California ISO

2026
SUMMER LOADS AND RESOURCES ASSESSMENT
TECHNICAL APPENDIX

May 4, 2026

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Acronyms

BAA	Balancing Authority Area	MWh	Megawatt-hour
CAISO	California Independent System Operator	NERC	North American Electric Reliability Corporation
CEC	California Energy Commission	NQC	Net Qualifying Capacity
COD	Commercial Operation Date	OASIS	Open Access Same-Time Information System
CPUC	California Public Utilities Commission	OOS	Out Of State
DEBA	Distributed Electricity Backup Assets Program	OR	Operating Reserves
DSGS	Demand Side Grid Support Program	OTC	Once-Through-Cooling
DWR	Department of Water Resources	PDR	Proxy Demand Response
EEA	Energy Emergency Alert	PG&E	Pacific Gas and Electric
ELCC	Effective Load Carrying Capability	PRM	Planning Reserve Margin
ELRP	Emergency Load Reduction Program	PSP	Preferred System Plan
ESSRRP	Electricity Supply Strategic Reliability Reserve Program	PDT	Pacific Daylight Time
EUE	Expected Unserved Energy	PST	Pacific Standard Time
F	Fahrenheit	PTO	Participating Transmission Owner
HE	Hour Ending	NQC	Net Qualifying Capacity
IEPR	Integrated Energy Policy Report	RA	Resource Adequacy
IOU	Investor-Owned Utility	RDRR	Reliability Demand Response Resource
IRP	Integrated Resource Planning	SCE	Southern California Edison
LOLE	Loss-of-Load Expectation	SDG&E	San Diego Gas and Electric
LOLH	Loss-of-Load Hours	SOC	State of Charge
LSE	Load Serving Entity	WECC	Western Electricity Coordinating Council
MW	Megawatt	WEIM	Western Energy Imbalance Market

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1 Loads and Resources

In this chapter, the ISO provides details on resource development and load forecasts that support the analysis presented in Chapter 1 of the 2026 Summer Assessment report.[1] Section 1.1 provides an update on existing and expected resources available for summer 2026. Section 1.2 shows the ISO's near-term load projections based on the CEC's 2025 IEPR demand forecast.

1.1 Supply Conditions for 2026

In this assessment, the ISO considers both existing and in-development resources expected to be available to serve demand during the forecasted summer peak in 2026. For existing resources, the ISO reports resource capacity based on their Net Qualifying Capacity (NQC)[2] and Net Dependable Capacity (NDC)[3] or installed capacity. The ISO identifies new resources as those projects in the late stages of the interconnection process that are estimated to be near to achieving commercial operation (COD). The ISO expects about 6,194 MW of NDC to be added to the grid by June 30, including 1,354 MW of battery and 1,370 MW of solar, and 3,467 MW of wind (including 3,167 MW of SunZia Wind in New Mexico).[4]

1.1.1 Existing Resources

Table 1.1 shows existing resource capacity by fuel type with their corresponding NQC and NDC totals and the amounts of each resource type by deliverability status. The table excludes pseudo-tie and dynamic import resources outside of the CAISO BAA, which total around 9,200 MW. Deliverability is a measure of the transmission system's ability to deliver energy to the grid in times of critical system need. The study process results in each resource being assigned either Full Capacity, Interim Deliverability, Partial Deliverability or Energy Only deliverability statuses.[5]

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[1] 2026 Summer Loads and Resource Assessment, May 4, 2026: https://www.caiso.com/library/seasonal-assessments

[2] Each resource has a qualifying capacity (QC) and net qualifying capacity (NQC). Qualifying capacity values are fuel-type specific and are set using methodologies determined by the appropriate local regulatory authority (LRA). The NQC value is resource-specific and is determined by the CAISO based on the QC and the deliverability status of the resource. NQC provides a reasonable estimation of a resource's capability to serve system needs in critical hours.

[3] Net dependable capacity is the maximum continuous net output of a generating unit (net of auxiliary load), considering seasonal de-rates.

[4] Expected new resources are calculated relative to existing resources in Table 1.1 as of March 2026 NQC list.

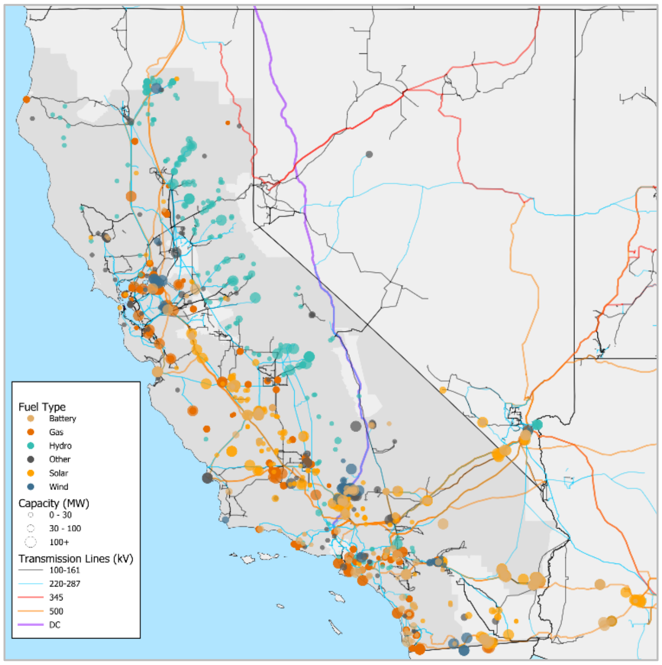
[5] *Full Capacity* deliverability status entitles a generating facility to a NQC amount that could be as large as its QC amount and may be less pursuant to the assessment of its Net Qualifying Capacity by the CAISO.
Interim Deliverability allows an interconnection customer that has requested Full Capacity or Partial Capacity deliverability status to obtain non-zero NQC pending the in-service date of all the required network upgrades required for its requested deliverability status.
Partial Capacity deliverability status entitles a generating facility to a NQC amount that cannot be larger than a specified fraction of its QC amount, and may be less pursuant to the assessment of its NQC amount by the CAISO.
Energy only is a condition elected by an interconnection customer for a generating facility interconnected with the CAISO-controlled grid where the generating facility will be deemed to have a NQC of zero, and, therefore, cannot be considered a resource adequacy resource.

The technology factor is based on historical performance by fuel type during each month of the year and results in a resource being assigned a NQC value. For dispatchable resources like battery and natural gas plants, the NQC value is typically near its NDC or installed capacity. For intermittent resources like wind and solar, NQC values are typically lower because the output of these resources are weather-dependent.

Table 1.1 Existing resources by fuel type and deliverability status (excludes tie-generators)[6]

Deliverability	Full Capacity		Interim Deliverability		Partial Deliverability		Energy Only		Total	
Fuel Type	**NDC**	**NQC**	**NDC**	**NQC**	**NDC**	**NQC**	**NDC**	**NQC**	**NDC**	**NQC**
Battery	8,864	8,764	4,131	3,977	1,059	624	78	0	14,131	13,365
Biogas	228	160					19	0	247	160
Biomass	421	332					8	0	429	332
Distillate	110	110							110	110
Geothermal	1,217	1,071			137	137			1,354	1,208
Hybrid	550	466	1,185	861	308	157			2,043	1,484
Hydro	9,057	6,295			2	0	17	0	9,076	6,295
Natural Gas	25,782	24,780	417	411	755	675	4	0	26,958	25,866
Nuclear	2,300	2,280							2,300	2,280
Other	451	42							451	42
Solar	11,612	4,611	3,296	1,189	3,127	703	2,424	0	20,459	6,503
Waste Heat	35	23							35	23
Wind	6,068	1,344	256	57			6	0	6,330	1,401
Total	**66,694**	**50,279**	**9,285**	**6,495**	**5,388**	**2,295**	**2,556**	**0**	**83,922**	**59,069**

Figure 1.1 ISO balancing area existing resources as of February 12, 2026



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[6] Existing resources data is sourced from the more recent March 2026 NQC list and accounts for known retirements in 2026. The table excludes SRR gas units, participating loads and any demand response resources.
The expected new resources are calculated relative to existing resources and captures any changes in resource status (e.g. declared COD). This way the total modeled capacity for existing and new resources is accounted for accurately.
September NQC values are used and installed capacity in NDC calculated as of April 1, 2026 from Master file.

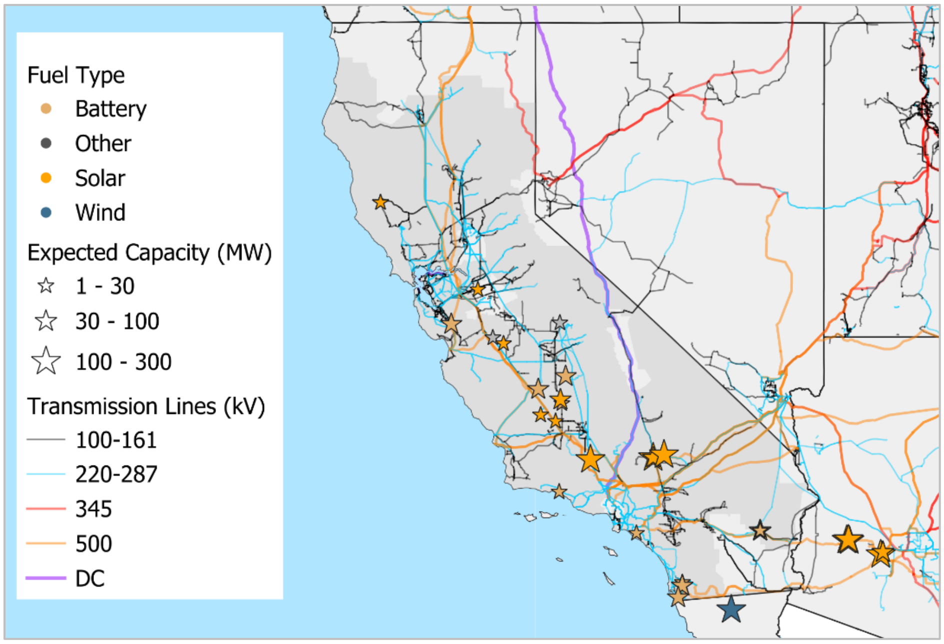
1.1.2 Expected Resources

In addition to existing resources, the ISO expects several in-development resources to come online by June 30, 2026. As shown in Table 1.2, there are about 1,354 MW of battery, 1,370 MW of solar, 3,467 MW of wind, 1 MW of hybrid, and 2 MW of other Biofuel resources (NDC values) have a high likelihood of declaring commercial operation by June 30, 2026. Wind additions includes ISO's share of SunZia Wind in New Mexico of about 3,167 MW going live as of May 1, 2026. The ISO used a set of criteria based on New Resource Implementation (NRI) status and target COD to determine whether to count a project as available for the summer. NRI status indicates the development stage of a resource as it progresses through construction and testing towards being fully commercially available. Notable NRI status labels are Active (under construction), SYNC (permission to connect to the grid and begin to test injecting energy at the point of interconnection), COMX (a resource at partial capacity may begin to participate in the market before full capacity is available), and COD (fully commercially online). All SYNC and COMX resources with target COD's before June 30, 2026 count as available in this assessment, while only those Active resources on the CAISO NQC list as of April 1, 2026 are counted.

