals and reduce gas generation, the local resources’ roles and SVP’s transmission capabilities with CAISO become important. If the local resources cannot be dispatched to meet SVP’s load, all system load must be met with energy delivered via the transmission line from CAISO. However, the existing and planned transmission capacity may not always be sufficient to cover SVP’s forecasted peak load. In this IRP, it is assumed that local resources would be able to run on emerging zero-emission fuel and can be dispatched in Scenario 3: Zero Emissions with Emerging Technology, but SVP should continue to study system transmission capabilities and the clean transition of local resources in future IRPs.

8.7. Potential Impacts on Retail Rates

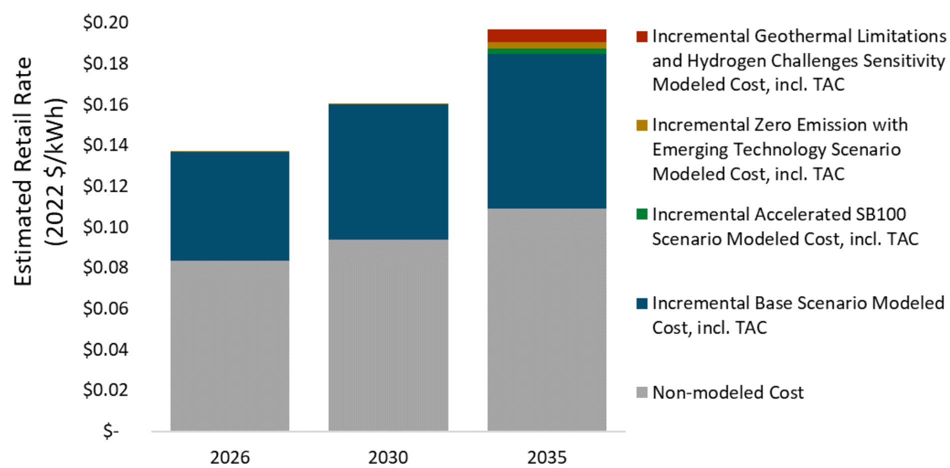
SVP is obligated to serve its customers at just and reasonable rates and to minimize impacts to ratepayers. Notably for SVP, lower rates have been an economic driver for robust development within Santa Clara, and continuing this long-standing focus on providing affordable and reliable services to customers is a goal of this IRP. This section explores the potential impact that the three scenarios explored in this work may have on retail rates through the planning horizon.

Figure 83 shows the estimated retail rate impacts of the scenarios from 2024 to 2035. Rates are calculated as the annual cost and annual retail demand ($/kWh). These estimates are based on two components 1) non-modeled costs, which are SVP baseline system rates, and 2) the incremental modeled scenario costs and TAC costs. The SVP baseline system rates are assumed to escalate at 3% real (5% nominal) per year, which SVP characterizes as the baseline revenue requirements for the system. The incremental scenario costs shown represent the additional cost to implement each scenario in order of least to most stringent clean energy requirements. Of note here is the impact of the significant impact of TAC, a charge from CAISO for energy delivered into SVP service area, on the final rates, which is a charge that is not overseen by SVP.

Scenario 1: Base SB 100 (Base Scenario) rates reach approximately $0.16/kWh in 2030 and approximately $0.185/kWh by 2035. Additional rate impacts from Scenario 2: Accelerated SB 100 begin later in the horizon, with an incremental cost of approximately $0.002/kWh by 2035 (or an estimated $0.187/kWh). Finally, Scenario 3: Zero Emissions with Emerging Technology (Zero Emissions Scenario) results in an incremental cost to the Base Scenario of approximately $0.005/kWh by 2035 reaching approximately $0.19/kWh by 2035.

Although the cost impacts are less apparent when spread across the annual load here, the 2035 annual costs of these scenarios relative to Base Scenario are *2022* $25 million and *2022* $55 million, in the Accelerated SB 100 and Zero Emissions Scenarios, respectively (see Figure 78).

Figure 83. Estimated Retail Rates Impacts



The uncertainties related to emerging technology availability and costs, as discussed in the previous section, of course, carry through to these estimated rate impacts. The relatively slight rate impacts of reaching the Zero Emissions Scenario ride on the assumptions that existing SVP resources can be retrofit to clean energy fuels at minimal to no capital costs by 2035 with low-cost (PTC- eligible) hydrogen fuel availability. The sensitivity case that tested potential geothermal availability limitations and high hydrogen costs results in an incremental cost to the Base Scenario of approximately $0.012/kWh by 2035 reaching approximately $0.197/kWh by 2035.

8.8. Consideration of Localized Air Pollutants and Disadvantaged Communities

Santa Clara's defined Disadvantaged Community is comprised of Industrial and Commercial customers with few residential and even fewer income-qualified FRAP (Federal Rate Assistance Program customers) residential customers residing within the borders as shown in

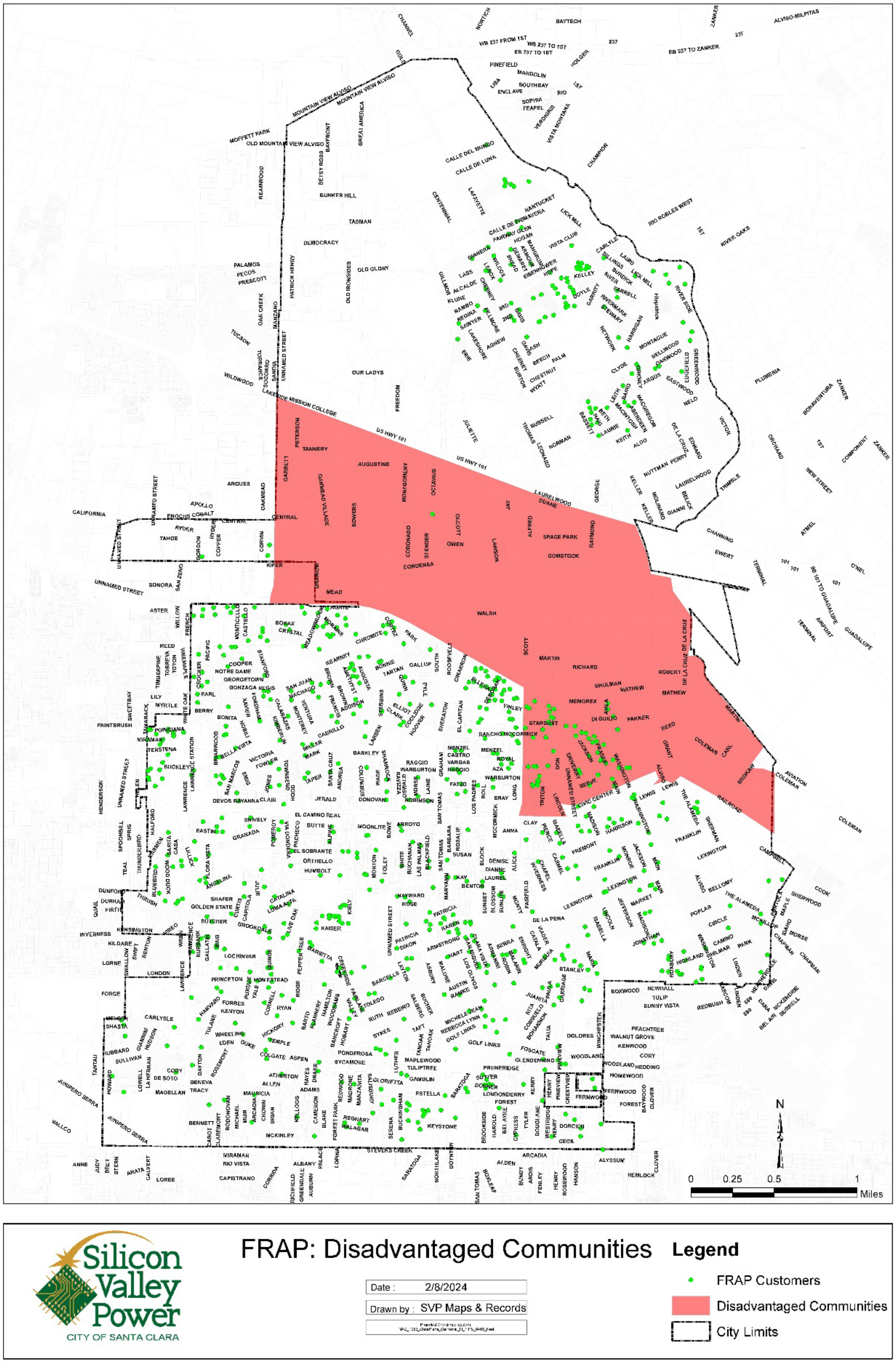
Figure 84. SVP's disadvantaged community (DAC) borders Highway 101 and the San Jose Airport and is comprised of 24/7 manufacturing, SVP's DVR power plant, data centers, high tech companies and small industrial customers. Santa Clara has zoned this area of the city for heavy industrial and commercial and has kept housing at a minimum with few exceptions.

Santa Clara is only 18.4 square miles and land is at a premium, and in most cases, utilized to maximum densities. In working with the City of Santa Clara as it updates its General Plan, there is an opportunity for SVP to encourage maximum infill building potential with whole building electrification and maximize potential of DERs. There is no land available to build large-scale PV projects (greater than 10 MW) within the city limits, but there is ample opportunity throughout California, keeping with SVP's position of having a diversified portfolio (both geographically and resource type). Adding renewable generation to SVP's portfolio is beneficial to the disadvantaged community as well as to SVP's service area.

SVP offers multiple customer programs and rebates to income-qualified customers, as outlined below. Specifically for energy efficiency, one of the many goals of the programs is to assist income-qualified residents in paying their electric bills and installing energy efficient appliances to lower energy costs. The following programs are offered by SVP to specifically support income-qualified and disadvantaged communities:

+ Financial Rate Assistance Program (FRAP)
+ Multifamily Residential and Commercial EV Charging Station Incentive Program (Equity+ Funding Lane)
+ Free EV Charging Technical Assistance for Multifamily Housing & Small Businesses
+ E-Bike Rebate (Increased incentives for FRAP customers)
+ Heat Pump Water Heater Rebate (Increased incentives for FRAP and LIHEAP customers)
+ Income-Qualified Pre-Owned Electric Vehicle Rebate
+ Income-Qualified Solar Grant
+ Smart Electric Panel (Increased incentives for FRAP and LIHEAP customers)
+ Battery Storage Systems Rebate (Increased incentives for FRAP and LIHEAP customers)
+ Medical Rate Assistance Program
+ Trade School Scholarships for income-qualified customers
+ Increased rebates on electric yard care equipment and room air cleaners for income-qualified customers through the online SVP Marketplace

Figure 84. Disadvantaged Communities within SVP's Service Territory



9. Conclusions

SVP's 2023 IRP identified three least-cost optimal resource portfolios, all of which meet or exceed SVP's clean energy, emissions reductions, and reliability requirements. In all portfolios, the power supply mix continues SVP's transition away from carbon-based generation with significant, new clean energy resource additions to meet increasing state policy goals and SVP's growing load. The portfolios studied represent increasingly progressive clean energy goals. Scenario 1: Base SB 100 (Base Scenario) meets the SB 100 target of 60% renewable energy in 2030 and 90% renewable and zero-carbon energy by 2035, relying only on mature clean energy technologies. Scenario 2: Accelerated SB 100 explores additional procurement required to meet an acceleration of the long-term SB 100 targets for 100% carbon free electricity from 2045 to 2035 and relies only on mature renewable technology options. Finally, Scenario 3: Zero Emissions with Emerging Technology (Zero Emissions Scenario) limits carbon emissions in all hours of the year, beginning in 2035, and explores the use of emerging clean energy technologies.

All the resulting portfolios represent diverse resource mixes of clean firm capacity, scalable clean energy, and balancing resources. Portfolio capacity additions include a mix of solar, in-state and out-of-state wind, energy storage, and geothermal capacity. The added firm geothermal and balancing storage resources, in addition to SVP's existing firm capacity, complement the intermittent nature of the high level of variable wind and solar resources added, ensuring SVP has sufficient capacity to meet its share of CAISO reliability needs. In the near term, through 2030, all resource portfolios present a common trend of at least 400 MW wind, 150 MW solar, 100 MW battery energy storage and 120 MW geothermal resource additions to meet increasing load as well as reliability and clean energy targets. This presents a robust, fairly low-regrets near-term planning pathway for the level of SVP clean energy resource additions.

The scenarios begin to diverge after 2030 as potential clean energy and emissions requirements and emerging technologies are assumed to become increasingly available. By 2035 the Zero Emissions Scenario diverges with the assumed availability of hydrogen and biofuel clean-firm resources, enabling SVP to retrofit existing fossil-fuel resources and add additional hydrogen combustion capacity.

Sensitivities on the availability of geothermal (clean firm) and hydrogen costs (retrofit capital costs and hydrogen fuel prices) show the increased costs that could occur due to competition over limited geothermal potential and a less optimistic view of hydrogen as an electricity generation fuel. Uncertainty for these "clean firm" resources needed to help SVP and the state achieve a zero-emissions grid can be addressed by further study in SVP's subsequent IRPs, when the California electricity market will have more clarity on the viability and cost parameters of new emerging technologies. However, with large near-term forecasted load growth, this IRP provides SVP with a clear pathway for near-term procurement to meet its needs over the next 5-10 years.

It is noted that while this IRP provides an outline for future resource additions, SVP's actual future resource additions will be determined by results of competitive solicitations for resources and these may differ based on changes in forecasted loads, economic conditions, technology advances, specific bid-based generation resource prices, and evolving environmental and regulatory standards.

Appendix A. SVP Community Survey Summary

Summary Of Responses

As of April 30, 2024, 8:37 AM, this forum had:		Topic Start
Attendees:	193	September 11, 2023, 2:55 PM
Responses:	118	
Hours of Public Comment:	5.9	

QUESTION 1

Do you live in the City of Santa Clara?

	%	Count
Yes	94.9%	112
No	5.1%	6

QUESTION 2

How satisfied are you with the electric services offered by Silicon Valley Power?

	%	Count
Very unsatisfied	6.9%	8
Neutral	10.3%	12
Satisfied	30.2%	35
Very satisfied	52.6%	61

QUESTION 3

Please rank the following electric services priorities in terms of importance: (1 being the most important, 4 being the least important)

High reliability (keeping the lights on and avoiding blackouts)

	%	Count
1	59.5%	69
2	11.2%	13
3	9.5%	11
4	19.8%	23

Affordable Rates

	%	Count
1	31.0%	36
2	31.9%	37
3	24.1%	28
4	12.9%	15

Minimizing Environmental Impacts

	%	Count
1	30.2%	35
2	22.4%	26
3	16.4%	19
4	30.2%	35

Quality of Customer Service

	%	Count
1	30.2%	35
2	25.0%	29

	%	Count
3	21.6%	25
4	23.3%	27

QUESTION 4

How much more would you be willing to pay monthly on your electric bill to achieve clean energy goals faster:

	%	Count
As much as it takes (~100%+ increase on average)	9.6%	11
A lot (~50% increase)	13.9%	16
Some (~25% increase)	20.0%	23
A little (~10% increase)	19.1%	22
None (0% increase)	33.9%	39
Not sure	3.5%	4

QUESTION 5

Would you be willing to experience occasional power outages instead of a cost increase? Example: no power for 2 hours, twice per year to achieve clean energy goals.

	%	Count
Yes	53.0%	61
No	47.0%	54

QUESTION 6

Estimate the percentage of electricity that comes to the City of Santa Clara from renewable resources:

	%	Count
10% or less	6.0%	7
11% to 30%	13.8%	16
31% to 50%	25.9%	30
51% to 70%	17.2%	20
71% to 100%	17.2%	20
Not sure	17.2%	20
Not a resident of Santa Clara	2.6%	3

QUESTION 7

Please list in order of importance the following energy initiatives:

1. More local roof top solar businesses with battery systems
2. Rewarding customers to voluntarily reduce energy
3. More large-scale wind turbine systems (not in Santa Clara)
4. More large-scale battery systems with solar (not in Santa Clara)
5. More stand-alone battery systems
6. Development of next generation small-scale nuclear power plants (not in Santa Clara)
7. Retain Santa Clara's in-town natural gas power plant
8. Charging customers more for energy during peak times when power is dirty and more expensive
9. Rewarding customers for allowing SVP to remotely adjust thermostats

QUESTION 8

California has a 60% renewable energy goal by 2030, which increases to 100% carbon-free by 2045. Do you support the pace of California's overall energy goals?

