Draft Inputs & Assumptions

Track 1: CAISO Resource Adequacy Modeling

October 08, 2024

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Acronyms

BAA	Balancing Authority Area
CAISO	California Independent System Operator
CCA	Community Choice Aggregator
CEC	California Energy Commission
CEDU	California Energy Demand Update
COD	Commercial Operation Date
CPUC	California Public Utilities Commission
DAM	Day ahead market
DEBA	Distributed Electricity Backup Assets Program
DLAP	Default Load Aggregated Point
DSGS	Demand Side Grid Support Program
DWR	Department of Water Resources
EEA	Energy Emergency Alert
ELCC	Effective Load Carrying Capability
ELRP	Emergency Load Reduction Program
ESP	Energy Service Provider
ESSRRP	Electricity Supply Strategic Reliability Reserve Program
ETC	Existing Transmission Contract
EUE	Expected Unserved Energy
F	Fahrenheit
FMM	Fifteen-Minute Market
HASP	Hour Ahead Scheduling Process
HE	Hour Ending
IEPR	Integrated Energy Policy Report
IFM	Integrated Forward Market
IOU	Investor-Owned Utility
IRP	Integrated Resource Planning
LMP	Locational Marginal Price
LOLE	Loss-of-Load Expectation
LOLH	Loss-of-Load Hours
LSE	Load Serving Entity
MSG	Multi-Stage Generator
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
NGR	Non-Generating Resource
NOB	Nevada-Oregon Border
NQC	Net Qualifying Capacity
NSI	Net Scheduled Interchange
OASIS	Open Access Same-Time Information System
OOS	Out Of State
OR	Operating Reserves
OTC	Once-Through-Cooling
PDR	Proxy Demand Response
PG&E	Pacific Gas and Electric
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
PSP	Preferred System Plan
PST	Pacific Standard Time
PTO	Participating Transmission Owner
NQC	Net Qualifying Capacity
RA	Resource Adequacy
RDRR	Reliability Demand Response Resource
RTM	Real-Time Market
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SMEC	System Marginal Energy Component
SOC	State of Charge
SPAP	State Power Augmentation Project
TOR	Transmission Ownership Right
WDAT	Wholesale Distribution Access Tariff
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market

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1 Introduction

The California Independent System Operator (CAISO) is working on a resource adequacy (RA) modeling and program design initiative through its working group structure to explore reforms needed to the CAISO's resource adequacy rules, requirements, and processes to ensure the future reliability and operability of the grid. This structure aims to give stakeholders a more active role in forming problem statements, identifying potential areas for analysis and supporting data, and scoping necessary market rule changes. Working group discussions help inform the scope of a formal stakeholder initiative.[1] This collaborative approach aims to align incentives, address concerns, and ensure that the RA program effectively supports grid reliability.

The overarching goal of CAISO's initiative is to create a robust and adaptive RA program that can respond to this changing energy landscape, support grid reliability, and facilitate the transition to a clean energy future. Overall, CAISO's RA modeling and program design initiative aims to ensure that the electric grid remains reliable and resilient by making sure there are adequate resources to meet demand, particularly during peak periods and under stressed conditions.

In this regard, CAISO is improving its models to better forecast and assess the availability of resources needed to meet peak demand and ensure grid reliability. This involves refining inputs, assumptions, and methodologies to reflect the evolving energy landscape, including the increasing penetration of renewable resources.

This document serves as a foundational reference for stakeholders ensuring transparency and consistency in the modeling process. By clearly defining these inputs and assumptions, CAISO aims to enhance the accuracy and reliability of its resource adequacy assessments and support informed decision-making. The following sections summarize the primary inputs and assumptions incorporated into this initiative's Track 1 modeling framework:

- **Chapter 2** details the scope of year-ahead, medium-term and long-term RA modeling with focus on year-ahead resource portfolio scenario development.
- **Chapter 3** gives a high-level overview of CAISO's production cost simulation model built using PLEXOS Integrated Energy Model.
- **Chapter 4** details capacity assumptions made under each year-ahead scenario and the data sources used to model supply-side resource operational attributes and constraints, generation profiles and any resource-specific modeling considerations.
- **Chapter 5** describes the methodology used to develop load, solar, wind and generator outage stochastic profiles.
- **Chapter 6** provides details on requirements and modeling of various ancillary service products.
- **Chapter 7** describes the transmission topology used in the model and assumptions about transmission limits, hurdle rates etc.

[1] CAISO Resource adequacy modeling and program design stakeholder initiative: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Resource-adequacy-modeling-and-program-design

- **Chapter 8** lists any resource-specific and transmission-related generic constraints enforced in the model.

2 CAISO Resource Adequacy Modeling

Current processes and procedures do not provide sufficient visibility into the entire generation fleet to enable CAISO to ensure system reliability as shown in Table 2.1. There is a need for additional consistent, transparent, and timely information on the sufficiency of the RA fleet in the CAISO Balancing Authority Area (BAA). Track 1 of the initiative aims to enhance CAISO's resource adequacy modeling capabilities by conducting a probabilistic assessment to evaluate the sufficiency of the CAISO BAA's resource adequacy (RA) portfolio in the year-ahead, medium-term (2-4 years) and long-term (5-10 years) timeframes to meet reliability objectives. In addition, this track will also consider updating CAISO's default resource counting rules and default planning reserve margin (PRM) to reflect reliability contribution of different resource types in a portfolio that achieves a "one day every 10 years loss-of-load expectation" ("1-in-10 LOLE") planning target.[2] This document focuses on CAISO's RA modeling in the year-ahead timeframe, provided details on its scope, and modeling assumptions.

Table 2.1 RA modeling needs and proposed timeframes

RA Timeframe	Sufficiency Analysis of..	Key Question
Year-Ahead (2025)	RA Showings	Are the year-ahead RA showings adequate?
Years 2-4 (2026-2028)	Existing installed capacity + authorized procurement	Is the current level of authorized procurement and contracted capacity sufficient?
Years 5-10 (2029 - 2034)	Resource plans by consolidating information from all IRPs	Are long-term plans producing resource adequate portfolios to meet reliability targets?

As part of this effort, the CAISO surveyed load-serving entities in its footprint to provide resource information under the year-ahead (2025), mid-term (2026-2028) and long-term (2029-2034) planning timeframes.[3] The LSE survey responses are non-binding, but informative for this effort.

Year-Ahead (2025): The survey requested LSE's to provide projected RA-eligible resource MWs of Net Qualifying Capacity (NQC) to meet 100 percent of LSE obligation for each month of 2025. LSE obligations (Load + Reserves) came from their respective Local Regulatory Authority (LRA) resource counting rules and Planning Reserve Margin (PRM) requirements.

Mid-term (2026-2028) and Long-term (2029-2034): The CAISO surveyed resource plans for the remaining nine years consistent with the IRP/Long-Term resource plans that LSE's provide to the CPUC via IRP filings or to the CEC. The LSE's provide their portfolio of resources to cover load + PRM for the annual peak month of years 2026-2028 (mid-term) and 2029-2034 (long-term).

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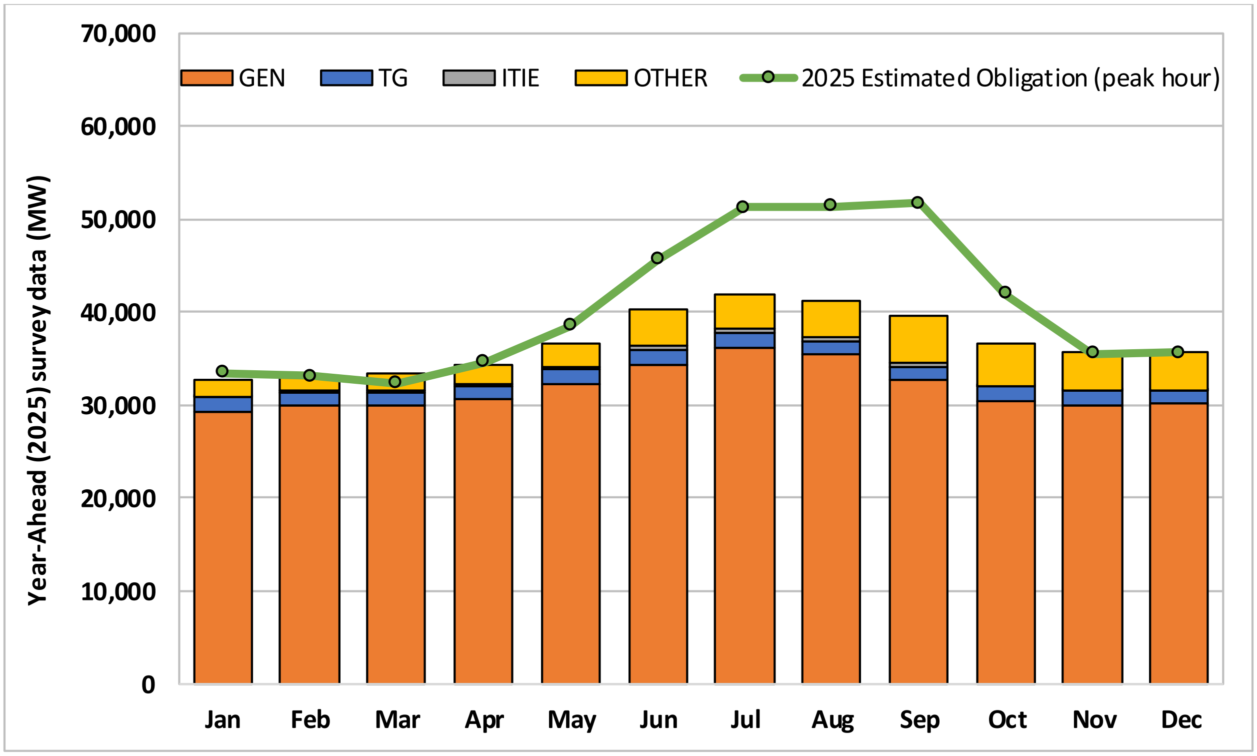
[2] LOLE is a measure of the number of days per year for which the available generation capacity is insufficient to serve the demand at least once during that day. 0.1 LOLE or 1-day-in-10 LOLE equates to "1 day with an event in 10 years".