Table 1.2 Expected additions from April 1, 2026 through June 30, 2026 (MW)[7]

Resource Additions	Battery	Wind	Solar	Biofuel	Hybrid	Total Nameplate Capacity (MW)
Expected additions by June 30 (as of April 1, 2026)	**1,354**	**3,467**	**1,370**	**2**	**1**	**6,194**
Internal	1,354	300	1,370	2	1	*3,028*
External		3,167				*3,167*

Figure 1.2 ISO balancing area expected new resources by June 30, 2026



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[7] Expected new resources are calculated relative to existing resources in Table 1.1 as of March 2026 NQC list.

1.1.3 Emergency Resources

For summer 2026, supply accessible through the Electricity Supply Strategic Reliability Reserve Program (ESSRRP) and emergency assistance on the interties totals around 3,379 MW. As stated earlier, the CEC and CPUC will provide estimates of state emergency demand response programs and other contingency resources in the CEC's California Reliability Outlook published in May 2026. The CAISO details processes for operation of various emergency resources in the CAISO's Emergency Procedure 4420.[8]

Following the extreme and widespread heat events of 2020, the CAISO, the California Legislature, and state entities have taken several measures to ensure grid reliability under extreme events, beyond conventional planning standards. These measures and programs include pursuing and approving procurement of additional resources, retaining existing resources in service, and improving operational readiness measures to access resources or load reductions when the risk of shortfalls exists. Several emergency resource programs have also emerged since summer 2021, which provide grid support during system emergencies and extreme events. These programs include both conventional generation assets and voluntary load reduction programs administered by state agencies such as the Department of Water Resources (DWR), the CPUC and the CEC. Many of these programs are triggered by various CAISO emergency notifications.

Table 1.3 Emergency supply accessible through various programs

<table>
<tr><th>Program</th><th>Description</th></tr>
<tr><td>**Strategic Reliability Reserve (SRR)**
The SRR was developed in 2022 under Assembly Bill 205 to expand resources capable of managing or reducing demand during extreme events. The SRR provides funding to secure additional resources to address extreme events beyond traditional</td><td>**Electricity Supply Strategic Reliability Reserve Program (ESSRRP)** [9]: DWR oversees the ESSRRP to provide additional generation during extreme events to support grid reliability in California BAAs.
<table>
<tr><th>Resource Name</th><th>BAA</th><th>Max Capacity (MW)</th></tr>
<tr><td>Alamitos Gen Sta. Unit 3</td><td>CISO</td><td>326.8</td></tr>
<tr><td>Alamitos Gen Sta. Unit 4</td><td>CISO</td><td>334.4</td></tr>
<tr><td>Alamitos Gen Sta. Unit 5</td><td>CISO</td><td>480.0</td></tr>
<tr><td>Huntington Beach Gen Sta. Unit 2</td><td>CISO</td><td>226.8</td></tr>
<tr><td>Ormond Beach Gen Sta. Unit 1</td><td>CISO</td><td>741.3</td></tr>
<tr><td>Ormond Beach Gen Sta. Unit 2</td><td>CISO</td><td>750.0</td></tr>
<tr><td>Channel Islands Power</td><td>CISO</td><td>27.5</td></tr>
<tr><td>Greenleaf 1</td><td>CISO</td><td>49.2</td></tr>
<tr><td>Enchanted Rock (Lodi & Claribel)</td><td>CISO</td><td>96 (48 MW each)</td></tr>
<tr><td>Enchanted Rock Marshall Unit 1-4</td><td>TIDC</td><td>46.8 (11.7 MW each)</td></tr>
<tr><td colspan="2">**Total ESSRRP Capacity (MW)**</td><td>**3,078.8**</td></tr>
</table>
In August 2023, the State Water Board extended the once-through cooling (OTC) policy compliance dates for Alamitos, Huntington Beach, and Ormond Beach generating</td></tr>
</table>

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[8] CAISO Operating Procedure 4420, System Emergency: http://www.caiso.com/Documents/4420.pdf

[9] Draft 2026 Report of the Statewide Advisory Committee on Cooling Water Intake Structures, pp. 12, March 20, 2026: https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/2026/saccwis-26dfrpt.pdf

resource planning targets.	stations for three years from December 31, 2023, to December 31, 2026, contingent on these resources participating in the ESSRRP. These OTC resources represent about 2,859 MW of generating capacity through the end of 2026, which will help to maintain electric grid reliability during extreme events. These resources are offline, except for testing or until a California balancing area issues an EEA or the CAISO balancing area determines that exceptional dispatches of these long-start resources are necessary to address system operations.
	Demand Side Grid Support (DSGS) Program: The CEC administers the DSGS program. This program provides incentives for electric customers to provide load reduction and backup generation to support grid reliability during extreme events from May through October. DSGS program participants can select different incentive options for each eligible load reduction resource type.
	Distributed Electricity Backup Assets (DEBA) Program: The CEC administers the DEBA program. This program incentivizes the construction of clean and efficient distributed energy assets that serve as emergency supply or load reduction for the electric grid during extreme events. The DEBA program is a statewide program, intended to procure clean and efficient distributed energy assets that will serve as on-call emergency supply or load reduction during extreme events. Since August 2024, the CEC has approved 9 grant agreements under the DEBA program. The projects related to these grant agreements are expected to come online through summer 2027, but no contingency resources are expected to be online in summer 2026.
Emergency Load Reduction Program (ELRP)	ELRP is a five-year demand response pilot program managed by the state's three investor-owned utilities (IOUs) – PG&E, SCE, and SDG&E. It is a voluntary demand response program designed to compensate customers for reducing energy consumption in the summer months (May - October) during a grid emergency. As a voluntary program, there are no penalties to customers for non-participation and no requirements to reduce load by a particular amount during an ELRP event. ELRP events are triggered by the CAISO's emergency notifications or, in some cases, a CAISO-issued Flex Alert.
Emergency Assistance on the Interties	The CAISO is authorized to take actions during system emergencies on whether to receive or provide emergency assistance on the interties in the real-time market.[10] Imports coming from emergency assistance reflect energy imported from neighboring BAAs with whom the CAISO has contractual agreements during emergency conditions. For summer of 2026, the CAISO projects about 300 MW of emergency assistance available on the interties.

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[10] CAISO Operating Procedure 4410, Emergency Assistance: http://www.caiso.com/Documents/4410.pdf

1.2 CEC's Near-Term Load Projections

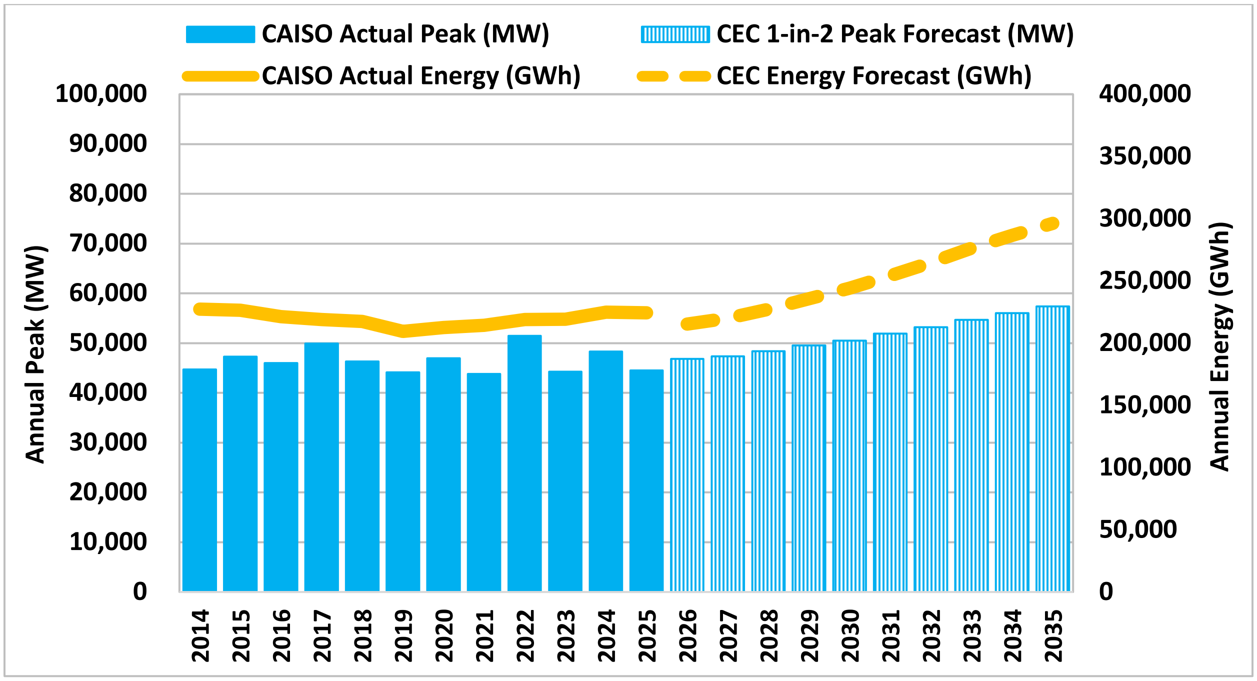
The ISO's near-term load projections rely on the CEC's 2025 IEPR demand forecast using the managed load from 1-in-2 planning forecast. The planning forecast is used by the ISO and state agencies for electricity system-level planning activities. It represents the CEC's estimates of baseline economic, demographic, and price scenarios, as well as "mid-level" impacts of energy efficiency, building electrification, and transportation electrification.[11] Table 1.4 shows 2026 summer monthly peak load forecasts for the ISO BAA. The table shows that CEC forecasted peak load for 2026 occurs in September.

Table 1.4 Monthly peak load forecast (May 2026 – October 2026)

Month	May	June	July	August	September	October
Monthly peak load forecast (MW)	31,029	41,537	46,301	45,511	46,844	37,888

Figure 1.3 shows that from 2014 to 2025, ISO's actual annual peak demand fluctuated between 43,789 MW and 51,479 MW while its actual annual energy consumption varied from 209,429 GWh to 227,309 GWh. The figure also shows CEC's ISO 1-in-2 peak demand forecast[12] of 46,844 MW in 2026 increases gradually by 8 percent to 50,498 MW in 2030. In addition, the CEC is also projecting ISO's annual energy in 2026 to be 215,318 GWh with an increase to 244,110 GWh by 2030.