	%	Count
Just right	33.6%	39
Too fast	21.6%	25

High reliability (keeping the lights on and avoiding blackouts)

	%	Count
1	59.5%	69
2	11.2%	13
3	9.5%	11
4	19.8%	23

Affordable Rates

	%	Count
1	31.0%	36
2	31.9%	37
3	24.1%	28
4	12.9%	15

Minimizing Environmental Impacts

	%	Count
1	30.2%	35
2	22.4%	26
3	16.4%	19
4	30.2%	35

Quality of Customer Service

	%	Count
1	30.2%	35
2	25.0%	29

	%	Count
Too slow	32.8%	38
Don't know/unsure	12.1%	14

QUESTION 9

What do you think Silicon Valley Power should prioritize as it develops the Integrated Resource Plan?

1. Reliability
2. Keeping costs down
3. Exceeding the environmental compliance requirements
4. Meeting the state and federal compliance requirements
5. Public outreach/community input

QUESTION 10

In general, what are your thoughts about Electric Vehicles (EV)? (Agree, Neutral, Disagree, Not Sure)

Priced right to buy or lease

	%	Count
Agree	20.0%	23
Neutral	27.0%	31
Disagree	45.2%	52
Not Sure	7.8%	9

Chargers are easy to use and accessible

	%	Count
Agree	21.7%	25
Neutral	26.1%	30

	%	Count
Disagree	34.8%	40
Not Sure	17.4%	20

It is easy for me to find a charger

	%	Count
Agree	25.2%	29
Neutral	21.7%	25
Disagree	29.6%	34
Not Sure	23.5%	27

There are cars with range that meets my needs

	%	Count
Agree	54.8%	63
Neutral	14.8%	17
Disagree	21.7%	25
Not Sure	7.0%	8

I own an EV or I plan on buying one within the next year

	%	Count
Agree	41.7%	48
Neutral	7.0%	8
Disagree	39.1%	45
Not Sure	11.3%	13

QUESTION 11

Have you participated in any of the following programs offered by Silicon Valley Power? Select all that apply. (Press the Ctrl button to select additional options)

	%	Count
Efficiency Rebates	44.8%	26
Solar Rebates	37.9%	22
Rate Discounts	19.0%	11
Home Energy Audit	29.3%	17
EV Charger rebate	13.8%	8
Other	17.2%	10

QUESTION 12

Please let us know what programs you would like SVP to have that we don't already offer.

Answered	44
Skipped	74

QUESTION 13

If you live in the City of Santa Clara, do you:

	%	Count
Own	81.1%	90
Rent	18.9%	21

QUESTION 14

Do you own or operate a business in the City of Santa Clara?

	%	Count
Yes	10.4%	12
No	89.6%	103

QUESTION 15

Do you work in the City of Santa Clara?

	%	Count
Yes	27.0%	31
No	73.0%	84

QUESTION 16

Do you have any questions or comments for us?

Answered	35
Skipped	83

Appendix B. Energy Demand

A.1. Energy Use and Demand

E3 leveraged a range of sources to develop a Reference Scenario and two sensitivities of annual peak load and hourly energy demand forecasts for SVP:

- **Reference:** a business-as-usual forecast of energy demand in SVP territory using the utility's baseline forecast of energy demand with additional energy efficiency and electrification projections from the Planning Forecast of the CEC 2022 IEPR[52]
- **High Electrification**: utilizes the same baseline forecast of energy demand as the Reference scenario, but layers in less aggressive energy efficiency assumptions and more aggressive electrification assumptions from the 2022 IEPR
- **IEPR Local Reliability**: utilizes the same baseline forecast of energy demand as the Reference scenario, but uses energy efficiency and electrification projections from the Local Reliability Forecast of the 2022 IEPR

Figure 85. Total Annual Electricity Demand by Scenario (GWh)

Scenario	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Reference	4,529	4,933	5,494	5,995	6,449	7,044	7,503	7,971	8,448	8,955	9,218	9,394	9,567
High Elec.	4,546	4,965	5,548	6,072	6,553	7,175	7,668	8,171	8,684	9,228	9,529	9,742	9,950
IEPR Local Reliability	4,773	5,171	5,794	6,381	6,938	7,489	7,919	8,381	8,883	9,415	9,838	10,040	10,248

E3 used two sources for energy efficiency assumptions: the 10 Year Energy Goals provided by SVP and AAEE modeled by CEC for the 2022 IEPR.[53] Different levels of AAEE were used for each:

- The **Reference** scenario used the "Scenario 3 (Mid)" AAEE assumptions from the 2022 IEPR for Residential and Commercial sector energy efficiency, aligning with the assumptions used in the 2022 IEPR Planning Forecast
- The **High Electrification** scenario used the "Scenario 1 (Very Low)" AAEE assumptions, the most conservative scenario for energy efficiency included in the 2022 IEPR
- The **IEPR Local Reliability** scenario used the "Scenario 2 (Low)" AAEE assumptions, aligning with the assumptions used in the 2022 IEPR Local Reliability forecast

[52] CEC, "CEC 2022 Integrated Energy Policy Report (IEPR)."
[53] CEC, "2022 IEPR AAEE-AAFS Annual Impacts."

Figure 86 shows the combined impact of energy efficiency measures on annual electricity demand in each scenario.

Figure 86. Annual Energy Efficiency Impact on Electricity Demand by Scenario (GWh)

Scenario	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Reference	-62	-97	-136	-171	-204	-226	-248	-271	-294	-313	-333	-350	-365
High Elec.	-45	-65	-83	-98	-110	-113	-116	-121	-126	-128	-132	-135	-138
IEPR Local Reliability	-52	-79	-104	-126	-146	-156	-166	-178	-189	-199	-209	-217	-224

Additional electricity demand modifiers for building electrification are layered into the baseline. For buildings, the electrification assumptions are based on the AAFS modeled by CEC for the 2022 IEPR in all scenarios. For the High Electrification and IEPR Local Reliability scenarios, E3 also included electrification assumptions based on the 2022 Electric Infrastructure Impacts from Proposed Zero NOx Standards report, where E3 analyzed the electricity demand implications of a zero NOx standard for space and water heaters for the Bay Area Air Quality Management District.[54]

- The **Reference** scenario used the "Scenario 3 (Mid)" AAFS assumptions, aligning with the assumptions used in the 2022 IEPR Planning Forecast
- The **High Electrification** scenario also used the "Scenario 3 (Mid)" AAFS assumptions and layered in additional electrification of space and water heating based on a zero NOx standard beginning in 2027 for residential water heating and 2029 for residential space heating, commercial water heating, and commercial space heating
- The **IEPR Local Reliability** scenario used the "Scenario 4 (High)" AAFS assumptions and layered in the same additional electrification of space and water heating from a zero NOx standard as the High Electrification scenario

Figure 87 shows the combined impact of building electrification measures on annual electricity demand in each scenario.

Figure 87. Annual Building Electrification Impact on Electricity Demand by Scenario (GWh)

Scenario	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Reference	13	21	29	36	43	51	59	67	74	81	88	94	99
High Elec.	13	21	29	36	47	57	73	89	105	121	136	151	165
IEPR Local Reliability	14	22	31	39	50	61	78	95	111	128	144	159	173

For transportation electrification, the Reference scenario reflects the Base level of electrification from the 2022 IEPR, while the High Electrification and Local Reliability scenario both use the Additional Annual Transportation Electrification (AATE) assumptions modeled in the 2022 IEPR Planning Forecast. While the

[54] E3, "Bay Area Air Quality Management District" (San Francisco, CA: Energy + Environmental Economics (E3), 2022), https://www.baaqmd.gov/~/media/dotgov/files/rules/reg-9-rule-4-nitrogen-oxides-from-fan-type-residential-central-furnaces/2021-amendments/documents/20221220_sr_appd_rg09040906-pdf.pdf?la=en.

AAEE and AAFS assumptions for energy efficiency and building electrification for the 2022 IEPR are provided at the SVP territory level, the Base and AATE assumptions are provided at the PG&E planning area level.[55] E3 downscaled the transportation loads to SVP territory through a two-step process. First, loads were scaled to Santa Clara County based on the county's share of light duty vehicle and medium-and-heavy duty vehicles registrations for all counties in PG&E service territory using California DMV vehicle registration data.[56] Next, transportation loads were scaled from Santa Clara County to SVP service territory using the City of Santa Clara's share of total vehicle miles travelled for Santa Clara County as reported in the city and county's respective GHG inventories.[57][58]

Figure 88 shows the combined impact of transportation electrification measures on annual electricity demand in each scenario.

Figure 88. Annual Transportation Electrification Impact on Demand by Scenario (GWh)

Scenario	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Reference	8	15	24	32	40	49	59	69	81	94	107	120	135
High Elec.	8	15	25	35	47	62	78	97	119	142	168	196	225
IEPR Local Reliability	8	15	25	35	47	62	78	97	119	142	168	196	225

Finally, the IEPR Local Reliability included a demand modifier to align total annual electricity demands between the E3 bottom-up constructed demand scenario with the published Local Reliability forecast from the 2022 IEPR.

The total annual electricity demand for each scenario is shown in Figure 89.

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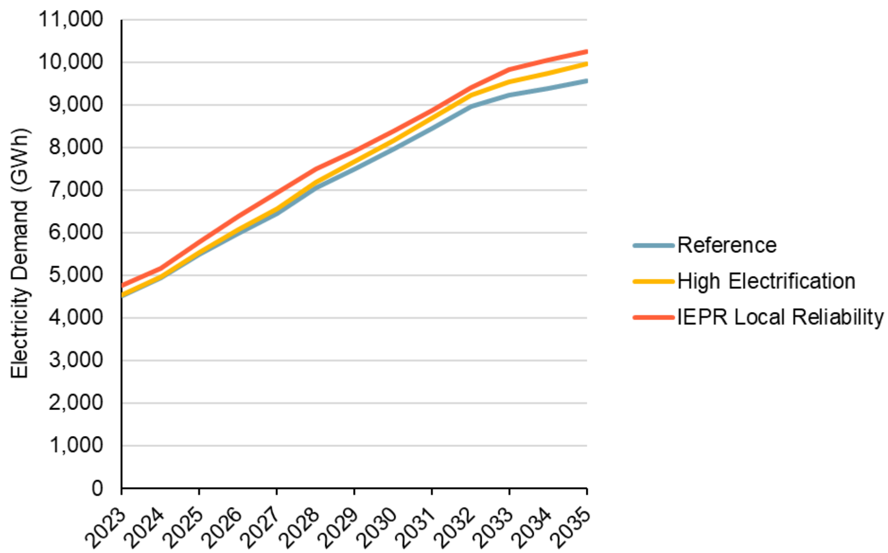
[55] CEC, "2022 IEPR AAEE-AAFS Annual Impacts"; CEC, "CED 2022 Hourly Forecast - PGE - Planning Scenario."

[56] CA DMV, "VEHICLES REGISTERED BY COUNTY," California Department of Motor Vehicles, 2023, https://www.dmv.ca.gov/portal/dmv-research-reports/research-development-data-dashboards/vehicles-registered-by-county/.

[57] Country of Santa Clara, "2017 Community Wide Greenhouse Gas Inventory and Forecast" (Santa Clara, CA: County of Santa Clara, 2021), https://sustainability.sccgov.org/sites/g/files/exjcpb976/files/documents/SCC%20GHG%20Inventory%20and%20Forecast%20Report_6-29-21_0.pdf.

[58] City of Santa Clara, "Climate Action Plan: 2018 Annual Report" (Santa Clara, CA: City of Santa Clara, 2018), https://www.santaclaraca.gov/home/showpublisheddocument/62433/636809212556470000.

Figure 89. Total Annual Electricity Demand by Scenario



Hourly Energy Demand Forecast

To enable capacity expansion modeling for the integrated planning process an hourly demand forecast was developed from this annual forecast. A separate hourly load profile was assigned to the annual baseline energy demand, energy efficiency and electrification load modifiers, and the IEPR Local Reliability alignment energy demands to get a complete hourly energy demand forecast for all scenarios. Figure 90 details the sources used for converting the energy demand components to hourly demand profiles.

Figure 90. Hourly Demand Profile Components

Energy Demand Component	Source for Hourly Demand Profile
Baseline Energy Demand	SVP Hourly Energy Demand Forecast 2023-2035
Energy Efficiency	2022 IEPR Hourly Forecast – PG&E Planning Scenario
Building Electrification from 2022 IEPR	2022 IEPR Hourly Forecast – PG&E Planning Scenario
Building Electrification from Zero NOx Standard	2022 Electric Infrastructure Impacts from Proposed Zero NOx Standards report
Transportation Electrification	2022 IEPR Hourly Forecast – PG&E Planning Scenario
IEPR Alignment (Local Reliability Scenario Only)	SVP Hourly Energy Demand Forecast 2023-2035

Appendix C. Hydrogen Price Forecasts

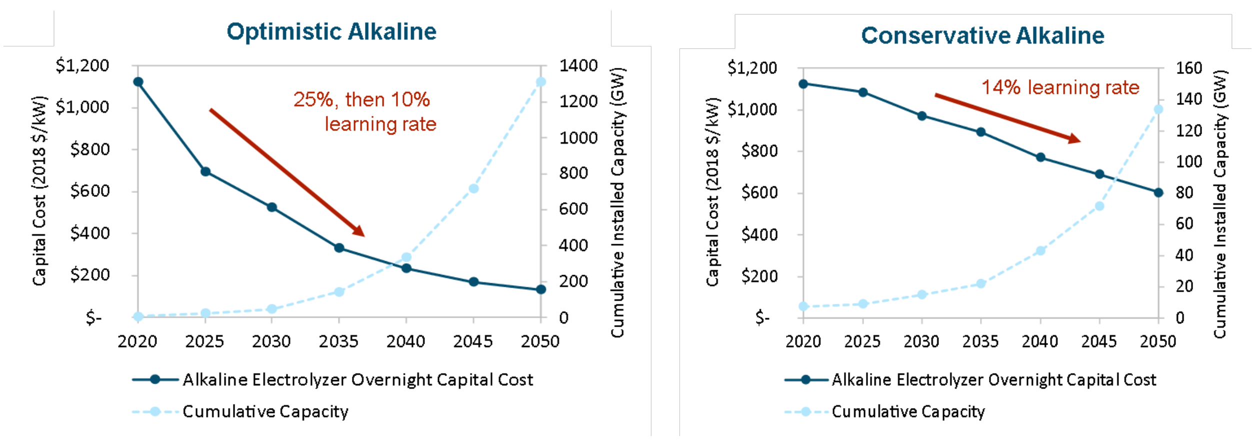
E3 developed an assessment of the cost trajectory of hydrogen that can be delivered to SVP's service territory.

The hydrogen assessment in this analysis stems from E3's and the University of California (UC) Irvine's work on the CEC's *The Challenge of Retail Gas in California's Low Carbon Future* Report. A set of cost and efficiency assumptions for the production of hydrogen using electrolysis was developed. The assumptions consist of inputs indexed by fuel, electrolysis technology, year, and level of industry learning assumed to occur between 2020 and 2050. Inputs consist of the levelized capital cost and annual fixed O&M cost, variable O&M cost, and overall energy efficiency, considering only renewable electricity as the energy input, including for heat input, if applicable.

Base Assumptions

E3 assumes alkaline electrolysis cell (AEC) as the primary means of producing green hydrogen[59] due to its low cost and technologically mature attributes. [60] E3 developed two cost trajectories for AEC based on cumulative national installed capacity, as shown in Figure 91. [61] The Conservative cost trajectory is used in this study.

Figure 91. Electrolyzer Costs for Producing Hydrogen and SNG



(Derived from E3's work for the California Energy Commission (CEC, The Challenge of Retail Gas in California's Low-Carbon Future) in partnership with UC Irvine. The secondary y-axis shows the potential electrolyzer market size.)

E3 assumed new off-grid solar resources from Southern California to power electrolyzers to produce hydrogen. Hydrogen is assumed to be stored underground in lined rock caverns and piped to SVP's service

[59] Hydrogen produced by breaking water into hydrogen and oxygen using an electric current in which electricity is renewable.

[60] As opposed to producing clean hydrogen through a proton-exchange membrane (PEM) or steam methane reforming or coal gasification with CCS.

[61] Cost trajectories were developed in partnership with UC Irvine in 2019. https://www.ethree.com/at-cec-e3-highlights-need-for-gas-transition-strategy-in-california/.

territory. New pipelines are assumed to be 400 miles long and are fully utilized by hydrogen producers and consumers beyond those modeled in this study. This assumption thereby spreads the cost of pipeline transportation more evenly across hydrogen produced by facilities modeled in this study. Hydrogen costs assumed in this study are delivered hydrogen costs and include production costs, new lined rock cavern underground storage, and new dedicated hydrogen pipelines.

