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Revised Inputs & Assumptions

SERVM 2026 Data Updates in Support of Resource Adequacy (RA) and Integrated Resource Planning (IRP)

June 5, 2026

California Public
Utilities Commission

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List of Acronyms

AAEE – Additional Achievable Energy Efficiency
AAFS – Additional Achievable Fuel Substitution
AATE – Additional Achievable Transportation Electrification
AB – Assembly Bill
ADS – Anchor Data Set
BAA – Balancing Authority Area
BANC – Balancing Area of Northern California
BOEM – Bureau of Ocean Energy Management
BTM – Behind the Meter
CAISO – California Independent System Operator
LESR – Limited Energy Storage Resource
LOLH – Loss of Load Hours
LSE – Load Serving Entity
LTPP – Long-Term Procurement Plan
MAG – Modeling Advisory Group
MERRA – Modern-Era Retrospective-Analysis for Research and Applications
MMT – Million Metric Tons
MTR – Mid-Term Reliability
MW – Megawatt
NAMGas – North American Market Gas-Trade Model

CAPEX – Capital Expenditure
CAPMAX – Maximum Capacity
CARB – California Air Resources Board
CCA – Community Choice Aggregator
CCGT – Combined Cycle Gas Turbine
CEC – California Energy Commission
CHP – Combined Heat and Power (Cogeneration)
CREZ – Competitive Renewable Energy Zone
CT – Combustion Turbine
DR – Demand Response
EFOR – Expected Forced Outage Rate
EFORd – EFOR during demand hours
EGS – Enhanced Geothermal System
EIA – Energy Information Administration
ELCC – Effective Load Carrying Capability
EMS – Energy Management System
EO – Energy-Only Deliverability Status
ESP – Energy Service Provider
EUE – Expected Unserved Energy
EV – Electric Vehicle
FCDS – Full Capacity Deliverability Status
FERC – Federal Energy Regulatory Commission
FZ – Forecast Zone
GADS – Generator Availability Data System
GHG – Greenhouse Gas
NCNC – Northern California Non-CAISO
NERC – North American Electric Reliability Corporation
NQC – Net Qualifying Capacity
NREL ATB – National Renewable Energy Laboratory Annual Technology Baseline
NREL SAM – National Renewable Energy Laboratory System Advisor Model
O&M – Operations and Maintenance
OOS – Out-of-State
OSW – Offshore Wind
OTC – Once-Through-Cooling
PCAP – Perfect Capacity
PCM – Production Cost Model
POU – Publicly-Owned Utility
PPA – Power Purchase Agreement
PRM – Planning Reserve Margin
PSP – Preferred System Plan
PU Code – Public Utilities Code
PV – Photovoltaic Solar
RA – Resource Adequacy
RPS – Renewable Portfolio Standard
SB – Senate Bill
SERVM – Strategic Energy Risk Valuation Model
SOD - Slice of Day
ST – Steam Turbine
SUN – Solar PV
TAC – Transmission Access Control

ICAP – Installed Capacity	TEPPC – Transmission Expansion Planning Policy Committee
IEA – International Energy Agency	TID – Turlock Irrigation District
IEPR – Integrated Energy Policy Report	TOU – Time-of-Use
IID – Imperial Irrigation District	TPP – Transmission Planning Process
IOU – Investor-Owned Utility	TRN – Total Reliability Need
IPP – Independent Power Producer	Tx – Transmission
IRP – Integrated Resource Planning	UCAP – Unforced Capacity
LADWP or LDWP – Los Angeles Department of Water and Power	USGS – U.S. Geological Survey
LBNL – Lawrence Berkeley National Laboratory	VEA – Valley Electric Association
LDES – Long-Duration Energy Storage	WECC – Western Electricity Coordinating Council
LOLE – Loss of Load Expectation	WRF – Weather Research and Forecasting Model

1. Introduction

This document describes this year's major updates to the key methodologies and sources of inputs and assumptions for the California Public Utilities Commission's (CPUC's) electric system reliability and related modeling and analysis. The analysis is primarily in support of the Integrated Resource Planning (IRP) and the Resource Adequacy (RA) proceedings. The CPUC also uses this modeling and analysis to support work in other CPUC proceedings such as the Avoided Cost Calculator and Gas System Reliability and Planning. The CPUC expects to perform major and minor input and assumptions updates in alternating years.

The inputs, assumptions, and methodologies described here are used primarily in the Strategic Energy Risk Valuation Model (SERVM) to assess CAISO electric system reliability, production cost, emissions, and other metrics given an assumed electric system, comprised of a resource portfolio, electric demand, fuel and operating costs, and a transmission network. SERVM is often used in conjunction with the RESOLVE capacity expansion model which determines optimal resource additions to the CAISO electric system that reflect projected load growth, technology costs and potential, and policy constraints. The two models share many inputs and assumptions – maintaining and improving upon inputs and assumptions alignment is key to achieving reasonable agreement in output between the models. This document describes just those used in SERVM. Refer to the RESOLVE-specific Inputs and Assumptions document (2024 -

2026 Integrated Resource Planning (IRP) Inputs & Assumptions report, February 2026) for descriptions of inputs and assumptions that are common or related between the two models.

At this juncture, the 2028 Loss-Of-Load-Expectation (LOLE) study, scoped in Track 2 of the RA proceeding, Rulemaking (R.)25-10-003, is the first major modeling effort that will utilize the new vintage of SERVM inputs described in this document. Many of these new inputs are not yet used in any past or planned studies for the IRP proceeding – as such, IRP stakeholders should continue to use the 2024-2026 IRP Inputs & Assumptions report (February 2026) referenced above. This maintains consistency and stability of inputs between any remaining analytical work and completed analytical work in the 2024-2026 IRP cycle, as well as adhere to the Joint Agency January 2026 Single Forecast Set agreement for the IRP proceeding, pursuant to 2022 Memorandum of Understanding, to continue using the California Energy Commission (CEC) 2024 Integrated Energy Policy Report (IEPR) electric demand forecast for now, while the upcoming RA work should use the 2025 IEPR forecast without known loads. Despite the differences in inputs between current IRP analysis and the upcoming 2028 LOLE study for RA, CPUC staff are still continuing to coordinate inputs and assumptions across both the IRP and RA proceedings to the extent possible within the confines of the Single Forecast Set agreement and the specific needs of each proceeding. This coordination was acknowledged in the December 2025 Scoping Memo in R.25-10-003.[1]

The prior version of this document, Proposed Inputs and Assumptions, March 2024, was issued via Ruling in the CPUC's prior RA proceeding, R.23-10-011, and the corresponding key inputs are posted here: System Reliability Modeling Datasets 2024. The Proposed Inputs and Assumptions, March 2024, were the basis for the initial (July 2024) and revised (December 2024) 2026 LOLE studies that CPUC staff conducted to inform R.23-10-011, Track 2 and 3. These studies contributed to the June 2025 Decision (D.)25-06-048 adopting Local Capacity Obligations for 2026-2028, Flexible Capacity Obligations for 2026, and Program Refinements.

Since the completion of the prior studies at the end of 2024, SERVM inputs were updated for IRP purposes in 2025 and largely described in the 2024-2026 IRP Inputs and Assumptions report, February 2026 and the corresponding key inputs are posted here: System Reliability Modeling Datasets 2025. SERVM inputs are now further updated herein for the forthcoming RA 2028 LOLE study and the corresponding key inputs are/will be posted here: System Reliability

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[1] See: 2025 RA scoping ruling 590884355.PDF - "We acknowledge parties' comments about further coordination with the IRP proceeding, in addition to alignment after an RCPPP decision. With regards to coordination between the IRP and RA proceedings on the Inputs and Assumptions in an LOLE study, we clarify that Energy Division Staff currently uses the same modeling data sets to inform the Inputs and Assumptions in both the IRP and RA proceedings and confirm that coordination between the two proceedings will continue."

Modeling Datasets 2026. See section 1.3 for a summary of the key data and model updates that are in common with or different from the 2024-2026 IRP Inputs and Assumptions report, February 2026.

A draft version of this document was issued by Ruling in the current RA proceeding, R.25-10-003 on April 10, 2026. CPUC staff held a public (remote) workshop on April 14 to discuss the draft. Proceeding parties submitted comments on April 24 and CPUC staff reviewed those comments. This document has been revised in consideration of those comments. Most of the key changes are reflected in the External Regions Calibration section 3.7 and the Resource Adequacy Modeling section 5. The next step is to perform the Loss of Load study of study year 2028.

1.1 Overview of the SERVM Model

The CPUC uses SERVM[2] to analyze system reliability by calculating numerous reliability, production cost, and other performance metrics for a given study year while considering uncertainty and variability in weather, economic growth, electric demand, resource generation, and unit performance.[3] An individual year (aka target year or study year) is simulated each hour of the year many times over, with each simulation having an assigned probability and reflecting a slightly different set of weather, economic conditions, and unit performance. Unit commitment and dispatch for all hours of the study year are simulated while considering expected system conditions several days ahead. The prior RA LOLE study of 2026 considered possible weather and hydro conditions from 2000-2022 (23 historical years), five points of economic load forecast uncertainty, and multiple unit outage variations (draws). This SERVM input update to be used for the forthcoming RA LOLE study focused on study year of 2028 expands the range of possible weather and hydro conditions to 2000-2024 (25 historical years).

Model outputs include probability-weighted expected values as well as the complete distribution of reliability, production cost, and other performance metrics. CPUC staff typically use SERVM to quantify a variety of metrics, including the following:

- Reliability in terms of Loss of Load Expectation (LOLE) and Expected Unserved Energy (EUE)
- Expected values for market and ancillary service prices, fuel burn, generation by technology, curtailment, emissions, and other system operations metrics

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[2] Licensed from PowerGEM: https://power-gem.co/software/servm-resource-adequacy-planning/

[3] Unit performance here refers to varying maximum output levels due to ambient temperatures as well as how long and when a unit is out of service due to scheduled maintenance or forced outages.

- The Total Reliability Need (TRN)[4] to achieve a chosen reliability target
- Effective Load Carrying Capability (ELCC) by technology

1.2 Document Contents

The remainder of this document is organized as follows:

- **Section 2 (Electric Demand Forecast)** documents the assumptions and data sources for the electric demand forecast in CAISO, California, and regions outside California, including the impacts of demand modifiers and electrification.
- **Section 3 (Baseline Resources)** documents the assumptions and data sources for updating the list of baseline resources, including key attributes such as in-service date, retirement date, technology, maximum output, location, offtaker, and unit name. Baseline resources are existing online units or projects in-development and assumed to be online by the project's in-service date.
- **Section 4 (Generator Operations and Hourly Profiles)** documents the assumptions and data sources to characterize weather-variability-driven hourly electricity demand and variable generation hourly profiles, and the operational attributes and constraints of each of the resource classes that SERVM can model.
- **Section 5 (Resource Adequacy Modeling)** discusses certain proposals and modeling conventions staff will use to conduct analysis to inform policy questions in the Resource Adequacy proceeding.
- **Section 6 (Emissions Accounting)** documents assumptions, data sources, and accounting conventions to characterize greenhouse gas and criteria pollutant emissions.

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[4] TRN is quantified with "Perfect Capacity", a modeling construct representing an ideal generating unit with no operating constraints. Real generating units are always bigger in MW than Perfect Capacity for the same amount of reliability performance. A Planning Reserve Margin (PRM) can be calculated from a TRN but one must choose a capacity counting convention such as installed capacity, ELCC, or UCAP.

1.3 Key Data and Model Updates

Since the prior version of this document (Proposed Inputs and Assumptions, March 2024), CPUC staff have completed or will complete numerous updates to SERVM model functionality, inputs, and assumptions intended for use in the upcoming 2028 RA LOLE study to be completed by about August 2026.