Figure 1.3 ISO historical and projected annual peak load and energy (2014 – 2035)



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[11] CEC, 2025 Integrated Energy Policy Report, Hourly Demand Forecast Files: https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2025-integrated-energy-policy-report-0

[12] A 1-in-2 forecast assumes a 50 percent probability that actual peak load will be higher than the forecasted peak and a 50 percent probability that it will be lower.

2 Probabilistic Modeling Assumptions

This chapter discusses probabilistic assessment's resource portfolio capacity assumptions as well as resource modeling considerations, operational attributes/constraints, stochastic profiles (solar, wind, load and outages), and details on ancillary services modeling.

2.1 Capacity Assumptions

The ISO's Summer Assessment considers "All RA Eligible" resources for meeting a "1-in-10 LOLE" planning target against a wide range of load, solar, wind, outage conditions. Table 2.1 shows modeled capacity by month and fuel type in ISO's probabilistic assessment of summer 2026. Existing resource capacities are based on final net qualifying capacity (NQC) list published on February 12, 2026. Expected new resources are sourced from ISO's NRI database using criteria previously discussed in section 1.1.2.

Table 2.1 Probabilistic assessment modeled capacity (MW) by month and fuel type (2026)

Fuel type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Battery Storage	13,682	13,774	13,776	14,118	14,695	15,145	15,199	15,199	15,199	15,199	15,199	15,199
Biogas	143	143	141	130	140	138	137	146	142	132	148	152
Biomass	245	253	240	190	278	268	278	291	289	234	240	261
Demand Response	283	287	283	407	477	720	909	835	822	582	439	316
Geothermal	1,213	1,214	1,213	1,211	1,195	1,192	1,205	1,204	1,206	1,192	1,214	1,219
Hybrid	2,042	2,042	2,042	2,042	2,042	2,043	2,043	2,043	2,043	2,043	2,043	2,043
Hydro	8,643	8,643	8,643	8,643	8,643	8,643	8,643	8,643	8,643	8,643	8,643	8,643
Natural Gas	26,123	26,142	26,103	26,126	26,096	26,138	26,135	26,135	26,127	26,089	26,036	26,073
Nuclear	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280
Other	145	147	133	133	141	147	148	152	160	166	147	159
Solar	19,202	19,202	19,202	19,536	20,104	20,401	20,618	20,618	20,618	20,618	20,618	20,618
Wind	6,298	6,324	6,324	6,324	6,324	6,624	6,624	6,624	6,624	6,624	6,624	6,624
Total	**80,300**	**80,453**	**80,380**	**81,140**	**82,415**	**83,740**	**84,220**	**84,171**	**84,153**	**83,801**	**83,631**	**83,586**
Net Import Limit*	11,665	11,665	11,665	11,665	11,665	5,500	5,500	5,500	5,500	11,665	11,665	11,665

Following are capacity assumptions by fuel type considered in Table 2.1[13]:

1. Natural gas and battery resources are modeled at their nameplate capacities.
2. For solar, wind and hydro resources, the table lists nameplate capacity. For solar and wind resources, the study uses nameplate capacities in the creation of stochastic profiles for the simulation. Hydro resources use a 2022 hydro year profile based on EMS data.
3. Hybrid and co-located resource components are modeled individually with corresponding Pmax and aggregate capability constraints enforced, respectively.
4. Non-dispatchable thermal resource capacity is aligned with ISO's default QC methodology to avoid over-estimating of available generation from these resources.
5. Demand response (DR) category includes projected capacity from CPUC-jurisdictional utility-scale DR programs, non-CPUC DR as well as NQC values for third-party supply plan DR.

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[13] Other category includes Distillate, Waste Heat and Other fuel types

6. Partial deliverable resources have their capacity scaled down based on their deliverable MW.[14]
7. "Energy-only" solar resources that are co-located with "fully-deliverable" battery resources that support onsite charging are included.[15]

Since the NQC list does not have information on external tie-generators, the table excludes pseudo-tie and dynamic import resources outside of the CAISO BAA, with nameplate capacity totaling around 9,200 MW. For these resources and any non-resource specific imports, the assessment defines "RA eligible" as those which have contracts and Maximum Import Capability (MIC) reserved. Further, according to latest NRI data, the 3,650.2 MW SunZia Wind project located in New Mexico is set to go-live on May 1, 2026. Sunzia units which are considered internal to ISO balancing area will be subject to MIC until the "2022-23 TPP approved Southern California Upgrades" are completed with in-service dates around June 2034. After all those projects are in-service, they will not be subject to MIC and they will have their own deliverability. From RA showings validation perspective, they are treated like an import and need MIC to ensure deliverability. This is a special treatment for the Subscriber PTO (SPTO) model since the resource will not have deliverability until 2034. For RA, the highest MIC that could be assigned to Sunzia contracts would be 1,009.18 MW per the qualifying capacity ("QC") value based on CPUC's 2026 Tech Factors for New Mexico wind. Although 3,650 MW is the installed capacity of the resource, about 3,167 MW of it represents the ISO's share. With this project, there's about 3,100 MW of physical transmission outlet capability and CAISO only has 2,131 MWs of transmission rights through Arizona, all coming at Palo Verde intertie.

Historically, a reasonable historical firm RA import levels-based assumption of 5,500 MW was used during summer net peak hours of June through September during hours 16 – 22. In all other hours, the net import limit is 11,665 MW. For 2026 Summer Assessment, SunZia wind is modeled with a stochastic generation shape tied to New Mexico wind potential. The net import limit of 5,500 MW during summer net peak hours will be increased by the modeled SunZia generation up to an "import availability limit" of 1,009.18 MW based SunZia's QC value.

2026 Net import limit = 5,500 MW + min (SunZia generation, 1,009.18)

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[14] *Partial Capacity* deliverability status entitles a generating facility to a NQC amount that cannot be larger than a specified fraction of its QC amount and may be less pursuant to the assessment of its NQC amount by the CAISO.

[15] *Energy only* is a condition elected by an interconnection customer for a generating facility interconnected with the CAISO controlled grid where the generating facility will be deemed to have a NQC of zero, and, therefore, cannot be considered a resource adequacy resource.

2.2 Thermal Generators Modeling

Thermal generators are modeled at a unit level in this study. The CPUC's Integrated Resource Planning (IRP) process is the source for the fuel prices for these units.[16] Diablo Canyon nuclear plant is modeled as available through 2029 (Unit 1) and 2030 (Unit 2) based on SB 846 ruling.[17] As shown in Table 2.2, operating characteristics that constrain unit commitment and dispatch of thermal resources (natural gas, distillate, and nuclear resources etc.) include maximum and minimum capacity, minimum up and down times, ramp up and down times, start-up times, start fuel and start-up cost, heat rate curve, and variable operations and maintenance (VOM) cost. The CAISO's Master File is the primary source for these operating characteristics on a technology level and the model uses group averages to preserve confidentiality.

Table 2.2 Thermal resource modeling attributes

PLEXOS Modeling Attribute	Methodology	Source
Max Capacity	Resource-specific values	CAISO Master File
Min Stable Level		
Heat Rate	Class Averages - Grouped by Average Heat Rate, Max Ramp Rate	
VO&M Charge		
Start Cost Time (Cold, Warm and Hot)		
Offtake at Start		
Start Cost		
Run up rate (Zero to Pmin)		
Max Ramp Up/Down		
Min Up/Down time		
Forced Outage Rate	Resource-specific values	CAISO OMS
Maintenance Rate		
Mean Time to Repair		

Ambient due to temp derates for thermal resources were also reflected in the PLEXOS model. Figure 2.1 shows a distribution of monthly resource-specific rating factor for modeled thermal units. Each data point corresponds to a monthly average rating of one unit calculated using ambient due to temp derates from OMS data between November 2022 and October 2025. For example, a monthly rating of 80 percent for a unit means that the specific unit will be modeled at 80 percent of its Max Capacity during that month in the model. The dotted line in the figure represents the median. The figure shows that in July, half of the thermal units modeled have a rating greater than 98 percent.

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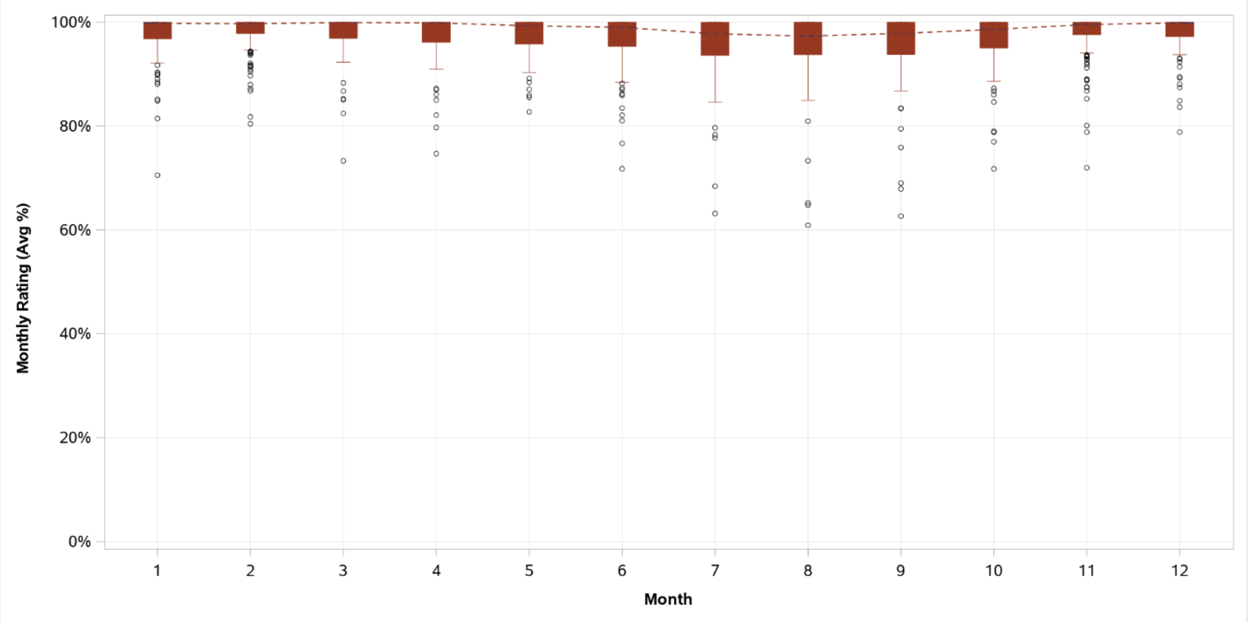
[16] System Reliability Modeling Datasets 2024: https://files.cpuc.ca.gov/energy/modeling/2024_servm_updates/FuelAndTransportCosts_20250108_values.xlsx