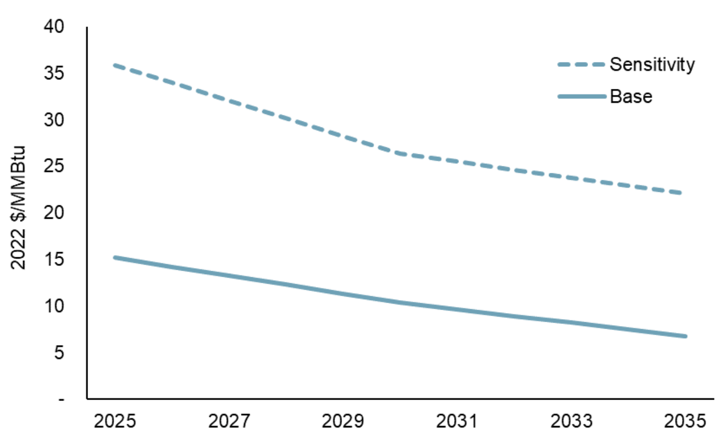
All hydrogen plants that being operation between 2025 and 2035 are assumed to receive the full $3/kg 45V tax credit. The 45V tax credit is applied to all hydrogen production in the first 10 years of plants' lives, but it's impact is levelized across the entire 25-year lifetimes of all plants. As a result, hydrogen costs from E3's electrofuel spreadsheet should be treated as a PPA-like cost, rather than the instantaneous cost of hydrogen each year.

Geothermal Limitations and Hydrogen Challenges Sensitivity Assumptions

Compared to base assumptions, the sensitivity case studies a future with higher hydrogen costs. The electrolyzer technology is assumed to be proton exchange membrane electrolysis cell (PEMEC) instead of AEC. The electricity source for hydrogen production is assumed to be SoCal wind and the hydrogen pipelines are only half utilized.

See Figure 92 for the resulting hydrogen price forecast through 2035.

Figure 92. Hydrogen Price Forecast



Appendix D. Standardized Tables

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
Capacity Resource Accounting Table
Form CEC 109 (May 2017)

Scenario Name: Base SB 100

Yellow fill relates to an application for confidentiality.
Units = MW
Data input by User are in dark green font.

	PEAK LOAD CALCULATIONS			2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	Forecast Total Peak-Hour 1-in-2 Demand			715	801	875	943	1,027	1,097	1,164	1,237	1,306	1,351	1,377	1,400
2	[Customer-side solar: nameplate capacity]			23	23	24	24	25	25	26	27	27	28	29	30
2a	[Customer-side solar: peak hour output]			15	16	16	17	17	17	18	18	19	19	20	20
3	[Peak load reduction due to thermal energy storage]														
4	[Light Duty PEV consumption in peak hour]			1	3	4	5	6	5	6	10	11	13	15	11
5	Additional Achievable Energy Efficiency Savings on Peak			16	25	30	36	40	41	41	51	54	63	61	59
6	Demand Response / Interruptible Programs on Peak			8	8	8	8	8	8	8	8	8	8	8	8
7	Managed Peak Demand (1-5-6)			692	768	837	898	979	1,048	1,116	1,178	1,243	1,279	1,307	1,333
7a	Coincident gross peak (managed peak plus BTM PV peak shift)			637	719	798	850	866	960	1,018	1,093	1,171	1,171	1,152	1,219
8	Planning Reserve Margin	14%	This is a perfect capacity (PCAP)-based PRM. The 14% PCAP PRM translates to about 22% ICAP PRM and is a more stringent target than previous CAISO studies to ensure a 1-day-in-10-years LOLE target. The 14% PCAP PRM is applied to the coincident gross peak (managed peak plus BTM PV peak shift). See details on the right.	89	101	112	119	121	134	143	153	164	164	161	171
9	Firm Sales Obligations			-	-	-	-	-	-	-	-	-	-	-	-
10a	Total Peak Procurement Requirement Based on the Total Reliability Need Framework (7a+8+9)		See details on the right.	727	819	909	970	987	1,094	1,160	1,246	1,335	1,335	1,314	1,389
10b	CAISO Portfolio Effects		See details on the right.	92	93	85	116	125	212	251	309	342	379	343	442
10	Total Peak Procurement Requirement Based on the Marginal Reliability Need Framework (10a-10b)		See details on the right.	635	727	825	853	863	882	909	937	993	956	970	947

Resource capacity accreditation is based on the marginal effective load carrying capability (ELCC) and marginal reliability framework.

	EXISTING AND PLANNED CAPACITY SUPPLY RESOURCES	Fuel	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	Utility-Owned Generation and Storage (not RPS-eligible):													
	[list resource by name]													
11a	DVR	Gas - CC	125	127	130	129	129	127	126	128	129	131	133	135
11b	Gianera 1	Gas - CT	20	20	21	20	20	20	20	20	20	20	21	21
11c	Gianera 2	Gas - CT	20	20	21	20	20	20	20	20	20	20	21	21
11d	Alameda CT 1	Gas - CT	8	8	8	8	8	8	8	8	8	8	8	8
11e	Alameda CT 2	Gas - CT	8	8	8	8	8	8	8	8	8	8	8	8
11f	Lodi CT	Gas - CT	8	8	8	8	8	8	8	8	8	8	8	8
11g	LEC	Gas - CC	66	67	68	0	0	0	0	0	0	0	0	0
11h	LEC Hydrogen 45 Blend	Hydrogen Blend	0	0	0	68	68	67	66	67	68	69	70	71
11i	Collierville	Large Hydro	52	52	51	49	46	45	44	43	42	41	40	39
11j	BESS 50MW 200MWh	Li-ion Battery (4-hr)	0	45	46	42	39	38	37	34	30	27	23	20
	Long-Term Contracts (not RPS-eligible):													
	[list contracts by name]	Fuel												
11k	Tri-Dam Donnells	Large Hydro	41	41	40	38	36	35	35	34	33	32	32	31
11l	WAPA Base Resource	Large Hydro	71	71	71	67	63	62	61	59	58	57	55	54
11m	South Feather - Forbstown	Large Hydro	14	14	13	13	12	12	12	11	11	11	11	10
11n	South Feather - Woodleaf	Large Hydro	22	22	22	20	19	19	19	18	18	17	17	17
11	Total peak dependable capacity of existing and planned supply resources (not RPS-eligible) (sum of 11a…11n)		454	503	507	492	477	469	461	458	454	451	447	443
	Utility-Owned RPS-eligible Resources:													
	[list resource by plant or unit]	Fuel												
12a	Black Butte	Small Hydro	3	3	2	2	2	2	2	2	2	2	2	2
12b	Stony Gorge	Small Hydro	2	2	2	2	2	2	2	2	2	2	2	2

12c	Grizzly Hydro	Small Hydro	7	7	7	7	6	6	6	6	6	6	6	5
12d	Big Horn 1	Wind	27	25	23	0	0	0	0	0	0	0	0	0
12e	Big Horn 2	Wind	5	4	4	4	4	3	3	3	3	3	3	3
12f	Geo Plant 1 Unit 1	Geothermal	10	11	11	11	11	11	11	11	11	11	11	11
12g	Geo Plant 1 Unit 2	Geothermal	10	11	11	11	11	11	11	11	11	11	11	11
12h	Geo Plant 2 Unit 4	Geothermal	14	14	14	15	15	15	15	15	15	15	15	15
12i	Spicer	Small Hydro	1	1	1	1	1	1	1	1	1	1	1	1
	Long-Term Contracts (RPS-eligible):													
	[list contracts by name]	Fuel												
12j	Ameresco Forward	Biogas	3	3	3	3	3	3	3	3	3	3	0	0
12k	Ameresco Vasco	Biogas	3	3	3	3	3	3	3	3	3	4	0	0
12l	G2 Landfill	Biogas	0	0	0	0	0	0	0	0	0	0	0	0
12m	Tri-Dam Beardsley	Small Hydro	5	5	5	4	4	4	4	4	4	4	4	4
12n	Tri-Dam Sand Bar	Small Hydro	7	7	7	6	6	6	6	5	5	5	5	5
12o	Tri-Dam Tulloch	Small Hydro	11	10	10	10	9	9	9	9	9	8	8	8
12p	Friant 1	Small Hydro	10	10	10	10	9	9	9	8	8	8	8	8
12q	Friant 2 (Quinten)	Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
12r	Rio Bravo (Index+)	Small Hydro	6	6	6	5	5	5	5	5	5	5	4	4
12s	Camp Far West Hydro (Index+)	Small Hydro	3	3	3	3	2	2	2	2	2	2	2	2
12t	South Feather - Kelly Ridge	Small Hydro	3	3	3	3	3	2	2	2	2	2	2	2
12u	South Feather - Sly Creek	Small Hydro	3	3	3	3	3	3	3	3	3	3	3	3
12v	Central 40 Solar	Solar	4	4	4	4	4	3	2	2	2	2	3	3
12w	Rosamond Solar	Solar	2	2	2	2	2	2	1	1	1	1	1	1
12x	Aquamarine Westside (Index+)	Solar	7	0	0	0	0	0	0	0	0	0	0	0
12y	Manzana Wind	Wind	8	8	8	6	4	4	4	4	3	0	0	0
12z	Cimmaron Wind	Wind	0	0	0	0	0	0	0	0	0	0	0	0
12aa	Calpine Geo	Geothermal	0	31	31	64	65	65	64	65	65	66	66	67
12ab	Sand Hill A	Wind	0	0	4	3	2	2	2	2	2	2	1	1
12ac	Sand Hill B	Wind	0	0	5	4	3	3	3	3	2	2	2	2
12ad	Rooney Ranch	Wind	0	0	6	5	3	3	3	3	3	2	2	2
12	**Total peak dependable capacity of existing and planned RPS-eligible resources (sum of 12a…12n)**		**153**	**175**	**189**	**190**	**184**	**180**	**176**	**175**	**174**	**170**	**162**	**161**
13	**Total peak dependable capacity of existing and planned supply resources (11+12)**		**607**	**677**	**695**	**682**	**661**	**649**	**638**	**633**	**628**	**621**	**609**	**605**
	GENERIC ADDITIONS		Resource capacity accreditation is based on the marginal effective load carrying capability (ELCC) and marginal reliability framewor											
	NON-RPS ELIGIBLE RESOURCES:													
	[list resource by name or description]	Fuel	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
14a	Li_Battery_4hr	Li-ion Battery (4-hr)	0	0	79	92	84	83	81	74	66	59	51	44
14	**Total peak dependable capacity of generic supply resources (not RPS-eligible)**		**0**	**0**	**79**	**92**	**84**	**83**	**81**	**74**	**66**	**59**	**51**	**44**
	RPS-ELIGIBLE RESOURCES:													
	[list resource by name or description]	Fuel												
15a	Central_California_Wind	Wind	0	0	0	0	0	8	12	11	12	11	9	14
15b	Geothermal	Geothermal	0	0	0	0	49	49	108	148	215	268	272	279
15c	New_Mexico_Wind	Out-of-state Wind	0	0	34	36	37	34	26	27	29	30	32	33
15d	Southern_California_Solar	Solar	0	0	16	15	14	12	9	9	9	9	9	10
15e	Wyoming_Wind	Out-of-state Wind	0	0	0	28	29	47	35	37	39	41	43	45
15	**Total peak dependable capacity of generic RPS-eligible resources**		**0**	**0**	**50**	**79**	**130**	**150**	**190**	**233**	**304**	**360**	**366**	**381**
16	**Total peak dependable capacity of generic supply resources (14+15)**		**0**	**0**	**129**	**171**	**214**	**233**	**271**	**307**	**370**	**418**	**417**	**425**
	CAPACITY BALANCE SUMMARY													
			2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
17	**Total peak procurement requirement based on the marginal reliability need framework (from line 10)**		**635**	**727**	**825**	**853**	**863**	**882**	**909**	**937**	**993**	**956**	**970**	**947**

18	**Total peak dependable capacity of existing and planned supply resources based on the marginal reliability need framework (from line 13)**			**607**	**677**	**695**	**682**	**661**	**649**	**638**	**633**	**628**	**621**	**609**	**605**
19	**Current capacity surplus (shortfall) based on the marginal reliability need framework (18-17)**			**(28)**	**(49)**	**(129)**	**(171)**	**(202)**	**(233)**	**(271)**	**(304)**	**(365)**	**(335)**	**(361)**	**(342)**
20	**Total peak dependable capacity of generic supply resources based on the marginal reliability need framework (from line 16)**			**0**	**0**	**129**	**171**	**214**	**233**	**271**	**307**	**370**	**418**	**417**	**425**
21	**Planned capacity surplus/shortfall based on the marginal reliability need framework (shortfalls assumed to be met with short-term capacity purchases) (19+20)**			**(28)**	**(49)**	**0**	**(0)**	**12**	**0**	**(0)**	**3**	**6**	**83**	**56**	**82**

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
Energy Balance Table
Form CEC 110 (May 2017)

Scenario Name: Base SB 100

Units = MWh

Yellow fill relates to an application for confidentiality.

	NET ENERGY FOR LOAD CALCULATIONS	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	Retail sales to end-use customers												
2	Other loads												
3	Unmanaged net energy for load												
4	Managed retail sales to end-use customers	4,778,145	5,327,789	5,809,004	6,248,254	6,832,383	7,274,182	7,732,322	8,182,580	8,692,095	8,941,747	9,114,090	9,280,661
5	Managed net energy for load	4,921,356	5,487,475	5,983,112	6,435,528	7,037,165	7,492,205	7,964,077	8,427,829	8,952,617	9,209,750	9,387,259	9,558,823
6	Firm Sales Obligations												
7	Total net energy for load (5+6)	4,921,356	5,487,475	5,983,112	6,435,528	7,037,165	7,492,205	7,964,077	8,427,829	8,952,617	9,209,750	9,387,259	9,558,823
8	[Customer-side solar generation]	36,503	37,411	38,352	39,310	40,299	41,305	42,327	43,398	44,469	45,588	46,724	47,892
9	[Light Duty PEV electricity consumption/procurement requirement]												
10	[Other transportation electricity consumption/procurement requirement]												
11	[Other electrification/fuel substitution; consumption/procurement requirement]												

EXISTING AND PLANNED GENERATION RESOURCES

	Utility-Owned Generation Resources (not RPS-eligible): [list resource by name]	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
12a	DVR	1,280,374	1,294,510	1,103,074	1,194,738	1,214,048	1,162,511	1,035,509	1,011,746	1,005,102	1,034,296	1,040,822	945,962
12b	Gianera 1	9,900	9,900	9,900	9,900	9,900	6,689	3,184	7,060	5,314	0	218	561
12c	Gianera 2	9,900	9,900	9,900	9,900	9,900	5,103	3,681	4,383	5,049	0	0	384
12d	Alameda CT 1	0	0	0	0	0	0	0	0	0	0	0	0
12e	Alameda CT 2	0	12,052	0	0	0	0	0	0	0	0	0	0
12f	Lodi CT	13,076	20,267	0	0	0	0	0	0	0	0	0	0
12g	LEC	479,537	584,603	283,592	0	0	0	0	0	0	0	0	0
12h	LEC Hydrogen 45 Blend	0	0	0	253,668	256,896	214,436	75,705	107,509	66,502	16,281	77,795	93,002
12i	Collierville	158,355	158,302	158,302	158,302	158,355	158,302	158,302	158,302	158,355	158,302	158,302	158,302
12j	BESS 50MW 200MWh	0	(1,046)	(6,531)	(6,014)	(6,999)	(7,315)	(10,342)	(11,143)	(12,822)	(13,400)	(10,625)	(13,338)
	Long-Term Contracts (not RPS-eligible): [list contracts by name]												
12k	Tri-Dam Donnells	242,640	242,640	242,640	242,640	242,640	242,640	242,640	242,640	242,640	242,640	242,640	242,640
12l	WAPA Base Resource	249,840	249,840	249,840	249,840	249,840	249,840	249,840	249,840	249,840	249,840	249,840	249,840
12m	South Feather - Forbstown	60,030	59,310	58,930	59,999	59,137	57,244	57,625	59,829	57,638	59,146	59,645	57,490
12n	South Feather - Woodleaf	103,004	98,823	98,950	100,048	98,548	97,781	94,981	98,930	100,235	98,065	94,854	95,060
12	Total energy from existing and planned supply resources (not RPS-eligible) (sum of 12a…12n)	2,606,656	2,739,100	2,208,596	2,273,021	2,292,265	2,187,231	1,911,125	1,929,096	1,877,853	1,845,170	1,913,490	1,829,903
	Utility-Owned RPS-eligible Generation Resources: [list resource by plant or unit]												
13a	Black Butte	8,183	7,485	7,628	7,696	7,674	7,836	7,779	7,521	7,695	7,596	7,624	7,662
13b	Stony Gorge	6,651	6,570	6,391	6,907	6,645	6,671	6,655	6,656	6,843	7,125	6,701	6,913
13c	Grizzly Hydro	43,392	43,392	43,392	43,392	43,392	43,392	43,392	43,392	43,392	43,392	43,392	43,392
13d	Big Horn 1	212,116	227,991	208,543	0	0	0	0	0	0	0	0	0
13e	Big Horn 2	35,353	37,998	41,309	39,590	41,843	36,898	36,678	41,728	36,003	34,711	37,160	28,021
13f	Geo Plant 1 Unit 1	105,408	105,120	105,120	105,120	105,408	105,120	105,120	105,120	105,408	105,120	105,120	105,120
13g	Geo Plant 1 Unit 2	105,408	105,120	105,120	105,120	105,408	105,120	105,120	105,120	105,408	105,120	105,120	105,120