The table below summarizes the key data and model updates to SERVM and notes whether the update is the same or different from the IRP proceeding's 2024-2026 IRP Inputs and Assumptions report, February 2026:

Table 1: Key Data and Model Updates and Relationship to 2024-2026 IRP Inputs and Assumptions

Key Data or Model Update	**2024-2026 IRP Inputs and Assumptions report, February 2026**
Deployed and benchmarked an updated SERVM client (version 10.28) which includes changes to use storage resources more optimally and to improve how storage contributes to reliability performance	Same
Updated the list of baseline resources in CAISO considering the large number of projects that have come online or have begun construction since January 2024. Key sources include: • August 2025 vintage of the CAISO Master Generating Capability List • August 2025 vintage of in-development resources included in the CAISO Generation Interconnection Resource ID Report • September 2025 vintage of the CAISO Retirement and Mothball List Unit maximum outputs are quantified at Net Dependable Capacity and do not use the capping at monthly NQC convention that IRP modeling uses.	Uses prior (2024) Baseline and also includes capping at monthly NQC for certain units
Updated the list of baseline resources not in CAISO from the 2034 WECC Anchor Data Set (ADS) dated July 29, 2024, and where available, incorporated resource and demand forecast information from the IRPs of non-CAISO regions. This means updating data on new generators, online or in-development (excluding planned or generic generation), updating retirement or termination status, and updating electric demand peak and energy forecasts for regions outside California.	Uses prior (2024) Baseline Uses prior non-California demand forecast
Updated the electric demand forecast and GHG emissions price forecast according to the CEC 2025 IEPR California Energy Demand Forecast	Uses 2024 IEPR Uses 2022 IEPR Mid GHG price scenario

Key Data or Model Update	2024-2026 IRP Inputs and Assumptions report, February 2026
Expanded the range of historical weather and hydro conditions that can be modeled from 2000-2022 to 2000-2024. Weather informs solar and wind hourly production, hourly electric demand, and ambient temperature output derating.	Uses weather and hydro ranging from 2000-2022
Updated to new BTMPV model with calibration to better align with proprietary CEC BTMPV model	Uses new BTMPV model but lacking latest calibration to better align with proprietary CEC BTMPV model
Implemented ambient temperature output derating for thermal generating units (gas-fired and geothermal)	Same
Updated scheduled maintenance and forced outage parameters based on CAISO Outage Management System (OMS) data	Uses mix of slightly older CAISO OMS data and NERC GADS data
Allow up to 20% of scheduled maintenance to be optimized according to the specific weather year being simulated	Same
Updated heat rates and unit-specific operating constraints and operating costs based on the CAISO Master File for CAISO units, and the ADS for non-CAISO units	Mostly the same, only lacking a small number of updates
Updated maximum output and other operating parameters to achieve tighter alignment with observed dispatch in CAISO Settlement data	Does not include these updates
Separated hydro generation representation in the PGE and SCE subregions of CAISO into non-run-of-river (scheduled) and run-of-river categories	Same
Carved out a portion of Northwest (NW) hydro (from the BPAT region) to be a specified import to CAISO and counted as a GHG-free import	Same
Added ramping to the CAISO Simultaneous Import Constraint to gradually transition between peak hour and off-peak hour constraints	Same
Changed all cost parameters from 2022 real dollars to 2024 real dollars	Uses 2022 real dollars
Continuing to use the CEC 2023 version of the North American Market Gas-Trade Model (NAMGas) to characterize monthly fuel and transport costs	Same

2. Electric Demand Forecast

2.1 California Regions

SERVM annual electric demand peak and energy inputs for California regions are updated to the CEC 2025 IEPR California Energy Demand 2025-2045 "Planning Scenario" (no Known Loads) Forecast. The modeled regions in SERVM correspond to the Planning Areas used in the IEPR as shown in Table 2. The IEPR Managed Forecast[5] can be decomposed into "consumption" and "demand modifier" components and represented explicitly in modeling with hourly profiles. For how the hourly profiles for consumption and demand modifiers will be developed and used in SERVM, see Section 4.2.

Table 2: Map of SERVM Regions and IEPR Planning Areas

SERVM Region	IEPR Planning Area	Description
IID	IID	Imperial Irrigation District
LADWP	LADWP + BUGL	LA Dept. of Water and Power + Burbank and Glendale
NCNC	NCNC	Northern California Non-CAISO
PGE	PGE	Pacific Gas and Electric
SCE	SCE + VEA	Southern California Edison + Valley Electric Association
SDGE	SDGE	San Diego Gas and Electric

Demand modifiers explicitly modeled in SERVM follow the categories from the IEPR:

- Electric vehicle charging including baseline and Additional Achievable Transportation Electrification (AATE) from light, medium, and heavy-duty vehicles
- Additional Achievable Fuel Substitution (AAFS) which includes building electrification as well as industrial heating
- Behind-the-meter (BTM) PV
- BTM storage
- Additional Achievable Energy Efficiency (AAEE)

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[5] See this CEC presentation for an overview of the structure and components of the demand forecast including a definition of the "managed" demand forecast: https://efiling.energy.ca.gov/GetDocument.aspx?tn=253522&DocumentContentId=88746

- Climate Change Adjustment
- Data Centers

Demand forecast inputs are frequently presented as demand at the customer meter. However, CPUC's system planning models quantify demand at the generator busbar. Consequently, demand forecasts at the customer meter are "grossed up" for transmission and distribution (T&D) losses. To the extent possible, SERVM will use the same loss factor assumptions as the IEPR for each modeled region. The factors are calculated from 2025 IEPR Baseline Demand Forecast Files Form 1.2.

Table 3: Modeled T&D Loss Factors by SERVM Region

Region	IID	LADWP	NCNC	PGE	SCE	SDGE
T&D Loss Factor	1.128	1.129	1.064	1.091	1.069	1.082

2.1.1 Consumption and Demand Modifier Derivation

Consumption represents the fundamental pattern of end-use electricity demand and varies with weather, the economy, demographic changes, and region. In SERVM, consumption is defined with annual peak and energy inputs for each forecast year. For the CAISO regions (PGE, SCE, SDGE) the peak and energy inputs are set to UNADJUSTED_CONSUMPTION + PUMPING + OTHER_ADJUSTMENTS, as defined in the 2025 IEPR Hourly Demand Forecast Files. This equates to the managed demand forecast **without** the effects of explicitly modeled demand modifiers (enumerated above). In other words, the demand modifier effects are removed (backed out) from the managed forecast to reconstitute consumption. For the POU regions (IID, LADWP, NCNC) the consumption peak inputs are set to the 2025 IEPR Baseline Demand Forecast Files Form 1.5 1-in-2 peak values with the peak reduction effect of BTMPV added back,[6] while the consumption energy inputs are set to the 2025 IEPR Baseline Demand Forecast Files Form 1.2 Total_Energy_to_Serve_Load + PV_Generation.

Demand modifiers generally represent incremental changes to consumption due to policy and/or technology. With the exception of BTM PV, all of the explicitly modeled demand modifiers are assumed weather independent. Therefore, staff directly translates each demand modifier's peak, energy, and hourly profile attributes from the IEPR into fixed hourly profile "generating" units in SERVM.

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[6] Peak impacts of BTMPV by region were obtained directly from CEC staff since that data is generally not posted to the CEC website

2.1.2 Behind-the-Meter PV

In SERVM, staff models BTM PV capacity at the same geographic granularity as the 19 Forecast Zones defined in the IEPR. The IEPR provides monthly installed capacity by Forecast Zone for the entire forecast horizon. SERVM inputs are initially set exactly to the IEPR amounts. However, the average capacity factor and thus the average annual energy by Forecast Zone across the full weather distribution in SERVM differs somewhat from single capacity factor by Forecast Zone in the IEPR. Prioritizing energy alignment between the IEPR and SERVM modeling, the average annual energy across the full weather distribution was calibrated to match with the single annual energy value from the IEPR for each Forecast Zone by adjusting the BTM PV installed capacity in SERVM. Calibration factors were developed using 2030 values and then applied to all years in the forecast as staff experience has shown that the factor by which IEPR energy values differ from the average energy of SERVM's full weather distribution does not vary by forecast year (but it does by Forecast Zone so it is important to calculate factors for each Forecast Zone).

2.1.3 Behind-the-meter CHP and Other Non-PV/Non-Storage Self Generation

The forecast of non-PV/non-storage self-generation in the IEPR is not explicitly modeled in SERVM and is left combined with consumption. On-site combined heat and power that does not export to the grid (BTM CHP) makes up the majority of this self-generation component. Like prior SERVM modeling (for IRP purposes), CPUC staff will continue to assume that BTM CHP phases out linearly between 2036 and 2040. This differs from the IEPR which assumes the BTM CHP persists unchanged through the forecast horizon. To implement the BTM CHP phase out assumption, CPUC staff assumes the electric demand once served by retiring BTM CHP will return to system electric demand and SERVM consumption peak and energy inputs are adjusted upward accordingly between 2036 and 2040. The remainder of non-PV/non-storage self-generation forecasted by the IEPR is unchanged and left combined with consumption. BTM CHP phase out is not relevant to the RA LOLE study of 2028 since the phase out assumption does not start until 2036.

2.1.4 Calibration

Although SERVM consumption and demand modifier inputs including BTM PV derive from the IEPR, it is difficult to achieve full alignment of both consumption and managed demand between the IEPR and SERVM. This is because the IEPR data is presented as a single 1-in-2 annual peak and energy forecast for each year of the forecast horizon whereas consumption and managed demand in SERVM have a 25-year weather distribution based on 2000-2024 historical weather patterns. Through calibration, CPUC staff can achieve reasonable alignment between the IEPR and SERVM for either consumption or managed demand, but not both together.

CPUC staff has chosen to match the SERVM weather distribution median consumption to the IEPR single 1-in-2 consumption for each forecast year. For the POU regions this is simply calibrating the SERVM median annual consumption peak and energy to match the corresponding IEPR 1-in-2 annual consumption peak and energy values. For the CAISO regions more steps are involved because the objective is to make the CAISO annual coincident consumption peak as well as the annual consumption energy match between the IEPR single 1-in-2 values and the SERVM weather distribution median. The SERVM hourly weather distribution of the three CAISO regions, PGE, SCE, and SDGE, have a slightly different load diversity than the corresponding IEPR single 1-in-2 hourly shapes. Thus, simply calibrating the SERVM median annual consumption peak and energy to match the corresponding IEPR 1-in-2 annual consumption peak and energy values for each CAISO region will not result in a matching CAISO coincident consumption peak between the IEPR 1-in-2 and the SERVM weather distribution median. Instead, staff calibrates the PGE, SCE, and SDGE peak inputs in SERVM such that the resulting weather distribution median CAISO coincident consumption peak does match the IEPR 1-in-2 CAISO coincident consumption peak. This means the SERVM weather distribution medians of the individual PGE, SCE, and SDGE consumption peaks will no longer match the IEPR single 1-in-2 PGE, SCE, and SDGE consumption peaks exactly.

As a final step, CPUC staff combines SERVM consumption hourly shapes with the demand modifiers represented in SERVM including BTM PV to produce the SERVM weather distribution of managed hourly shapes for comparison to the IEPR 1-in-2 managed demand forecast. The charts and tables below show the comparisons. As expected, there is very good alignment of consumption peak and energy, whereas the managed peak is somewhat higher in SERVM. Some amount of misalignment for the managed peak is expected because as stated above, IEPR data is presented as a single 1-in-2 peak and energy forecast (and hourly shape for the CAISO regions) for each year of the forecast horizon whereas consumption, BTMPV, and managed demand in SERVM have a 25-year weather distribution based on 2000-2024 historical weather patterns. Consumption was directly calibrated to match the IEPR whereas the SERVM managed demand is dependent on the interactions between the SERVM hourly shapes of consumption and demand modifiers including BTMPV. This dependency results in the peak hours of the SERVM median consumption and median managed demand differing from the IEPR 1-in-2 peak hours for consumption and managed demand, and consequently the SERVM median managed peak and IEPR 1-in-2 managed peak differing.