[17] Diablo Canyon nuclear power plant has received federal approval to operate another 20 years, with its license now stretching until 2045: https://www.noozhawk.com/diablo-canyon-nuclear-power-plant-can-operate-another-20-years-nrc-says/

Figure 2.1 Distribution of average monthly rating for thermal units with ambient derates

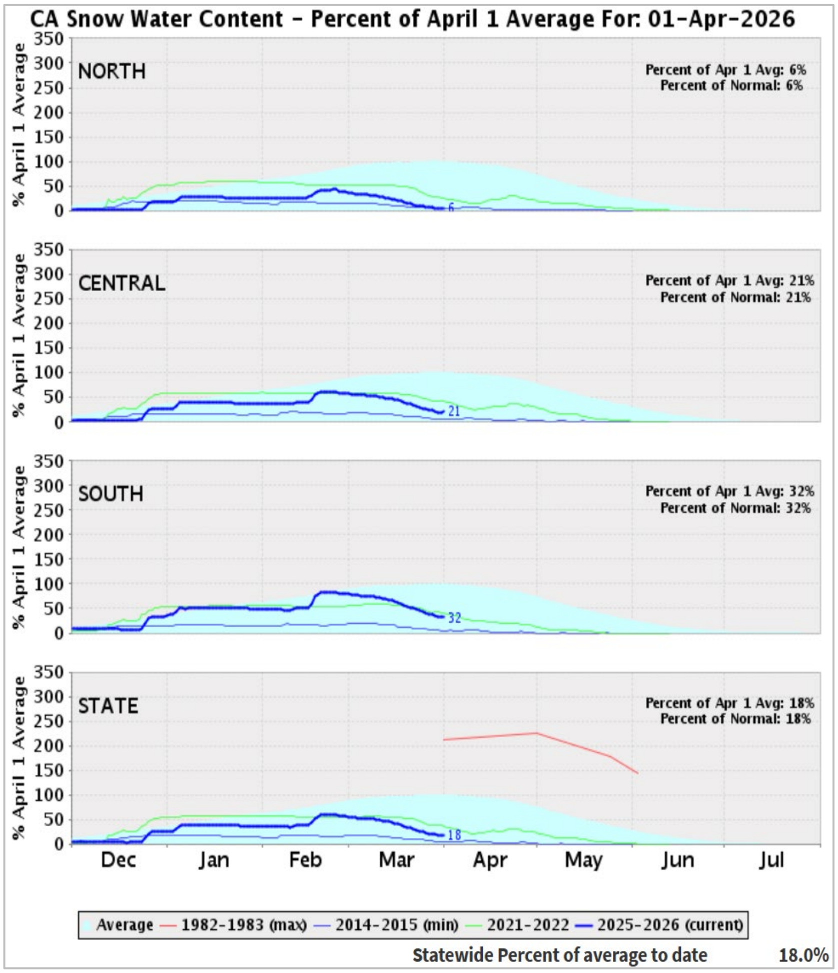


With respect to ancillary services and load-following reserve modeling, the model includes relevant properties that determine each generator's reserve provision in proportion to its ramping capabilities. That is, in upward direction, its total provision of ancillary services cannot exceed its 10-minute ramping capability and any unused capacity. Total provision of ancillary services and load following cannot exceed its 20-minute ramping capability and any unused capacity. In addition, the sum of energy ramping and provision of ancillary services and load following cannot exceed its 60-minute ramping capability and any unused capacity.

2.3 Hydro and Pumped Storage Modeling

Hydro generation is modeled on an aggregated basis as two types: non-dispatchable run-of-river and dispatchable hydro generation. Run-of-river hydro generation is modeled as a fixed generation profile. These resources cannot provide ancillary services or load following. As shown in Figure 2.2, as of April 1, 2026 on a statewide basis, the snow water content is the second lowest (after 2015) on record at 18 percent. This is due to a combination of warm storms and unusually hot temperatures in March that led to rapid melting of what remained of this year's already sparse snowpack. Further, DWR's water supply forecasts use data from the April 1 snowpack to calculate how much snowmelt runoff will eventually make its way into California's rivers and reservoirs. This information is critical for reservoir managers, who must balance flood control and water supply goals through the winter and depend on snowmelt to slowly refill reservoirs as demand increases during the dry season.

Figure 2.2 California snow water content for water years 2025-26, 2021-22, 1982-83 & 2014-15[18]



Dispatchable hydro generation is optimized subject to daily maximum energy limits as shown in Figure 2.3. These energy limits are derived from historical generation data where snowpack conditions that most closely resemble 2021-22 hydro year. Dispatchable hydro generation can provide system capacity, ancillary service and load following. The hydro resources are aggregated by zone in the model. They do not have outages since the outages are already reflected in the hydro generation profile.

For pumped storage resources, pumping and generation schedules are optimized with constraints on storage capacity, water inflow and target limits, reservoir storage volume and cycling efficiencies. In generation mode, pumped storage resources can provide all ancillary services and load following. Pumped storage have defined forced and maintenance outages.

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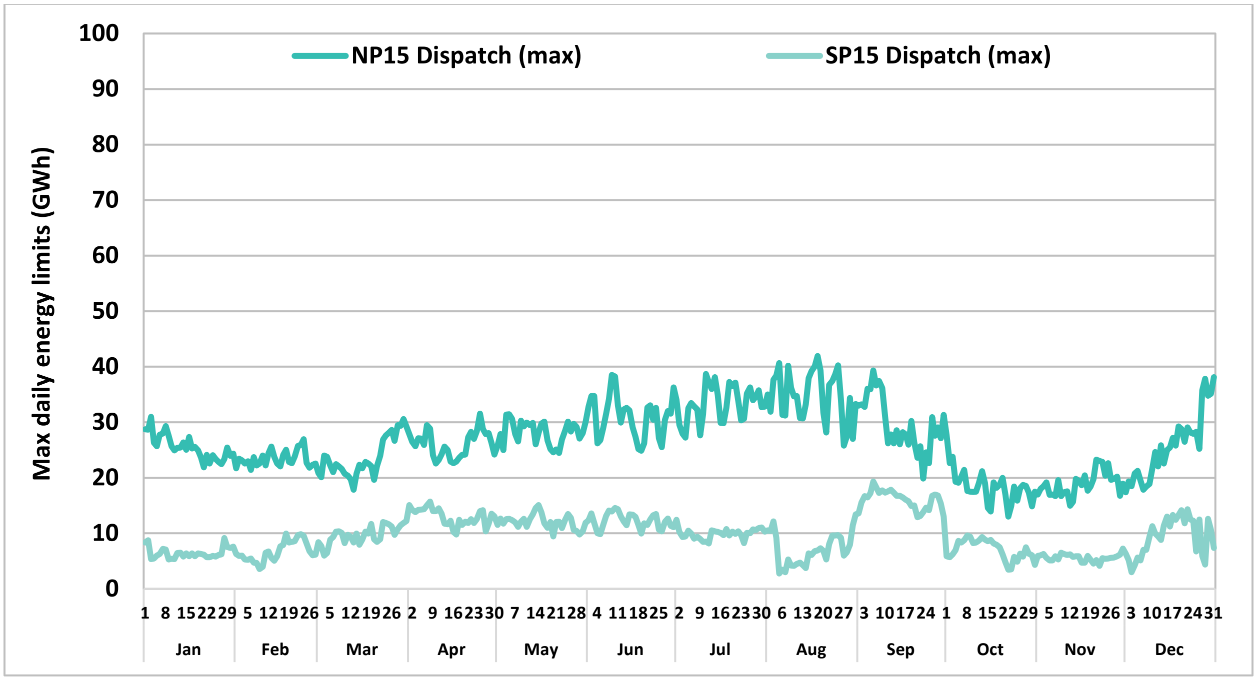
[18] California Department of Water Resources, California Data Exchange Center, CA Snow Water Content – Percent of April 1 average: http://cdec.water.ca.gov/snowapp/swcchart.action

Figure 2.3 Dispatchable hydro daily energy limits (2026)



2.4 Battery Energy Storage Modeling

Battery energy storage resources are modeled at a unit level in PLEXOS with resource-specific operating parameters such as energy capacity, power rating, round-trip efficiency, and ramp rates as shown in Table 2.3. The CAISO's Master File is the primary source for these operating characteristics and the model uses group averages to preserve confidentiality. The model treats batteries as bi-directional resources and co-optimizes battery charging and discharging across time intervals to minimize system costs or meet specified objectives (such as minimizing depth verses duration of shortfalls), while adhering to operational constraints. State-of-charge limits are captured in modeled outage rates calculated using CAISO OMS data. Currently, there is no constraint enforced on the number of cycles a battery resource can undergo in a day. Battery storage resources can provide ancillary services and load following in both charging and discharging modes.

Storage components of hybrid and co-located resources are modeled individually and are subject to their respective Pmax and aggregate capability constraints, respectively.

Table 2.3 Battery storage modeling attributes

PLEXOS Modeling Attribute	Methodology	Source
Max Power (Installed Cap, MW)	Resource-specific values	CAISO Master File
Capacity (Energy, MWh)	Class Averages - Grouped by Energy Limit, Max Ramp Rate	
Charge Efficiency		
Max Ramp Up Rate		
Forced Outage Rate	Resource-specific values	CAISO OMS
Maintenance Rate		
Mean Time to Repair		

2.5 Demand Response Modeling

Demand response (DR) capacity in the market includes CPUC-jurisdictional utility (IOU) DR, non-CPUC jurisdictional DR, and third party DR. Utility demand response includes reliability demand response resources (RDRR) and proxy demand resources (PDR) and accounts for majority of demand response used to meet resource adequacy requirements. RDRR capacity represents a major portion of utility demand response capacity. This capacity can be economically scheduled in the day-ahead market but can only be dispatched in real-time if the ISO is in an EEA Watch. Table 2.4 shows the amount of utility, third party, and non-CPUC DR capacity modeled for 2026 summer assessment. Utility DR capacity values are based on CPUC's Slice of Day hourly ex-ante load impacts from hour ending 17 to 21 for January to February and June to December and from hour ending 18 to 22 for March to May at the portfolio level on monthly worst load days under 1-in-2 utility weather year conditions.[19] Third party or supply plan DR capacity values are based on CAISO's February 2026 net qualifying capacity list. Non-CPUC jurisdictional load serving entities (municipal utilities) DR values are sourced from DMM's 2024 DR issues and performance report[20]. As shown in the table, DR capacity is available only to be dispatched during net load peak hours of 17 through 22 in the model.