13h	Geo Plant 2 Unit 4	140,544	140,160	140,160	140,160	140,544	140,160	140,160	140,160	140,544	140,160	140,160	140,160
13i	Spicer	5,449	5,203	5,186	5,073	5,242	5,178	5,089	5,103	5,114	5,137	5,162	5,162
	Long-Term Contracts (RPS-eligible):												
	[list contracts by name]												
13j	Ameresco Forward	36,893	36,792	36,792	36,792	36,893	36,792	36,432	36,519	36,273	36,107	5,947	0
13k	Ameresco Vasco	37,771	37,668	37,668	37,668	37,771	37,668	37,238	37,350	37,173	36,890	6,089	0
13l	G2 Landfill	614	0	0	0	0	0	0	0	0	0	0	0
13m	Tri-Dam Beardsley	44,316	44,014	43,229	44,357	44,565	45,182	44,466	44,809	44,298	44,463	43,329	43,405
13n	Tri-Dam Sand Bar	73,927	73,830	70,679	73,739	73,411	75,048	73,066	74,693	74,452	73,200	70,112	70,450
13o	Tri-Dam Tulloch	109,238	110,174	110,943	109,007	108,219	107,609	107,955	109,597	109,660	107,938	106,428	106,198
13p	Friant 1	66,165	64,859	66,469	66,570	65,702	65,634	64,649	66,134	66,268	65,698	65,206	64,772
13q	Friant 2 (Quinten)	39,234	39,246	39,238	39,212	39,187	39,256	39,295	39,588	38,770	38,765	38,490	37,901
13r	Rio Bravo (Index+)	14,459	13,864	14,514	14,585	14,155	13,980	14,282	14,629	14,281	13,468	14,741	14,227
13s	Camp Far West Hydro (Index+)	24,963	24,647	25,829	25,924	24,303	26,070	24,509	25,332	24,746	26,303	25,116	25,643
13t	South Feather - Kelly Ridge	27,305	27,241	26,537	27,156	27,443	27,590	26,768	27,344	26,897	27,003	26,953	27,159
13u	South Feather - Sly Creek	14,312	14,130	13,847	14,188	13,951	13,655	13,664	14,077	14,100	13,821	13,765	13,553
13v	Central 40 Solar	107,505	115,113	113,097	112,812	109,665	111,053	111,618	113,238	107,308	109,030	110,652	109,808
13w	Rosamond Solar	60,046	63,134	62,629	62,849	60,997	61,759	62,357	62,039	59,655	60,922	62,685	59,568
13x	Aquamarine Westside (Index+)	169,825	0	0	0	0	0	0	0	0	0	0	0
13y	Manzana Wind	118,443	137,913	131,625	124,608	115,771	119,246	127,914	126,320	124,894	0	0	0
13z	Cimmaron Wind	0	0	929,781	786,072	742,419	783,090	885,876	820,291	855,443	785,958	797,190	760,904
13aa	Calpine Geo	0	306,600	306,600	613,200	614,880	613,200	613,200	613,200	614,880	613,200	613,200	613,200
13ab	Sand Hill A	0	0	30,339	28,276	29,266	28,105	27,759	28,676	29,673	26,465	27,321	29,853
13ac	Sand Hill B	0	0	40,841	38,064	39,396	37,833	37,439	38,603	39,910	35,798	36,779	40,187
13ad	Rooney Ranch	0	0	44,341	41,326	42,773	41,076	40,740	41,943	43,351	38,834	39,931	43,469
13	**Total energy from RPS-eligible resources (sum of 13a…13n, and 13z)**	**1,607,516**	**1,788,263**	**2,807,847**	**2,749,464**	**2,696,923**	**2,734,220**	**2,839,219**	**2,789,179**	**2,812,439**	**2,602,225**	**2,554,372**	**2,501,845**
13z	**Undelivered RPS energy**												
14	**Total energy from existing and planned supply resources (12+13)**	**4,214,173**	**4,527,363**	**5,016,443**	**5,022,484**	**4,989,189**	**4,921,451**	**4,750,344**	**4,718,276**	**4,690,292**	**4,447,395**	**4,467,863**	**4,331,748**

GENERIC ADDITIONS

NON-RPS ELIGIBLE RESOURCES:

	[list resource by name or description]	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
15a	Li_Battery_4hr	0	0	(10,151)	(9,746)	(12,159)	(13,113)	(17,343)	(18,750)	(23,379)	(20,454)	(20,516)	(21,648)
15	**Total energy from generic supply resources (not RPS-eligible)**	**0**	**0**	**(10,151)**	**(9,746)**	**(12,159)**	**(13,113)**	**(17,343)**	**(18,750)**	**(23,379)**	**(20,454)**	**(20,516)**	**(21,648)**
	RPS-ELIGIBLE RESOURCES:												
	[list resource by name or description]												
16a	Central_California_Wind	0	0	0	0	0	256,441	470,843	471,261	560,038	560,873	568,725	948,346
16b	Geothermal	0	0	0	0	466,207	464,933	1,025,676	1,397,250	2,011,760	2,481,544	2,507,523	2,541,369
16c	New_Mexico_Wind	0	0	432,068	415,491	437,239	513,827	524,991	504,589	483,645	486,072	562,389	500,368
16d	Southern_California_Solar	0	0	437,950	441,516	426,314	437,579	442,049	449,992	425,621	440,165	443,327	424,255
16e	Wyoming_Wind	0	0	0	328,454	354,299	615,500	683,382	674,484	640,398	662,292	694,953	703,358
16	**Total energy from generic RPS-eligible resources**	**0**	**0**	**870,018**	**1,185,461**	**1,684,059**	**2,288,280**	**3,146,941**	**3,497,576**	**4,121,462**	**4,630,946**	**4,776,918**	**5,117,695**
17	**Total energy from generic supply resources (15+16)**	**0**	**0**	**859,867**	**1,175,715**	**1,671,901**	**2,275,167**	**3,129,598**	**3,478,825**	**4,098,083**	**4,610,492**	**4,756,402**	**5,096,047**
17z	**Total energy from RPS-eligible short-term contracts**												

ENERGY FROM SHORT-TERM PURCHASES

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
18	Short term and spot market purchases:	953,809	1,164,973	406,571	559,797	728,259	670,713	482,702	653,130	611,998	612,740	632,683	609,398
18a	Short term and spot market sales:	(246,625)	(204,861)	(299,769)	(322,469)	(352,184)	(375,125)	(398,567)	(422,402)	(447,757)	(460,876)	(469,689)	(478,371)

ENERGY BALANCE SUMMARY

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
19	Total energy from supply resources (14+17+17z)	4,214,173	4,527,363	5,876,310	6,198,199	6,661,089	7,196,617	7,879,942	8,197,101	8,788,375	9,057,887	9,224,265	9,427,796
19a	Undelivered RPS energy (from 13z)	0	0	0	0	0	0	0	0	0	0	0	0
20	Short term and spot market purchases (from 18 + 18a)	707,184	960,111	106,802	237,329	376,075	295,588	84,135	230,728	164,242	151,864	162,994	131,027
21	Total delivered energy (19-19a+20)	4,921,356	5,487,475	5,983,112	6,435,528	7,037,165	7,492,205	7,964,077	8,427,829	8,952,617	9,209,750	9,387,259	9,558,823
22	Total net energy for load (from 7)	4,921,356	5,487,475	5,983,112	6,435,528	7,037,165	7,492,205	7,964,077	8,427,829	8,952,617	9,209,750	9,387,259	9,558,823
23	Surplus/Shortfall (21-22)	0	(0)	0	(0)	0	(0)	(0)	0	(0)	(0)	0	0

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
GHG Emissions Accounting Table
Form CEC 111 (May 2017)

Scenario Name: Base SB 100

Yellow fill relates to an application for confidentiality.

Emissions Intensity Units = mt CO2e/MWh
Yearly Emissions Total Units = Mmt CO2e

GHG EMISSIONS FROM EXISTING AND PLANNED SUPPLY

	Utility-Owned Generation (not RPS-eligible):													
	[list resource by name]	Emissions Intensity	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
1a	DVR	0.426	0.549	0.556	0.467	0.508	0.518	0.496	0.438	0.426	0.426	0.437	0.441	0.400
1b	Gianera 1	0.809	0.008	0.008	0.008	0.008	0.008	0.005	0.003	0.006	0.004	0.000	0.000	0.000
1c	Gianera 2	0.809	0.008	0.008	0.008	0.008	0.008	0.004	0.003	0.004	0.004	0.000	0.000	0.000
1d	Alameda CT 1	0.762	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1e	Alameda CT 2	0.762	0.000	0.009	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1f	Lodi CT	0.742	0.010	0.015	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1g	LEC	0.363	0.174	0.212	0.103	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1h	LEC Hydrogen 45 Blend	0.286	0.000	0.000	0.000	0.073	0.074	0.061	0.022	0.031	0.019	0.005	0.022	0.027
1i														
1j														
	Long-Term Contracts (not RPS-eligible):													
	[list contracts by name]	Emissions Intensity												
1k														
1l														
1m														
1	**Total GHG emissions of existing and planned supply resources (not RPS-eligible) (sum of 1a…1n)**		**0.749**	**0.809**	**0.586**	**0.597**	**0.607**	**0.567**	**0.465**	**0.466**	**0.453**	**0.442**	**0.463**	**0.427**
	Utility-Owned RPS-eligible Generation Resources:													
	[list resource by plant or unit]	Emissions Intensity												
2a														
2b														
2c														
2d														
2e														
2f														
2g														
	Long-Term Contracts (RPS-eligible):													
	[list contracts by name]	Emissions Intensity												
2h														
2i														
2j														
2k														
2l														
2m														
2n														
2	**Total GHG emissions from RPS-eligible resources (sum of 2a…2n)**		**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
3	**Total GHG emissions from existing and planned supply resources (1+2)**		**0.749**	**0.809**	**0.586**	**0.597**	**0.607**	**0.567**	**0.465**	**0.466**	**0.453**	**0.442**	**0.463**	**0.427**

EMISSIONS FROM GENERIC ADDITIONS

	NON-RPS ELIGIBLE RESOURCES: [list resource by name or description]	Emissions Intensity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
4a														
4b														
4c														
4d														
4e														
4f														
4g														
4h														
4i														
4j														
4k														
4l														
4m														
4n														
4	**Total GHG emissions from generic supply resources (not RPS-eligible)**		**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

	RPS-ELIGIBLE RESOURCES: [list resource by name or description]	Emissions Intensity												
5a														
5b														
5c														
5d														
5e														
5f														
5g														
5h														
5i														
5j														
5k														
5l														
5m														
5n														
5	**Total GHG emissions from generic RPS-eligible resources**		**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
6	**Total GHG emissions from generic supply resources (4+5)**		**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

GHG EMISSIONS OF SHORT TERM PURCHASES

		Emissions Intensity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
7	**Net spot market/short-term purchases:**	Hourly Emission Intensity	**0.267**	**0.371**	**0.034**	**0.078**	**0.119**	**0.069**	**(0.000)**	**0.019**	**(0.012)**	**(0.009)**	**(0.024)**	**(0.052)**
	Spot market/short-term purchases:	Hourly Emission Intensity	0.366	0.452	0.153	0.210	0.260	0.221	0.160	0.190	0.168	0.174	0.164	0.139
	Spot market/short-term sales:	Hourly Emission Intensity	(0.099)	(0.081)	(0.119)	(0.132)	(0.142)	(0.152)	(0.161)	(0.170)	(0.180)	(0.183)	(0.188)	(0.191)

TOTAL GHG EMISSIONS

			2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
8	**Total GHG emissions to meet net energy for load (3+6+7)**		**1.015**	**1.180**	**0.620**	**0.675**	**0.726**	**0.635**	**0.465**	**0.485**	**0.441**	**0.434**	**0.439**	**0.375**

EMISSIONS ADJUSTMENTS

8a	**Undelivered RPS energy (MWh from EBT)**	0	0	0	0	0	0	0	0	0	0	0	0
8b	**Firm Sales Obligations (MWh from EBT)**	0	0	0	0	0	0	0	0	0	0	0	0
8c	**Total energy for emissions adjustment (8a+8b)**	0	0	0	0	0	0	0	0	0	0	0	0
8d	**Emissions intensity (portfolio gas/short-term and spot market purchases)**												
8e	**Emissions adjustment (8Cx8D)**	0	0	0	0	0	0	0	0	0	0	0	0

	PORTFOLIO GHG EMISSIONS												
8f	Portfolio emissions (8-8e)	1.015	1.180	0.620	0.675	0.726	0.635	0.465	0.485	0.441	0.434	0.439	0.375
	GHG EMISSIONS IMPACT OF TRANSPORTATION ELECTRIFICATION												
		2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
9	GHG emissions reduction due to gasoline vehicle displacement by LD PEVs												
10	GHG emissions increase due to LD PEV electricity loads												
11	GHG emissions reduction due to fuel displacement - other transportation electrification												
12	GHG emissions increase due to increased electricity loads - other transportation electrification												

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
RPS Procurement Table
Form CEC 112 (May 2017)

Scenario Name: Base SB 100

Units = MWh

	RPS ENERGY REQUIREMENT CALCULATIONS	Beginning balances Start of 2017	Compliance Period 3: 2017	2018	2019	2020		Compliance Period 4: 2021	2022	2023	2024	
1	(Managed) Retail sales to end-use customers (From EBT)		3,523,784	3,548,030	3,575,729	3,722,544		4,011,842	4,397,926	4,755,204	4,778,145	
2	Green pricing program/hydro exclusion											
3	Soft target (%)		27.00%	29.00%	31.00%	33.00%		35.75%	38.50%	41.25%	44.00%	
4	Required procurement for compliance period		4317266					7191340				
	Category 0, 1 and 2 RECs											
5	Excess balance/historic carryover at beginning/end of compliance period	987880					2,375,706					1,115,427
6	RPS-eligible energy procured (copied from EBT)		2,417,033	1,223,495	1,405,216	1,191,658		1,270,167	1,474,984	1,414,493	1,607,516	
6A	Amount of energy applied to procurement obligation		2,417,033	1,223,495	567,928	0		1,270,167	1,474,984	1,414,493	1,607,516	
7	Net purchases of Category 0, 1 and 2 RECs											
7A	Carryover and REC purchases applied to procurement obligation									765,412	494,867	
8	Net change in balance/carryover (6+7-6A-7A)		0	0	837,288	1,191,658		0	0	(765,412)	(494,867)	
	Category 3 RECs											
9	Excess balance/historic carryover at beginning/end of compliance period	0					0					0
10	Net purchases of Category 3 RECs		70000	38807	0	0		25,000	5,901	133,000		
11	Carryover and REC purchases applied to procurement obligation		70000	38807	0	0		25000	5901	133000		
12	Net change in REC balance/carryover		0	0	0	0		0	0	0	0	
13	Total generation plus RECs (all Categories) applied to procurement requirement (6A + 7A + 11)		4,317,263					7,191,340				
14	Over/under procurement for compliance period (13 - 4)		(3)					0				

	RPS ENERGY REQUIREMENT CALCULATIONS	Compliance Period 5: 2025	2026	2027		Compliance Period 6: 2028	2029	2030		Years 2031-2033: 2031	2032	2033		Years 2034-2035: 2034	2035	
1	(Managed) Retail sales to end-use customers (From EBT)	5,327,789	5,809,004	6,248,254		6,832,383	7,274,182	7,732,322		8,182,580	8,692,095	8,941,747		9,114,090	9,280,661	
2	Green pricing program/hydro exclusion															
3	Soft target (%)	46.67%	49.33%	52.00%		54.67%	57.33%	60.00%		60.00%	60.00%	60.00%		60.00%	60.00%	
4	Required procurement for compliance period	8,601,153				12,544,946				15,489,853				11,036,851		
	Category 0, 1 and 2 RECs															
5	Excess balance/historic carryover at beginning/end of compliance period				1,915,327				4,760,023				9,723,996			13,637,976
6	RPS-eligible energy procured (copied from EBT)	1,788,263	3,677,865	3,934,924		4,380,983	5,022,500	5,986,160		6,286,755	6,933,900	7,233,171		7,331,291	7,619,540	
6A	Amount of energy applied to procurement obligation	1,788,263	3,677,865	3,135,025		4,380,983	5,022,500	3,141,463		6,286,755	6,933,900	2,269,198		7,331,291	3,705,560	
7	Net purchases of Category 0, 1 and 2 RECs															
7A	Carryover and REC purchases applied to procurement obligation															
8	Net change in balance/carryover (6+7-6A-7A)	0	0	799,900		0	0	2,844,697		0	0	4,963,973		0	3,913,980	
	Category 3 RECs															
9	Excess balance/historic carryover at beginning/end of compliance period				0				0				0			0
10	Net purchases of Category 3 RECs															
11	Carryover and REC purchases applied to procurement obligation															
12	Net change in REC balance/carryover	0	0	0		0	0	0		0	0	0		0	0	
13	Total generation plus RECs (all Categories) applied to procurement requirement (6A + 7A + 11)	8,601,153				12,544,946				15,489,853				11,036,851		
14	Over/under procurement for compliance period (13 - 4)	0				0				0				0		

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
Capacity Resource Accounting Table
Form CEC 109 (May 2017)

Scenario Name: Accelerated SB 100

Yellow fill relates to an application for confidentiality.
Units = MW
Data input by User are in dark green font.