[3] LSE Survey for RA modeling, RAM&PD Working Group, April 23, 2024: https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-Resource-Adequacy-Modeling-and-Program-Design-Working-Group-April23-2024.pdf

In response to CAISO's survey, 27 LSE's, representing an estimated 72 percent of CAISO balancing area load, have submitted resource portfolios corresponding to year-ahead, mid-term and long-term timeframes. Figure 2.1 shows a comparison of year-ahead (2025) survey data (based on shown/NQC values) by resource type (stacked bars) to an estimate of the 2025 obligation by month (green line). The estimated obligation based on peak hour for 2025 in this figure is calculated using the California Energy Commission's 2023 IEPR forecast for 2025 and the 2025 LSE's PRM, including credits. If the 2025 PRM data is unavailable, the 2024 data is used. The CAISO uses 2024 LSE plans to complete a 2025 resource portfolio for the year-ahead assessment.[4]

Figure 2.1 Year Ahead: Comparison of RA capacity from the survey to estimated obligation[5]



"Other" category includes 2025 expected resources and any resources without a matching Resource ID in Master File

[4] LSE's with submissions are mostly long on their 2025 obligations so the gap shown in the graph appears to be insignificant especially during winter months.

[5] CAM, DCCP, CPE and other credit allocations reported as RA capacity in year-ahead survey responses are excluded in this figure.

Year-ahead assessment modeling scenarios

The year-ahead assessment evaluates the reliability of the 2025 CAISO balancing area's reliability using the three resource portfolios in Table 2.2. The "Showings capped at obligation" and "Showings based on historical pattern" scenarios seek to assess different resource portfolios, which are based on the shown RA capacity from LSE survey plans available to the CAISO BA in 2025. The LSE's year-ahead (2025) survey responses and 2024 LSE plans[6] for LSEs without a survey response is the basis for the portfolios in both these scenarios.[7]

"Showings capped at Obligation" is one bookend scenario, which aims to capture a theoretical "what-if" case where LSEs only show resources up to their individual obligation.

Historically, on a system level, the total shown RA capacity exceeds RA obligations in each month, indicating a system that is long on shown RA capacity. Hence, the "Showings based on historical pattern" scenario uses the "Showings capped at obligation" resource portfolio and supplements it with extra capacity based on levels similar to historical averages of excess shown RA capacity from 2022 through 2024 as shown in Figure 2.2.

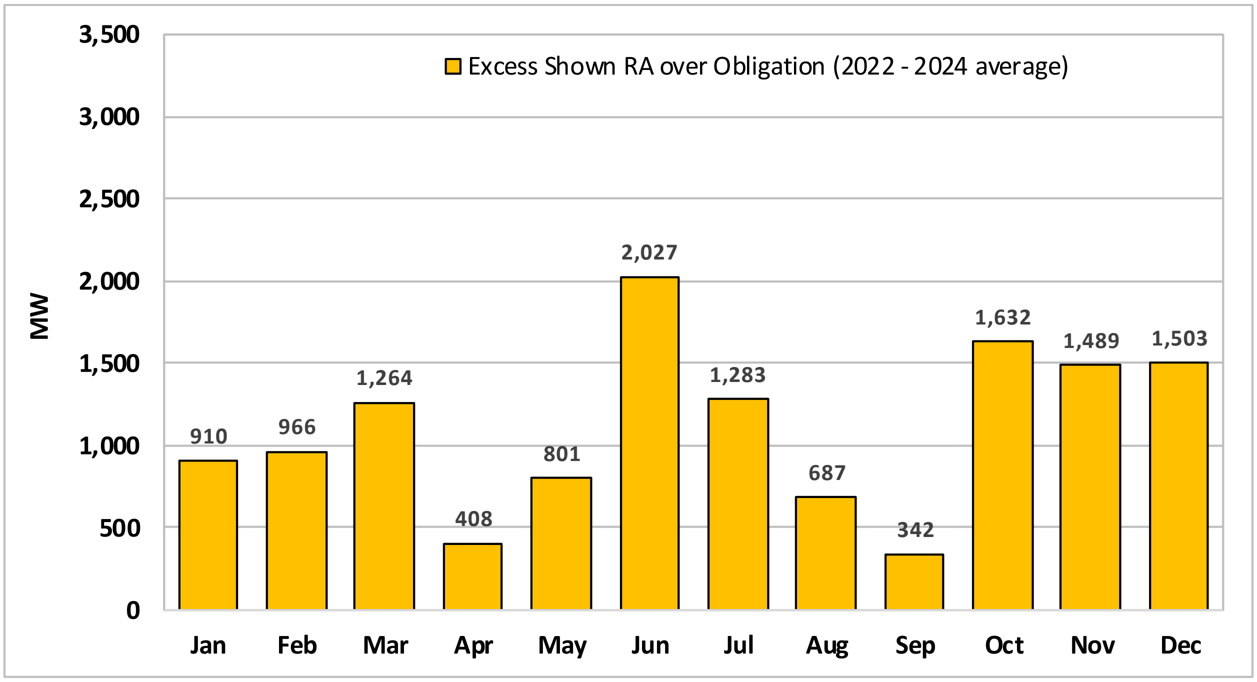
Table 2.2 Year-ahead modeling scenarios

Category	Year-Ahead (2025)		
	Showings capped at obligation	Showings based on historical pattern	All RA eligible
Objective	Assess CAISO BA reliability if LSEs only show resources up to their individual obligation	Assess CAISO BA reliability based on LSE RA showings only	Assess CAISO BA reliability based on all RA eligible resources
Resource list	LSE survey plus resource assumptions for LSE's without a survey response	LSE survey plus resource assumptions for LSE's without a survey response	June 14, 2024 NQC list plus expected additions and retirements
Resource Portfolio	•Shown RA resources only. On a system level, cap monthly shown capacity to obligation	•Shown RA resources only. On a system level, cap excess monthly shown capacity to historical levels	•All RA eligible resources from the NQC list. Including energy-only resources that support on-site charging.
	•RA imports only (2019-2024 average shown RA)	•RA imports only (2019-2024 average shown RA)	•Imports up to the net import limit
	•Average hydro conditions	•Average hydro conditions	•Average hydro conditions
Outage Assumptions	•Planned outages "not" modeled	•Planned outages "not" modeled	•Planned outages "are" modeled
	•Class average forced outage rates	•Class average forced outage rates	•Class average forced outage rates

[6] At the time data was compiled for year-ahead assessment, 100 percent monthly showing data for 2024 was available from January through September. For October through December, year-ahead showings data for 2024 was used.

[7] Performed resource level validation to ensure total contracted resource capacity is within that specific resource's Pmax.