In the PLEXOS model, demand response resources are represented as supply resources with high triggering prices calculated based on a 1,000 BTU/kWh heat rate and a high fuel price. When the energy price reaches the triggering price, the demand response resources' loads are dropped. The triggering prices are high enough so that the demand response resources are not triggered more frequently than is realistic. Demand response resources cannot provide ancillary services or load following reserves.

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[19] CPUC Resource Adequacy Compliance Materials, 2026 – 2028 IOU DR projections: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials

[20] DMM 2024 DR Issues and Performance report, Table 2.1: https://www.caiso.com/documents/demand-response-issues-and-performance-2024-mar-14-2025.pdf

Table 2.4 Monthly utility, third party, and non-CPUC demand response capacity (MW)

Demand Response type	Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PG&E Utility DR Programs	17	139	144	0	0	0	243	264	251	265	201	167	154
	18	139	144	153	163	199	243	264	251	265	201	167	154
	19	139	144	153	163	199	243	264	251	265	201	167	154
	20	139	144	153	163	199	243	264	251	265	201	167	154
	21	139	144	153	163	199	243	264	251	265	201	167	154
	22	0	0	153	163	199	0	0	0	0	0	0	0
SCE Utility DR Programs	17	168	170	0	0	0	472	546	493	442	393	289	167
	18	168	170	155	296	251	472	546	493	442	393	289	167
	19	168	170	155	296	251	472	546	493	442	393	289	167
	20	168	170	155	296	251	472	546	493	442	393	289	167
	21	168	170	155	296	251	472	546	493	442	393	289	167
	22	0	0	155	296	251	0	0	0	0	0	0	0
SDG&E Utility DR Programs	17	0	0	0	0	0	0	0	0	0	0	0	0
	18	0	0	0	0	0	0	0	0	0	0	0	0
	19	0	0	0	0	0	0	0	0	0	0	0	0
	20	0	0	0	0	0	0	0	0	0	0	0	0
	21	0	0	0	0	0	0	0	0	0	0	0	0
	22	0	0	0	0	0	0	0	0	0	0	0	0
3rd Party DR (Supply Plan DR)	17	43	38	0	0	0	149	174	189	183	104	71	57
	18	40	36	35	29	123	149	174	189	183	104	71	57
	19	34	32	35	29	123	149	174	189	183	104	71	57
	20	28	26	30	29	123	149	174	189	183	104	71	57
	21	22	24	28	29	123	149	174	189	183	104	71	57
	22	0	0	29	29	123	0	0	0	0	0	0	0
Non-CPUC DR	17							89	58	81			
	18							89	58	81			
	19							89	58	81			
	20							89	58	81			
	21							89	58	81			
	22							89	58	81			
Total Modeled DR	17	349	352	0	0	0	864	1,073	991	971	698	527	379
	18	346	349	343	488	573	864	1,073	991	971	698	527	379
	19	341	345	342	488	573	864	1,073	991	971	698	527	379
	20	334	340	338	488	573	864	1,073	991	971	698	527	379
	21	329	338	336	488	573	864	1,073	991	971	698	527	379
	22	0	0	337	488	573	0	89	58	81	0	0	0
Total Modeled DR (Average)	**17-22**	**283**	**287**	**283**	**407**	**477**	**720**	**909**	**835**	**822**	**582**	**439**	**316**

2.6 Stochastic Solar and Wind Profiles

The ISO's model has stochastic variables for solar generation, wind generation, outages, and load. The solar and wind variables are the aggregate generation of solar and wind resources inside the CAISO and external tie-generators.

For solar and wind resources, their respective nameplate capacities shown in Table 2.5 are used as an input into creating 500 stochastic profiles for 2026. Table 2.5 reflects the increases in capacity from the planned resources expected online in 2026, including 3,650 MW of out-of-CAISO wind tie-gen starting in May that represents the SunZia wind resources located in New Mexico. The SunZia wind resources are modeled as Tie-Gen resources and are included under imports in the model because the wind interconnects to a non-contiguous area of CAISO's balancing area and its system deliverability is still contingent on existing available MIC as specifically allocated deliverability is not available until requisite transmission upgrades are completed. Given these import restrictions, generation from SunZia wind resources are also subjected to the updated import limits described in 2.1.

The table excludes solar and wind capacity from hybrid resources, but those resources are used in developing the respective stochastic profiles. Solar and wind components of hybrid and co-located resources are modeled individually and are subject to their respective Pmax and aggregate capability constraints. The table also excludes any energy-only solar resources that are not co-located with "fully-deliverable" battery resources.

Table 2.5 2026 Solar and wind nameplate capacities (MW)

Fuel Type	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Solar	Gen	19,202	19,202	19,202	19,536	20,104	20,401	20,618	20,618	20,618	20,618	20,618	20,618
Solar	Tie-Gen	984	984	984	984	1,069	1,069	1,069	1,069	1,069	1,069	1,069	1,069
Wind	Gen	6,298	6,324	6,324	6,324	6,324	6,624	6,624	6,624	6,624	6,624	6,624	6,624
Wind	Tie-Gen	2,051	2,051	2,051	2,051	5,701	5,701	5,701	5,701	5,701	5,701	5,701	5,701

In the simulations, the stochastic values of solar and wind generation are distributed to the five zones - PG&E Bay, PG&E Valley, SCE, SDG&E, and the external zone. The solar profile is allocated to each of the regions by ratios calculated based on their respective base profiles. For wind, the instate profile is allocated by ratios to the four internal regions, and a separate external profile is used for wind resources located outside of the CAISO. Solar and wind base profiles are used as an input into the ISO's mean reversion stochastic model.[21] Utility scale solar base profile is based on CPUC's most recently adopted Preferred System Plan (PSP).[22] For wind generation, separate base profiles and stochastic values for in-CAISO wind and out-of-CAISO wind are developed to better represent the wind output difference from the geographic distribution of the portfolio's wind resources. For in-CAISO generation, the wind base profile comes from a 5-year (2021 – 2025) average of actual CAISO EMS data normalized by annual installed capacity. For the out-of-CAISO wind, there is limited CAISO EMS data available, as most of these resources are not yet online or are only dynamically scheduled. Instead, the out-of-CAISO wind profile is derived from modeled wind generation profiles for 23 historic weather years (2000-2022) developed by the CPUC as part of its 2024 System Reliability Modeling Datasets.[23] With 90 percent of the out-of-CAISO wind located in New Mexico, the out-of-CAISO wind base profile comes from a 5-year average (2018-2022) of the CPUC wind profiles developed specifically to represent New Mexico wind. Mean reversion

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[21] The methodology was filed as part of CAISO's expert testimony in the CPUC Long-Term Procurement Plan (LTPP) proceeding, Appendix A, pg. 5 – 19, Nov 20, 2014: https://www.caiso.com/documents/nov20_2014_liu_stochasticstudytestimony_ltpp_r13-12-010.pdf

[22] CPUC, 2023 Preferred System Plan Proposed Decision, Modeling & Analysis, pp. 13, January 12, 2024: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-longterm-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/2024-01-12-presentation-summarizing-updatedservm-and-resolve-analysis.pdf

Solar base profile is downscaled to 85.4 percent of the existing profile, which is maximum hourly capacity factor observed for solar, averaged across 2022-2024. Solar stochastic profiles are capped at maximum hourly value at 112.18 percent of the base profile peak. This is the maximum observed hourly capacity factor since 2016, adjusted relative to the base profile peak.

[23] CPUC, System Reliability Modeling Datasets 2024 (used for RA proceeding's (R.23-10-011) July 2024 Loss of Load Expectation (LOLE) study of target year 2026 and IRP proceeding's (R.20-05-003) 2025-2026 TPP Portfolio development: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/energy-modeling/servm-inputs-2024

ratios for solar and in-CAISO wind generation are calculated with a regression model using historical wind (2007 – 2014) and solar (2010 – 2021) data sourced from the National Renewable Energy Laboratory (NREL). The mean reversion ratios for the out-of-CAISO wind generation are calculated with a regression model that utilizes all 23 historic weather years (2000-2022) wind data for the New Mexico region from the CPUC's 2024 modeling datasets.

The ISO then applied these ratios to the solar and wind base profiles to generate 500 stochastic samples for solar and wind generation. Figure 2.4 and Figure 2.5 show hourly distribution of solar and in-CAISO wind profiles for each month of 2026 based on capacities listed in Table 2.5. Figure 2.6 shows monthly distribution of out-of-CAISO wind generation for 2026.

Stochastic profiles for solar and wind are based on respective generation potential and do not include outages. Table 2.6 shows capacity-weighted rating factors applied to solar and wind by zone, which represents capacity not on outage each month calculated from OMS data (2022-2024).

Table 2.6 Solar and wind rating factors by zone

Resource type	Zone	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SOLR	PG&E Bay	96.4%	95.8%	94.4%	95.6%	91.2%	91.7%	93.7%	92.6%	97.2%	96.4%	95.6%	94.6%
SOLR	PG&E Valley	96.8%	96.1%	97.1%	96.8%	96.5%	95.9%	95.5%	96.4%	96.7%	95.8%	96.3%	96.0%
SOLR	SCE	96.8%	96.9%	98.0%	97.6%	97.3%	97.8%	97.5%	96.7%	97.4%	97.5%	97.6%	98.1%
SOLR	SDG&E	97.6%	98.3%	98.2%	98.4%	98.6%	98.9%	97.9%	96.9%	97.2%	97.5%	97.6%	97.7%
WIND	PG&E Bay	94.0%	91.0%	92.8%	91.0%	92.2%	93.6%	91.6%	93.1%	92.9%	88.4%	91.2%	91.3%
WIND	PG&E Valley	97.6%	96.3%	96.6%	98.1%	98.4%	99.7%	99.4%	99.6%	99.6%	99.3%	98.0%	96.0%
WIND	SCE	96.0%	95.6%	95.2%	95.1%	95.2%	94.7%	95.0%	94.8%	95.3%	94.5%	93.9%	93.9%
WIND	SDG&E	90.8%	93.9%	92.4%	91.6%	89.6%	88.6%	93.3%	92.8%	93.4%	95.0%	94.0%	96.3%

Figure 2.4 Hourly utility scale solar stochastic sample distribution by month (2026)