	PEAK LOAD CALCULATIONS			2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	Forecast Total Peak-Hour 1-in-2 Demand			715	801	875	943	1,027	1,097	1,164	1,237	1,306	1,351	1,377	1,400
2	[Customer-side solar: nameplate capacity]			23	23	24	24	25	25	26	27	27	28	29	30
2a	[Customer-side solar: peak hour output]			15	16	16	17	17	17	18	18	19	19	20	20
3	[Peak load reduction due to thermal energy storage]														
4	[Light Duty PEV consumption in peak hour]			1	3	4	5	6	5	6	10	11	13	15	11
5	Additional Achievable Energy Efficiency Savings on Peak			16	25	30	36	40	41	41	51	54	63	61	59
6	Demand Response / Interruptible Programs on Peak			8	8	8	8	8	8	8	8	8	8	8	8
7	Managed Peak Demand (1-5-6)			692	768	837	898	979	1,048	1,116	1,178	1,243	1,279	1,307	1,333
7a	Coincident gross peak (managed peak plus BTM PV peak shift)			637	719	798	850	866	960	1,018	1,093	1,171	1,171	1,152	1,219
8	Planning Reserve Margin	14%	This is a perfect capacity (PCAP)-based PRM. The 14% PCAP PRM translates to about 22% ICAP PRM and is a more stringent target than previous CAISO studies to ensure a 1-day-in-10-years LOLE target. The 14% PCAP PRM is applied to the coincident gross peak (managed peak plus BTM PV peak shift). See details on the right.	89	101	112	119	121	134	143	153	164	164	161	171
9	Firm Sales Obligations			0	0	0	0	0	0	0	0	0	0	0	0
10a	Total Peak Procurement Requirement Based on the Total Reliability Need Framework (7a+8+9)		See details on the right.	727	819	909	970	987	1,094	1,160	1,246	1,335	1,335	1,314	1,389
10b	CAISO Portfolio Effects		See details on the right.	92	93	85	116	125	212	251	309	342	379	343	442
10	Total Peak Procurement Requirement Based on the Marginal Reliability Need Framework (10a-10b)		See details on the right.	635	727	825	853	863	882	909	937	993	956	970	947
	EXISTING AND PLANNED CAPACITY SUPPLY RESOURCES			Resource capacity accreditation is based on the marginal effective load carrying capability (ELCC) and marginal reliability framework.											
	Utility-Owned Generation and Storage (not RPS-eligible):														
	[list resource by name]		Fuel	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
11a	DVR		Gas - CC	125	127	130	129	129	127	126	128	129	131	133	135
11b	Gianera 1		Gas - CT	20	20	21	20	20	20	20	20	20	20	21	21
11c	Gianera 2		Gas - CT	20	20	21	20	20	20	20	20	20	20	21	21
11d	Alameda CT 1		Gas - CT	8	8	8	8	8	8	8	8	8	8	8	8
11e	Alameda CT 2		Gas - CT	8	8	8	8	8	8	8	8	8	8	8	8
11f	Lodi CT		Gas - CT	8	8	8	8	8	8	8	8	8	8	8	8
11g	LEC		Gas - CC	66	67	68	0	0	0	0	0	0	0	0	0
11h	LEC Hydrogen 45 Blend		Hydrogen Blend	0	0	0	68	68	67	66	67	68	69	70	71
11i	Collierville		Large Hydro	52	52	51	49	46	45	44	43	42	41	40	39
11j	BESS 50MW 200MWh		Li-ion Battery (4-hr)	0	45	46	42	39	38	37	34	30	27	23	20
	Long-Term Contracts (not RPS-eligible):														
	[list contracts by name]		Fuel												
11k	Tri-Dam Donnells		Large Hydro	41	41	40	38	36	35	35	34	33	32	32	31
11l	WAPA Base Resource		Large Hydro	71	71	71	67	63	62	61	59	58	57	55	54
11m	South Feather - Forbstown		Large Hydro	14	14	13	13	12	12	12	11	11	11	11	10
11n	South Feather - Woodleaf		Large Hydro	22	22	22	20	19	19	19	18	18	17	17	17
11	Total peak dependable capacity of existing and planned supply resources (not RPS-eligible) (sum of 11a…11n)			454	503	507	492	477	469	461	458	454	451	447	443
	Utility-Owned RPS-eligible Resources:														
	[list resource by plant or unit]		Fuel												
12a	Black Butte		Small Hydro	3	3	2	2	2	2	2	2	2	2	2	2
12b	Stony Gorge		Small Hydro	2	2	2	2	2	2	2	2	2	2	2	2

12c	Grizzly Hydro	Small Hydro	7	7	7	7	6	6	6	6	6	6	6	5
12d	Big Horn 1	Wind	27	25	23	0	0	0	0	0	0	0	0	0
12e	Big Horn 2	Wind	5	4	4	4	4	3	3	3	3	3	3	3
12f	Geo Plant 1 Unit 1	Geothermal	10	11	11	11	11	11	11	11	11	11	11	11
12g	Geo Plant 1 Unit 2	Geothermal	10	11	11	11	11	11	11	11	11	11	11	11
12h	Geo Plant 2 Unit 4	Geothermal	14	14	14	15	15	15	15	15	15	15	15	15
12i	Spicer	Small Hydro	1	1	1	1	1	1	1	1	1	1	1	1
	Long-Term Contracts (RPS-eligible):													
	[list contracts by name]	Fuel												
12j	Ameresco Forward	Biogas	3	3	3	3	3	3	3	3	3	3	0	0
12k	Ameresco Vasco	Biogas	3	3	3	3	3	3	3	3	3	4	0	0
12l	G2 Landfill	Biogas	0	0	0	0	0	0	0	0	0	0	0	0
12m	Tri-Dam Beardsley	Small Hydro	5	5	5	4	4	4	4	4	4	4	4	4
12n	Tri-Dam Sand Bar	Small Hydro	7	7	7	6	6	6	6	5	5	5	5	5
12o	Tri-Dam Tulloch	Small Hydro	11	10	10	10	9	9	9	9	9	8	8	8
12p	Friant 1	Small Hydro	10	10	10	10	9	9	9	8	8	8	8	8
12q	Friant 2 (Quinten)	Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
12r	Rio Bravo (Index+)	Small Hydro	6	6	6	5	5	5	5	5	5	5	4	4
12s	Camp Far West Hydro (Index+)	Small Hydro	3	3	3	3	2	2	2	2	2	2	2	2
12t	South Feather - Kelly Ridge	Small Hydro	3	3	3	3	3	2	2	2	2	2	2	2
12u	South Feather - Sly Creek	Small Hydro	3	3	3	3	3	3	3	3	3	3	3	3
12v	Central 40 Solar	Solar	4	4	4	4	4	3	2	2	2	2	3	3
12w	Rosamond Solar	Solar	2	2	2	2	2	2	1	1	1	1	1	1
12x	Aquamarine Westside (Index+)	Solar	7	0	0	0	0	0	0	0	0	0	0	0
12y	Manzana Wind	Wind	8	8	8	6	4	4	4	4	3	0	0	0
12z	Cimmaron Wind	Wind	0	0	0	0	0	0	0	0	0	0	0	0
12aa	Calpine Geo	Geothermal	0	31	31	64	65	65	64	65	65	66	66	67
12ab	Sand Hill A	Wind	0	0	4	3	2	2	2	2	2	2	1	1
12ac	Sand Hill B	Wind	0	0	5	4	3	3	3	3	2	2	2	2
12ad	Rooney Ranch	Wind	0	0	6	5	3	3	3	3	3	2	2	2
12	**Total peak dependable capacity of existing and planned RPS-eligible resources (sum of 12a…12n)**		**153**	**175**	**189**	**190**	**184**	**180**	**176**	**175**	**174**	**170**	**162**	**161**
13	**Total peak dependable capacity of existing and planned supply resources (11+12)**		**607**	**677**	**695**	**682**	**661**	**649**	**638**	**633**	**628**	**621**	**609**	**605**
	GENERIC ADDITIONS		Resource capacity accreditation is based on the marginal effective load carrying capability (ELCC) and marginal reliability frameworl											
	NON-RPS ELIGIBLE RESOURCES:													
	[list resource by name or description]	Fuel	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
14a	Li_Battery_4hr	Li-ion Battery (4-hr)	0	0	74	88	81	79	78	70	63	56	49	42
14	**Total peak dependable capacity of generic supply resources (not RPS-eligible)**		**0**	**0**	**74**	**88**	**81**	**79**	**78**	**70**	**63**	**56**	**49**	**42**
	RPS-ELIGIBLE RESOURCES:													
	[list resource by name or description]	Fuel												
15a	Central_California_Wind	Wind	0	0	0	0	0	8	10	9	11	10	9	18
15b	Geothermal	Geothermal	0	0	0	0	49	49	110	148	210	264	312	317
15c	New_Mexico_Wind	Out-of-state Wind	0	0	35	37	38	36	27	28	30	31	33	34
15d	Southern_California_Solar	Solar	0	0	19	18	17	14	11	11	11	11	11	11
15e	Wyoming_Wind	Out-of-state Wind	0	0	0	28	29	47	35	37	39	41	43	60
15	**Total peak dependable capacity of generic RPS-eligible resources**		**0**	**0**	**55**	**83**	**134**	**154**	**194**	**233**	**301**	**358**	**408**	**442**
16	**Total peak dependable capacity of generic supply resources (14+15)**		**0**	**0**	**129**	**171**	**214**	**233**	**271**	**304**	**365**	**414**	**457**	**484**
	CAPACITY BALANCE SUMMARY													
			2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
17	**Total peak procurement requirement based on the marginal reliability need framework (from line 10)**		**635**	**727**	**825**	**853**	**863**	**882**	**909**	**937**	**993**	**956**	**970**	**947**

18	**Total peak dependable capacity of existing and planned supply resources based on the marginal reliability need framework (from line 13)**			**607**	**677**	**695**	**682**	**661**	**649**	**638**	**633**	**628**	**621**	**609**	**605**
19	**Current capacity surplus (shortfall) based on the marginal reliability need framework (18-17)**			**(28)**	**(49)**	**(129)**	**(171)**	**(202)**	**(233)**	**(271)**	**(304)**	**(365)**	**(335)**	**(361)**	**(342)**
20	**Total peak dependable capacity of generic supply resources based on the marginal reliability need framework (from line 16)**			**0**	**0**	**129**	**171**	**214**	**233**	**271**	**304**	**365**	**414**	**457**	**484**
21	**Planned capacity surplus/shortfall based on the marginal reliability need framework (shortfalls assumed to be met with short-term capacity purchases) (19+20)**			**(28)**	**(49)**	**0**	**(0)**	**12**	**0**	**(0)**	**0**	**0**	**79**	**96**	**141**

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
Energy Balance Table
Form CEC 110 (May 2017)

Scenario Name: Accelerated SB 100

Units = MWh

Yellow fill relates to an application for confidentiality.

	NET ENERGY FOR LOAD CALCULATIONS	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	Retail sales to end-use customers												
2	Other loads												
3	Unmanaged net energy for load												
4	Managed retail sales to end-use customers	4,778,145	5,327,789	5,809,004	6,248,254	6,832,383	7,274,182	7,732,322	8,182,580	8,692,095	8,941,747	9,114,090	9,280,661
5	Managed net energy for load	4,921,356	5,487,475	5,983,112	6,435,528	7,037,165	7,492,205	7,964,077	8,427,829	8,952,617	9,209,750	9,387,259	9,558,823
6	Firm Sales Obligations												
7	Total net energy for load (5+6)	4,921,356	5,487,475	5,983,112	6,435,528	7,037,165	7,492,205	7,964,077	8,427,829	8,952,617	9,209,750	9,387,259	9,558,823
8	[Customer-side solar generation]	36,503	37,411	38,352	39309.59	40299.22	41305.08	42327.16	43397.92	44468.67	45588.09	46723.74	47891.83
9	[Light Duty PEV electricity consumption/procurement requirement]												
10	[Other transportation electricity consumption/procurement requirement]												
11	[Other electrification/fuel substitution; consumption/procurement requirement]												

	EXISTING AND PLANNED GENERATION RESOURCES												
	Utility-Owned Generation Resources (not RPS-eligible):												
	[list resource by name]	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
12a	DVR	1,280,374	1,294,510	1,056,358	1,152,061	1,192,865	1,139,261	1,026,286	1,006,640	1,004,775	1,020,471	876,076	508,473
12b	Gianera 1	9,900	9,900	9,900	9,900	9,900	6,233	1,355	4,962	5,436	0	0	0
12c	Gianera 2	9,900	9,900	9,900	9,900	9,900	4,029	2,905	4,809	5,049	0	0	0
12d	Alameda CT 1	0	0	0	0	0	0	0	0	0	0	0	0
12e	Alameda CT 2	0	12,052	0	0	0	0	0	0	0	0	0	0
12f	Lodi CT	13,076	20,267	0	0	0	0	0	0	0	0	0	0
12g	LEC	479,537	584,603	273,649	0	0	0	0	0	0	0	0	0
12h	LEC Hydrogen 45 Blend	0	0	0	237,103	235,722	188,146	57,352	111,329	65,412	15,035	21,541	38,463
12i	Collierville	158,355	158,302	158,302	158,302	158,355	158,302	158,302	158,302	158,355	158,302	158,302	158,302
12j	BESS 50MW 200MWh	0	(1,046)	(7,781)	(6,457)	(7,370)	(7,877)	(10,705)	(11,553)	(13,304)	(12,275)	(13,253)	(37,981)
	Long-Term Contracts (not RPS-eligible):												
	[list contracts by name]												
12k	Tri-Dam Donnells	242,640	242,640	242,640	242,640	242,640	242,640	242,640	242,640	242,640	242,640	242,640	242,640
12l	WAPA Base Resource	249,840	249,840	249,840	249,840	249,840	249,840	249,840	249,840	249,840	249,840	249,840	249,840
12m	South Feather - Forbstown	60,030	59,310	58,543	59,999	59,137	57,155	58,909	59,942	57,851	59,289	59,645	57,020
12n	South Feather - Woodleaf	103,004	98,823	98,533	100,048	98,548	97,535	97,206	99,067	100,578	98,286	94,854	93,745
12	Total energy from existing and planned supply resources (not RPS-eligible) (sum of 12a…12n)	2,606,656	2,739,100	2,149,884	2,213,337	2,249,537	2,135,263	1,884,090	1,925,978	1,876,633	1,831,587	1,689,644	1,310,501
	Utility-Owned RPS-eligible Generation Resources:												
	[list resource by plant or unit]												
13a	Black Butte	8,183	7,485	7,628	7,696	7,674	7,836	7,779	7,521	7,695	7,596	7,624	7,662
13b	Stony Gorge	6,651	6,570	6,391	6,907	6,645	6,671	6,655	6,656	6,843	7,125	6,701	6,913
13c	Grizzly Hydro	43,392	43,392	43,392	43,392	43,392	43,392	43,392	43,392	43,392	43,392	43,392	42,967
13d	Big Horn 1	212,116	227,991	208,482	0	0	0	0	0	0	0	0	0
13e	Big Horn 2	35,353	37,998	40,760	39,590	41,843	36,898	36,828	41,632	35,848	34,600	37,134	26,779
13f	Geo Plant 1 Unit 1	105,408	105,120	105,120	105,120	105,408	105,120	105,120	105,120	105,408	105,120	105,120	105,120
13g	Geo Plant 1 Unit 2	105,408	105,120	105,120	105,120	105,408	105,120	105,120	105,120	105,408	105,120	105,120	105,120