Figure 1: IEPR vs. SERVM, CAISO Coincident Peak

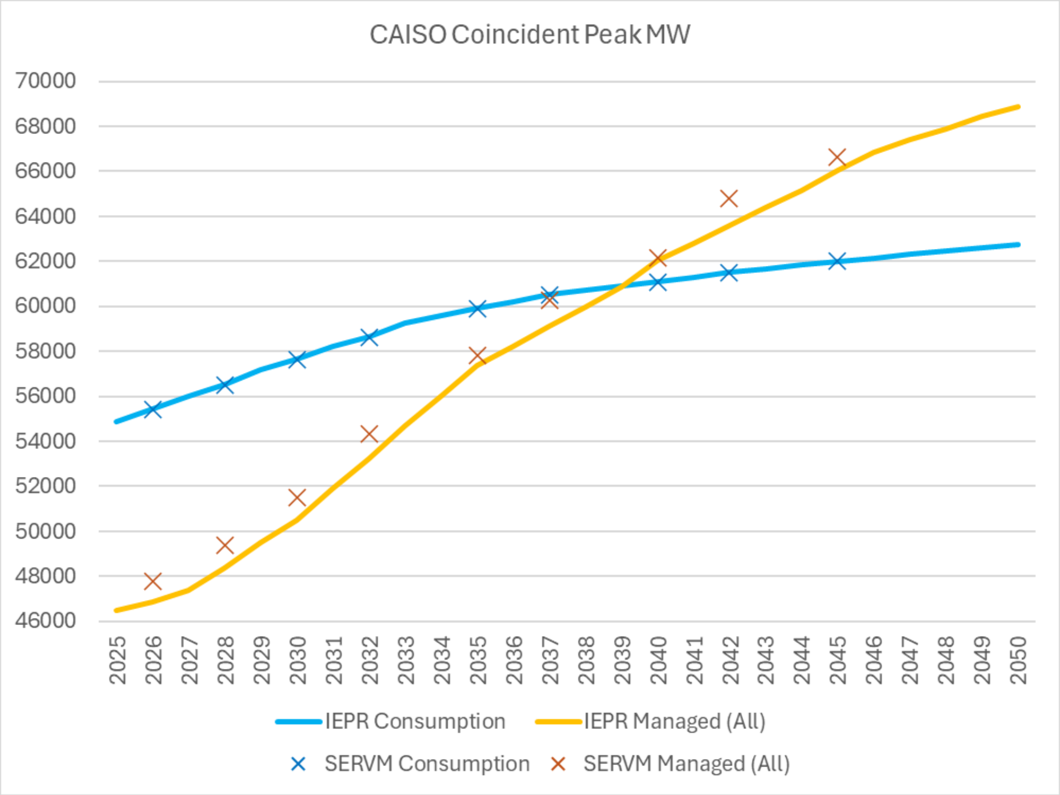

Figure 2: IEPR vs. SERVM, CAISO Annual Energy

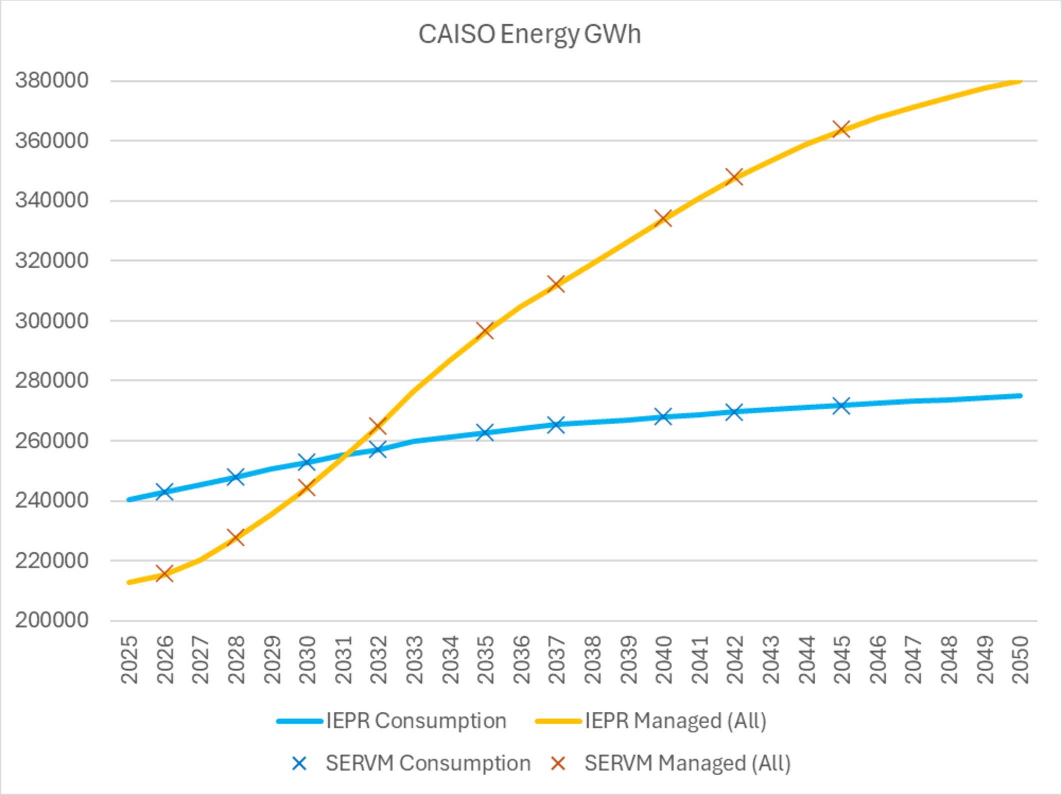

Table 4: IEPR vs. SERVM, CAISO Coincident Peak and Annual Energy

	CAISO Coincident Consumption Peak MW			CAISO Consumption Energy GWh			CAISO Coincident Managed Peak MW			CAISO Managed Energy GWh		
Year	IEPR	SERVM	Diff	IEPR	SERVM	Diff	IEPR	SERVM	Diff	IEPR	SERVM	Diff
2025	54,874			240,439			46,479			212,700		
2026	55,449	55,427	-22	242,994	242,993	-1	46,844	47,761	917	215,318	215,650	331
2027	55,977			245,396			47,360			220,055		
2028	56,518	56,491	-27	247,886	247,885	0	48,356	49,388	1,032	227,284	227,664	380
2029	57,182			250,701			49,501			235,580		
2030	57,655	57,632	-23	252,799	252,798	-1	50,498	51,511	1,013	244,110	244,479	369
2031	58,207			255,228			51,882			254,307		
2032	58,635	58,613	-22	257,027	257,025	-2	53,211	54,334	1,123	264,641	265,047	407
2033	59,252			259,806			54,704			276,320		
2034	59,581			261,231			56,022			286,649		
2035	59,909	59,873	-36	262,726	262,725	-1	57,350	57,822	472	296,238	296,607	369
2036	60,206			264,020			58,229			304,547		
2037	60,518	60,482	-36	265,378	265,377	-2	59,103	60,256	1,153	311,899	312,360	461
2038	60,706			266,179			59,958			318,750		
2039	60,902			267,024			60,866			326,107		
2040	61,109	61,082	-27	267,996	267,994	-1	62,015	62,142	127	333,748	334,339	591
2041	61,301			268,805			62,774			340,815		
2042	61,497	61,476	-21	269,650	269,649	-2	63,592	64,814	1,222	347,391	347,907	517
2043	61,678			270,427			64,414			353,291		
2044	61,853			271,264			65,166			358,681		
2045	62,000	61,988	-12	271,809	271,809	0	66,026	66,610	584	363,425	363,916	491

Table 5: IEPR vs. SERVM, 2028 Peak and Peak Hour Differences

Target Year	2028				
	Consumption Peak MW	Consumption Peak Hour	Month	Day	Hour of Day
IEPR 1-in-2	56,518	4983	7	26	15
Delta (SERVM - IEPR)	-27				
SERVM Median and Weather Year 2012	56,491	5415	8	14	15
	Managed Peak MW	Managed Peak Hour	Month	Day	Hour of Day
IEPR 1-in-2	48,356	5993	9	6	17
Delta (SERVM - IEPR)	1,032				
SERVM Median and Weather Year 2016	49,388	6473	9	27	17

2.2 Other Regions

SERVM models regions external to California to simulate transfers between CAISO and other regions as well as California and other regions. To limit model complexity and shorten run time, CPUC staff have chosen to model seven neighboring regions external to California in addition to the six regions within California. These regions external to California are detailed in the table below.

Table 6: Regions external to California modeled in SERVM

SERVM Region	WECC BAA Name	Baseline Generator List Name
AZPS	Arizona Public Service Company	AZPS
BPAT	Avista Corporation	AVA
BPAT	Bonneville Power Administration-Transmission	BPAT
BPAT	PUD No. 1 of Chelan County	CHPD
BPAT	PUD No. 1 of Douglas County	DOPD
BPAT	PUD No. 1 of Grant County	GCPD
BPAT	Puget Sound Energy	PSEI
BPAT	Seattle City Light	SCL
BPAT	City of Tacoma, Department of Public Utilities	TPWR
NEVP	Nevada Power Company	NEVP
PACW	PacifiCorp West	PACW
PortlandGE	Portland General Electric Company	PortlandGE
SRP	Salt River Project	SRP
WALC	Western Area Power Administration - Lower Colorado Region	WALC

The electricity sales forecasts (equivalent to managed demand in IEPR terms) for external regions are obtained from a survey of the most recently available IRPs of the external region utilities. BTM PV data in these IRPs are often incomplete – therefore staff utilized the most recently available historical BTM PV monthly installed capacity[7] data from EIA Net Metering Information Form EIA-861M and extrapolated to 2050. The BTM PV data is extrapolated to 2050 based on the average monthly MW increase in installed BTM PV from 1/1/2020 to 12/31/25. Using this information and the SERVM weather-normalized consumption and BTM PV production shapes for these external regions, staff assume values for consumption peak and energy and iteratively adjust those until the SERVM weather distribution median sales (managed) peak and energy match reasonably well with the sales forecast peak and energy

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[7] Assumed to be AC MW at customer meter. Absent reliable information on T&D loss factors for the external to California regions, staff used these values as-is which may slightly undercount the corresponding installed capacity and energy impact at the system level.

obtained from the external region IRPs. In other words, consumption is reconstituted from sales so that SERVM can explicitly model weather-based consumption and BTM PV production for the external regions. The external regions' electricity sales forecasts, consumption, and BTM PV inputs are still being developed by staff and will be shared with stakeholders as soon as available.

3. Baseline Resources

3.1 Overview

Baseline resources are resources that are currently online or have entered the CAISO New Resource Interconnection (NRI) process. This criterion indicates the resource is relatively certain to come online.

The capacity of both **baseline** and **candidate** resources are inputs to SERVM. In the near-term (e.g. 2-3 years into the future), modeling baseline resources only may result in a sufficiently reliable system, but in the mid to long-term (3 years into the future and beyond) due to load growth and other changes over time, future additional candidate resources may need to be included on top of baseline resources to result in a sufficiently reliable system. Candidate resources are selected using capacity expansion modeling such as RESOLVE or derived from IRPs and other resource projections. For some resources, baseline resource capacity is reduced over time to reflect announced retirements. This document describes the updating process of baseline resources only. Modeling performed for RA LOLE determination of 2028 will only use baseline resources without any RESOLVE candidates.

Baseline resources include:

- Existing resources (built and currently available) in CAISO as well as in external regions: Each resource is listed with an in-service date and a retirement date. Resources that are retired or will retire during the planning horizon are still present in the SERVM database and the retirement date, as well as in service date, are used to determine whether the unit is included in a study of a chosen target year.
- Resources confidently under development to serve CAISO load: To ensure that these resources are more credible, they are sourced only from the CAISO NRI process. Resources listed in LSE IRP plans are no longer included in the Baseline if they are not also listed in the CAISO NRI data.
- Resources under development in non-CAISO balancing areas: These resources come from the WECC Anchor Data Set (ADS). Resources described as "planned" or "generic" are excluded.

Baseline resources are assembled from the primary sources listed in Table 7 and are further described below.

Table 7. Data Sources for Baseline Resources

Region	Online Status	Dataset Used
In CAISO	Existing	CAISO Master Generating Capability List[8] and confidential CAISO Master File, both vintage August 2025
In CAISO	In-development	CAISO Generation Interconnection Resource ID Report, vintage August 2025[9]
Out of CAISO	Existing and In-development	2034 WECC ADS V1.0,[10] vintage July 2024
In CAISO	Retirement Dates	CAISO Announced Retirement and Mothball List dated September 19, 2025 [11]
Out of CAISO	Retirement Dates	2034 WECC ADS V1.0

Staff performed an iterative and detailed process to assemble the Baseline, starting well before the Baseline is published to the CPUC website. The steps are summarized below:

- The list of generators currently operational to serve the CAISO area is compiled from the CAISO Master Generating Capability List as of August 2025. WECC ADS information for generation serving the CAISO area is not used, as CAISO information is assumed to be more accurate and current. These generators serve demand inside CAISO and are composed of renewable and non-renewable generation resources, as well as some demand response resources. The CAISO Master Generating Capability List information provides a listing of the resources by name and CAISO Schedule Resource ID (CAISO ID) and their Net Dependable Capacity (NDC, used as capmax in SERVM), in-service dates, and location. Operational data for those generating units come from the corresponding CAISO Master File, a confidential data set with unit-specific operational attributes. Both of these CAISO lists also include information related to dynamically scheduled generators, which are physically located outside of the CAISO but can participate in the CAISO market as if they were internal to CAISO. However, because they have no obligation to sell into CAISO they are modeled as unspecified imports and do not have special priority given to their energy dispatch. Nevertheless, information for these dynamically scheduled resources is taken from the CAISO listings rather than those same resources listed in the WECC ADS. Some dynamically scheduled generators also

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[8] CAISO Master Control Area Generating Capability List - PRODUCTION - PUBLIC - apapjbos4392 - 0

[9] CAISO New Generator Interconnection Resource ID Report

[10] WECC Anchor Data Set (ADS) | Western Electricity Coordinating Council

[11] CAISO Announced Resource Retirement and Mothball List Posted

have contracts to provide energy and capacity to CAISO LSEs. Such generators are modeled as specified imports (remote generators) in SERVM.

- Future in-development generators for CPUC-jurisdictional LSEs are compiled from the August 31, 2025 version of the CAISO Generation Interconnection Resource ID Report.
- For generators outside of CAISO, all identifying information and operating information are taken from the WECC's 2034 Anchor Data Set (ADS) v1.0.
- Confirmation of some data regarding in-development resources for CAISO and outside CAISO regions were sourced from Energy Information Administration (EIA) data[12]
- This baseline will replace the prior list dated November 2024[13].
- The baseline update also involved making additions and updates to individual units from the prior baseline list, including updates to operating parameters and maximum capacity. Staff updated regions, unit types, and unit categories to correct errors and oversights. Staff consolidated planned capacity with newly online capacity if a planned project came online. Staff separated hybrid units into Limited Energy Storage Resource (LESR) and Solar PV (SUN) portions by creating two units and appending "LESR" or "SUN" to the SERVM Unit names.

Table 8 summarizes the CAISO nameplate MW by technology category that is expected to be online and operating in 2028, i.e. retirement dates are after 2028, and in-service dates are 2028 or before. The table compares the prior Baseline and the proposed new Baseline for units online in 2028. Changes reflect newly online units and corrections made to unit categories (mostly shifting from other thermal categories to CHP). 858 MW were classified as CCGT in the 2024 Baseline that are now corrected to be categorized as CHP. Likewise, 843 MW were classified as Peaker in the 2024 Baseline that are now corrected to be categorized as CHP. Retirements or program termination are accounted for, for example, Shed DR is now reduced by the amount of the DRAM programs that were discontinued by the Commission since the creation of the prior Baseline in 2024.