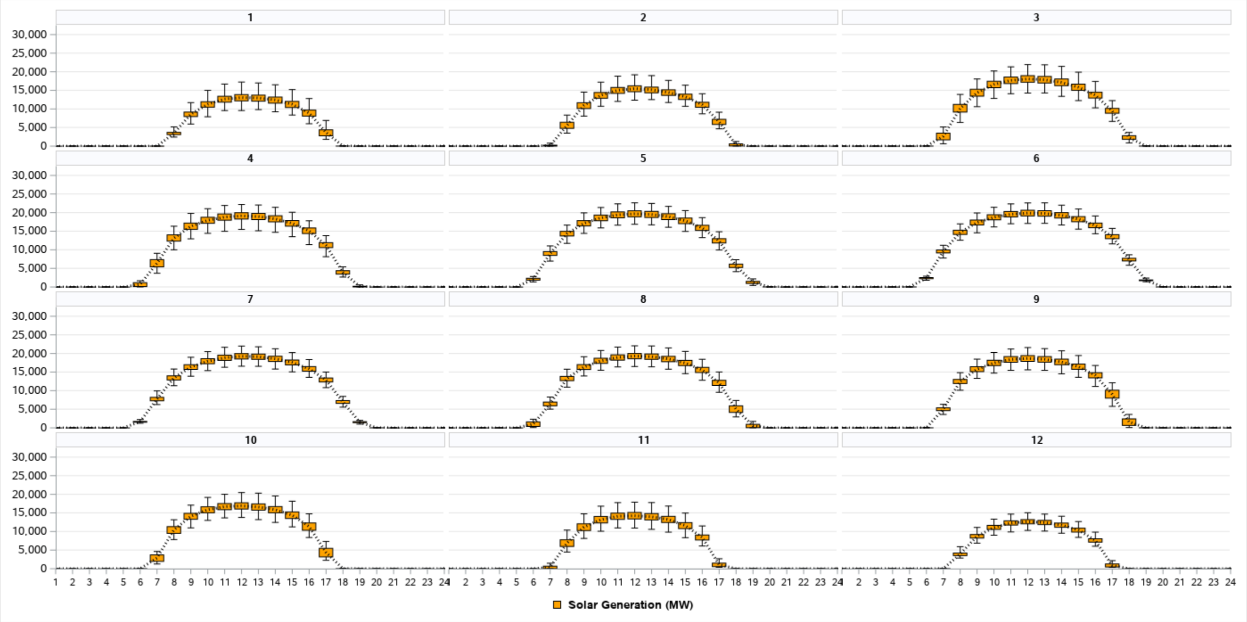


Figure 2.5 Hourly in-CAISO wind stochastic sample distribution by month (2026)

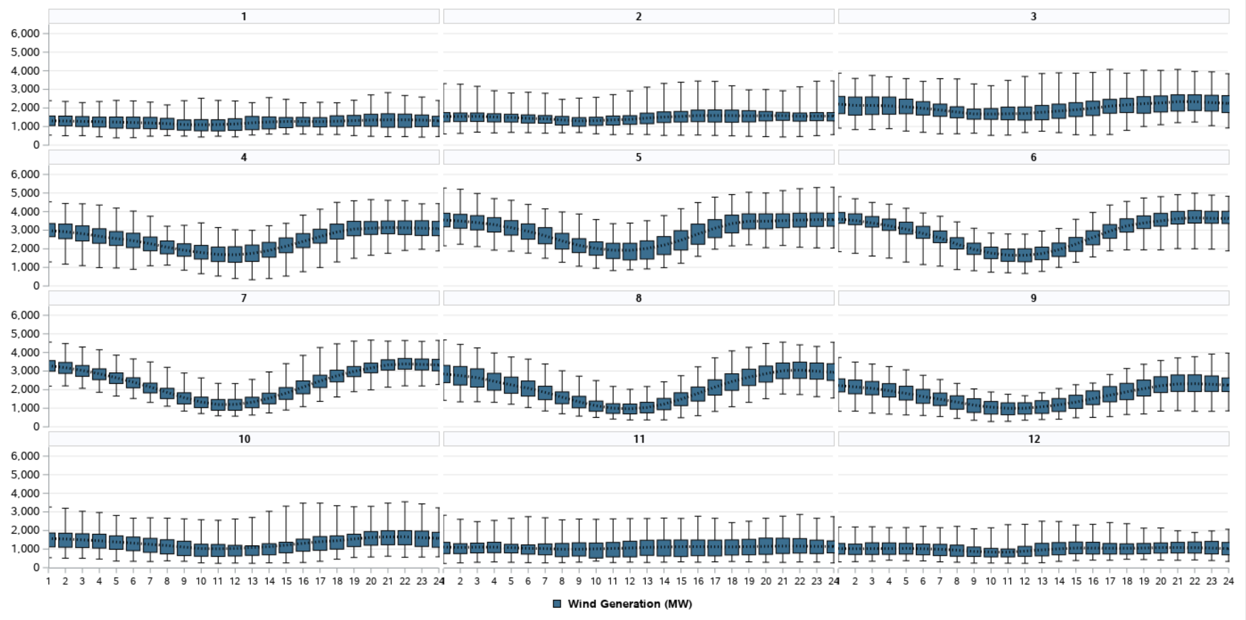
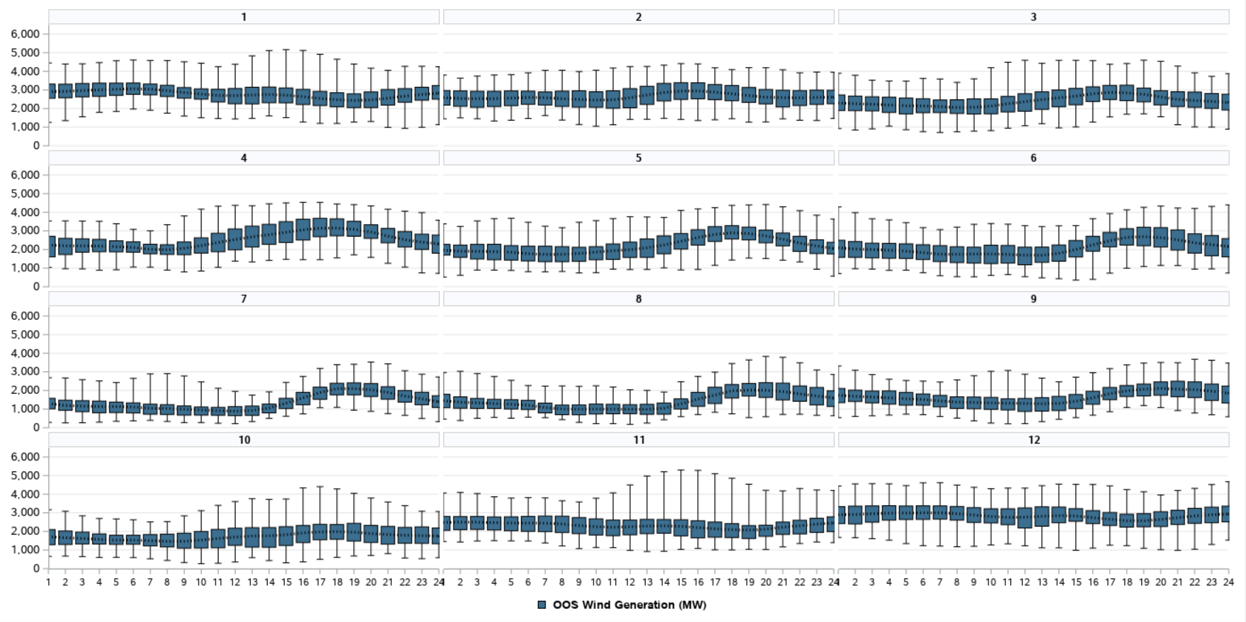


Figure 2.6 Hourly out-of-CAISO wind stochastic sample distribution by month (2026)



2.7 Stochastic Generator Outage Profiles

Annual forced outage rate, maintenance rate and mean time to repair generator properties are used to create 500 independent outage samples for each generator using the converged Monte Carlo method. PLEXOS' PASA simulation phase is used to create outage events that can be used as an input into subsequent hourly chronological simulations. The converged Monte Carlo method is used in generating the forced outages so that the percent of hours with forced outage is close to the forced outage rates of the resources. Planned maintenance factor on a region level (PG&E Bay, PG&E Valley, SCE and SDG&E) is used to schedule outages by month. It is a profiling factor used by PASA to 'shape' maintenance events into appropriate periods of high capacity reserves. As mentioned earlier, the outage stochastic variable is independent of any other stochastic variables in the model.

CAISO OMS data from November 2022 – October 2025 (36 months) was used to update annual outage rates in the model. The assessment includes all natures of work in planned and forced outage categories except Transmission Induced Gen Outages (TIGO) to calculate resource-specific planned and forced outage rates. Ambient due to temp forced outages are separated and applied as a monthly derate to each thermal resource as shown in Figure 2.1. To account for solar and wind outages, a static monthly derate based on historical outages is applied to their respective stochastic profiles (see Table 2.6). Planned nuclear maintenance for refueling is sourced from publicly available sources.

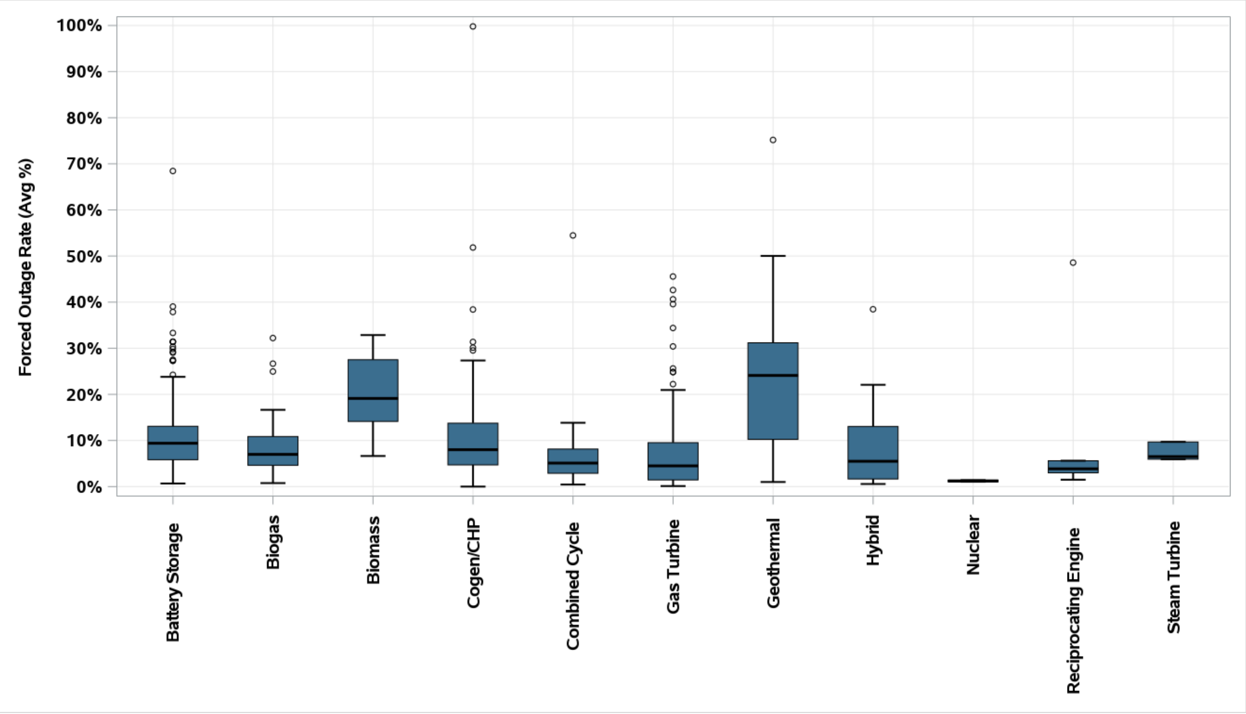
Figure 2.7 and Figure 2.8 show a distribution of resource-specific average forced and planned outage rates, respectively. Each data point in these distributions corresponds to an average forced or planned outage rate of one resource over the 36-month timeframe. The respective rates are calculated based on unavailable capacity for each outage type divided by nameplate capacity of the resource. Unavailable capacity includes both partial derates and full outages.