13h	Geo Plant 2 Unit 4	140,544	140,160	140,160	140,160	140,544	140,160	140,160	140,160	140,544	140,160	140,160	140,160
13i	Spicer	5,449	5,203	5,186	5,073	5,242	5,178	5,089	5,103	5,114	5,137	5,162	5,042
	Long-Term Contracts (RPS-eligible):												
	[list contracts by name]												
13j	Ameresco Forward	36,893	36,792	36,653	36,792	36,893	36,792	36,561	36,523	36,070	35,848	5,947	0
13k	Ameresco Vasco	37,771	37,668	37,526	37,668	37,771	37,668	37,355	37,364	37,070	36,726	6,089	0
13l	G2 Landfill	614	0	0	0	0	0	0	0	0	0	0	0
13m	Tri-Dam Beardsley	44,316	44,014	43,229	44,357	44,565	45,182	44,466	44,809	44,298	44,463	43,329	43,405
13n	Tri-Dam Sand Bar	73,927	73,830	70,679	73,739	73,411	75,048	73,066	74,693	74,452	73,200	70,112	70,450
13o	Tri-Dam Tulloch	109,238	110,174	110,943	109,007	108,219	107,609	107,955	109,597	109,660	107,938	106,428	106,198
13p	Friant 1	66,165	64,859	66,469	66,570	65,702	65,634	64,649	66,134	66,268	65,698	65,206	64,772
13q	Friant 2 (Quinten)	39,234	39,246	39,238	39,212	39,187	39,256	39,295	39,588	38,770	38,765	38,490	37,901
13r	Rio Bravo (Index+)	14,459	13,864	14,514	14,585	14,155	13,980	14,282	14,629	14,281	13,468	14,741	14,227
13s	Camp Far West Hydro (Index+)	24,963	24,647	25,829	25,924	24,303	26,070	24,509	25,332	24,746	26,303	25,116	25,643
13t	South Feather - Kelly Ridge	27,305	27,241	26,393	27,156	27,443	27,590	26,849	27,375	26,833	26,859	26,867	25,775
13u	South Feather - Sly Creek	14,312	14,130	13,805	14,188	13,951	13,655	13,683	14,077	14,011	13,722	13,740	12,793
13v	Central 40 Solar	107,505	115,113	112,925	112,812	109,665	111,053	111,556	112,887	106,903	106,971	110,173	103,396
13w	Rosamond Solar	60,046	63,134	62,189	62,849	60,997	61,759	61,899	62,342	58,921	60,510	61,968	55,495
13x	Aquamarine Westside (Index+)	169,825	0	0	0	0	0	0	0	0	0	0	0
13y	Manzana Wind	118,443	137,913	131,009	124,608	115,771	119,246	128,083	126,602	123,129	0	0	0
13z	Cimmaron Wind	0	0	929,781	786,072	742,419	783,090	886,409	821,648	851,494	777,069	794,488	731,747
13aa	Calpine Geo	0	306,600	306,600	613,200	614,880	613,200	613,200	613,200	614,880	613,200	613,200	613,200
13ab	Sand Hill A	0	0	30,177	28,276	29,266	28,105	27,857	28,606	29,481	26,413	27,253	28,021
13ac	Sand Hill B	0	0	40,661	38,064	39,396	37,833	37,630	38,557	39,729	35,646	36,687	37,313
13ad	Rooney Ranch	0	0	44,153	41,326	42,773	41,076	40,714	42,066	42,966	38,766	39,832	40,780
13	**Total energy from RPS-eligible resources (sum of 13a…13n, and 13z)**	**1,607,516**	**1,788,263**	**2,805,013**	**2,749,464**	**2,696,923**	**2,734,220**	**2,840,162**	**2,790,732**	**2,804,212**	**2,589,815**	**2,550,079**	**2,450,878**
13z	**Undelivered RPS energy**												
14	**Total energy from existing and planned supply resources (12+13)**	**4,214,173**	**4,527,363**	**4,954,897**	**4,962,800**	**4,946,460**	**4,869,482**	**4,724,252**	**4,716,710**	**4,680,845**	**4,421,402**	**4,239,723**	**3,761,379**

GENERIC ADDITIONS

	NON-RPS ELIGIBLE RESOURCES:												
	[list resource by name or description]	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
15a	Li_Battery_4hr	0	0	(10,523)	(9,905)	(12,259)	(13,257)	(17,209)	(19,578)	(21,450)	(19,712)	(20,640)	(33,451)
15	**Total energy from generic supply resources (not RPS-eligible)**	**0**	**0**	**(10,523)**	**(9,905)**	**(12,259)**	**(13,257)**	**(17,209)**	**(19,578)**	**(21,450)**	**(19,712)**	**(20,640)**	**(33,451)**
	RPS-ELIGIBLE RESOURCES:												
	[list resource by name or description]												
16a	Central_California_Wind	0	0	0	0	0	256,441	389,350	389,696	525,981	526,766	534,141	1,241,653
16b	Geothermal	0	0	0	0	466,207	464,933	1,044,972	1,388,597	1,960,945	2,446,798	2,868,676	2,820,743
16c	New_Mexico_Wind	0	0	444,519	427,464	449,839	533,724	545,321	524,128	502,373	504,894	584,167	519,744
16d	Southern_California_Solar	0	0	524,895	529,168	510,948	524,450	529,807	539,327	510,118	527,549	531,340	508,480
16e	Wyoming_Wind	0	0	0	328,454	354,299	615,500	683,382	674,484	640,398	662,292	694,953	937,810
16	**Total energy from generic RPS-eligible resources**	**0**	**0**	**969,413**	**1,285,086**	**1,781,293**	**2,395,048**	**3,192,832**	**3,516,232**	**4,139,816**	**4,668,299**	**5,213,276**	**6,028,430**
17	**Total energy from generic supply resources (15+16)**	**0**	**0**	**958,890**	**1,275,181**	**1,769,034**	**2,381,792**	**3,175,623**	**3,496,654**	**4,118,366**	**4,648,587**	**5,192,636**	**5,994,979**
17z	**Total energy from RPS-eligible short-term contracts**												

ENERGY FROM SHORT-TERM PURCHASES

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
18	**Short term and spot market purchases:**	953,809	1,170,398	369,094	520,015	673,854	616,056	462,769	636,866	601,162	600,638	424,590	280,836
18a	**Short term and spot market sales:**	(246,625)	(210,287)	(299,769)	(322,469)	(352,184)	(375,125)	(398,567)	(422,402)	(447,757)	(460,876)	(469,689)	(478,371)

ENERGY BALANCE SUMMARY

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
19	**Total energy from supply resources (14+17+17z)**	**4,214,173**	**4,527,363**	**5,913,787**	**6,237,982**	**6,715,495**	**7,251,274**	**7,899,875**	**8,213,365**	**8,799,211**	**9,069,989**	**9,432,358**	**9,756,358**
19a	**Undelivered RPS energy (from 13z)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
20	**Short term and spot market purchases (from 18 + 18a)**	**707,184**	**960,111**	**69,325**	**197,546**	**321,670**	**240,931**	**64,201**	**214,465**	**153,406**	**139,761**	**(45,099)**	**(197,535)**
21	**Total delivered energy (19-19a+20)**	**4,921,356**	**5,487,475**	**5,983,112**	**6,435,528**	**7,037,165**	**7,492,205**	**7,964,077**	**8,427,829**	**8,952,617**	**9,209,750**	**9,387,259**	**9,558,823**
22	**Total net energy for load (from 7)**	**4,921,356**	**5,487,475**	**5,983,112**	**6,435,528**	**7,037,165**	**7,492,205**	**7,964,077**	**8,427,829**	**8,952,617**	**9,209,750**	**9,387,259**	**9,558,823**
23	**Surplus/Shortfall (21-22)**	**0**	**(0)**	**(0)**	**0**	**(0)**	**0**	**(0)**	**(0)**	**0**	**(0)**	**0**	**0**

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
GHG Emissions Accounting Table
Form CEC 111 (May 2017)

Scenario Name: Accelerated SB 100

Yellow fill relates to an application for confidentiality.

Emissions Intensity Units = mt CO2e/MWh
Yearly Emissions Total Units = Mmt CO2e

GHG EMISSIONS FROM EXISTING AND PLANNED SUPPLY

	Utility-Owned Generation (not RPS-eligible):														
	[list resource by name]	Emissions Intensity	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
1a	DVR	0.424	0.549	0.556	0.447	0.489	0.509	0.486	0.433	0.427	0.426	0.431	0.368	0.214
1b	Gianera 1	0.809	0.008	0.008	0.008	0.008	0.008	0.005	0.001	0.004	0.004	0.000	0.000	0.000
1c	Gianera 2	0.809	0.008	0.008	0.008	0.008	0.008	0.003	0.002	0.004	0.004	0.000	0.000	0.000
1d	Alameda CT 1	0.762	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1e	Alameda CT 2	0.762	0.000	0.009	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1f	Lodi CT	0.742	0.010	0.015	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1g	LEC	0.363	0.174	0.212	0.099	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1h	LEC Hydrogen 45 Blend	0.286	0.000	0.000	0.000	0.068	0.067	0.054	0.016	0.032	0.019	0.004	0.006	0.011
1i														
1j														
	Long-Term Contracts (not RPS-eligible):													
	[list contracts by name]	Emissions Intensity												
1k														
1l														
1m														
1	**Total GHG emissions of existing and planned supply resources (not RPS-eligible) (sum of 1a…1n)**		**0.749**	**0.809**	**0.562**	**0.573**	**0.592**	**0.548**	**0.453**	**0.466**	**0.453**	**0.436**	**0.374**	**0.225**
	Utility-Owned RPS-eligible Generation Resources:													
	[list resource by plant or unit]	Emissions Intensity												
2a														
2b														
2c														
2d														
2e														
2f														
2g														
	Long-Term Contracts (RPS-eligible):													
	[list contracts by name]	Emissions Intensity												
2h														
2i														
2j														
2k														
2l														
2m														
2n														
2	**Total GHG emissions from RPS-eligible resources (sum of 2a…2n)**		**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
3	**Total GHG emissions from existing and planned supply resources (1+2)**		**0.749**	**0.809**	**0.562**	**0.573**	**0.592**	**0.548**	**0.453**	**0.466**	**0.453**	**0.436**	**0.374**	**0.225**

EMISSIONS FROM GENERIC ADDITIONS

	NON-RPS ELIGIBLE RESOURCES: [list resource by name or description]	Emissions Intensity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
4a														
4b														
4c														
4d														
4e														
4f														
4g														
4h														
4i														
4j														
4k														
4l														
4m														
4n														
4	**Total GHG emissions from generic supply resources (not RPS-eligible)**		**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

	RPS-ELIGIBLE RESOURCES: [list resource by name or description]	Emissions Intensity												
5a														
5b														
5c														
5d														
5e														
5f														
5g														
5h														
5i														
5j														
5k														
5l														
5m														
5n														
5	**Total GHG emissions from generic RPS-eligible resources**		**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
6	**Total GHG emissions from generic supply resources (4+5)**		**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

GHG EMISSIONS OF SHORT TERM PURCHASES

		Emissions Intensity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
7	**Net spot market/short-term purchases:**	Hourly Emission Intensity	**0.267**	**0.371**	**0.019**	**0.062**	**0.099**	**0.052**	**(0.004)**	**0.016**	**(0.013)**	**(0.012)**	**(0.073)**	**(0.141)**
	Spot market/short-term purchases:	Hourly Emission Intensity	0.366	0.454	0.139	0.194	0.241	0.204	0.156	0.187	0.167	0.171	0.115	0.048
	Spot market/short-term sales:	Hourly Emission Intensity	(0.099)	(0.083)	(0.119)	(0.132)	(0.141)	(0.152)	(0.161)	(0.170)	(0.180)	(0.182)	(0.188)	(0.189)

TOTAL GHG EMISSIONS

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
8	**Total GHG emissions to meet net energy for load (3+6+7)**	**1.015**	**1.180**	**0.581**	**0.635**	**0.691**	**0.600**	**0.449**	**0.482**	**0.440**	**0.424**	**0.301**	**0.085**

EMISSIONS ADJUSTMENTS

8a	**Undelivered RPS energy (MWh from EBT)**	0	0	0	0	0	0	0	0	0	0	0	0
8b	**Firm Sales Obligations (MWh from EBT)**	0	0	0	0	0	0	0	0	0	0	0	0
8c	**Total energy for emissions adjustment (8a+8b)**	0	0	0	0	0	0	0	0	0	0	0	0
8d	**Emissions intensity (portfolio gas/short-term and spot market purchases)**												
8e	**Emissions adjustment (8Cx8D)**	0	0	0	0	0	0	0	0	0	0	0	0

PORTFOLIO GHG EMISSIONS

8f	Portfolio emissions (8-8e)		1.015	1.180	0.581	0.635	0.691	0.600	0.449	0.482	0.440	0.424	0.301	0.085

GHG EMISSIONS IMPACT OF TRANSPORTATION ELECTRIFICATION

			2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
9	GHG emissions reduction due to gasoline vehicle displacement by LD PEVs													
10	GHG emissions increase due to LD PEV electricity loads													
11	GHG emissions reduction due to fuel displacement - other transportation electrification													
12	GHG emissions increase due to increased electricity loads - other transportation electrification													

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
RPS Procurement Table
Form CEC 112 (May 2017)

Scenario Name: Accelerated SB 100

Units = MWh

	RPS ENERGY REQUIREMENT CALCULATIONS	Beginning balances Start of 2017	Compliance Period 3: 2017	2018	2019	2020		Compliance Period 4: 2021	2022	2023	2024	
1	(Managed) Retail sales to end-use customers (From EBT)		3,523,784	3,548,030	3,575,729	3,722,544		4,011,842	4,397,926	4,755,204	4,778,145	
2	Green pricing program/hydro exclusion											
3	Soft target (%)		27.00%	29.00%	31.00%	33.00%		35.75%	38.50%	41.25%	44.00%	
4	Required procurement for compliance period		4317266					7191340				
	Category 0, 1 and 2 RECs											
5	Excess balance/historic carryover at beginning/end of compliance period	987880					2,375,706					1,115,427
6	RPS-eligible energy procured (copied from EBT)		2,417,033	1,223,495	1,405,216	1,191,658		1,270,167	1,474,984	1,414,493	1,607,516	
6A	Amount of energy applied to procurement obligation		2,417,033	1,223,495	567,928	0		1,270,167	1,474,984	1,414,493	1,607,516	
7	Net purchases of Category 0, 1 and 2 RECs											
7A	Carryover and REC purchases applied to procurement obligation									765,412	494,867	
8	Net change in balance/carryover (6+7-6A-7A)		0	0	837,288	1,191,658		0	0	(765,412)	(494,867)	
	Category 3 RECs											
9	Excess balance/historic carryover at beginning/end of compliance period	0					0					0
10	Net purchases of Category 3 RECs		70000	38807	0	0		25,000	5,901	133,000		
11	Carryover and REC purchases applied to procurement obligation		70000	38807	0	0		25000	5901	133000		
12	Net change in REC balance/carryover		0	0	0	0		0	0	0	0	
13	Total generation plus RECs (all Categories) applied to procurement requirement (6A + 7A + 11)		4,317,263					7,191,340				
14	Over/under procurement for compliance period (13 - 4)		(3)					0				

	RPS ENERGY REQUIREMENT CALCULATIONS	Compliance Period 5: 2025	2026	2027		Compliance Period 6: 2028	2029	2030		Years 2031-2033: 2031	2032	2033		Years 2034-2035: 2034	2035	
1	(Managed) Retail sales to end-use customers (From EBT)	5,327,789	5,809,004	6,248,254		6,832,383	7,274,182	7,732,322		8,182,580	8,692,095	8,941,747		9,114,090	9,280,661	
2	Green pricing program/hydro exclusion															
3	Soft target (%)	46.67%	49.33%	52.00%		54.67%	57.33%	60.00%		60.00%	60.00%	60.00%		60.00%	60.00%	
4	Required procurement for compliance period	8,601,153				12,544,946				15,489,853				11,036,851		
	Category 0, 1 and 2 RECs															
5	Excess balance/historic carryover at beginning/end of compliance period				2,111,514				5,207,047				10,226,301			15,432,112
6	RPS-eligible energy procured (copied from EBT)	1,788,263	3,774,427	4,034,550		4,478,217	5,129,268	6,032,994		6,306,964	6,944,028	7,258,114		7,763,355	8,479,307	
6A	Amount of energy applied to procurement obligation	1,788,263	3,774,427	3,038,463		4,478,217	5,129,268	2,937,461		6,306,964	6,944,028	2,238,860		7,763,355	3,273,496	
7	Net purchases of Category 0, 1 and 2 RECs															
7A	Carryover and REC purchases applied to procurement obligation															
8	Net change in balance/carryover (6+7-6A-7A)	0	0	996,087		0	0	3,095,533		0	0	5,019,254		0	5,205,812	
	Category 3 RECs															
9	Excess balance/historic carryover at beginning/end of compliance period				0				0				0			0
10	Net purchases of Category 3 RECs															
11	Carryover and REC purchases applied to procurement obligation															
12	Net change in REC balance/carryover	0	0	0		0	0	0		0	0	0		0	0	
13	Total generation plus RECs (all Categories) applied to procurement requirement (6A + 7A + 11)	8,601,153				12,544,946				15,489,853				11,036,851		
14	Over/under procurement for compliance period (13 - 4)	0				0				0				0		

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
Capacity Resource Accounting Table
Form CEC 109 (May 2017)

Scenario Name: Zero Emissions with Emerging Technology

Yellow fill relates to an application for confidentiality.
Data input by User are in dark green font.