Figure 2.2 Month-ahead excess shown RA over obligation by month (2022 – 2024)



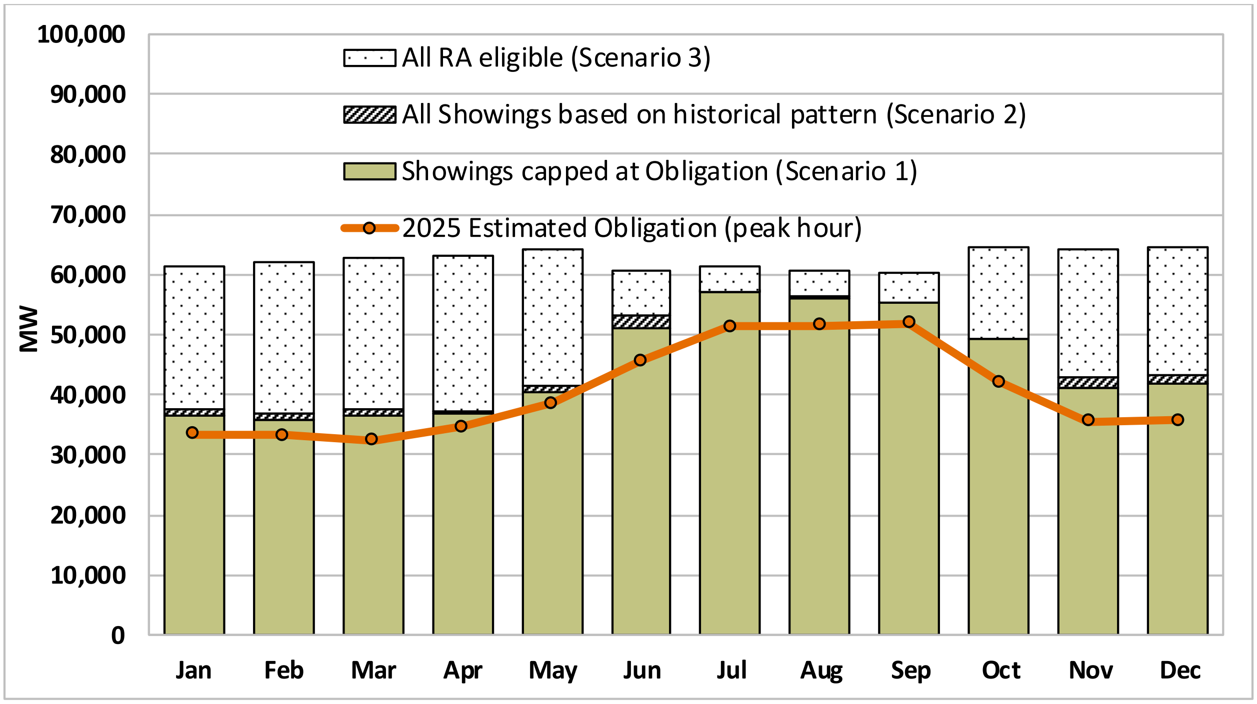
For both the "Showings based on historical pattern" and "Showings capped at Obligation" scenarios, shown RA capacity from interties (ITIEs) comes from the average showings between 2019 through 2024.

The final "All RA eligible" scenario is another bookend, which aims to assess CAISO BA's reliability of a portfolio that includes all RA eligible resources from CAISO's publicly posted NQC list. The portfolio for this scenario comes from NQC list published on June 14, 2024, expected new resources identified from the LSE survey in 2025 timeframe, and information on external tie-generators. The NQC list does not contain information on pseudo-tie generators and dynamic imports.

With respect to outage assumptions, "Showings based on historical pattern" and "Showings capped at Obligation" scenarios do not model planned outages. Under the RA program, if a shown RA resource is on planned outage, LSE has a requirement to substitute it with replacement capacity. These scenarios assume that any shown RA capacity that is on planned outage will be 100 percent substituted, hence these scenarios do not account for planned outages in the model. For the all RA eligible scenario, all the available and eligible RA resources are being modeled, so it is important capture planned outages of those resources.

Figure 2.3 shows the total shown capacity modeled each month under the "Showings capped at Obligation" scenario and incremental capacity modeled in "Showings based on historical pattern" and "All RA eligible" scenarios. As shown in the figure, the green bars represent the "Showings capped at Obligation" scenario where the system level capacity resulted in capacity over the estimated obligation, which is a peak hour obligation for each month for 2025. This is because the portfolio adjustments are made with a deterministic multi-hour stack model using CPUC's 2025 slide-of-day counting rules. The resource portfolio is adjusted to meet a load forecast plus 16.7 percent PRM obligation, the load-weighted PRM of CPUC and non-CPUC jurisdictional LSEs). Incremental capacity, diagonally shaded bars, represents the excess capacity (based on Figure 2.2) in the model under the "Showings based on historical pattern" scenario. The top most shaded bars represents the additional capacity modeled each month under the "All RA eligible" scenario.[8]

Figure 2.3 Modeled capacity differences between year-ahead portfolios



8 "All RA Eligible" scenario bars include a net import limit of 5,500 MW from June – Sep HE 16 – 22 and 11,665 MW during other hours. The import capacity from tie-generators (approximately 9,000 MW nameplate capacity) and interties from rest of WECC is counted against this limit in the model. Hence, the incremental capacity for "All RA Eligible" shown in this graph might be overstated.

3 CAISO's Production Cost Simulation Model Overview

The CAISO's stochastic production cost simulation model maintains a detailed representation of individual generation resources and load inside the CAISO across four zones: PG&E Bay, PG&E Valley, SCE and SDG&E with inter-zonal limits enforced. The zonal model assumes no transmission limits within each zone. This does not mean there are no transmission constraints within a zone. Such constraints may require local resources to be committed and dispatched, but the zonal model does not capture this requirement.

Out of state tie-generators are modeled as imports and are counted against the net import limit. Economic imports and exports are modeled as a single external market zone and are directly connected to the CAISO through the PG&E Valley, SCE and SDG&E zones. The interchange from the external zone is subject to CAISO's net import limit. The net import limit requires the sum of all imports and exports to the CAISO system to be less than 5,500 MW from June through September during hours 16 – 22. In all other hours, the net import limit is set to 11,665 MW.[9]

The zones also have ancillary services and load following requirements, either as fixed profiles or as a certain percent of their loads. The CAISO has total ancillary service and load following requirements for PG&E, SCE, and SDG&E zones together. Internal resources and select resources outside the CAISO may provide capacity for the ancillary service and load following requirements. All iterations use a single set of deterministic regulation and load following requirements. Spinning and non-spinning reserves are each set at 3 percent of load. Because load is a stochastic variable, the hourly values of spinning and non-spinning reserve requirements vary in each iteration.

The CAISO assesses the three resource portfolios discussed in Chapter 2, against a 1-in-10 Loss of Load Expectation (LOLE) planning target[10] using probabilistic production cost simulations in the energy modeling software PLEXOS. This approach utilizes 500-iteration full year hourly chronological simulations and is able to capture a wide range of system conditions in load, solar and wind generation, and generation resource outages. Hence, the model was able to simulate 500 years with a unique combination of load, solar, wind and outage profiles for each year. The simulation runs chronologically to co-optimize generation dispatch, ancillary services and load following requirements, subject to various operational and availability constraints.

The outcome of the co-optimization is a least-cost solution that meets load, ancillary service and load following requirements simultaneously. A capacity shortfall may occur if insufficient capacity is available to meet load or any of the ancillary service, frequency response (headroom), or load following requirements, or in meeting load. Alternatively, there are cases in which there is still available capacity but the unused capacity is not capable of following the load ramp.

The model sets a priority order for what requirements to meet first. The model design prioritizes serving, from high to low, energy, regulation-up, spinning, non-spinning, and load following-up on the upward side, and dump power, regulation-down, and load following-down on the downward side. That means when there is an upward shortfall, the shortfall occurs first in load following-up. If the shortfall is large enough, it will spill over to non-spinning, spinning, regulation-up and finally to unserved energy (loss of

[9] Net import limit is only applicable to "All RA Eligible" scenario.

[10] LOLE is a measure of the number of days per year for which the available generation capacity is insufficient to serve the demand at least once during that day. 0.1 LOLE or 1-day-in-10 LOLE equates to "1 day with an event in 10 years".

load). For this assessment, LOLE is number of days per year where the modeled resources are insufficient to serve load, frequency response (headroom), regulation up, or spinning reserves. Shortfall of non-spinning and load following up do not contribute to loss of load. The resulting frequency distribution of capacity shortfalls was used to calculate each portfolio's LOLE level in days per year.

As mentioned before, the model uses four stochastic variables – load, solar, wind and outages. The subsequent sections describe the methodology to derive load, solar and wind stochastic variables and their distributions. The outage variable is independent of the other stochastic variables and is unique for each resource in the CAISO BAA. The annual outage samples are generated randomly using historical class average forced outage and maintenance rates and are independent for each resource.

4 Resource Portfolio Assumptions

This chapter details capacity assumptions made under each year-ahead scenario as well as the data sources for the supply-side resource operational attributes and constraints, generation profiles, and any resource-specific modeling considerations generally applicable to all scenarios.

Table 4.1 shows RA shown capacity by month and fuel type primarily from the LSE survey in year-ahead timeframe (2025). As mentioned in Chapter 2, 2024 showings information supplements the survey data for LSE's that did not respond to the survey. These two sources create a complete resource portfolio that is used to compare against an estimated obligation for each month in 2025. This information combined with historical surplus patterns each month (based on Figure 2.2) form the basis of capacity modeled for "Showings capped at Obligation" and "All Showings based on historical pattern" scenarios.