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[12] EIA July 2025 Monthly Generator Inventory https://www.eia.gov/electricity/data/eia860M/ dated July 2025

[13] BaselineGeneratorList_ExternalBuildCalibration_v20241125.xlsx

Table 8: CAISO Nameplate MW Operating in 2028 – 2024 (current) Baseline vs. 2026 (proposed) Baseline

Technology Type	2028 Capmax MW (2024 Baseline)	2028 Capmax MW (2026 Baseline)	Increase or (Decrease)[14]
Biogas	283	288	5
Biomass	521	465	(55)
CCGT	19,484	18,846	(638)
CHP	2,363	4,040	1,676
Geothermal	1,950	1,592	(358)
Hydro	9,144	9,149	4
Li-ion Battery	14,880	24,771	9,891
Nuclear	2,935	2,935	0
Peaker	7,876	7,429	(447)
PSH	1,443	1,487	44
Reciprocating_Engine	255	303	48
Shed_DR	3,870	3,362	(508)
Solar	23,527	29,081	5,555
Wind	9,820	11,064	1,244
Total	97,843	114,813	16,970

3.2 Natural Gas, Coal, and Nuclear Generation

Natural gas, coal, and nuclear resources are represented in SERVM as individual units. Unit information such as capacity, operating constraints, and variable costs is drawn directly from the CAISO Master File, the CAISO Master Generating Capability List, or the WECC 2034 ADS v1.0[15]. New generation under development for the CAISO area is taken from the CAISO Generation Interconnection Resource ID Report.

For regions external to the CAISO, the ADS is used to characterize the existing and anticipated future generation fleet in each non-CAISO zone. Although the ADS is sourced from utility IRPs to

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[14] Increases or decreases are the net effect of any new units coming online, any retirements/terminations, and corrections to technology category (shifting from one to another category)

[15] Data available on WECC website: https://www.wecc.org/ReliabilityModeling/Pages/AnchorDataSet.aspx

track generator additions and retirements as well as projected electric demand changes, the ADS is a snapshot of a single year ten years in the future, and information may be dated.

Details on how SERVM models operating constraints are covered in section 4.3. Units that are contracted to serve load in a region that is different than the units' physical location are virtually assigned to the region holding the contract. For example, the share of Palo Verde nuclear plant that is contracted to SCE is assigned to the SCE region while the share that is contracted to LADWP is assigned to the LADWP region.

3.2.1 Retirement Assumptions

Retirement assumptions are drawn from the CAISO Announced Retirement and Mothball List[16], the WECC 2034 ADS v1.0, or other public sources. The capacity of fossil-fueled and nuclear thermal generators that have formally announced retirement are removed from baseline thermal capacity using the announced retirement schedule. California steam turbines are all modeled to retire by default at the end of 2023 to achieve compliance with the State Water Board's Once-Through-Cooling (OTC) regulations, even though some of those plants are part of California's Strategic Reliability Reserve.[17] Diablo Canyon Nuclear Power Plant (DCPP) is expected to extend Unit 1 to October 2029 and Unit 2 to October 2030 as per the extension agreement and pursuant to SB846 (Dodd, 2022). As such, DCPP is included in the Baseline for the 2028 LOLE study but for IRP modeling DCPP is still modeled to retire according to its original schedule of Unit 1 in November 2024 and Unit 2 August 2025.[18] Cogeneration (also called combined heat and power or CHP) facilities follow any announced retirement schedule and on top of that, are assumed to be phased out between 2036 and 2040 with an approximately linear trajectory.

3.3 Renewables

Baseline renewable resources include all existing biomass, biogas, geothermal, solar photovoltaic (PV), solar thermal, and wind in each region. Small hydro (usually run-of-the-river hydro) is modeled separately from large scheduled hydro and is described in section 3.4 below. All wind in the baseline is currently onshore, though some is located out of state.

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[16] Version 9/19/2025 was used. The most recent version is posted at: https://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

[17] https://www.energy.ca.gov/data-reports/california-energy-planning-library/reliability/strategic-reliability-reserve

[18] See CPUC Decision (D.)23-12-036 authorizing DCPP to continue operating until October 2029 for Unit 1 and October 2030 for Unit 2

3.3.1 CAISO Renewable Resources

CAISO baseline renewable resources include (1) existing resources and (2) resources that are in the CAISO New Resource Implementation process. As mentioned above, existing CAISO renewable resources are compiled from the CAISO Master Generating Capability List and the CAISO Master File. Information on resources that are under development is compiled from the CAISO Generation Interconnection Resource ID Report as of August 31, 2025.

CAISO renewables also include dynamically-scheduled generators physically located outside the CAISO that have energy and capacity contracts with a CAISO offtaker. These are called “remote generators” and grouped with “direct purchases” (specified imports) in SERVM. The energy and GHG attributes accrue to the “remote region”, i.e. the offtaker which is located within CAISO.

3.3.2 Non-CAISO Renewables

For non-CAISO entities in or out of California, the renewable resource portfolio is derived from the WECC 2034 ADS v1.0 and EIA Monthly Generator Inventory (EIA-860M) data. Baseline renewable capacities for non-CAISO entities do not include resources that are physically located in those regions but with energy and capacity contracts with a CAISO offtaker since they are already counted as part of baseline CAISO renewable resources.

3.4 Hydro

Baseline hydro units in SERVM are generally modeled as aggregate units by region, with the aggregate unit representing all the individual hydro units that exist in the region. The aggregate hydro units provide energy to their local zone with two exceptions, Hoover, which is split among the CAISO, LADWP, NEVP, and AZPS regions in proportion to ownership shares, and NW hydro located in the BPAT region, which has a portion of its annual energy specifically dedicated to CAISO.

The total amount of NW hydro has 8.31 percent (of capmax, energy, and flow constraints) separated out into a “remote generator” (grouped with “direct purchases,” aka specified imports in SERVM) with the PGE region as the offtaker. This models the assumed energy from Asset Controlling Supplier (ACS) NW hydro that accrues to CAISO including the GHG-free attribute. The 8.31 percent is derived from historical import data from BPA and Powerex as reported in CARB’s GHG emissions inventory.[19] This NW hydro remote generator to CAISO is subject to transmission constraints into California but does not incur hurdle rates or GHG emissions, same as any other remote generator in SERVM.

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[19] CARB GHG Current California Emission Inventory Data available at: https://ww2.arb.ca.gov/ghg-invento-ry-data

To characterize the baseline hydro units, staff sources historical monthly and hourly hydro unit flow data from EIA Form 906/923, CAISO, and Bonneville Power Administration (BPA). Staff uses the data to model constraints on hydro resources in particular regions, including minimum flows, maximum hydro capacities, and monthly available hydro energy that can be dispatched during a month. See section 4.3.2 for more details on modeling hydro operation.

The aggregate hydro units for the PGE and SCE regions are further separated into non-Run-Of-River (nROR, aka large scheduled hydro) and Run-Of-River (ROR, aka small hydro) hydro units. See section 4.3.2 for more details on how this separation was done.

Finally, the PGE and SCE regions each have an emergency hydro unit modeled in addition to the aggregate large scheduled hydro unit in each region. The emergency unit represents the ability to borrow from the monthly generation budget under grid stress conditions. The emergency units are modeled to be available only during certain month/hydro year combinations that represent sufficient hydro availability for borrowing. See section 4.3.2 for more details.

The table below summarizes each of the hydro units modeled in SERVM. SERVM characterizes its hydro unit sizes by monthly maximum output across all available hydro years (2000-2024) rather than using the nameplate of each specific hydro unit (the sum of nameplates of each individual hydro unit is generally greater than any of its corresponding aggregate hydro unit monthly maximum output values in any hydro year).

Table 9. SERVM hydro unit September maximum output under 2010 hydro conditions

Unit Name	Region	Sep Max MW
AZPS_Hoover_Hydro_V0024	AZPS	147
LADWP_Hoover_Hydro_V0024	LADWP	119
NEVP_Hoover_Hydro_V0024	NEVP	181
SCE_Hoover_Hydro_V0024	SCE	327
BANC_Hydro_V0024	NCNC	1,485
LADWP_Hydro_V0024	LADWP	197
PACW_Hydro_V0024	PACW	443
SW_Hydro_V0024	SRP	521
NW_BPAT_Hydro_V0024	BPAT	13,680
NW_CAISO_Remote_Hydro_V0024	BPAT	1,240
PGE_nROR_Hydro_V0024	PGE	3,152
PGE_ROR_Hydro_V0024	PGE	80
PGE_Emergency_Hydro_V0024	PGE	947
SCE_nROR_Hydro_V0024	SCE	893
SCE_ROR_Hydro_V0024	SCE	132
SCE_Emergency_Hydro_V0024	SCE	278

3.5 Energy Storage

3.5.1 Pumped Storage

Existing pumped storage resources in CAISO are based on the CAISO Master Generating Capability List and shown below.

Table 10. Existing pumped storage resources in CAISO

Common Name	SERVM Unit Name	Capacity (MW)
Eastwood	EASTWD_7_UNIT	200
Helms	HELMPG_7_UNIT_1 HELMPG_7_UNIT_2 HELMPG_7_UNIT_3	1,218
O’Neil	ONLLPP_6_UNITS	25
Total		**1,443**

Operating characteristics of pumped storage hydro resources (including total energy storage MWh, transition time, minimum pumping and flowing capacity and efficiency of conversion from pumping to discharging) are taken from the CAISO MasterFile.

3.5.2 Battery Storage

Baseline storage resources include all battery storage that is currently installed in the CAISO region, as well as further battery storage listed in the CAISO NRI process on the August 31, 2025 CAISO Generation Interconnection Resource ID Report. Operating parameters including MWh volume for baseline utility scale storage resources come from the CAISO MasterFile and in the case of "in development" storage, from the Generation Interconnection Resource ID Report. Baseline behind-the meter storage resources are based on CEC's 2025 IEPR demand forecast. Battery storage units co-located with a generator that meet the baseline criteria are identified by their own Unit Categories in SERVM, namely, Paired_BattStorage and Hybrid_BattStorage. An additional unit variable in SERVM links the storage unit to its generating unit. Paired_BattStorage is used when the CAISO source data has the storage unit and its co-located generator unit each with their own CAISO Resource ID. In SERVM the storage unit has capmax matching the CAISO storage unit nameplate and the generating unit has capmax matching the CAISO generating unit nameplate. Hybrid_BattStorage is used when the CAISO source data has a single Resource ID for both the storage unit and the generating unit. In SERVM the project is split into a storage unit and a generating unit where the storage capmax is the max output of the storage portion of the project and the generating unit capmax is the max output of the generating portion of the project. The interconnection capacity of the entire project (the single Resource ID in the CAISO source data) is reflected in a special variable in SERVM called max_combined_capacity, which is always less than or equal to the sum of the storage and generating unit nameplates. All co-located projects are modeled as AC-coupled (alternating current-coupled) with no charging restrictions.

3.6 Demand Response

Shed (or "conventional") demand response reduces demand during peak demand events or when they are triggered at extremely high prices. Baseline Demand Response resources will consist of IOUs' existing shed demand response programs and any third-party Load Impact Protocol (LIP) programs with LSE contracts. The assumed peak load impact of demand response programs are based on final annual LIP reports by the IOUs.[20] Additional interruptible pumping load (mostly Department of Water Resources bulk water pumping load) is also included as baseline shed DR capacity in all years. The total pumping load modeled in SERVM varies by month approximately ranging from 500 to 600 MW and has been derated from source data (CAISO Master Generating Capability List) due to water limits and expected deliveries. Note that

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[20] Guide to CPUC's Load Impact Protocols (LIP) Process v3.1. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/lip-filing-guide-and-related-materials/lip-filing-guide-v31.pdf

this DR capacity is equivalent to the pumping load that is included in the “pumping” component of the IEPR demand forecast, and represents the ability of that demand to shift according to reliability or cost similar to other DR.

3.7 External Region Calibration

To reasonably model grid conditions in external regions and produce a realistic pattern of import exchanges between CAISO and external regions, accurate representations of load and resource balance, projected load growth, and capacity expansion in external areas are vital. However, accurate and detailed data on future loads and resources in external regions may be difficult or impossible to obtain and even if accurate data were available, it may not be desirable to model external regions in detail to reduce model complexity and run time.

Staff chose to model only external regions closest to California. Those regions closest to California were maintained in the model while regions further from California were left out. See **Table 6: Regions external to California modeled in SERVM** in section 2.2 for a map of SERVM region names to the balancing areas and utilities they represent.

The default amounts of baseline generation and forecasted electric demand drawn from available public sources, particularly the WECC ADS and surveys of external region IRPs as described above, may not result in all regions meeting an industry standard 0.1 days/year LOLE reliability level in all years. In previous studies, staff assumed that these external regions were planning to maintain their reliability level within industry standards of 0.1 LOLE. To implement that assumption, additional calibration and research into the IRPs of external region entities were performed, and where gaps in external region data and IRPs existed, staff performed heuristics informed by regional growth patterns, the mix of recent resource procurement, or clean energy and reliability policies in these external regions. For external regions whose LOLE was far above 0.1, staff added perfect capacity or a generic mix of new resources informed by the aforementioned heuristics to bring the LOLE closer to 0.1. Staff’s experience has shown that iteratively calibrating each of the many external regions to achieve a LOLE of approximately 0.1 is both difficult and time-consuming. Therefore, in previous studies staff only calibrated each region towards the 0.1 LOLE target until the point where further calibration had little effect on changing the LOLE result of California regions. Staff also found that 2030 was the first year where calibration was necessary based on the prior Baseline Generating List (used for IRP modeling in 2025).