Units = MW

	PEAK LOAD CALCULATIONS			2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	Forecast Total Peak-Hour 1-in-2 Demand			715	801	875	943	1,027	1,097	1,164	1,237	1,306	1,351	1,377	1,400
2	[Customer-side solar: nameplate capacity]			23	23	24	24	25	25	26	27	27	28	29	30
2a	[Customer-side solar: peak hour output]			15	16	16	17	17	17	18	18	19	19	20	20
3	[Peak load reduction due to thermal energy storage]														
4	[Light Duty PEV consumption in peak hour]			1	3	4	5	6	5	6	10	11	13	15	11
5	Additional Achievable Energy Efficiency Savings on Peak			16	25	30	36	40	41	41	51	54	63	61	59
6	Demand Response / Interruptible Programs on Peak			8	8	8	8	8	8	8	8	8	8	8	8
7	Managed Peak Demand (1-5-6)			692	768	837	898	979	1,048	1,116	1,178	1,243	1,279	1,307	1,333
7a	Coincident gross peak (managed peak plus BTM PV peak shift)			637	719	798	850	866	960	1,018	1,093	1,171	1,171	1,152	1,219
8	Planning Reserve Margin	14%	This is a perfect capacity (PCAP)-based PRM. The 14% PCAP PRM translates to about 22% ICAP PRM and is a more stringent target than previous CAISO studies to ensure a 1-day-in-10-years LOLE target. The 14% PCAP PRM is applied to the coincident gross peak (managed peak plus BTM PV peak shift). See details on the right.	89	101	112	119	121	134	143	153	164	164	161	171
9	Firm Sales Obligations			0	0	0	0	0	0	0	0	0	0	0	0
10a	Total Peak Procurement Requirement Based on the Total Reliability Need Framework (7a+8+9)		See details on the right.	727	819	909	970	987	1,094	1,160	1,246	1,335	1,335	1,314	1,389
10b	CAISO Portfolio Effects		See details on the right.	92	93	85	116	125	212	251	309	342	379	343	442
10	Total Peak Procurement Requirement Based on the Marginal Reliability Need Framework (10a-10b)		See details on the right.	635	727	825	853	863	882	909	937	993	956	970	947

EXISTING AND PLANNED CAPACITY SUPPLY RESOURCES

Resource capacity accreditation is based on the marginal effective load carrying capability (ELCC) and marginal reliability framework.

	Utility-Owned Generation and Storage (not RPS-eligible):													
	[list resource by name]	Fuel	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
11a	DVR	Gas - CC	125	127	130	129	129	127	126	128	129	131	133	0
11b	Gianera 1	Gas - CT	20	20	21	20	20	20	20	20	20	20	21	0
11c	Gianera 2	Gas - CT	20	20	21	20	20	20	20	20	20	20	21	0
11d	Alameda CT 1	Gas - CT	8	8	8	8	8	8	0	0	0	0	0	0
11e	Alameda CT 2	Gas - CT	8	8	8	8	8	8	0	0	0	0	0	0
11f	Lodi CT	Gas - CT	8	8	8	8	8	8	8	8	0	0	0	0
11g	LEC	Gas - CC	66	67	68	0	0	0	0	0	0	0	0	0
11h	LEC Hydrogen 45 Blend	Hydrogen Blend	0	0	0	68	68	67	66	67	0	0	0	0
11i	Collierville	Large Hydro	52	52	51	49	46	45	44	43	42	41	40	39
11j	BESS 50MW 200MWh	Li-ion Battery (4-hr)	0	45	46	42	39	38	37	34	30	27	23	20
	Long-Term Contracts (not RPS-eligible):													
	[list contracts by name]	Fuel												
11k	Tri-Dam Donnells	Large Hydro	41	41	40	38	36	35	35	34	33	32	32	31
11l	WAPA Base Resource	Large Hydro	71	71	71	67	63	62	61	59	58	57	55	54
11m	South Feather - Forbstown	Large Hydro	14	14	13	13	12	12	12	11	11	11	11	10
11n	South Feather - Woodleaf	Large Hydro	22	22	22	20	19	19	19	18	18	17	17	17
11	Total peak dependable capacity of existing and planned supply resources (not RPS-eligible) (sum of 11a…11n)		454	503	507	492	477	469	446	442	362	357	353	171
	Utility-Owned RPS-eligible Resources:													
	[list resource by plant or unit]	Fuel												
12a	Black Butte	Small Hydro	3	3	2	2	2	2	2	2	2	2	2	2
12b	Stony Gorge	Small Hydro	2	2	2	2	2	2	2	2	2	2	2	2

12c	Grizzly Hydro	Small Hydro	7	7	7	7	6	6	6	6	6	6	6	5
12d	Big Horn 1	Wind	27	25	23	0	0	0	0	0	0	0	0	0
12e	Big Horn 2	Wind	5	4	4	4	4	3	3	3	3	3	3	3
12f	Geo Plant 1 Unit 1	Geothermal	10	11	11	11	11	11	11	11	11	11	11	11
12g	Geo Plant 1 Unit 2	Geothermal	10	11	11	11	11	11	11	11	11	11	11	11
12h	Geo Plant 2 Unit 4	Geothermal	14	14	14	15	15	15	15	15	15	15	15	15
12i	Spicer	Small Hydro	1	1	1	1	1	1	1	1	1	1	1	1
	Long-Term Contracts (RPS-eligible):													
	[list contracts by name]	Fuel												
12j	Ameresco Forward	Biogas	3	3	3	3	3	3	3	3	3	3	0	0
12k	Ameresco Vasco	Biogas	3	3	3	3	3	3	3	3	3	4	0	0
12l	G2 Landfill	Biogas	0	0	0	0	0	0	0	0	0	0	0	0
12m	Tri-Dam Beardsley	Small Hydro	5	5	5	4	4	4	4	4	4	4	4	4
12n	Tri-Dam Sand Bar	Small Hydro	7	7	7	6	6	6	6	5	5	5	5	5
12o	Tri-Dam Tulloch	Small Hydro	11	10	10	10	9	9	9	9	9	8	8	8
12p	Friant 1	Small Hydro	10	10	10	10	9	9	9	9	8	8	8	8
12q	Friant 2 (Quinten)	Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
12r	Rio Bravo (Index+)	Small Hydro	6	6	6	5	5	5	5	5	5	5	4	4
12s	Camp Far West Hydro (Index+)	Small Hydro	3	3	3	3	2	2	2	2	2	2	2	2
12t	South Feather - Kelly Ridge	Small Hydro	3	3	3	3	3	2	2	2	2	2	2	2
12u	South Feather - Sly Creek	Small Hydro	3	3	3	3	3	3	3	3	3	3	3	3
12v	Central 40 Solar	Solar	4	4	4	4	4	3	2	2	2	2	3	3
12w	Rosamond Solar	Solar	2	2	2	2	2	2	1	1	1	1	1	1
12x	Aquamarine Westside (Index+)	Solar	7	0	0	0	0	0	0	0	0	0	0	0
12y	Manzana Wind	Wind	8	8	8	6	4	4	4	4	3	0	0	0
12z	Cimmaron Wind	Wind	0	0	0	0	0	0	0	0	0	0	0	0
12aa	Calpine Geo	Geothermal	0	31	31	64	65	65	64	65	65	66	66	67
12ab	Sand Hill A	Wind	0	0	4	3	2	2	2	2	2	2	1	1
12ac	Sand Hill B	Wind	0	0	5	4	3	3	3	3	2	2	2	2
12ad	Rooney Ranch	Wind	0	0	6	5	3	3	3	3	3	2	2	2
12	**Total peak dependable capacity of existing and planned RPS-eligible resources (sum of 12a…12n)**		**153**	**175**	**189**	**190**	**184**	**180**	**176**	**175**	**174**	**170**	**162**	**161**
13	**Total peak dependable capacity of existing and planned supply resources (11+12)**		**607**	**677**	**695**	**682**	**661**	**649**	**622**	**617**	**536**	**528**	**515**	**333**
	GENERIC ADDITIONS		**Resource capacity accreditation is based on the marginal effective load carrying capability (ELCC) and marginal reliability frameworl**											
	NON-RPS ELIGIBLE RESOURCES:													
	[list resource by name or description]	Fuel	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
14a	Hydrogen_Aero_CT_2035	Hydrogen	0	0	0	0	0	0	0	0	0	0	0	24
14b	Li_Battery_4hr	Li-ion Battery (4-hr)	0	0	73	86	79	77	76	69	62	55	48	41
14c	DVR Hydrogen	Hydrogen	0	0	0	0	0	0	0	0	0	0	0	135
14d	Alameda CT 1 Hydrogen	Hydrogen	0	0	0	0	0	0	8	8	8	8	8	8
14e	Alameda CT 2 Hydrogen	Hydrogen	0	0	0	0	0	0	8	8	8	8	8	8
14f	Lodi CT Hydrogen	Hydrogen	0	0	0	0	0	0	0	0	8	8	8	8
14g	LEC Hydrogen 100 Blend	Hydrogen	0	0	0	0	0	0	0	0	68	69	70	71
14	**Total peak dependable capacity of generic supply resources (not RPS-eligible)**		**0**	**0**	**73**	**86**	**79**	**77**	**91**	**84**	**154**	**148**	**142**	**295**
	RPS-ELIGIBLE RESOURCES:													
	[list resource by name or description]	Fuel												
15a	Central_California_Wind	Wind	0	0	0	0	0	8	10	9	12	10	9	8
15b	Geothermal	Geothermal	0	0	0	0	49	49	111	150	211	263	304	331
15c	New_Mexico_Wind	Out-of-state Wind	0	0	40	42	44	40	30	32	34	35	37	39
15d	Southern_California_Solar	Solar	0	0	16	15	14	12	9	9	9	9	9	10
15e	Wyoming_Wind	Out-of-state Wind	0	0	0	28	29	47	35	37	39	41	43	60
15f	Gianera 1 RNG	Biogas	0	0	0	0	0	0	0	0	0	0	0	21
15g	Gianera 2 RNG	Biogas	0	0	0	0	0	0	0	0	0	0	0	21

15	Total peak dependable capacity of generic RPS-eligible resources	0	0	56	85	136	156	196	237	305	359	402	489
16	Total peak dependable capacity of generic supply resources (14+15)	0	0	129	171	215	233	287	321	459	507	545	784
	CAPACITY BALANCE SUMMARY												
		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
17	Total peak procurement requirement based on the marginal reliability need framework (from line 10)	635	727	825	853	863	882	909	937	993	956	970	947
18	Total peak dependable capacity of existing and planned supply resources based on the marginal reliability need framework (from line 13)	607	677	695	682	661	649	622	617	536	528	515	333
19	Current capacity surplus (shortfall) based on the marginal reliability need framework (18-17)	(28)	(49)	(129)	(171)	(202)	(233)	(287)	(320)	(457)	(428)	(456)	(615)
20	Total peak dependable capacity of generic supply resources based on the marginal reliability need framework (from line 16)	0	0	129	171	215	233	287	321	459	507	545	784
21	Planned capacity surplus/shortfall based on the marginal reliability need framework (shortfalls assumed to be met with short-term capacity purchases) (19+20)	(28)	(49)	0	(0)	13	0	(0)	2	2	79	89	169

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
Energy Balance Table
Form CEC 110 (May 2017)

Scenario Name: Zero Emissions with Emerging Technology

Units = MWh

Yellow fill relates to an application for confidentiality.

	NET ENERGY FOR LOAD CALCULATIONS	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	Retail sales to end-use customers												
2	Other loads												
3	Unmanaged net energy for load												
4	Managed retail sales to end-use customers	4,778,145	5,327,789	5,809,004	6,248,254	6,832,383	7,274,182	7,732,322	8,182,580	8,692,095	8,941,747	9,114,090	9,280,661
5	Managed net energy for load	4,921,356	5,487,475	5,983,112	6,435,528	7,037,165	7,492,205	7,964,077	8,427,829	8,952,617	9,209,750	9,387,259	9,558,823
6	Firm Sales Obligations												
7	Total net energy for load (5+6)	4,921,356	5,487,475	5,983,112	6,435,528	7,037,165	7,492,205	7,964,077	8,427,829	8,952,617	9,209,750	9,387,259	9,558,823
8	[Customer-side solar generation]	36,503	37,411	38,352	39309.59	40299.22	41305.08	42327.16	43397.92	44468.67	45588.09	46723.74	47891.83
9	[Light Duty PEV electricity consumption/procurement requirement]												
10	[Other transportation electricity consumption/procurement requirement]												
11	[Other electrification/fuel substitution; consumption/procurement requirement]												

EXISTING AND PLANNED GENERATION RESOURCES

Utility-Owned Generation Resources (not RPS-eligible):

	[list resource by name]	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
12a	DVR	1,280,374	1,294,510	1,067,193	1,159,847	1,195,739	1,141,055	1,027,149	1,007,030	1,006,495	1,027,345	891,153	0
12b	Gianera 1	9,900	9,900	9,900	9,900	9,900	6,367	1,622	4,743	5,237	0	0	0
12c	Gianera 2	9,900	9,900	9,900	9,900	9,900	4,259	2,767	4,647	5,049	0	0	0
12d	Alameda CT 1	0	0	0	0	0	0	0	0	0	0	0	0
12e	Alameda CT 2	0	12,052	0	0	0	0	0	0	0	0	0	0
12f	Lodi CT	13,076	20,267	0	0	0	0	0	0	0	0	0	0
12g	LEC	479,537	584,603	272,837	0	0	0	0	0	0	0	0	0
12h	LEC Hydrogen 45 Blend	0	0	0	242,398	239,641	197,913	67,414	113,013	0	0	0	0
12i	Collierville	158,355	158,302	158,302	158,302	158,355	158,302	158,302	158,302	158,355	158,302	158,302	158,302
12j	BESS 50MW 200MWh	0	(1,046)	(7,129)	(5,899)	(6,604)	(7,355)	(11,007)	(10,974)	(13,534)	(13,301)	(13,266)	(14,934)
	Long-Term Contracts (not RPS-eligible):												
	[list contracts by name]												
12k	Tri-Dam Donnells	242,640	242,640	242,640	242,640	242,640	242,640	242,640	242,640	242,640	242,640	242,640	242,640
12l	WAPA Base Resource	249,840	249,840	249,840	249,840	249,840	249,840	249,840	249,840	249,840	249,840	249,840	249,840
12m	South Feather - Forbstown	60,030	59,310	58,668	59,999	59,137	57,193	58,909	59,942	57,793	59,289	59,496	57,167
12n	South Feather - Woodleaf	103,004	98,823	98,533	100,048	98,548	97,781	97,206	99,067	100,476	98,286	94,739	94,272
12	Total energy from existing and planned supply resources (not RPS-eligible) (sum of 12a…12n)	2,606,656	2,739,100	2,160,683	2,226,975	2,257,096	2,147,995	1,894,841	1,928,248	1,812,351	1,822,400	1,682,904	787,287
	Utility-Owned RPS-eligible Generation Resources:												
	[list resource by plant or unit]												
13a	Black Butte	8,183	7,485	7,628	7,696	7,674	7,836	7,779	7,521	7,695	7,596	7,624	7,662
13b	Stony Gorge	6,651	6,570	6,391	6,907	6,645	6,671	6,655	6,656	6,843	7,125	6,701	6,913
13c	Grizzly Hydro	43,392	43,392	43,392	43,392	43,392	43,392	43,392	43,392	43,392	43,392	43,392	42,631
13d	Big Horn 1	212,116	227,991	208,543	0	0	0	0	0	0	0	0	0
13e	Big Horn 2	35,353	37,998	40,991	39,590	41,843	36,898	36,899	41,755	36,027	34,792	36,958	27,865
13f	Geo Plant 1 Unit 1	105,408	105,120	105,120	105,120	105,408	105,120	105,120	105,120	105,408	105,120	105,120	105,120
13g	Geo Plant 1 Unit 2	105,408	105,120	105,120	105,120	105,408	105,120	105,120	105,120	105,408	105,120	105,120	105,120