Following are capacity assumptions by fuel type considered in Table 4.1:

1. For solar, wind and hydro resources, the table lists total shown capacity from LSE surveys (and 2024 LSE plans where data is not available) to be able to compare against the estimated obligation. However, solar and wind resources use nameplate capacities in the creation of stochastic profiles for the simulation. Hydro resources use an average hydro year profile.
2. Proxy demand response resources are modeled at their shown capacity and included in "Other" category.
3. Some of the contracted capacity from LSE survey was missing a fuel type identifier and was modeled as firm capacity in this study and categorized under "Unknown" fuel type below.
4. Import RA capacity on interties is the average shown RA each month from 2019 through 2024. External tie-generators and dynamic imports are modeled at their shown capacity from the survey. Hence, modeled import capacity on ties and all pseudo-tied and dynamic imports from out of state generators is considered firm in the "Showings" scenarios and the exceeds the net import limit of 5,500 MW enforced in the "All RA eligible" in some summer months as indicated by "Tie-generators" and "Import RA on ties" values in Table 4.1.
5. For the remaining fuel types, modeled capacity in these scenarios is consistent with shown capacity either in the LSE survey or in 2024 LSE plans where data is not available.

Table 4.1 2025 Shown capacity by month and fuel type

Fuel type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Battery	9,482	9,607	9,985	10,094	10,419	11,573	11,646	11,735	12,469	12,211	12,211	12,212
Biogas	148	144	141	139	130	128	109	138	138	133	136	138
Biomass	242	244	219	189	250	260	269	253	260	222	236	239
Distillate	110	110	110	110	110	110	110	110	110	110	110	110
Geothermal	862	858	832	832	842	858	847	857	858	887	904	897
Hybrid	618	635	672	641	754	909	1,042	997	927	815	796	780
Hydro*	4,541	4,383	4,613	5,199	5,196	5,490	5,832	5,898	5,597	4,027	4,128	4,334
Natural Gas	21,098	20,728	19,325	19,810	20,725	22,129	22,040	22,307	22,068	22,215	20,802	21,104
Nuclear	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,290	2,280	2,280	2,280	2,280
Other	61	62	68	137	151	189	208	215	225	36	32	25
Solar*	100	358	543	664	2,512	3,558	4,739	4,159	1,493	744	547	350
Unknown	265	238	248	274	200	281	333	402	1,018	580	331	255
Waste Heat	0	0	0	0	0	24	24	23	24	24	0	0
Wind*	908	1,017	989	1,182	1,422	1,194	1,134	897	752	549	788	935
Tie-Generators	2,121	1,923	1,904	1,832	2,080	1,957	2,101	2,232	2,343	2,131	2,032	2,122
Import RA on Ties	732	720	778	1,054	1,607	2,365	3,419	3,545	4,767	2,243	900	776
2025 Total Shown Capacity	43,566	43,306	42,705	44,437	48,677	53,305	56,132	56,059	55,330	49,206	46,233	46,555

As the CPUC is moving to slide-of-day framework beginning 2025, portfolio adjustments are made using a deterministic multi-hour stack model using CPUC's 2025 slide-of-day counting rules applied to a resource portfolio such that it at least meets a load forecast plus 16.7 percent PRM obligation (load-weighted PRM which includes CPUC and non-CPUC jurisdictional LSEs). Figure 4.1 shows the resulting adjustments under the "Showings capped at obligation" scenario for January 2025. The figure also shows how the excess storage during evening peak hours (left) addresses the shortfalls in the stack (right) which is in line with CPUC's slice-of-day rules.

Figure 4.1 "Showings capped at obligation" multi-hour stack with adjustments (Jan 2025)

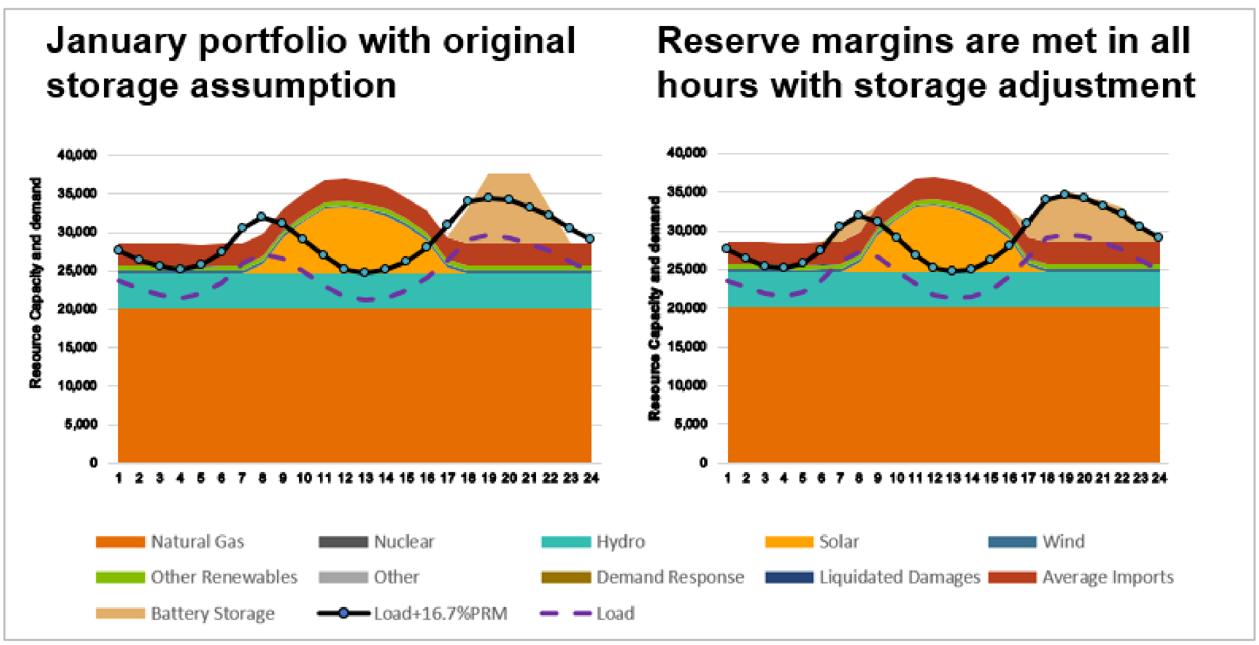


Table 4.2 includes the amount of shown capacity (from Table 4.1) removed by fuel type and the final modeled capacity for each scenario. These adjustments also take into account historical shown RA (2024)

by resource class relative to total shown capacity in each month. The difference between total shown capacity in Table 4.1 and any resource class adjustments made in Table 4.2 is the final modeled capacity for each scenario. For the "All Showings based on historical pattern" scenario, the adjustments ensure there is a surplus in most months, consistent with historical levels (based on Figure 2.2). To reflect this in the production cost model for each scenario, constraints are enforced at the technology level (Gas, Storage and Nuclear) such that only the resulting monthly supply capacity after these adjustments is available for commitment and dispatch.

Table 4.2 Capacity adjustments by scenario

Showings capped at obligation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gas	1,000	1,000		3,000	3,851							
Storage	3,877	4,098	4,038	2,927	3,004	2,282					4,978	4,689
Nuclear	2,280	2,280	2,280	1,774	1,281							
Total capacity removed (MW)	*7,157*	*7,378*	*6,318*	*7,701*	*8,136*	*2,282*	*0*	*0*	*0*	*0*	*4,978*	*4,689*
Import capacity added (MW)							*820*					
Modeled capacity (MW)	*36,408*	*35,928*	*36,387*	*36,736*	*40,541*	*51,023*	*56,952*	*56,059*	*55,330*	*49,206*	*41,255*	*41,866*
Showings based on historical pattern	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Gas				2,600	3,000							
Storage	3,877	4,098	2,800	2,927	3,004	250					3,500	3,200
Nuclear	2,280	2,280	2,280	1,774	1,281							
Total excess capacity removed	*6,157*	*6,378*	*5,080*	*7,301*	*7,285*	*250*	*0*	*0*	*0*	*0*	*3,500*	*3,200*
Import capacity added (MW)							*1,120*	*300*				
Modeled capacity (MW)	*37,408*	*36,928*	*37,625*	*37,136*	*41,392*	*53,055*	*57,252*	*56,359*	*55,330*	*49,206*	*42,733*	*43,355*

Table 4.3 shows "All RA Eligible" scenario modeled capacity by month and fuel type, based on the final NQC list published on June 14, 2024 and the 2025 contracted capacity from expected new resources in the LSE survey data. Following are capacity assumptions by fuel type considered in Table 4.3:

1. Natural gas and battery resources are modeled at their nameplate capacities.
2. For solar, wind and hydro resources, the table lists total NQC capacity to be able to be comparable to other scenarios mentioned before. However, this scenario uses nameplate capacities in the creation of stochastic profiles for the simulation and when modeling solar and wind resources in the study. Hydro resources use an average hydro year profile.
3. For QFs, CHP, cogen facilities, must-take, geothermal and bio fuel resources, NQC value is modeled consistent with their bidding levels in the market.
4. Proxy demand response resources are modeled at their NQC capacity and included in "Other" category.
5. Partial deliverable resources have their capacity scaled down based on their deliverable MW.[11]

[11] *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.

6. "Energy-only" solar resources that are co-located with a "fully-deliverable" battery resource which support onsite charging are included in this scenario.[12]
7. 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, which total around 9,000 MW. However, these resources are subject to the net import limit of 5,500 MW from June through September during hours 16 – 22. In all other hours, the net import limit is 11,665 MW.