The parties American Clean Power – California (ACP-CA) and Western Power Trading Forum (WPTF) urged staff to examine the possibility that some external regions, particularly from the Pacific Northwest, may face resource deficiencies. They noted that the ADS data for some regions may in fact accurately reflect those regions’ resource planning status and that the inclusion of generic resource additions may be inappropriate. Thus, they recommended that

CPUC's planning for the CAISO region should use the ADS data as-is, including the possibility that some external regions may not be resource sufficient. Based on this feedback, staff will perform LOLE studies of 2028 with the Baseline (ADS-sourced) resources as-is with no generic additions, in addition to performing LOLE studies of 2028 where external regions are calibrated towards 0.1 LOLE when necessary. The results of these studies (including the differences in LOLE and PRM levels) will be included in the final LOLE study report and presented at a workshop.

4. Generator Operations and Hourly Profiles

4.1 Overview

SERVM is a full production cost model (PCM) which seeks to completely characterize the electric system with generators represented in an hourly dispatch model. This section describes hourly weather-based electric demand and weather-based generation profiles and non-weather dependent generator operating constraints, and how they are developed and used in SERVM.

4.2 Electric Demand and Renewable Production Profiles

Historical weather-based hourly electric demand, and wind and solar production profiles ("shapes") are key inputs to SERVM. The prior cycle of modeling used the weather years 2000-2022 as the basis for hourly shapes. In this modeling cycle staff added the two most recent and available weather years. Thus, the overall ensemble of weather patterns tested in SERVM is now 25 years in length covering weather years 2000 through 2024.

4.2.1 Electric Demand Profiles

Staff developed weather normalized electric demand profiles for SERVM using a weather normalization model and existing temperature and humidity data from 2000-2024 in a three-step process. In step one, for the most recent and available three years (2022-2024), staff gathered CAISO region hourly electric sales data from the CAISO's Energy Management System (EMS) and other region data from FERC Form 714 hourly electric sales data[21] for regions outside the CAISO and added back the impacts of simulated historical BTM PV generation, historical demand response (curtailable load) events if any, and historical system storage charging,

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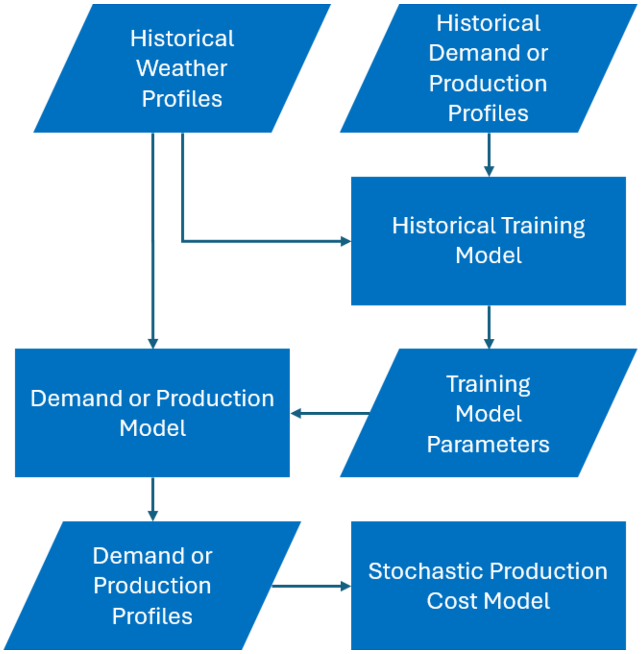
[21] FERC Form 714 data is available at https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-no-714-annual-electric/data up to and including 2020. After 2020, data is available through the FERC ePortal located at https://ecollection.ferc.gov/

thereby reconstituting the counterfactual hourly consumption demand for 2022-2024. In step two, this counterfactual consumption demand was used to train the Monash[22] regression model which uses historical temperature and humidity to forecast electric demand. Using the most recent and available three years means the most recent patterns of consumption demand and its relationship to weather are used as the basis for hourly consumption patterns to model in future years. In step three, the trained model is used to build out 25 years of weather normalized hourly consumption demand for all regions, corresponding to 2000-2024 weather patterns. The figure below is a flow chart illustrating the process for creating the 25-weather year ensemble of consumption demand profiles for use in SERVM. The general flow also applies to the creation of production profiles for wind and solar though the input profiles and the training models are different and described in the following sections.

Figure 3. Flowchart for Creation of Demand or Production Profiles from Historical Weather



In leap years of demand profiles, February 29 is retained and December 31 is dropped such that the profiles remain 8760 hours long but do not introduce a discontinuity in the weekday/weekend pattern.

Staff also shifted the final 2000-2024 weather normalized demand profiles such that all years start with a Monday (i.e. January 1 is Monday for all years) to ensure that variability in hourly demand was driven solely by weather variability and not from which day-of-week start was used. Staff chose Monday as the uniform start day based on prior analysis showing that a

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[22] Monash electric demand model is described in a paper here: MEFMR1.pdf (robjhyndman.com)

Monday start was about the median out of the seven possible day-of-week starts in terms of average percentage of peak temperatures occurring on a weekend day.

The final weather normalized demand profiles are then input into SERVM and scaled such that the median annual peak and average annual energy of the full weather distribution for each region matches the corresponding region's annual peak and energy forecast that is input into SERVM. Refer to sections 2.1 and 2.2 above, respectively, for descriptions of the demand forecast consumption peak and energy inputs for California and external to California regions.

4.2.2 Electric Demand Modifier Profiles

As described in section 2.1 above, SERVM models electric demand modifiers separately from electric consumption demand. Consumption and BTM PV are modeled with the full weather distribution while all the other explicitly modeled demand modifiers are assumed weather independent, that is they do not vary by modeled weather but only vary by forecast year being modeled. Hourly demand modifier profiles are taken from the "Planning Forecast" scenario of CEC's 2025 IEPR demand forecast for all California regions. This includes AAEE, AAFS, electric vehicle charging demand (both baseline and Additional Achievable), BTM storage, Climate Change, and Data Centers. For non-California regions, only BTM PV generation, if any, is explicitly modeled separately from electric demand.

For non-BTM PV demand modifier profiles, staff directly processes the hourly profiles provided by the CEC's 2025 IEPR demand forecast into normalized profiles for each forecast year paired with the maximum value (whether positive or negative) that together recreate the original IEPR demand modifier profile in SERVM as "fixed profile generator" units for each California region. Staff further process the profiles to "leap year correct" and "shift to Monday start" the profiles to ensure weekday/weekend patterns are in sync with the consumption profiles. The leap year correction involves inserting a copy of February 22 as February 29 if the IEPR source profile was missing February 29, and dropping December 31 to ensure the profile length stays at 8760 hours. The shift to Monday start involves dropping the initial days of a forecast year profile until the first day is Monday and adding back the number of dropped days at the end of the year by making copies of the last days of the year starting with December 25, which is seven days before the end of the year. This preserves the weekday/weekend pattern.

See section 2.1.2 for how BTM PV monthly capacity and annual energy inputs are developed and the next section for how BTM PV hourly profiles are developed.

4.2.3 Solar Production Profiles

Weather normalized solar production profiles are created using NREL's PVWATTS Version 5 calculator.[23] The software creates PV production profiles based on historical solar radiation data from the National Solar Radiation Database (NSRDB),[24] and is used to produce both utility-scale and behind-the-meter solar profiles. 2000-2024 NSRDB weather data is used to create the profiles used in SERVM.

To create utility-scale solar profiles using the PVWATTS Version 5 calculator, the various solar array parameters used by PVWATTS are determined by fitting historical CAISO settlement data to modeled solar production data. SERVM simulates solar production profiles for single and double axis tracking configurations as well as fixed axis/tilt configuration.

In previous cycles BTM PV profiles were based on the fixed utility scale profiles developed from PVWATTS using parameters based on CAISO historical settlement data and an assumed inverter loading ratio sourced from the CEC's IEPR demand forecast, currently 1.13. However, BTM PV installations differ in some significant ways from fixed utility-scale installations. First, BTM PV installations are typically less efficient than utility-scale installations of the same size. Second, utility-scale installation profiles are developed for a single point source location, whereas the BTM PV profiles used in SERVM need to reflect the behavior of a distribution of geographically dispersed locations. For this cycle, staff have developed new weather-normalized BTM PV profiles specifically to reflect these differences, with assistance from CEC staff in the interest of maximizing alignment between CEC and CPUC-developed BTM PV profiles. While CEC staff were unable to provide CPUC staff with the historical BTM PV vendor data that informs their BTM PV model, they were instead able to provide efficiency ratios by TAC area which allowed the CPUC model to more accurately capture historically observed BTM PV behavior. The CPUC model was also modified to reflect a geographic distribution of locations instead of the point source behavior used to develop fixed utility-scale profiles.

Historical monthly MW capacity by IEPR Forecast Zone (1-19) were provided by CEC staff along with the city at the center of each IEPR Forecast Zone. The monthly capacity together with the new CPUC model for weather normalized BTM PV profiles and the 1.13 inverter loading ratio assumption were used to create simulated historical BTM PV profiles – which were used for reconstituting historical hourly consumption demand from historical hourly electricity sales data, as described in step one of section 4.2.1 above. Likewise, 2025 IEPR Planning scenario forecasted monthly MW capacity by IEPR Forecast Zone were provided by CEC staff and used with the new CPUC model to produce full weather distributions of BTM PV profiles or each

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[23] See: https://pvwatts.nrel.gov/downloads/pvwattsv5.pdf

[24] See: https://nsrdb.nrel.gov/current-version

forecast year and Forecast Zone. See section 2.1.2 above for other details including how BTM PV annual energy production values by Forecast Zone were calibrated in SERVM to match the IEPR.

To summarize, the full weather distribution of normalized hourly solar production profiles in SERVM represent more than two dozen specific locations ("weather stations") in California and across WECC for each technology class of double axis tracking, single axis tracking, fixed-tilt, and BTM PV. The normalized hourly profiles (identified by a "weather station" name) get paired with the installed capacity of individual solar units at a specific location, resulting in the final fully scaled hourly solar production profiles for those units at that location. Individual utility-scale solar units as itemized in the set of baseline generators described earlier are modeled. For BTM PV units in California, one aggregate unit for each Forecast Zone of the IEPR demand forecast is modeled.

4.2.4 Wind Production Profiles

The updated CPUC wind model produces 25 years of normalized hourly production profiles (2000 – 2024) for all locations at which wind resources exist within the model. For each wind resource in the model, hourly wind production curves (MWh) can be produced by simply scaling the respective normalized hourly production profile closest to the resource by the installed capacity (in MW) of the resource. Individual efforts were undertaken for each of the Offshore Wind (Offshore) profiles, CAISO onshore profiles (Onshore), and onshore Out of State profiles (OOS) to ensure accuracy.

Normalized hourly wind production profiles are developed in two different ways:

Velocity: For regions for which we do not have historical wind production data including some onshore as well as all offshore locations, we are using hourly wind speed data with an appropriate power response curve[25] to create normalized hourly wind production profiles. The power response curve gives normalized production as a function of wind speed. Offshore wind production profiles are calibrated by adjusting the input velocities by a velocity offset factor such that resulting modeled annual capacity factor matches a target annual capacity factor. Estimated annual capacity factors for Morro and Humboldt Bays[26] are used to calculate two

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[25] Gaertner (2020): "Definition of the IEA 15-Megawatt Offshore Reference Wind Turbine", https://www.nrel.gov/docs/fy20osti/75698.pdf. For the actual power curve see: https://github.com/IEAWindSystems/IEA-15-240-RWT

26 National Renewable Energy Laboratory National Offshore Wind data set (NOW-23), https://dx.doi.org/10.25984/1821404

separate estimates of the velocity offset factor, and the average velocity offset factor is then used to build all subsequent normalized hourly wind production profiles.

Onshore wind speed profiles are obtained from the Copernicus ERA5 reanalysis dataset[27]. We have moved from the high resolution WRF/ERA5 wind speed dataset to the lower resolution Copernicus/ERA5 dataset since the WRF dataset does not yet contain data past 2020. Offshore windspeed profiles are obtained from the National Renewable Energy Labs (NREL) 2023 National Offshore Wind data set (NOW-23).[28] NOW-23 wind speeds only cover the years 2000 through 2022, and there are no immediate plans to update this dataset. We therefore build synthetic offshore wind speed profiles for 2023 and later by taking a representative, existing year, and then resort the wind speed values to match the rank order corresponding to the closest Copernicus/ERA5 profile. In this way we maintain a historical distribution of wind speed values present in the NOW-23 dataset but preserve spatial and temporal correlation captured by the Copernicus/ERA5 for more recent years past 2022.

Monte Carlo: For regions where historical wind production data is available (2000 – 2024), the process for developing normalized hourly wind profiles is as follows:

a. Map each wind resource to a wind weather station.
b. Aggregate historical hourly wind production to each wind weather station.
c. Normalize hourly wind production for each weather station by 1.1 * yearly peak, where the diversity factor of 1.1 accounts for the non-simultaneity of wind production associated with each given weather station.
d. For each weather station and for each hour of the year, develop Monte Carlo random draws (with replacement) from the historically observed normalized production values for each of the desired weather years (2000 - 2024).

For each weather station, choose wind speed profiles from the Copernicus ERA5 dataset that are physically closest to the region centroid, and then resort the Monte Carlo random draws according to the rank order of the historical annual velocity profiles. Choose the single wind speed profile that minimizes the difference between the simulated and historical aggregated monthly and hourly capacity factors. Like the case for developing solar profiles, the normalized hourly wind production profiles (identified by a “weather station” name) get paired with the installed capacity of individual wind units at a specific location, resulting in the final fully scaled wind production profiles for those units at that location.