Following rules were applied for treatment of existing and new resources without outage data:

- For existing resources without full 36-month data, capacity weighted class average rates shown in the figures below will be used for months with missing outage data. For example, a resource has 20 months of outage data depending on when it came online, class average rates will be used for 16 months and unit specific rates for the 20 months.
- For existing resources without any planned outage rate in the past 36 months, it is assumed that the plant will not undergo maintenance in future years as well. For example, units that did not undergo maintenance in the past 3 years.
- For existing resources without forced outage rates, capacity-weighted class-average rates will be used. These are units that did not experience a forced outage in the past 3 years but it is assumed that the plant will experience forced outages at the class average level in the future timeframe. In this case, the class average will be used in the SA model, but the resource will not receive a derate in the UCAP calculation.
- For new resources without planned and forced outage data, capacity-weighted class-average rates will be used to model these rates.
- Capacity-weighted class-average rates are also used for any resources modeled on an aggregated basis (non-dispatchable biofuels, CHP).

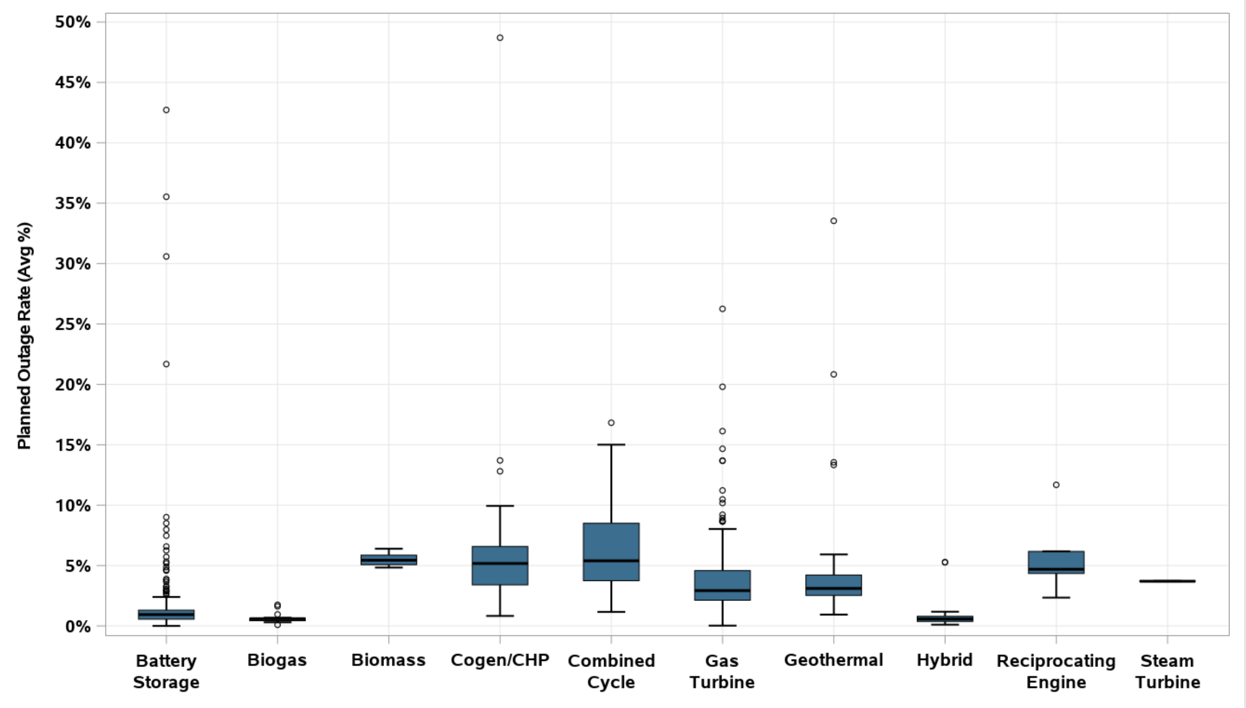
The median of the distribution in these figures is represented as a horizontal line within each box. For example, on an annual basis, half of the battery storage resources have a forced outage rate higher than 9 percent (Figure 2.7). Similarly, half of the combined cycle resources have an annual planned outage rate higher than 5 percent (Figure 2.8). Forced and planned outage mean time to repairs are modeled separately for each individual resource and calculated as total time on outage divided by number of repairs.

Figure 2.7 Distribution of resource-specific forced outage rate by fuel/technology type



Capacity-weighted average Forced Outage Rate (%)	Battery Storage	Biogas	Biomass	Cogen/CHP	Combined Cycle	Gas Turbine	Geothermal	Hybrid	Nuclear	Reciprocating Engine	Steam Turbine
	10.7%	9.5%	18.6%	11.0%	5.3%	7.7%	26.2%	11.4%	1.2%	5.0%	7.2%

Figure 2.8 Distribution of resource-specific planned outage rate by fuel/technology type



Capacity-weighted average Planned Outage Rate (%)	Battery Storage	Biogas	Biomass	Cogen/CHP	Combined Cycle	Gas Turbine	Geothermal	Hybrid	Reciprocating Engine	Steam Turbine
	1.4%	0.9%	5.5%	8.2%	6.8%	3.7%	5.1%	1.1%	6.6%	3.7%

2.8 Stochastic Load Profiles

The CEC baseline managed hourly demand forecast from the CEC's 2025 IEPR[24] as an input to ISO's mean reversion load forecast model.[25] This model has two processes: the first process uses ISO's historical load profiles (2015 – 2025) to calculate the mean reversion ratios with a regression model. The second process applies the calculated mean reversion ratios to CEC's baseline hourly demand forecast to generate 500 stochastic hourly managed load profiles. Figure 2.9 shows the frequency distribution of hourly managed loads used in the stochastic model. Figure 2.10 shows hourly distribution of managed load profiles for each month of 2026.

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[24] CEC, 2025 Integrated Energy Policy Report, Hourly Demand Forecast Files: https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2025-integrated-energy-policy-report-0

[25] The methodology was filed as part of CAISO's expert testimony in the CPUC Long-Term Procurement Plan (LTPP) proceeding, Appendix A, pg. 5 – 19, Nov 20, 2014: https://www.caiso.com/documents/nov20_2014_liu_stochasticstudytestimony_ltpp_r13-12-010.pdf

Figure 2.9 Frequency distribution of hourly load samples (2026)

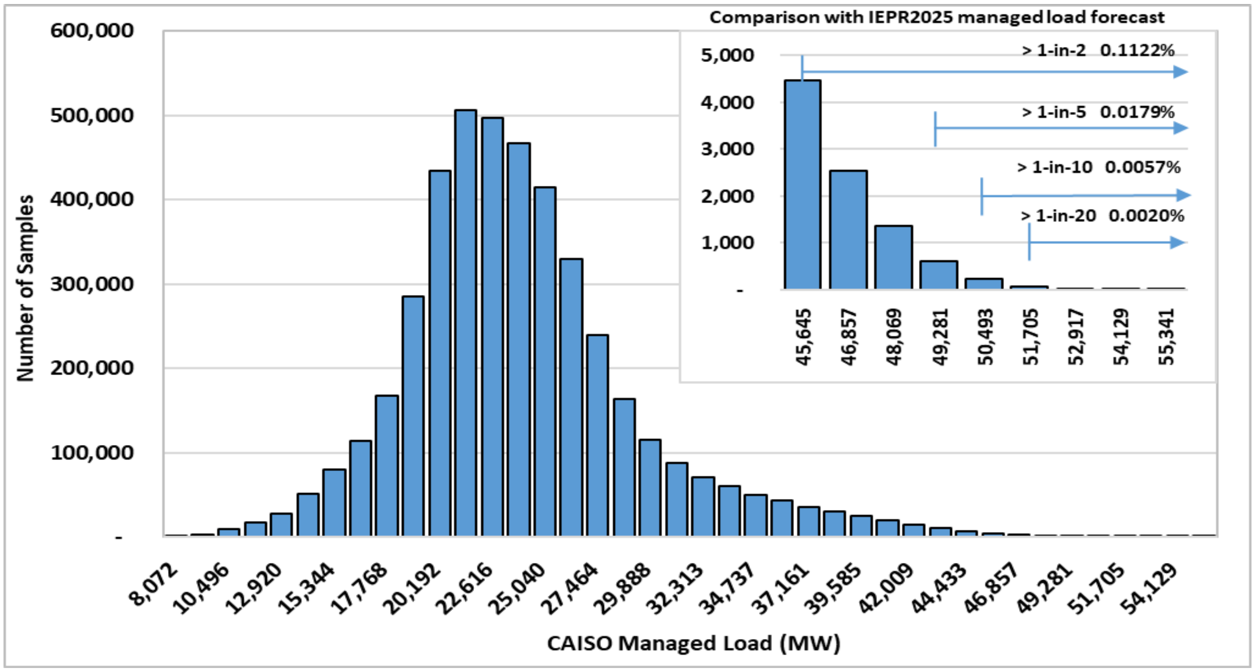
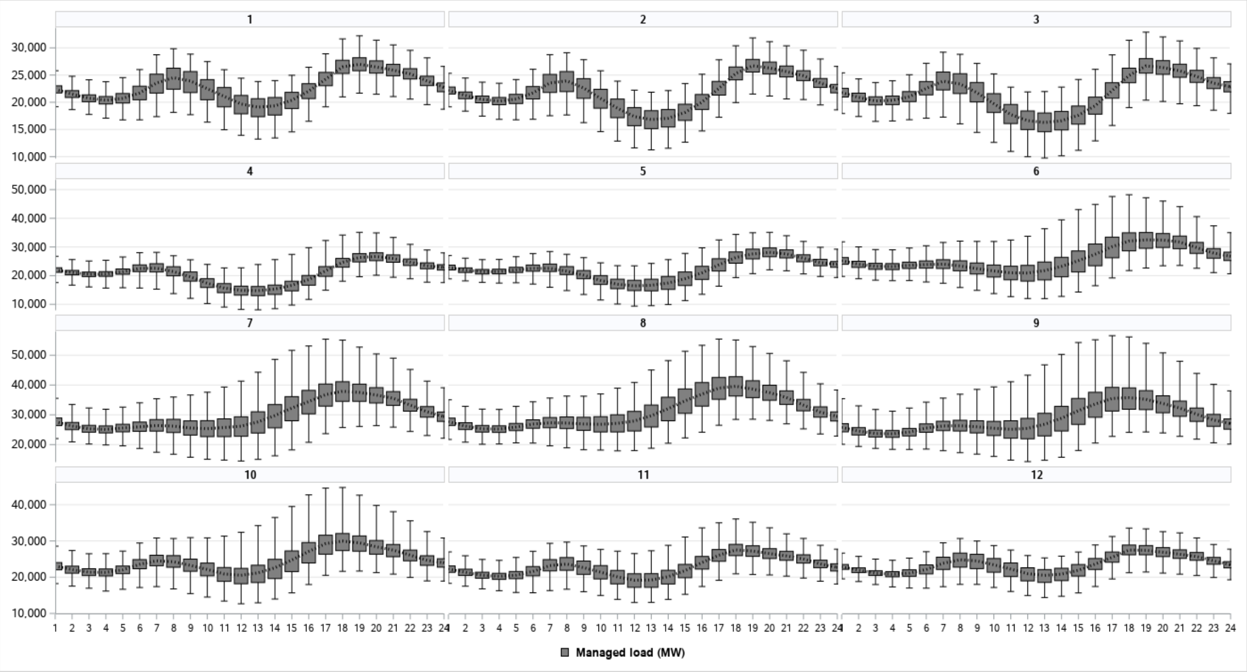