Table 4.3 "All RA Eligible" scenario modeled capacity by month and fuel type

Fuel type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Battery	10,038	10,238	10,608	10,738	10,988	12,191	12,304	12,304	13,042	13,042	13,042	13,057
Biogas	179	179	178	175	176	176	175	173	174	172	175	175
Biomass	305	307	289	291	313	323	329	320	320	304	304	307
Distillate	110	110	110	110	110	110	110	110	110	110	110	110
Geothermal	1,310	1,308	1,308	1,291	1,294	1,300	1,298	1,298	1,300	1,293	1,310	1,310
Hybrid	1,718	1,718	1,718	1,718	1,718	1,623	1,623	1,623	1,623	1,623	1,623	1,623
Hydro*	5,699	5,767	6,160	6,277	6,540	6,975	7,386	7,291	6,813	5,778	5,666	6,005
Natural Gas	26,195	26,196	26,115	26,210	26,221	26,233	26,232	26,262	26,244	26,288	26,211	26,191
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	207	238	237	280	311	369	378	334	54	48	44	37
Solar*	124	518	616	776	1,296	2,415	2,748	2,367	1,817	1,202	899	550
Waste	79	79	78	76	71	79	78	78	79	79	69	80
Wind*	1,357	1,451	1,289	1,216	1,280	1,093	995	812	833	746	978	1,202
Total	**49,602**	**50,387**	**50,988**	**51,441**	**52,598**	**55,167**	**55,935**	**55,253**	**54,688**	**52,964**	**52,711**	**52,926**
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

Extreme weather events and risks such as wildfire or severe drought remain a threat to grid reliability and can strain the grid for days or weeks. Assembly Bill 205 created the Strategic Reliability Reserve (SRR) in 2022, to expand the resources capable of managing or reducing demand during extreme events. The SRR provides funding to secure additional resources to address extreme events beyond traditional resource planning targets. Table 4.4 lists existing and new resources contracted under the state's Strategic Reliability Reserve (SRR) program, which are not included in the year-ahead modeling scenarios.

[12] *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.

Table 4.4 Electricity Supply Strategic Reliability Reserve Program (ESSRRP) resources

Resource Name	BAA	Max Capacity (MW)
Alamitos Gen Sta. Unit 3	CISO	326.8
Alamitos Gen Sta. Unit 4	CISO	334.4
Alamitos Gen Sta. Unit 5	CISO	480.0
Huntington Beach Gen Sta. Unit 2	CISO	226.8
Ormond Beach Gen Sta. Unit 1	CISO	741.3
Ormond Beach Gen Sta. Unit 2	CISO	750.0
Channel Islands Power	CISO	27.5
Greenleaf 1	CISO	60.0
Roseville Peakers TM2500	BANC	60.0
Enchanted Rock Lodi	CISO	48.0
Enchanted Rock Claribel	BANC	48.0
Enchanted Rock Marshall Unit 1	TIDC	11.7
Enchanted Rock Marshall Unit 2	TIDC	11.7
Enchanted Rock Marshall Unit 3	TIDC	11.7
Enchanted Rock Marshall Unit 4	TIDC	11.7
Total ESSRRP Capacity (MW)		**3,149.5**

Thermal Generators

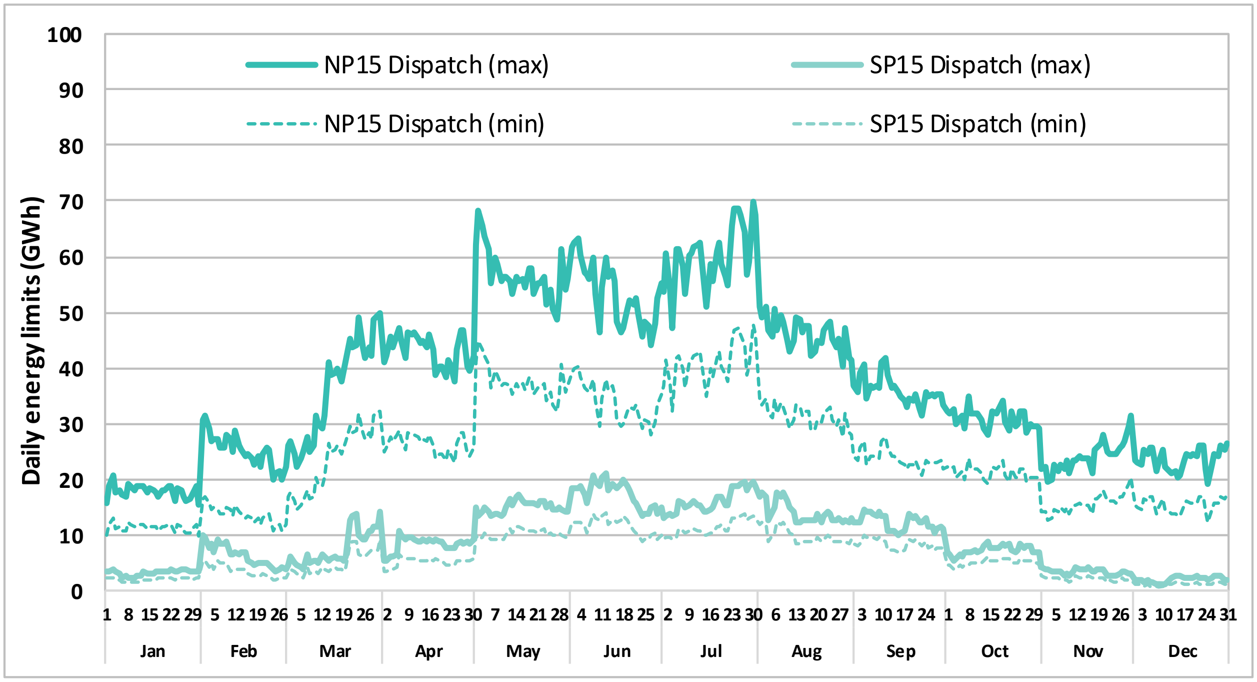
Thermal generators are modeled at a unit level in this study. Diablo Canyon nuclear plant is modeled as available through 2029 (Unit 1) and 2030 (Unit 2) based on SB 846 ruling. Operating characteristics that constraint the unit commitment and dispatch of thermal resources (natural gas, distillate, and 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 and WECC ADS dataset are the primary sources for these operating characteristics on a technology level. CPUC's Integrated Resource Planning (IRP) process is the source for the fuel prices.

With respect to ancillary services (regulation and spinning) 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.

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. The dispatchable hydro generation is optimized subject to daily maximum and minimum energy limits as shown in Figure 4.2. These energy limits are derived from historical generation data where snowpack and reservoir conditions that most closely resemble an average hydro year. The model in this analysis for an "average hydro" year was based on the 2018 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.

Figure 4.2 Dispatchable hydro daily energy limits



Pump storage generators are modeled individually and are optimized subject to storage capacity, inflow and target limits, and cycling efficiency. The pumping and generation schedules for pumped storage resources 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.

Renewables

The model represents renewable resources such as solar, wind, geothermal, biofuels and small hydro resources on an aggregated basis and by zone. The modeled capacities for each of these resource types (except solar and wind) differ based on the scenarios and outlined in Table 4.1 and Table 4.3. For solar and wind resources, their respective nameplate capacities shown in Table 4.5 and Table 4.6 are calculated by scenario and are used as an input into creating 500 stochastic profiles for 2025.[13]

Solar and wind components of hybrid and co-located resources are aggregated and modeled separately and used in developing the stochastic profiles. Hybrid and co-located resources are subject to their respective Pmax and aggregate capability constraints, respectively.

[13] The tables exclude solar and wind capacity from hybrid resources but are used in developing the respective stochastic profiles.

Table 4.5 Solar and Wind nameplate capacities for "Showings" scenarios

Fuel type	Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Solar	GEN	15,839	15,991	15,839	15,991	15,991	16,146	16,450	17,043	17,043	15,391	15,641	15,489
Solar	TG	522	592	592	592	592	592	592	592	592	522	522	522
Wind	GEN	5,508	5,508	5,603	5,603	5,603	5,699	5,694	5,699	5,673	5,523	5,523	5,523
Wind	TG	1,596	1,596	1,596	1,596	1,596	1,596	1,596	1,596	1,596	1,596	1,596	1,596

Table 4.6 Solar and Wind nameplate capacities for "All RA Eligible" scenario

FUEL_TYPE	Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Solar	GEN	17,031	17,031	17,331	17,331	17,631	17,887	17,887	17,887	17,887	17,887	17,807	17,922
Solar	TG	702	702	702	702	702	832	832	832	832	832	832	832
Wind	GEN	6,319	6,319	6,317	6,081	6,081	6,081	6,062	6,066	6,066	6,060	6,060	6,060
Wind	TG	2,051	2,051	2,051	2,051	2,051	2,051	2,051	2,051	2,051	2,051	2,051	2,051

Battery Energy Storage Modeling

Battery energy storage resources are modeled as 4-hour duration with an 85 percent round trip efficiency on an aggregated basis and by zone. The modeled capacities differ based on the modeling scenarios and outlined in Table 4.1 and Table 4.3. 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 aggregated and modeled separately by zone. As mentioned earlier, hybrid and co-located resources are subject to their respective Pmax and aggregate capability constraints, respectively.