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[27] See: https://cds.climate.copernicus.eu/cdsapp#!/dataset/reanalysis-era5-single-levels?tab=form

[28] See: https://data.openei.org/submissions/4500

4.3 Operating Characteristics

4.3.1 Natural Gas, Coal, Nuclear

SERVM models the thermal fleet individually using actual unit-level data and operating constraints to the extent possible. Principal operating characteristics include Pmax, Pmin, heat rate, start cost, start fuel consumption, ramp rates, minimum up and down times, start up profiles and generator maintenance and forced outage rates. Data is sourced primarily from the confidential CAISO Master File (August 2025) and the public 2034 WECC ADS V1.0 (July 2024). In the prior cycle all costs were characterized in 2022 real dollars. Staff intend to update all costs to 2024 real dollars prior to starting the RA 2028 LOLE study.

4.3.1.1 Generator Maintenance and Forced Outage Distributions

Every generator requires maintenance time during the course of a year, and generator operators schedule that maintenance to avoid peak demand times and to be available when needed by the system operator to maintain reliability and capture high priced energy hours. Generators are also subject to unplanned, forced outages throughout the year, often associated with age, operating history, and operational time since the last major maintenance. For that reason, staff apply a static maintenance rate to each generator, which SERVM then uses to schedule maintenance in off-peak times as an owner would likely do, and a stochastic distribution from which SERVM will draw frequency and duration of forced outage events. Maintenance and outage rate data are drawn from CAISO's Outage Management System (OMS), publicly available as the Curtailed and Non-Operational Generators Prior Trade-Day Reports.[29]

Maintenance rates are determined from OMS data by filtering outage data for reports with outage type "PLANNED" and nature-of-work "PLANT_MAINTENANCE". An equivalent outage rate is then determined from the records for each resource individually using the following formula:

$$[\text{Equivalent Maintenance Outage Rate}] = \frac{\sum_{\text{Outage Reports}}[\text{Outage MW}][\text{Outage Duration}]}{[\text{Resource Pmax}] * [\text{Total Hours}]}$$

where $[\text{Outage MW}]$ and $[\text{Outage Duration}]$ are specified in each of the Outage Reports across which outages are summed, $[\text{Resource Pmax}]$ is the Pmax or Net Dependable Capacity of the resource, and $[\text{Total Hours}]$ is the total number of hours in the most recent available four-year historic period.

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[29] https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators

Forced outage rates are determined similarly to maintenance rates, with the only distinction being which reported outages are included in the calculation. Whereas maintenance outage rates consider only reports flagged with the outage type “PLANNED” and the “PLANT_MAINTENANCE” nature-of-work, forced outage rates include reports with an outage type of “FORCED” and any nature-of-work except the following:

- NEW_GENERATOR_TEST_ENERGY
- RIMS_TESTING
- TRANSMISSION_INDUCED
- UNIT_TESTING

These excluded natures-of-work were selected as most likely to identify outages outside the control of a unit’s operator, but we recognize flexibility in OMS data standards and discrepancies in reporting practices among operators that make perfect confirmation of forced outages within this data set impossible.

The maintenance rates and the forced outage rates, both expressed as percentages, signify the proportions of hours a given facility undergoes maintenance or experiences a forced outage within a typical year. Each plant is assigned individual maintenance and outage rates in SERVM. SERVM then individually schedules each power plant for maintenance based on monthly demand and resource balance conditions to minimize reliability shortages while forced outage rates are stochastically created by drawing failure and time to repair from the entered distribution.

For this data update cycle, staff have made a change to the way SERVM schedules maintenance. In prior cycles, SERVM scheduled all maintenance to occur at times of low demand across an average of all weather years. For this update cycle, SERVM is configured to schedule up to 20% of available maintenance based on the particular weather year being simulated while the remaining 80% is scheduled based on all weather years in the model. Staff have found that weather events in particular historical weather years can be drivers of LOLE results and allowing the model to adjust a portion of maintenance schedules to avoid having maintenance during extreme weather can result in a material reduction in LOLE, while potentially reflecting operator foresight and planning. The 20% setting was chosen as a proxy representing some ability for system operators to adjust maintenance outages according to week-ahead weather forecasts.

For this data update cycle, staff have also added refueling outage representation for the nuclear units serving CAISO. Refueling usually occurs at approximately 18-month intervals for one unit of a given nuclear facility. Data was compiled from historical outage records to schedule the likely future refueling outages for Diablo Canyon and Palo Verde in SERVM.

4.3.1.2 Derating Thermal Plants due to Ambient Temperatures

CPUC staff developed a model to derate the output of thermal plants (gas-fired and geothermal) based on ambient temperatures. The model involves performing linear regression analyses of historic weather and curtailment data for each thermal plant to determine the best-fit coefficients for a set of deration curves, i.e., available percentages of resource capacity, as functions of ambient temperature. This function is shown below:

$$y_i = \beta_0 x_{0,i} + \beta_1 x_{1,i} + \epsilon_i$$

In this formulation, $y_i$represents an ambient deration value reported from a given unit simultaneously as temperature observation $x_{1,i}$, recorded at the nearest available weather station. The variable $x_{0,i}$ is set to a constant value of 1, and coefficients β_0 and β_1 are determined through regression analysis to minimize the sum of the squares of the error term ϵ_i across all hourly observations.

While the curtailment data include outages due to a variety of factors, only those indicated as “forced” outages which are “ambient due to temperature” are included in the analysis. The model is piecewise-linear, constrained to between 0% and 100% and applying the regression coefficients above to estimate derations as the following function of temperature:

$$\hat{y}_j = \min(\max(\beta_0 + \beta_1 x_j, 0\%), 100\%)$$

Where $\hat{y}_j$ represents an estimated ambient deration corresponding to a given temperature x_j. Limiting the estimated deration ensures units aren’t modelled as operating beyond their rated capacity due to a negative deration, nor as a net power consumer due to a deration above 100%, although such high derations are exceedingly unlikely.

This model is used to forecast derations based on historic weather data since 2000, before consistent outage data was available, to produce hourly deration factors which are then processed into SERVM weather year hourly profiles for derating each thermal power plant.

4.3.2 Hydro

SERVM models hourly hydro production based on 25 years (2000-2024) of monthly data from EIA Form 906/923 and multiple recent years of hourly data (2020-2024). Hourly data was collected from CAISO settlement data, BPAT, and EIA[30]. In the past, monthly hydro data was detrended for some regions, but recent examination of the detrending approach revealed longer time horizon patterns that suggest detrending may not be appropriate in some cases.

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[30] For hourly EIA data see: https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48

For the current hydro model, staff decided to avoid detrending historical monthly data, apart from adjusting for installed capacity.

Historical hydro data were translated into monthly generation, daily minimum, average, and maximum energy, and monthly maximum output constraints in SERVM to represent the seasonal and hourly patterns of large and small hydro energy generation for each historical hydro year in SERVM. Each of these variables is entered by month, historical hydro year (2000-2024), and region.

The hydro operating constraints were aggregated from the actual historical hydro production data for both large and small hydro, by region. Thus, each region that has hydro contains a single aggregate hydro unit to represent all the individual hydro units in that region. Two exceptions are the Hoover hydro generation unit and hydro in the PGE and SCE regions. Hoover was split into four units, proportional to the shares contracted to the SCE, AZPS, LADWP, and NEVP regions.

For the PGE and SCE regions, the hydro was split into large (scheduled, or non-run-of-river), small (run-of-river), and emergency hydro units for each region, respectively. The non-run-of-river (nROR) hydro is dispatchable while the run-of-river (ROR) hydro is not. The former retains the "Hydro" Unit Category in SERVM while the latter has the "Hydro_RoR" Unit Category to make their dispatch results separately viewable in model results. Additionally, staff defined emergency hydro units in PGE and SCE, respectively. SERVM has an emergency mode to allow "borrowing" energy from the future dispatch of scheduled hydro during hours under high price (stress) conditions, subject to an energy maximum. The emergency units are defined with monthly maximum output and availability dependent on hydro year. The emergency unit settings were determined by analyzing historical hydro production data and finding that hydro dispatched higher than average, coincident with some high load days when excess hydro production was available.

SERVM considers all of the constraints described above and develops a hydro schedule according to the hourly net load condition of the specific weather year, hydro year, and economic load forecast uncertainty level that will be simulated.

4.3.3 Energy Storage

In SERVM, storage units can be configured to prioritize energy arbitrage or system reliability and can commit available headroom and footroom to satisfying hourly operational reserve requirements. For storage devices, headroom and footroom are defined as the difference between the current operating level and maximum discharge or charge capacity (respectively). For example, a 100 MW battery charging at 50 MW has a headroom of 150 MW (100 – (-50)) and a footroom of 50 MW.

Reflecting lack of direct market signals and lack of insight into customer behavior, BTM storage devices are modeled as fixed profiles defined by the 2025 IEPR demand forecast, as described in section 4.2.2 above.

In SERVM, battery storage is modeled with a 90% of nameplate discharge range, except during scarcity hours when full discharge is allowed. This constraint was chosen to reflect real world behavior of operators seeking to avoid increased maintenance from operating batteries at their extremes regularly. Pumped storage hydro (PSH) units in SERVM do not have this constraint, though they do have individual charging capmax and discharging capmax values reflecting the individual limitations on the operation of the facility's pumps and turbines.

New (planned) or recently online battery storage is broadly assumed to have round-trip efficiency of 85% while new (planned) pumped storage is assumed to have round-trip efficiency of 81%. Existing pumped storage facilities have round trip cycle efficiencies generally between 60% and 70% and are sourced from the CAISO Master File.

Similar to the derivation of seasonal maintenance rates and forced outage rates for thermal units described earlier in section 4.3.1, staff used CAISO daily curtailment reports[31] to generate seasonal maintenance rates and forced outage rates for battery storage and PSH resources. However, storage resources are assumed unsusceptible to derations due to ambient temperatures.

4.4 Operational Reserve Requirements

SERVM models reserve products for each hour to ensure reliable operation during normal conditions (regulation and load following) and contingency events (frequency response and spinning reserve). Information on these requirements came from discussions with CAISO staff and is summarized below.

Reserves can be provided by available headroom or footroom from various resources, subject to operating limits (Table 11). For generators, headroom and footroom represent the difference between the current operating level and the maximum and minimum generation output, respectively. For storage resources, the operational range from the current operating level to maximum output (headroom) and maximum charging (footroom) is available, subject to constraints on energy availability. Reserves are modeled as mutually exclusive, meaning that headroom or footroom committed to one reserve product cannot be used towards other requirements. Regulation reserves can only be provided by resources that are on Automated Generator Control (AGC). If a resource is not on AGC, it is able to only provide spinning reserve.

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[31] http://www.caiso.com/market/Pages/OutageManagement/CurtailedandNonOperationalGenerators.aspx

Further, for storage resources, if they are on AGC they can provide regulation when charging as well as discharging. Individual resources may provide certain reserves, and it is not a good idea to generalize across a technology category. Age, technological limitations, or operator preference can determine which reserve services a generator can provide. Information for individual generators is sourced either from the ADS or CAISO Masterfile database.

Table 11. Reserve types modeled in SERVM

Product	Description	Modeling Requirement	Operating Limits
Regulation Up/Down	Frequency regulation operates on the 4-second to 5-minute timescale. This reserve product ensures that the system's frequency, which can deviate due to real-time swings in the load/generation balance, stays within a defined band during normal operations. In practice, this is controlled by generators on Automated Generator Control (AGC), which are sent a signal based on the frequency deviations of the system.	In SERVM this requirement is equivalent to 3% of hourly demand. Lack of sufficient capacity to provide regulation reserve leads directly to LOLE.	Gas-fired generators on AGC can provide available headroom/footroom, limited by their 10-minute ramp rate. Storage resources and hydro generators on AGC are only constrained by available headroom/footroom. Most other types of resources are not on AGC and cannot provide this service.
Load Following Up/Down	This reserve product ensures that sub-hourly variations from load, wind, and solar forecasts, as well as lumpy blocks of imports/exports/generator commitments, can be addressed in real-time.	In SERVM this is modeled as 6% of hourly demand each for load following up and down. Load following up and down are targets, not requirements however and do not lead directly to LOLE.	Gas-fired generators can provide all available headroom/footroom, limited by their 10-minute ramp rate. Storage resources and hydro generators are only constrained by available headroom/footroom.
Frequency Response	Resources that provide frequency response headroom must increase output within a few seconds in response to large dips in system frequency. Frequency response is operated through governor or governor-like response and is typically only deployed in contingency events.	770 MW of headroom is held in all hours on gas-fired, conventional hydroelectric, pumped storage, and battery resources. At least half of the headroom (385 MW) must be held on gas-fired and battery resources. This requirement is sourced directly from conversations with CAISO operators.	Reflecting governor response limitations, gas-fired generators can contribute available headroom up to 8% of their committed capacity. Wholesale battery storage, pumped storage, and conventional hydroelectric resources are constrained by available headroom.