13h	Geo Plant 2 Unit 4	140,544	140,160	140,160	140,160	140,544	140,160	140,160	140,160	140,544	140,160	140,160	140,160
13i	Spicer	5,449	5,203	5,186	5,073	5,242	5,178	5,089	5,103	5,114	5,137	5,162	5,042
	Long-Term Contracts (RPS-eligible):												
	[list contracts by name]												
13j	Ameresco Forward	36,893	36,792	36,691	36,792	36,893	36,792	36,637	36,523	36,130	35,952	5,947	0
13k	Ameresco Vasco	37,771	37,668	37,526	37,668	37,771	37,668	37,475	37,393	36,989	36,761	6,089	0
13l	G2 Landfill	614	0	0	0	0	0	0	0	0	0	0	0
13m	Tri-Dam Beardsley	44,316	44,014	43,229	44,357	44,565	45,182	44,466	44,809	44,298	44,463	43,329	43,405
13n	Tri-Dam Sand Bar	73,927	73,830	70,679	73,739	73,411	75,048	73,066	74,693	74,452	73,200	70,112	70,450
13o	Tri-Dam Tulloch	109,238	110,174	110,943	109,007	108,219	107,609	107,955	109,597	109,660	107,938	106,428	106,198
13p	Friant 1	66,165	64,859	66,469	66,570	65,702	65,634	64,649	66,134	66,268	65,698	65,206	64,772
13q	Friant 2 (Quinten)	39,234	39,246	39,238	39,212	39,187	39,256	39,295	39,588	38,770	38,765	38,490	37,901
13r	Rio Bravo (Index+)	14,459	13,864	14,514	14,585	14,155	13,980	14,282	14,629	14,281	13,468	14,741	14,227
13s	Camp Far West Hydro (Index+)	24,963	24,647	25,829	25,924	24,303	26,070	24,509	25,332	24,746	26,303	25,116	25,643
13t	South Feather - Kelly Ridge	27,305	27,241	26,482	27,156	27,443	27,590	26,925	27,375	26,943	26,861	26,779	26,848
13u	South Feather - Sly Creek	14,312	14,130	13,821	14,188	13,951	13,655	13,744	14,071	14,046	13,827	13,692	13,328
13v	Central 40 Solar	107,505	115,113	112,925	112,812	109,665	111,053	112,518	113,269	106,012	108,044	109,637	108,391
13w	Rosamond Solar	60,046	63,134	62,409	62,849	60,997	61,759	62,612	62,047	58,929	59,998	61,806	58,706
13x	Aquamarine Westside (Index+)	169,825	0	0	0	0	0	0	0	0	0	0	0
13y	Manzana Wind	118,443	137,913	131,601	124,608	115,771	119,246	128,170	126,383	122,730	0	0	0
13z	Cimmaron Wind	0	0	929,781	786,072	742,419	783,090	887,117	821,361	854,243	783,256	794,386	751,733
13aa	Calpine Geo	0	306,600	306,600	613,200	614,880	613,200	613,200	613,200	614,880	613,200	613,200	613,200
13ab	Sand Hill A	0	0	30,270	28,276	29,266	28,105	28,025	28,698	29,534	26,558	27,235	29,418
13ac	Sand Hill B	0	0	40,766	38,064	39,396	37,833	37,887	38,636	39,652	35,604	36,692	39,827
13ad	Rooney Ranch	0	0	44,116	41,326	42,773	41,076	41,122	42,110	43,155	38,848	39,805	43,141
13	**Total energy from RPS-eligible resources (sum of 13a…13n, and 13z)**	**1,607,516**	**1,788,263**	**2,806,421**	**2,749,464**	**2,696,923**	**2,734,220**	**2,843,866**	**2,790,674**	**2,806,148**	**2,597,188**	**2,548,928**	**2,487,699**
13z	**Undelivered RPS energy**												
14	**Total energy from existing and planned supply resources (12+13)**	**4,214,173**	**4,527,363**	**4,967,104**	**4,976,439**	**4,954,019**	**4,882,214**	**4,738,707**	**4,718,922**	**4,618,499**	**4,419,588**	**4,231,832**	**3,274,986**

GENERIC ADDITIONS

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	NON-RPS ELIGIBLE RESOURCES:												
	[list resource by name or description]												
15a	Hydrogen_Aero_CT_2035	0	0	0	0	0	0	0	0	0	0	0	25,274
15b	Li_Battery_4hr	0	0	(8,929)	(8,555)	(10,890)	(12,389)	(16,519)	(17,364)	(20,148)	(18,546)	(18,172)	(15,150)
15c	DVR Hydrogen	0	0	0	0	0	0	0	0	0	0	0	855,828
15d	Alameda CT 1 Hydrogen	0	0	0	0	0	0	0	0	0	0	0	0
15e	Alameda CT 2 Hydrogen	0	0	0	0	0	0	0	0	0	0	0	4,513
15f	Lodi CT Hydrogen	0	0	0	0	0	0	0	0	0	0	0	4,607
15g	LEC Hydrogen 100 Blend	0	0	0	0	0	0	0	0	38,116	13,632	74,995	157,701
15	**Total energy from generic supply resources (not RPS-eligible)**	**0**	**0**	**(8,929)**	**(8,555)**	**(10,890)**	**(12,389)**	**(16,519)**	**(17,364)**	**17,968**	**(4,914)**	**56,824**	**1,032,773**
	RPS-ELIGIBLE RESOURCES:												
	[list resource by name or description]												
16a	Central_California_Wind	0	0	0	0	0	256,441	377,523	377,859	541,257	542,064	549,653	562,909
16b	Geothermal	0	0	0	0	466,207	464,933	1,054,903	1,413,244	1,976,863	2,432,089	2,801,917	3,000,053
16c	New_Mexico_Wind	0	0	508,927	489,401	515,018	598,826	611,837	588,060	563,651	566,480	655,422	583,141
16d	Southern_California_Solar	0	0	436,951	440,509	425,341	436,581	441,040	448,966	424,650	439,161	442,316	423,287

16e	Wyoming_Wind	0	0	0	328,454	354,299	615,500	683,382	674,484	640,398	662,292	694,953	937,810
16f	Gianera 1 RNG	0	0	0	0	0	0	0	0	0	0	0	9,780
16g	Gianera 2 RNG	0	0	0	0	0	0	0	0	0	0	0	8,188
16	**Total energy from generic RPS-eligible resources**	**0**	**0**	**945,878**	**1,258,364**	**1,760,866**	**2,372,281**	**3,168,686**	**3,502,612**	**4,146,820**	**4,642,086**	**5,144,262**	**5,525,168**
17	**Total energy from generic supply resources (15+16)**	**0**	**0**	**936,949**	**1,249,809**	**1,749,976**	**2,359,893**	**3,152,167**	**3,485,248**	**4,164,788**	**4,637,172**	**5,201,085**	**6,557,941**
17z	**Total energy from RPS-eligible short-term contracts**												
	ENERGY FROM SHORT-TERM PURCHASES												
		2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
18	**Short term and spot market purchases:**	953,809	1,170,398	378,828	531,749	685,353	625,224	471,770	646,062	617,087	613,867	424,032	204,267
18a	**Short term and spot market sales:**	(246,625)	(210,287)	(299,769)	(322,469)	(352,184)	(375,125)	(398,567)	(422,402)	(447,757)	(460,876)	(469,689)	(478,371)
	ENERGY BALANCE SUMMARY												
		2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
19	**Total energy from supply resources (14+17+17z)**	**4,214,173**	**4,527,363**	**5,904,053**	**6,226,248**	**6,703,995**	**7,242,107**	**7,890,874**	**8,204,170**	**8,783,286**	**9,056,760**	**9,432,917**	**9,832,927**
19a	**Undelivered RPS energy (from 13z)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
20	**Short term and spot market purchases (from 18 + 18a)**	**707,184**	**960,111**	**79,060**	**209,280**	**333,169**	**250,098**	**73,202**	**223,660**	**169,330**	**152,990**	**(45,658)**	**(274,104)**
21	**Total delivered energy (19-19a+20)**	**4,921,356**	**5,487,475**	**5,983,112**	**6,435,528**	**7,037,165**	**7,492,205**	**7,964,077**	**8,427,829**	**8,952,617**	**9,209,750**	**9,387,259**	**9,558,823**
22	**Total net energy for load (from 7)**	**4,921,356**	**5,487,475**	**5,983,112**	**6,435,528**	**7,037,165**	**7,492,205**	**7,964,077**	**8,427,829**	**8,952,617**	**9,209,750**	**9,387,259**	**9,558,823**
23	**Surplus/Shortfall (21-22)**	**0**	**(0)**	**0**	**0**	**(0)**	**(0)**	**(0)**	**(0)**	**0**	**0**	**0**	**0**

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
GHG Emissions Accounting Table
Form CEC 111 (May 2017)

Scenario Name: Zero Emissions with Emerging Technology

Yellow fill relates to an application for confidentiality.

Emissions Intensity Units = mt CO2e/MWh
Yearly Emissions Total Units = Mmt CO2e

GHG EMISSIONS FROM EXISTING AND PLANNED SUPPLY

	Utility-Owned Generation (not RPS-eligible):													
	[list resource by name]	Emissions Intensity	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
1a	DVR	0.424	0.549	0.556	0.452	0.492	0.510	0.487	0.434	0.427	0.426	0.434	0.374	0.000
1b	Gianera 1	0.809	0.008	0.008	0.008	0.008	0.008	0.005	0.001	0.004	0.004	0.000	0.000	0.000
1c	Gianera 2	0.809	0.008	0.008	0.008	0.008	0.008	0.003	0.002	0.004	0.004	0.000	0.000	0.000
1d	Alameda CT 1	0.762	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1e	Alameda CT 2	0.762	0.000	0.009	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1f	Lodi CT	0.742	0.010	0.015	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1g	LEC	0.363	0.174	0.212	0.099	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1h	LEC Hydrogen 45 Blend	0.286	0.000	0.000	0.000	0.069	0.069	0.057	0.019	0.032	0.000	0.000	0.000	0.000
1i														
1j														
	Long-Term Contracts (not RPS-eligible):													
	[list contracts by name]	Emissions Intensity												
1k														
1l														
1m														
1	**Total GHG emissions of existing and planned supply resources (not RPS-eligible) (sum of 1a…1n)**		**0.749**	**0.809**	**0.567**	**0.577**	**0.594**	**0.552**	**0.457**	**0.467**	**0.434**	**0.434**	**0.374**	**0.000**
	Utility-Owned RPS-eligible Generation Resources:													
	[list resource by plant or unit]	Emissions Intensity												
2a														
2b														
2c														
2d														
2e														
2f														
2g														
	Long-Term Contracts (RPS-eligible):													
	[list contracts by name]	Emissions Intensity												
2h														
2i														
2j														
2k														
2l														
2m														
2n														
2	**Total GHG emissions from RPS-eligible resources (sum of 2a…2n)**		**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
3	**Total GHG emissions from existing and planned supply resources (1+2)**		**0.749**	**0.809**	**0.567**	**0.577**	**0.594**	**0.552**	**0.457**	**0.467**	**0.434**	**0.434**	**0.374**	**0.000**

EMISSIONS FROM GENERIC ADDITIONS

	NON-RPS ELIGIBLE RESOURCES:													
	[list resource by name or description]	Emissions Intensity	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
4a														
4b														
4c														
4d														
4e														
4f														
4g														
4h														
4i														
4j														
4k														
4l														
4m														
4n														
4	**Total GHG emissions from generic supply resources (not RPS-eligible)**		**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
	RPS-ELIGIBLE RESOURCES:													
	[list resource by name or description]	Emissions Intensity												
5a														
5b														
5c														
5d														
5e														
5f														
5g														
5h														
5i														
5j														
5k														
5l														
5m														
5n														
5	**Total GHG emissions from generic RPS-eligible resources**		**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
6	**Total GHG emissions from generic supply resources (4+5)**		**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**

GHG EMISSIONS OF SHORT TERM PURCHASES

		Emissions Intensity	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
7	**Net spot market/short-term purchases:**	Hourly Emission Intensity	**0.267**	**0.371**	**0.023**	**0.067**	**0.103**	**0.054**	**(0.003)**	**0.018**	**(0.008)**	**(0.008)**	**(0.085)**	**0.000**
	Spot market/short-term purchases:	Hourly Emission Intensity	0.365	0.454	0.142	0.199	0.245	0.206	0.158	0.188	0.171	0.175	0.103	0.000
	Spot market/short-term sales:	Hourly Emission Intensity	(0.099)	(0.083)	(0.119)	(0.132)	(0.141)	(0.152)	(0.161)	(0.170)	(0.180)	(0.183)	(0.188)	0.000

TOTAL GHG EMISSIONS

			2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
8	**Total GHG emissions to meet net energy for load (3+6+7)**		**1.015**	**1.180**	**0.590**	**0.644**	**0.698**	**0.606**	**0.453**	**0.485**	**0.426**	**0.426**	**0.289**	**0.000**

EMISSIONS ADJUSTMENTS

8a	**Undelivered RPS energy (MWh from EBT)**		0	0	0	0	0	0	0	0	0	0	0	0
8b	**Firm Sales Obligations (MWh from EBT)**		0	0	0	0	0	0	0	0	0	0	0	0
8c	**Total energy for emissions adjustment (8a+8b)**		0	0	0	0	0	0	0	0	0	0	0	0
8d	**Emissions intensity (portfolio gas/short-term and spot market purchases)**													
8e	**Emissions adjustment (8Cx8D)**		0	0	0	0	0	0	0	0	0	0	0	0

PORTFOLIO GHG EMISSIONS

8f	Portfolio emissions (8-8e)	1.015	1.180	0.590	0.644	0.698	0.606	0.453	0.485	0.426	0.426	0.289	0.000

GHG EMISSIONS IMPACT OF TRANSPORTATION ELECTRIFICATION

		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
9	GHG emissions reduction due to gasoline vehicle displacement by LD PEVs												
10	GHG emissions increase due to LD PEV electricity loads												
11	GHG emissions reduction due to fuel displacement - other transportation electrification												
12	GHG emissions increase due to increased electricity loads - other transportation electrification												

State of California
California Energy Commission
Standardized Reporting Tables for Public Owned Utility IRP Filing
RPS Procurement Table
Form CEC 112 (May 2017)

Scenario Name: Zero Emissions with Emerging Technology

	Beginning balances	**Units = MWh**																								
	Start of 2017	**Compliance Period 3**					**Compliance Period 4**					**Compliance Period 5**				**Compliance Period 6**				**Years 2031-2033**				**Years 2034-2035**		
RPS ENERGY REQUIREMENT CALCULATIONS		**2017**	**2018**	**2019**	**2020**		**2021**	**2022**	**2023**	**2024**		**2025**	**2026**	**2027**		**2028**	**2029**	**2030**		**2031**	**2032**	**2033**		**2034**	**2035**	
(Managed) Retail sales to end-use customers (From EBT)		3,523,784	3,548,030	3,575,729	3,722,544		4,011,842	4,397,926	4,755,204	4,778,145		5,327,789	5,809,004	6,248,254		6,832,383	7,274,182	7,732,322		8,182,580	8,692,095	8,941,747		9,114,090	9,280,661	
Green pricing program/hydro exclusion																										
Soft target (%)		27.00%	29.00%	31.00%	33.00%		35.75%	38.50%	41.25%	44.00%		46.67%	49.33%	52.00%		54.67%	57.33%	60.00%		60.00%	60.00%	60.00%		60.00%	60.00%	
Required procurement for compliance period		4317266					7191340					8,601,153				12,544,946				15,489,853				11,036,851		
Category 0, 1 and 2 RECs																										
Excess balance/historic carryover at beginning/end of compliance period	987880					2,375,706					1,115,427				2,062,665				5,094,561				10,090,235			14,759,441
RPS-eligible energy procured (copied from EBT)		2,417,033	1,223,495	1,405,216	1,191,658		1,270,167	1,474,984	1,414,493	1,607,516		1,788,263	3,752,299	4,007,828		4,457,789	5,106,501	6,012,552		6,293,285	6,952,968	7,239,274		7,693,190	8,012,867	
Amount of energy applied to procurement obligation		2,417,033	1,223,495	567,928	0		1,270,167	1,474,984	1,414,493	1,607,516		1,788,263	3,752,299	3,060,590		4,457,789	5,106,501	2,980,656		6,293,285	6,952,968	2,243,600		7,693,190	3,343,661	
Net purchases of Category 0, 1 and 2 RECs																										
Carryover and REC purchases applied to procurement obligation									765,412	494,867																
Net change in balance/carryover (6+7-6A-7A)		0	0	837,288	1,191,658		0	0	(765,412)	(494,867)		0	0	947,237		0	0	3,031,897		0	0	4,995,674		0	4,669,206	
Category 3 RECs																										
Excess balance/historic carryover at beginning/end of compliance period	0					0					0				0				0				0			0
Net purchases of Category 3 RECs		70000	38807	0	0		25,000	5,901	133,000																	
Carryover and REC purchases applied to procurement obligation		70000	38807	0	0		25000	5901	133000																	
Net change in REC balance/carryover		0	0	0	0		0	0	0	0		0	0	0		0	0	0		0	0	0		0	0	
Total generation plus RECs (all Categories) applied to procurement requirement (6A + 7A + 11)		4,317,263					7,191,340					8,601,153				12,544,946				15,489,853				11,036,851		
Over/under procurement for compliance period (13 - 4)		(3)					0					0				0				0				0		