Demand Response Modeling

Demand response resources are modeled 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 be triggered more frequently than is realistic. Demand response resources also have maximum run time and maximum daily starts constraints enforced. In the model, demand response resources cannot provide ancillary services or load following reserves.

5 Stochastic Variables

The CAISO's model has stochastic variables for load, solar generation, wind generation and outages. The load variable is the aggregate load of the CAISO, excluding the California Department of Water Resources (CDWR) pump load. The solar variable is the aggregate solar generation of behind-the-meter PV, solar resources inside the CAISO and from out-of-state. The wind variable is the aggregate wind generation by wind resources inside the CAISO and out-of-state. In the simulations, the stochastic values of load, solar and wind generation are distributed to the five zones - PG&E Bay, PG&E Valley, SCE, SDG&E, and the external zone by ratios calculated based on their respective base profiles. Lastly, the model includes 500 random outage samples for each generation resource inside the CAISO. Following sections provide a detailed description of mean reversion random walk solar, wind and load stochastic profiles methodology as well as outage profiles methodology, which is independent of all other variables.

5.1 Solar and Wind Profiles

Solar and wind base profiles are used as an input into the CAISO's mean reversion stochastic model.[14] Solar base profile comes from the CPUC's recently adopted Preferred System Plan (PSP).[15] The wind base profile comes from a 5-year (2019 – 2023) average of actual CAISO EMS data normalized by annual installed capacity. Mean reversion ratios of solar and wind 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 CAISO then applied these ratios to the solar and wind base profiles to generate 500 stochastic samples for solar and wind generation. Figure 5.1 and

Figure 5.2 shows hourly distribution of solar and wind profiles for each month of 2025 used in the "All RA Eligible" scenario based on capacities listed in Table 5.1. For the "Showings" scenarios, the same 500 sample profiles for solar and wind are scaled using the solar and wind nameplate capacities listed in Table 5.2.

Table 5.1 Solar and Wind nameplate capacities for "All RA eligible" scenario

FUEL_TYPE	Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Solar	GEN	17,031	17,031	17,331	17,331	17,631	17,887	17,887	17,887	17,887	17,887	17,807	17,922
Solar	TG	702	702	702	702	702	832	832	832	832	832	832	832
Wind	GEN	6,319	6,319	6,317	6,081	6,081	6,081	6,062	6,066	6,066	6,060	6,060	6,060
Wind	TG	2,051	2,051	2,051	2,051	2,051	2,051	2,051	2,051	2,051	2,051	2,051	2,051

[14] 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

[15] 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

Table 5.2 Solar and Wind nameplate capacities for "Showings" scenarios

Fuel type	Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Solar	GEN	15,839	15,991	15,839	15,991	15,991	16,146	16,450	17,043	17,043	15,391	15,641	15,489
Solar	TG	522	592	592	592	592	592	592	592	592	522	522	522
Wind	GEN	5,508	5,508	5,603	5,603	5,603	5,699	5,694	5,699	5,673	5,523	5,523	5,523
Wind	TG	1,596	1,596	1,596	1,596	1,596	1,596	1,596	1,596	1,596	1,596	1,596	1,596

Figure 5.1 2025 Hourly solar stochastic sample distribution (All RA Eligible scenario)

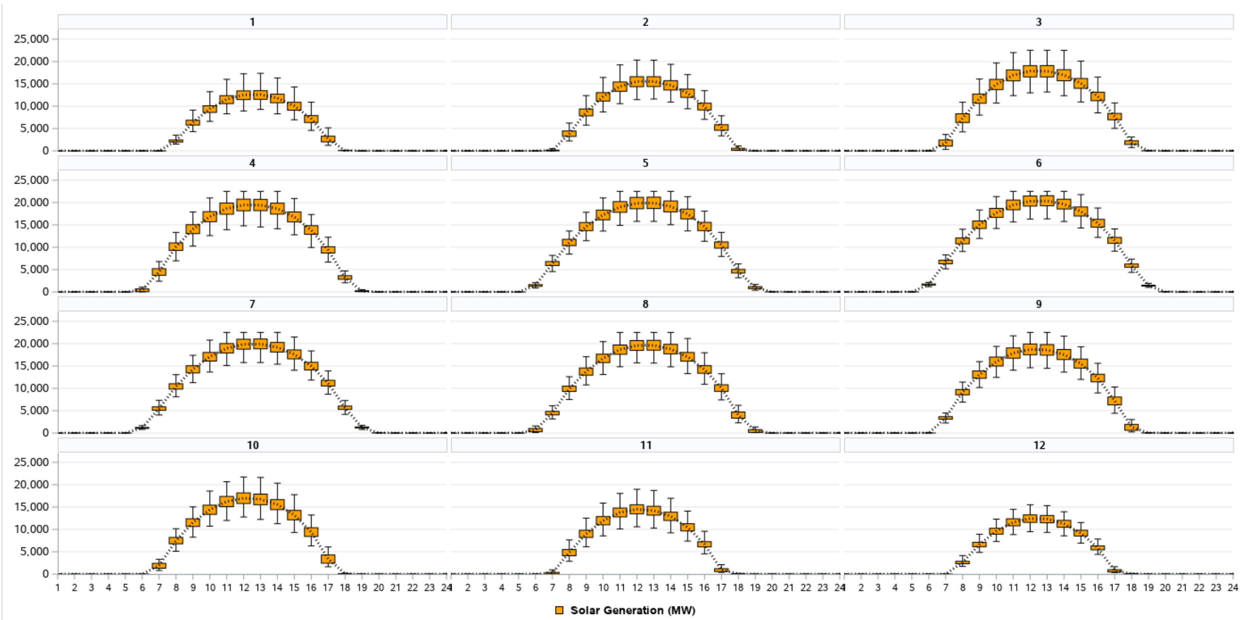
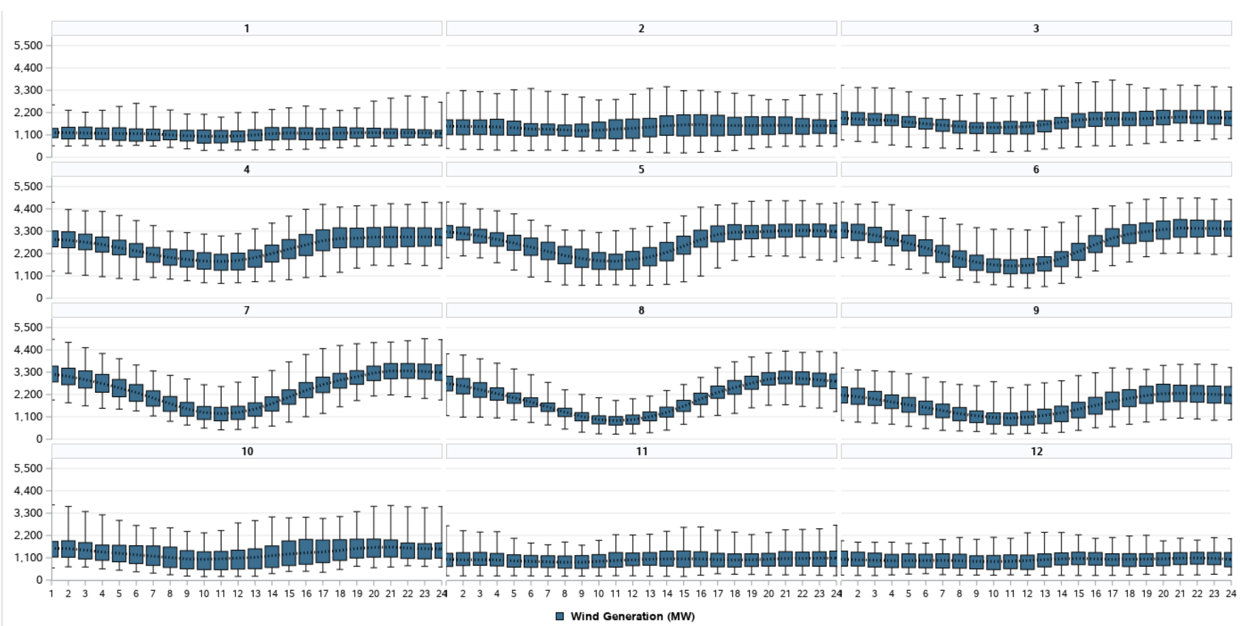