Figure 2.10 Hourly managed load stochastic sample distribution by month (2026)



2.9 Ancillary Services Modeling

ISO zones defined in the production cost model also have ancillary services and load following requirements, either as fixed profiles or as a certain percent of their loads. The ISO has total ancillary service and load following requirements for PG&E, SCE, and SDG&E zones together. Internal resources and resources outside the zone as designated in the model may meet the ancillary service and load following requirements.

Failure to meet any of these reserve requirements carries a high penalty price in the model. These prices align with the priority placed on each reserve, see Table 2.7.

Table 2.7 Modeled upward reserve products and contribution to LOLE[26]

Priority	Modeled Reserves	Description	Included in LOLE?
1	Unserved Energy (USE)	Unserved Energy is load that could not be met due to a shortage in generation and/or transmission capacity	Yes
2	Regulation up reserves	Requirements based on the 95th percentile of day-ahead and real-time requirements from the past three years	Yes
3	Spinning reserves	1.2% of load	Yes
4	Supplemental or non-spinning reserves	4.8% of load	Yes
5	Load following up	Used to address intra hour differences in load	No

Individual gas and battery resources providing a specific reserve product in the model are selected based on top “x” MW of capacity capable of providing a specific reserve, where x = total gas or battery capacity certified to provide a specific AS product according to Master File data.[27]

Regulation and Spinning/Non-Spinning Requirements

For 2026 regulation requirements, a month-hour profile is used based on the 95th percentile (P95) of the day-ahead (DA) and real-time (RT) (15-min intervals) requirements from the past three years. Analysis showed P95 values are consistently equal to or higher than the 2025 DA actual requirements. This approach is a reasonable improvement to capture some of the variability in 500 load, solar and wind profiles over the past approach which only included prior year DA data. All 500 iterations use a single set of deterministic regulation up and down requirements. Figure 2.11 shows hourly regulation requirements enforced in the model for each month of 2026.

Spinning and non-spinning reserve requirements total 6 percent of load (which does not include battery charging and pump load) and are each held at 1.2 percent and 4.8 percent of load, respectively.[28] Because

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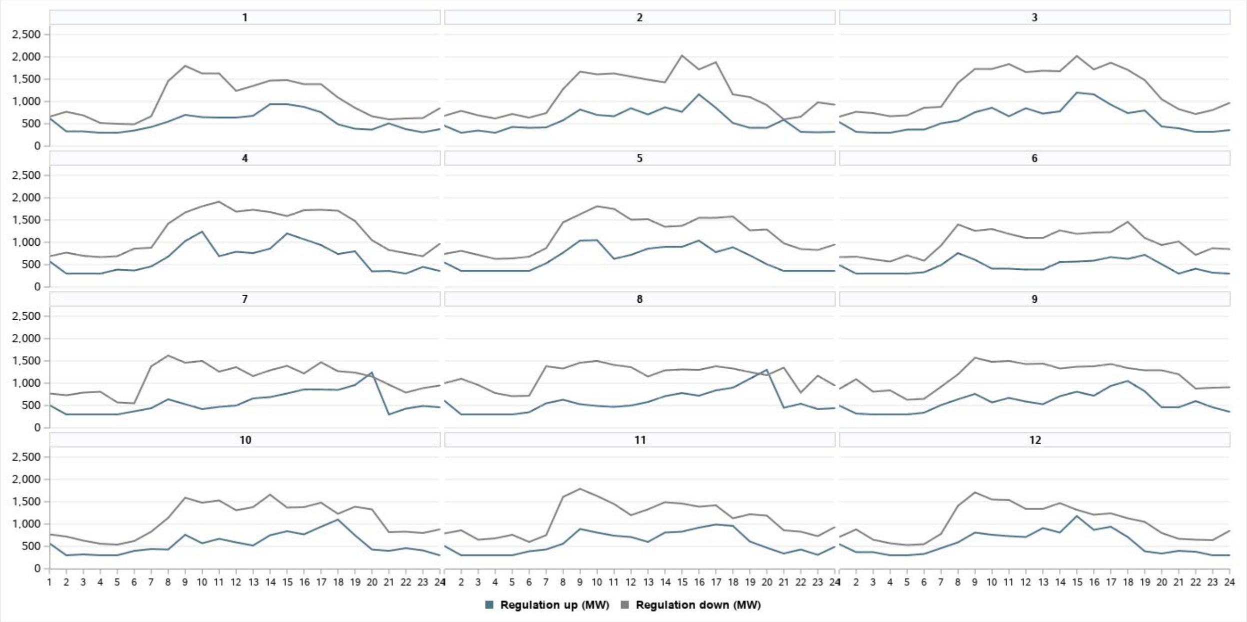
[26] Details on the CAISO’s various ancillary service products, pg. 263: https://www.caiso.com/documents/2024-annual-report-on-market-issues-and-performance-aug-07-2025.pdf

[27] For non-spin, fast start gas resources are selected based on a 10-minute or less cold startup time.

[28] Historically, operating reserve requirements were split equally between spinning and non-spinning reserves. However, starting on March 1, 2023, CAISO operators changed the procurement target for operating reserves following changes in WECC and NERC reliability standards, which now allow spinning reserves to account for less than 50 percent of requirements. In all months after the procurement target changed, CAISO operators procured 20 percent of operating reserves as spinning reserves, and the rest as non-spinning reserves.

load is a stochastic variable, the hourly values of spinning and non-spinning reserve requirements vary in each iteration. Minimum total provision for spin and non-spin is equal to maximum capacity (1,140 MW) of single unit of Diablo Canyon power plant.

Figure 2.11 Hourly regulation up and down requirements (2026)



Load Following Requirements

The load-following up or down requirement is the maximum of net load differences between the 5-minute and hourly forecast values within the hour in an upward or downward direction. All 500 iterations use a single set of deterministic load following up and down requirements. Figure 2.12 and Figure 2.13 show hourly distributions of load following up and down requirements for each month of 2026.

Figure 2.12 Hourly distribution of load following up requirements (2026)

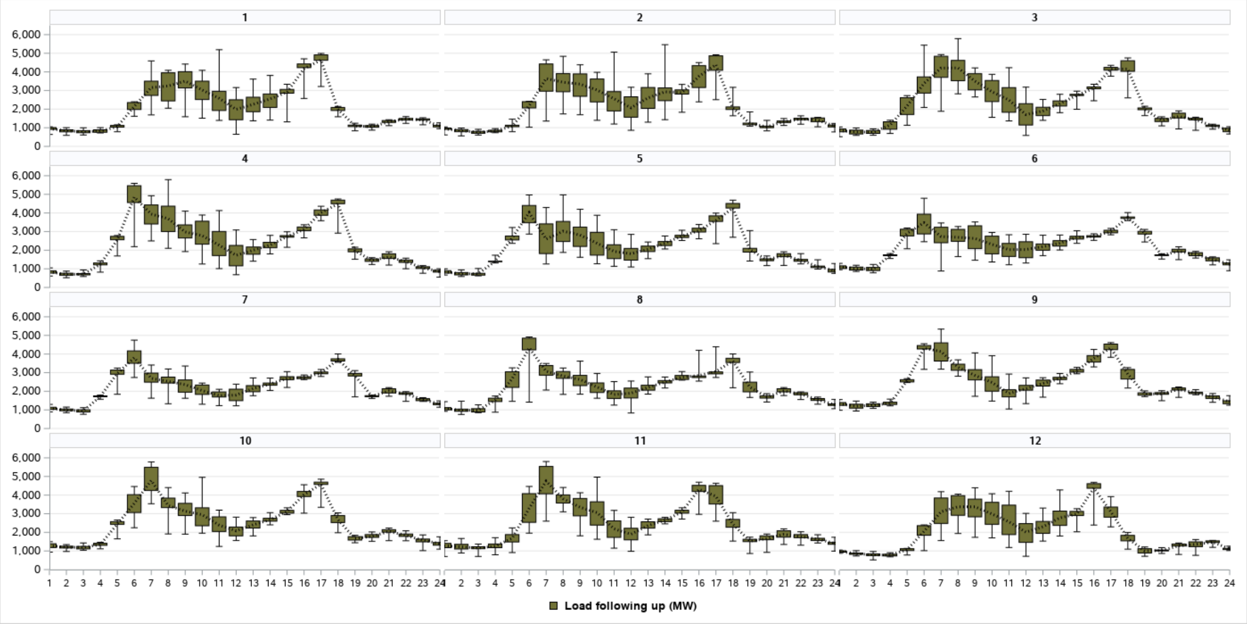


Figure 2.13 Hourly distribution of load following down requirements (2026)