Product	Description	Modeling Requirement	Operating Limits
Spinning Reserve	Spinning reserve ensures that enough headroom is committed on available resources to replace a sudden loss of power from large generation units or transmission lines. Spinning reserve is a type of contingency reserve.	This requirement is equivalent to 3% of the hourly CAISO load in SERVM. Lack of sufficient capacity to provide spinning reserve leads directly to LOLE.	Gas-fired generators can provide all available headroom, limited by their 10-minute ramp rate. Storage resources and hydro generators are constrained by available headroom/footroom.
Non-Spinning Reserve	Ensures that enough headroom is committed on available resources to replace spinning reserves within a given timeframe	Not modeled due to small impact on total system cost	N/A

4.5 Transmission Topology

SERVM transmission flow limits between regions in each direction were derived from the CAISO's PLEXOS model and Import Allocation process and further supplemented with information from the CEC's PLEXOS model. CAISO's PLEXOS model sources zonal flow ratings from the WECC 2034 ADS 1.0 dataset and path limits from the 2024 WECC Path Rating catalog. The CEC's PLEXOS model was used as a supplemental data source for paths that did not have enough geographic resolution in CAISO's dataset. Current transmission path settings between modeled regions in SERVM are posted to the CPUC website.[32] The posted file includes transmission capacity between regions in each direction as well as hurdle rates, both with and without GHG pricing added on to hurdle rates for transfers into California regions, all in 2022 real dollars. The GHG prices are derived from the mid scenario of the 2022 IEPR GHG price forecast though CPUC staff intend to update to the 2025 IEPR GHG Mid price forecast and inflate all cost parameters including hurdle rates to 2024 real dollars before conducting the 2028 LOLE study. There are no other updates for this 2026 data update cycle other than expanding the path between the SCE and SDGE regions to be non-binding under all conditions in 2035 and beyond, reflecting recently approved transmission upgrades from the CAISO's Transmission Planning Process. The following illustrative map shows some of the modeled transmission paths in SERVM with some paths modeled as one-way and some as bi-directional.

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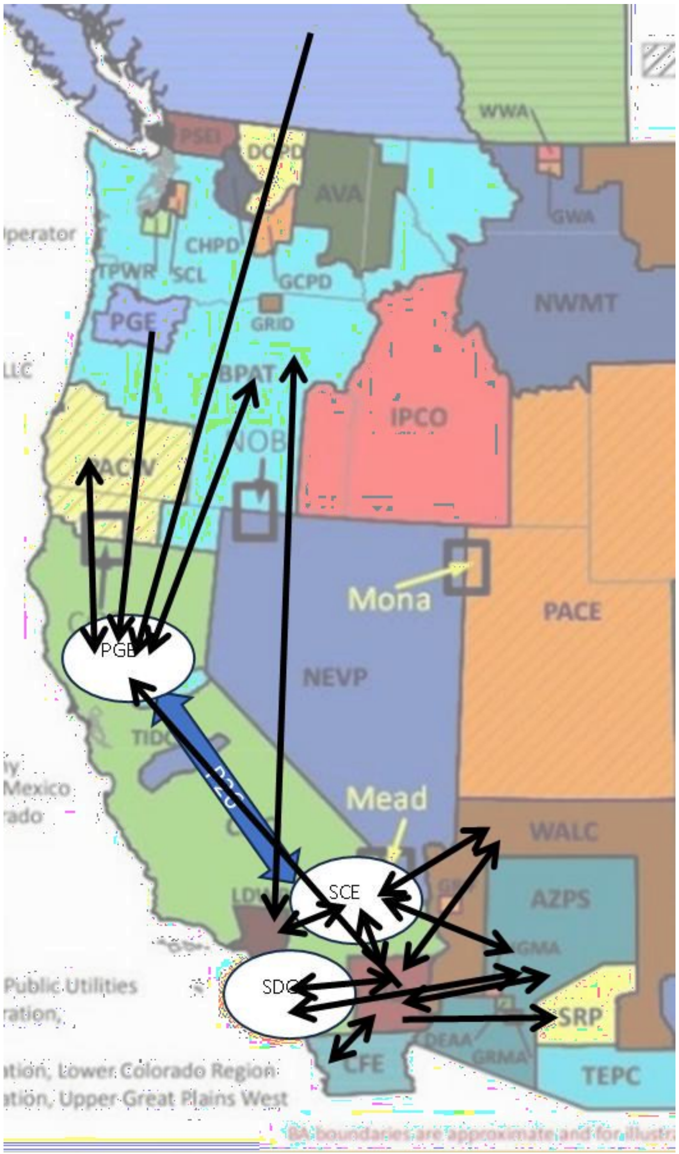
[32] https://files.cpuc.ca.gov/energy/modeling/2025_servm_updates/RegionTransferLimitsAndHurdles_2025Dec.xlsx

Figure 4: Illustrative Map Showing Abstraction of Transmission Between Regions into Directional Path Limits



4.5.1 Import and Export Constraints

In addition to the physical underlying transmission topology and individual path limits programmed into SERVM, staff use simultaneous net import and export constraints on the CAISO region. The export constraint is included to model uncertainty in the size of the future potential market for California’s exports of surplus renewable power and concerns about whether dispatch patterns and import/export patterns in SERVM are realistic and predictive of future patterns. The CAISO simultaneous net export limit is set at 5,000 MW and applies to all hours of the year.

The simultaneous import constraints are designed to cap flows to historically observed levels particularly at peak times so that the model produces realistic interchange patterns with regions neighboring the CAISO and to prevent overly optimistic leaning on other regions to support CAISO reliability. The simultaneous import constraints cover specified RA imports,[33] unspecified RA imports, and economic imports, but do not cover specified imports from three specific generators. These generators are modeled as generating directly within CAISO even though located outside the CAISO. They are the CAISO LSE shares of Hoover, SCE's 635 MW share of Palo Verde, and Sutter. The CAISO share of coal units at Intermountain were also previously modeled this way but that plant retired during 2025. A new generator that is under construction is the SunZia wind farm in New Mexico. This wind farm has firm rights to connect to the CAISO at Palo Verde for 2131 MW as a remote (specified import) generator before the generation tie is completed in 2035, and when that is complete the facility will be represented as completely within CAISO joining the other Hoover, Palo Verde, and Sutter units that already are represented that way.

There are currently two simultaneous import constraints used in the SERVM model. The first constraint is equal to the Maximum Available Import Constraint set at 11,040 MW, derived from CAISO RA import capability reports.[34] The second constraint caps imports at 4,000 MW from 5pm to 10pm, with 3-hour ramping to transition between the two constraints. The previous RA 2026 LOLE study applied the 4,000 MW simultaneous import constraint to all months of the year, since the objective was to surface LOLE in each month. Staff intend to apply the 4,000 MW simultaneous import constraint in all months for the RA 2028 LOLE study.

4.6 Fuel Costs

Monthly natural gas price inputs are derived from the preliminary 2023 IEPR burner tip price estimates from the CEC's North American Market Gas-trade (NAMGas) model runs.[35] SERVM simulates each region individually, and burner tip prices by hub are utilized directly in the model. Individual power plants are linked to their applicable fuel hub from the NAMGas model and monthly commodity price forecasts as well as fuel transportation rates are applied to the production cost of the generator. The 2023 vintage of natural gas price forecast has data through 2059 with three forecasts available, i.e., High Demand, Mid Demand, and Low Demand,

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[33] Specified RA imports are modeled in SERVM as "remote" generators, meaning units physically located in one region but contracted for energy and capacity to another region.

[34] CAISO Import Allocations, "Step 6: Assigned and Unassigned RA Import Capability on Branch Groups." http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

[35] https://www.energy.ca.gov/programs-and-topics/topics/energy-assessment/natural-gas-electric-generation-prices-california-and

corresponding to Low, Mid, and High natural gas prices, respectively. The Mid scenario is used for fuel and transportation costs. Coal and uranium prices are based on the forecasted prices in the 2023 Annual Energy Outlook[36] using data in that document's Table 3.9 for the Pacific zone and Table 3.8 for the Mountain zone. In SERVM nuclear power plants are currently modeled as a must-run resource;[37] therefore, uranium fuel prices do not impact nuclear generation dispatch results.

Biomass fuel costs of $15/MMBtu were taken as the median of the value range provided in an NREL Biomass technology report.[38]

The prior RA 2026 LOLE study used the same vintage of fuel price and transportation cost data as described above, however, at the end of 2024 staff improved the matching between the NAMGas model and SERVM inputs for fuel hub, units associated with a fuel hub, and the transportation costs seen by each unit. The upcoming RA 2028 LOLE study will use these improvements.

Finally, the fuel and transportation costs described above were characterized in 2022 real dollars in SERVM. Before conducting the RA 2028 LOLE study, all these costs will be inflated to 2024 real dollars in SERVM.

4.6.1 Emissions Price Forecast

Staff will continue to model emissions prices to affect the cost of dispatching emitting generation. Staff has added the CEC's 2025 IEPR GHG Price Projection Mid scenario to SERVM and intends to use it for the RA 2028 LOLE study with prices in 2024 real dollars.

5. Resource Adequacy Modeling

5.1 Overview

The CPUC uses SERVM for resource adequacy and reliability studies across multiple proceedings.[39] In the CPUC's IRP proceeding context, the RESOLVE capacity expansion model and SERVM are used together to develop and test optimal portfolios to ensure that the CAISO

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[36] Annual Energy Outlook 2023. https://www.eia.gov/outlooks/aeo/

[37] Nuclear power plants are characterized by high capital costs relative to fuel costs and are therefore, economically incentivized to run at high-capacity factors. This is likely true for more operationally flexible nuclear generator types (e.g., small modular reactors) as well based on existing cost data.

[38] https://www.energy.gov/sites/default/files/2018/11/f57/robi-biomass.pdf

[39] Resource adequacy is referred to here in a broad sense, rather than with specific reference to the CPUC RA program.

system reliability level does not exceed 0.1 day per year Loss of Load Expectation (LOLE), equivalent to satisfying the Commission's 1-day-in-10-year reliability standard in the IRP proceeding. SERVM is used to measure the amount of effective capacity required to meet the 0.1 LOLE reliability standard in the CAISO system. The required level of effective capacity (or perfect capacity equivalent) is a measure of the system's Total Reliability Need (TRN). Portfolios selected in RESOLVE's capacity expansion module are constrained to meet or exceed the TRN calculated in SERVM. The resulting portfolios are then retested in SERVM to verify they still meet the 0.1 LOLE reliability standard.

In the CPUC's Resource Adequacy (RA) proceeding context, SERVM is used to conduct annual reliability assessments that complement the Slice-Of-Day and monthly Planning Reserve Margin frameworks. SERVM can be used to support ongoing reform under consideration in the RA proceeding, including assessment of the proper reliability risks to include in planning assessments, how to create optimal study cases, and the most optimal way to surface or alleviate LOLE risk.

5.2 Reliability Risks and PRM Studies

LOLE studies are meant to assess potential risks across a range of potential risk drivers, each with their own unique distributions and probabilities. Common risks include weather variability which affects electric demand, hydroelectric production and wind and solar production. Other common risks include stochastic unit forced outages and maintenance, internal transmission constraints, and energy trading with neighboring BAs. Most of these risks are dealt with by development of modeling data and are discussed earlier in this document. This section seeks to lay them out in a list for parties to consider for inclusion. A key risk that raised comments in 2025 as the previous study results were considered was the correct modeling of economic and demographic growth.

Key reliability risks to be included in the 2028 LOLE study for RA:

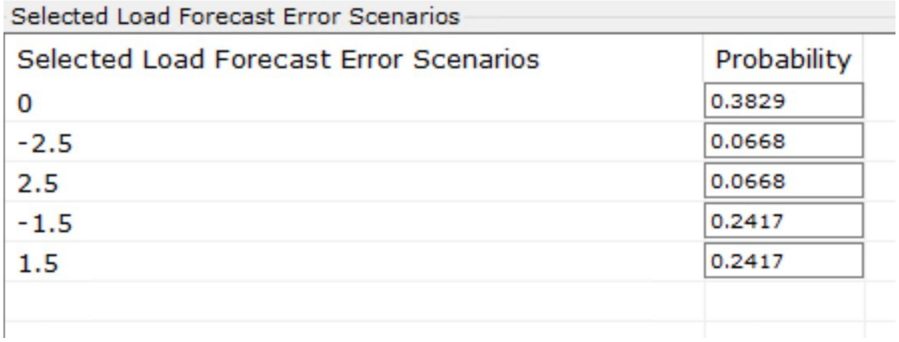
- Weather variability in demand, wind and solar
- Hydro variability
- Unit Forced Outages
- Purchases and Sales from Neighboring Regions
- Economic and Demographic Risk

5.3 Economic and Demographic Risk

Economic and demographic growth are core drivers of electric demand, and a median forecast of growth is a core part of the IEPR each year. Uncertainty is larger in future years, but present at smaller scales even in the near term, meaning it is reasonable to plan for this uncertainty in the 2028 LOLE study. Economic uncertainty could mean growth or decline in business demand caused by a boom or recession, or a structural change in the nature of economic activity like the internet boom or growth in AI. Demographic growth could increase or slow relative to the IEPR forecast if housing becomes more affordable, there are extreme weather events or natural disasters that encourage migration, or a healthy economy may attract additional residents to the state at rates greater or lower than forecasted in the IEPR. This uncertainty has significant impact on both the peak demand forecast, but also total energy and the hourly shape of electric demand.

In past studies, CPUC staff have included five points of economic and demographic uncertainty and associated probabilities in order to create a distribution that can account for this uncertainty. Staff have used the following uncertainty levels and probabilities in past studies.