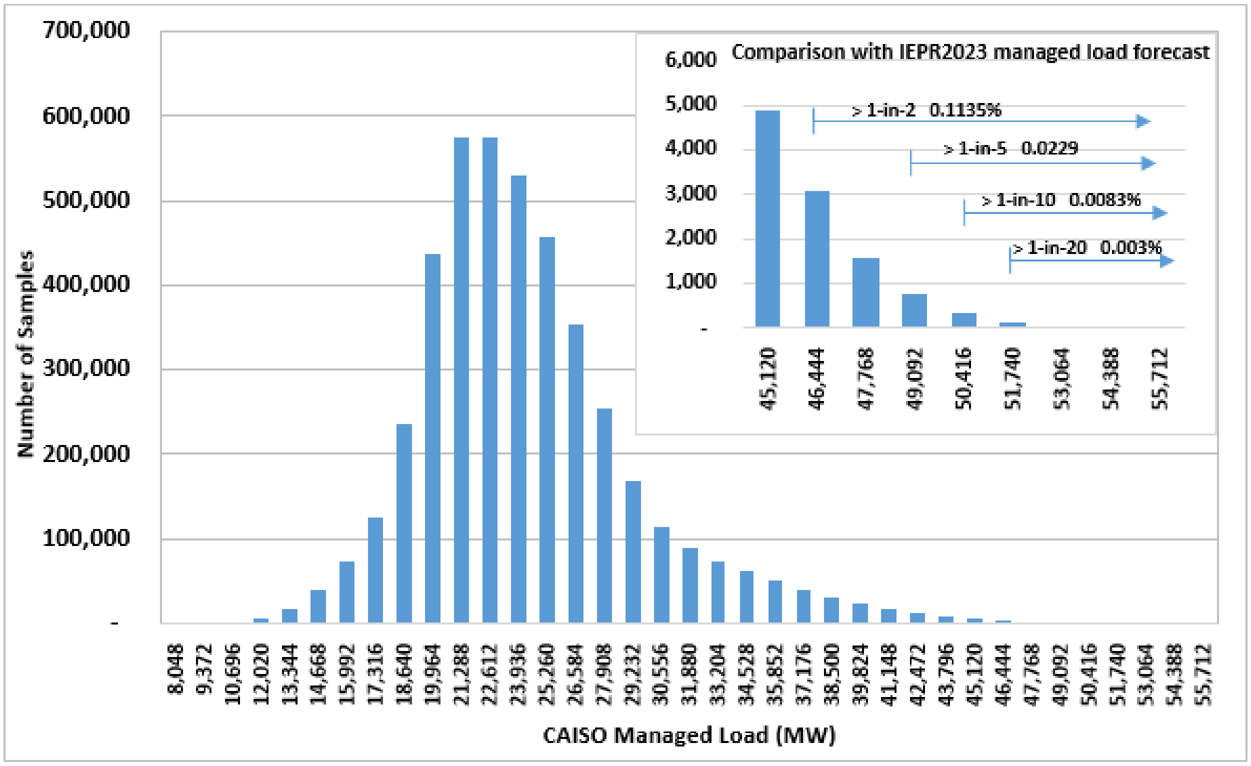
Figure 5.2 2025 Hourly wind stochastic sample distribution (All RA Eligible scenario)



5.2 Load Profiles

The CEC baseline managed hourly demand forecast from 2023 IEPR[16] was an input to CAISO's mean reversion load forecast model.[17] This model has two processes: The first process uses CAISO's historical load profiles 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 plus behind-the-meter solar generation to generate 500 stochastic hourly gross load profiles. The managed hourly load was calculated by subtracting behind-the-meter solar from the projected 500 stochastic gross load profiles. Figure 5.3 shows the frequency distribution of loads used in the stochastic model. Figure 5.4 shows hourly distribution of managed load profiles for each month of 2025.

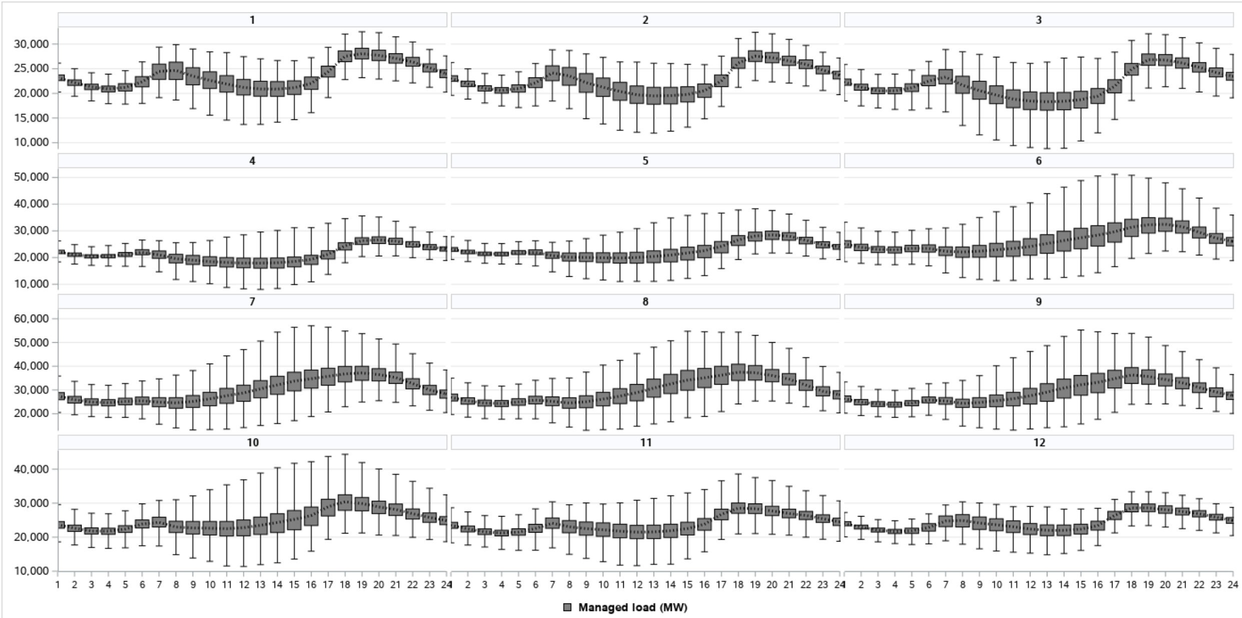
Figure 5.3 Frequency distribution of 2025 load



[16] CEC, Adopted 2023 Integrated Energy Policy Report with Errata, Feb 14, 2024: https://efiling.energy.ca.gov/GetDocument.aspx?tn=254463

[17] 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 5.4 2025 Hourly managed load stochastic sample distribution



5.3 Generator Outage Profiles

Table 5.3 shows forced and maintenance outage rates that are calculated as technology average based on the CAISO's 2009 - 2014 actual outage data. For battery, biofuels and geothermal resources a capacity derate is used to represent a combined outage rate. .

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 maintenance 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.

As shown in Table 2.2, "Showings based on historical pattern" and "Showings capped at Obligation" scenarios do not model planned outages. Under the RA program, if a shown RA resource is on planned outage, LSE has a requirement to substitute it with replacement capacity. These scenarios assume that any shown RA capacity that is on planned outage will be 100 percent substituted and hence does not account for planned outages in the model. On the other hand, since all the available and eligible RA resources are modeled in the "All RA eligible" scenario, it is important capture planned outages of those resources. Hence, generator outage profiles created using PASA module exclude planned maintenance rate properties when simulating the resource portfolios for "Showings based on historical pattern" and "Showings capped at Obligation" scenarios.

Table 5.3 Outage rates by technology type

Technology type	Forced Outage Rate	Maintenance Rate
Battery Storage	5.20%	
Biogas	7.60%	
Biomass	5.70%	
Cogen	4.57%	4.57%
Combined Cycle	5.82%	6.76%
Combustion Turbine	4.42%	4.53%
Geothermal	2.60%	
Steam Turbine	7.89%	9.11%
Pumped Storage	4.50%	8.65%

6 Transmission Topology

Figure 6.1 shows a high-level representation of CAISO and rest of the WECC topology used in the stochastic model. The stochastic model maintains a detailed representation of individual generation resources and load inside the CAISO across four zones: PG&E Bay, PG&E Valley, SCE and SDG&E with inter-zonal limits enforced. Economic imports and exports to CAISO are modeled as a single external market zone. The external zone is connected to the CAISO directly through the PG&E Valley, SCE and SDG&E zones and provides the CAISO with dedicated and economic imports. It also takes CAISO exports when economic, subject to the export constraints. CAISO scheduling coordinators own portions of some out-of-state renewable and non-renewable resources, such as Hoover, Palo Verde, etc. and are modeled as must-take dedicated imports. Hence, the external zone also models California out-of-state pseudo-tie generators for dedicated imports and a "market station" for economic import and export that is subject to a price curve.