Figure 5: Load Forecast Uncertainty Probability-Weighted Scenarios



Selected Load Forecast Error Scenarios

Selected Load Forecast Error Scenarios	Probability
0	0.3829
-2.5	0.0668
2.5	0.0668
-1.5	0.2417
1.5	0.2417

Some parties such as Southern California Edison (SCE) and California Community Choice Association (CalCCA) commented that the level of economic and demographic growth uncertainty factors (called Load forecast errors in the table above) exceeded realistic levels for near-term studies (such as 2028). During follow-up communications with CPUC staff, they proposed alternative lower assumptions. Instead of the current uncertainty distribution in SERVM shown above, they proposed implementing an approach to economic load uncertainty described in a 2025-2026 LOLE Study Report produced by the Midcontinent Independent System Operator (MISO).[40] MISO's study includes economic uncertainty, excludes demographic uncertainty, and has a narrower distribution of uncertainty around the load forecast. CPUC staff agree that this narrower distribution of uncertainty is reasonable for a near-term study of 2028 and will therefore run a sensitivity study using this approach in addition to the existing CPUC staff approach. Table 12 below shows the distributions. In general, staff is open to having a narrower distribution for near-term studies (e.g. 2028) and a wider distribution for long-term studies (e.g. 2035 and beyond).

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[40] MISO study linked here: https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401

Staff supports a more thorough review of the economic and demographic uncertainty parameters for use in future RA and IRP studies. For future I&A processes, staff will consider collaborating with the CEC on developing these parameters and socializing the results of this exercise with parties via future LOLE study I&A documents.

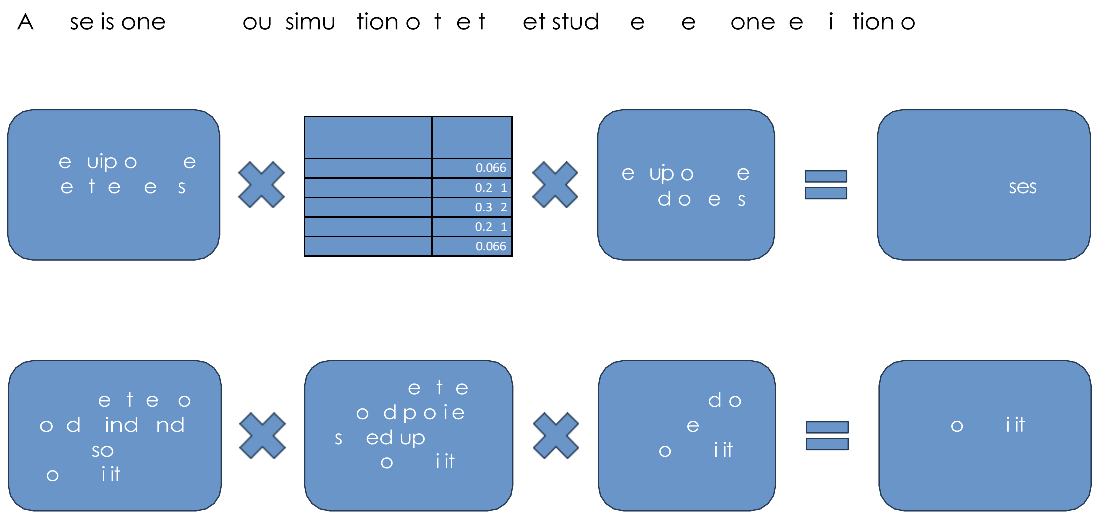
Table 12: CPUC staff proposed econ/demo factors versus MISO proposed factors

CPUC Staff Draft I&A		**MISO 2025-2026 LOLE Study**	
Load forecast error	Probability	Load forecast error	Probability
2.5%	0.0668	2.0%	0.0090
1.5%	0.2417	1.0%	0.2050
0%	0.3829	0.%	0.5730
-1.5%	0.2417	-1.0%	0.2050
-2.5%	0.0668	-2.0%	0.0090

5.4 Creation of Study Cases

CPUC staff simulate multiple, probability-weighted cases to assess reliability, each a unique combination of weather year, economic and demographic uncertainty and hydroelectric production. The diagram below illustrates the buildup of 2,645 cases for a single simulation of 2030, which would result in probability-weighted average reliability, cost, and GHG results that are indicative of the full distribution of all 2,645 cases. Since CPUC staff have finite computing resources, there is a tradeoff between the number of cases and how many iterations of each case are possible. One iteration is one 8760 hour simulation with a random draw of units on forced outage. Running a high number of cases can cover a broad range of scenarios, but at the cost of reducing the opportunity to run each individual case at sufficient iterations to fully converge each case (convergence means running additional iterations does not change the expected results of that specific case in a statistically significant way).

Figure 6: Illustrative Buildup of Probability-Weighted Cases



i o ni u i ti ities ommission

In the example above Staff do not assume that hydro performance (and hydro abundance in general) is tied to other weather dynamics, such as overall temperature, wind, and solar performance. This means that any weather year may be combined with any hydro year to form a particular realization of an operating year in SERVM simulations, e.g. 2010 weather for electric demand and wind and solar production can be combined with 2005 hydro patterns.

However, as Staff moves to include two more weather years, that increases the number of cases from 23*23*5=2,645 to be even greater with 25*25*5=3,125 cases. Staff observations from prior modeling work show that weather year variation is the dominant mover of EUE and LOLE while hydro year variation is much less so. This may mean that simulating each weather year with each hydro year may not yield additional distinct results and would prevent further convergence of individual cases due to the high number of cases simulated.

Staff intend to simulate each weather year together with the same year hydro year and instead increase the number of iterations (random outage draws) during SERVM simulation to arrive at a sufficiently large and diverse set of realizations of a given study year to make statistically valid observations in model results. In other words, the number of probability-weighted cases will be 25*5=125 cases but each case will now be run with 25 randomly determined outage draws, increasing the likelihood of statistically convergent results for each case. Staff expects this new simulation setup will have about the same run time as the prior setup.

5.5 Surfacing Annual and Monthly LOLE – Monthly LOLE Stress Test

Staff are conducting a LOLE study to determine the proper level of reserves to maintain the CAISO area at one day in ten years LOLE (0.1 LOLE) reliability target. Calibration to LOLE levels (especially in individual months) may be needed, either to raise or lower LOLE. In previous LOLE studies, such as the one performed in 2024 for the 2026 study year, staff lowered the simultaneous import constraint to raise LOLE since the original LOLE study was over reliable. In addition, once the overall annual study was calibrated to 0.1 LOLE (with all LOLE in September) staff used blocks of "Perfect Demand" (modeled as a "Negative Operating Unit (NOU)") to raise LOLE in individual months. Staff did not need to lower LOLE in any months, as all months were over reliable.

In the draft Inputs and Assumptions document released on April 10, staff gave stakeholders the chance to comment on our proposed alternative approaches. Stakeholders provided suggestions and refinements to the list, with SCE and Alliance for Retail Energy Markets (AREM) recommending to remove or broaden the approach of removing existing generation to surface LOLE. Each approach carries pros and cons. Overall, staff seek to ensure that LOLE across the entire 12 months still totals about 0.1 while being able to find a minimum reserve margin in each month. Staff will concentrate LOLE in the summer months of June through September and ensure that LOLE is 0 or only slightly above 0 in the other months of the year, using the same "Stress Test" approach[41] developed in the previous modeling cycle.

If Annual LOLE is higher than 0.1:

If the 2028 electric system is found to be unreliable (annual LOLE > 0.1), staff will reduce LOLE in individual months by adding Perfect Capacity (PCAP).

If Annual LOLE is lower than 0.1:

If the 2028 electric system is found to be over reliable (annual LOLE < 0.1), staff will increase LOLE through each of the following methods and show results for each method interpreted through the PRM Calibration Tool.

1. Adding Perfect Demand (aka Negative Operating Unit or NOU)
2. Reducing capacity pro rata across all tech types instead of just removing aging thermal
3. Lowering the CAISO simultaneous import limit.

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[41] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/2026_lole_final_report_07192024.pdf

Staff will include both a UCAP derated PRM and a non-UCAP derated PRM in the final LOLE study results.

6. Emissions Accounting

6.1 Greenhouse Gas Accounting

Greenhouse gas (GHG) emissions attributable to entities within the CAISO footprint are tracked using a method consistent with the California Air Resources Board's (CARB) regulation of the electric sector under California's cap & trade program.

6.1.1 CAISO Internal Generators

The annual emissions of generators within the CAISO are calculated as part of the dispatch simulation based on (1) the annual fuel consumed by each generator; and (2) an assumed carbon content for the corresponding fuel. Generators internal to CAISO are tracked individually and emissions are calculated based on their actual dispatch as all generation from these generators serves CAISO demand.

6.1.2 CAISO Imports

Emissions for generation external to CAISO and imported into CAISO are given a deemed emissions rate for unspecified imports as determined by CARB. The assumed carbon content of imports based on this deemed rate is 0.428 metric tons per MWh[42]—a rate slightly higher than the emissions rate of a combined cycle gas turbine.

Specified imports (called direct purchases in SERVM) to CAISO are modeled as balancing CAISO load, therefore any emissions associated with specified imports are included with emissions associated with CAISO generators. Most of the specified imports to CAISO are non-emitting resources, though imports from the coal-fired Intermountain Power Plant are simulated through the mid-2020s.

A fraction of the total Pacific Northwest hydro capacity is made available to CAISO as a directly scheduled import. Specified hydro imports from the Pacific Northwest are included as a reduction in annual electricity supply GHG emissions based on an estimate of hydro generation imported as part of the total unspecified import total. The quantity of specified hydro imported into California is based on historical import data from BPA and Powerex as reported in CARB's

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[42] Rules for CARB's Mandatory Greenhouse Gas Reporting Regulation are available here: https://ww2.arb.ca.gov/mrr-regulation

GHG emissions inventory.[43] Both SERVM and the RESOLVE model assume 8.31% of total NW hydro is GHG free hydro imported to CAISO and modeled as a remote generator subject to transmission constraints but no hurdle or emissions. This is separate from other unspecified imports that may flow from the NW which would have the deemed 0.428 metric tons per MWh emission factor and be subject to the corresponding transmission constraint and hurdle rate plus GHG price.

6.1.3 BTM CHP Accounting

CARB Scoping Plan electric sector emissions accounting includes emissions from behind-the-meter CHP generation. BTM CHP is represented as a load reduction in SERVM, and therefore emissions from BTM CHP are not explicitly modeled (no fuel is burned in the model corresponding to BTM CHP). To be consistent with CARB's Scoping Plan accounting conventions, staff will estimate BTM CHP emissions from the 2025 IEPR forecast of BTM CHP generation and combine that with modeled emissions from all other generation to determine the GHG emissions total attributed to the CAISO footprint.

6.2 Criteria Pollutants Accounting

The following description of how criteria pollutants can be analyzed from SERVM study results is unchanged from the prior version of RA Inputs and Assumptions. Staff have not repeated an analysis of criteria pollutants since this April 2024 Revised Supplemental Criterial Pollutant Analysis, performed during the 2022-2023 IRP Cycle.

6.2.1 Natural Gas and Coal Plants

Criteria pollutants are calculated in SERVM by dispatching power plants, tracking their emissions on startup and steady state operation, and separating emissions by technology type and operational mode. In the case of SO_2 and PM 2.5, emissions are a factor of the fuel consumed, thus tracking emissions is done by tracking fuel consumed in startups and steady state operation. In the case of NOx emissions, there is a separate reaction between the combustion temperature and nitrogen in the ambient air, meaning emissions differ at different levels of operation. Thus, there are different emissions factors for different kinds of startups (cold, warm, hot) and for steady state operations. CPUC staff also report criteria pollutant results in Disadvantaged Community areas (DAC areas) in order to track impact and improvement of impact in pollution over time and IRP cycles.

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[43] CARB GHG Current California Emission Inventory Data available at: https://ww2.arb.ca.gov/ghg-inventory-data

SOx and PM 2.5 emissions factors are presented as lbs per MMBtu of fuel burned, while NOx emissions factors are presented as lbs per MWh generated.

Table 13: NOx emissions factors (lbs/MWh)

Unit Category	steady_state_nox_ef lbs/mwh	hot_start_ef lbs/mwh	warm_start_ef lbs/mwh	cold_start_ef lbs/mwh
CC	0.081	0.256	0.837	1.417
CT	0.171	0.154	0.739	1.323
ICE	0.500	0.154	0.739	1.323
Cogen	0.241	0.154	0.739	1.323
Steam	0.150	0.154	0.739	1.323
Coal	0.713	2.469	2.965	3.461

Table 14: SOx and PM2.5 Emissions Factors (lbs/MMBtu)

Unit Category	SO2 lbs/MMBtu	PM2.5 lbs/MMBtu
CC	0.001	0.007
CT	0.001	0.007
ICE	0.001	0.010
Cogen	0.001	0.007
Steam	0.001	0.008
Coal	0.085	0.020

6.2.2 Biomass and Biogas Plants

For criteria pollutant analysis, biomass plants were studied separately as the emission factors for biomass and biogas are different. For biomass, criteria pollutant emissions were calculated based on factors estimated by Argonne National Lab and included in a report issued in 2020. The report estimates emissions in g/kWh electricity generation.[44] These values represent a change from the previous IRP Inputs and Assumptions document published in 2023 and are due to ongoing research into emissions factors for electric generators.

Table 15: Emission Factors for Biomass (g/kWh)

Unit Category	Nox_ g/kWh	PM2.5_ g/kWh	SOx_ g/kWh
BIOMASS/WOOD	0.752449	0.073985	0.060309

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[44] Argonne National Lab report linked here: https://publications.anl.gov/anlpubs/2020/09/162084.pdf

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