Figure 6.1 CAISO zonal topology in the stochastic model

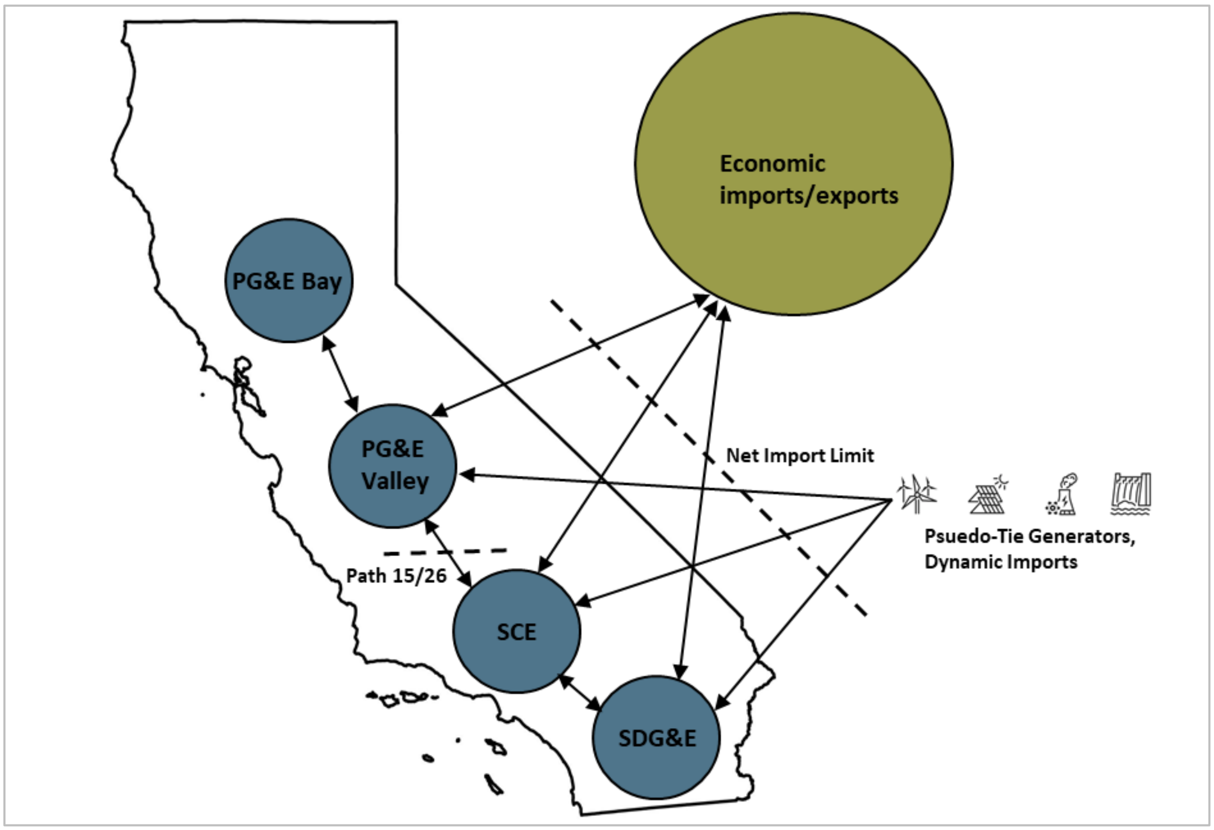


Table 6.1 summarizes the internal and external line path ratings and import/export hurdle rates used in the model. The model also enforces a Path 15 nomogram with a flow limit of 5,000 MW between PG&E Valley and SCE zones. Each of these path ratings and hurdle rates are derived from a deterministic model run. As mentioned earlier, the external zone, which provides with dedicated imports from pseudo-tie

generators and economic imports/exports from rest of the WECC region is subject to a net import limit of 5,500 MW (June through September during hours 16 – 22) and 11,665 MW (all other hours).[18]

Table 6.1 Model path ratings and hurdle rates

From	To	Min/Max Flow Ratings (MW)	Import/Export Hurdle Rate ($/MWh)
PG&E Bay	PG&E Valley	-15,000/15,000	0
PG&E Valley	SCE	-3,000/4,000	0
SCE	SDG&E	-2,500/4,104	0
External	PG&E Valley	-6,630/7,800	$10.48/$10.85
External	SCE	-12,538/13,502	$13.24/$10.85
External	SDG&E	-3,831/4,223	$13.24/$10.85

As mentioned before, the market station handles the CAISO's economic import and export. To enable the economic import and export capability, a 4-block price curve is used for the market station. This price curve is based on the market clearing prices (MCP) in the deterministic model run.[19] Table 6.2 represents the price curve for the market station resulting from the deterministic model run. When the CAISO MCP is higher than the price of the curve plus the import hurdle rate, the CAISO imports economically from the market station, subject to the CAISO net import limit. Conversely, when the CAISO MCP plus export hurdle rate is lower than the price of the first block of the curve, the CAISO exports economically to the market station; subject to the CAISO zero net export constraint.

Table 6.2 Price Curve of the Market Station

	1	2	3	4
Capacity (MW)	0 - 3,149	3,149 - 6,297	6,297 - 9,446	9,446 - 15,000
Price ($/MWh)	$15.02	$21.69	$24.94	$32.89

[18] Net import limit is only applicable to "All RA Eligible" scenario.

[19] CAISO IRP 38 MMT Core Portfolio PLEXOS Deterministic model, Feb 11, 2022: https://www.caiso.com/documents/caiso-integrated-resource-planning-38mmt-coreportfolio-plexos-deterministic-2026-2030.zip

7 Ancillary Services Modeling

CAISO 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 CAISO 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. All iterations use a single set of deterministic regulation and load following requirements.

The CAISO uses a probabilistic Monte Carlo simulation program to calculate regulation and load following requirements. The purpose of this program is to calculate the intra-hour regulation up/down and load following up/down requirements and convert these intra-hour requirements to hourly requirements. Inputs are 1-minute and hourly projected load, wind and solar generation profiles of the simulation year as well as hourly forecast standard deviations of load, wind and solar generation, and real time load forecast standard deviation. Outputs are hourly profiles for regulation and load following requirements that are inputs for the CAISO's stochastic production cost simulation model.

7.1 Regulation and Spinning/Non-Spinning Requirements

The regulation up or down requirement is the maximum of net load differences between the 1-minute and 5-minute forecast values within the 5-minute interval in an upward or downward direction. Spinning and non-spinning reserve are each 3 percent of load, respectively. Because load is a stochastic variable, the hourly values of spinning and non-spinning reserve requirements vary in each iteration. Figure 7.1 and Figure 7.2 show hourly distributions of regulation up and down requirements for each month of 2025.

Figure 7.1 Hourly distribution of regulation up requirements (2025)

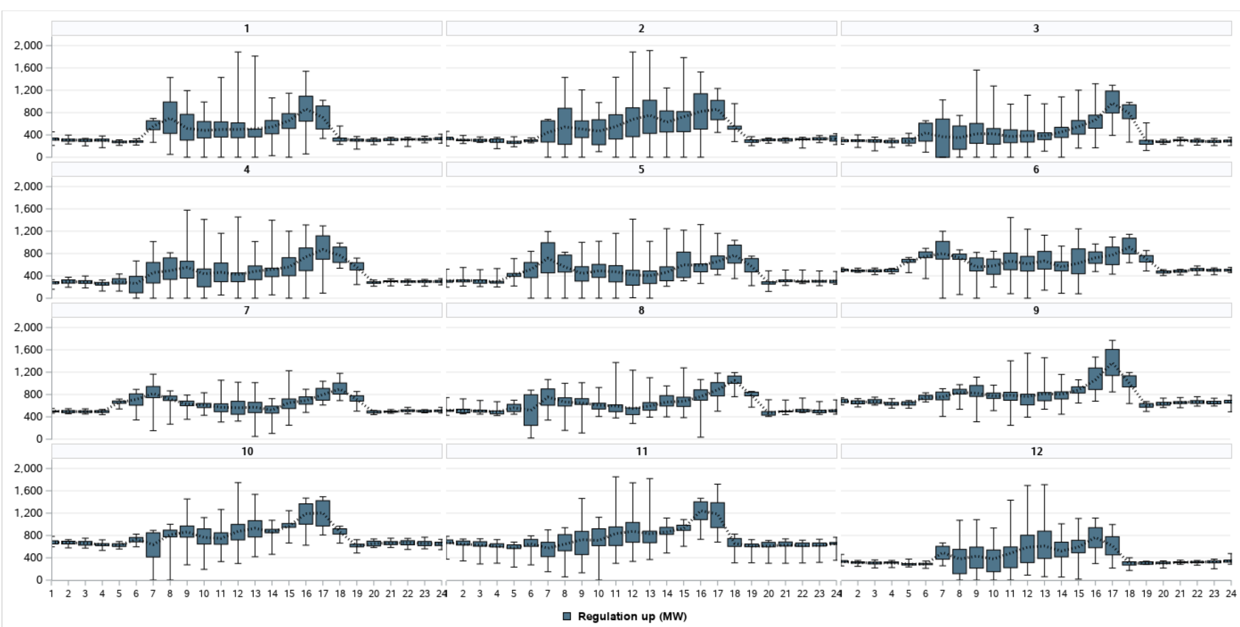
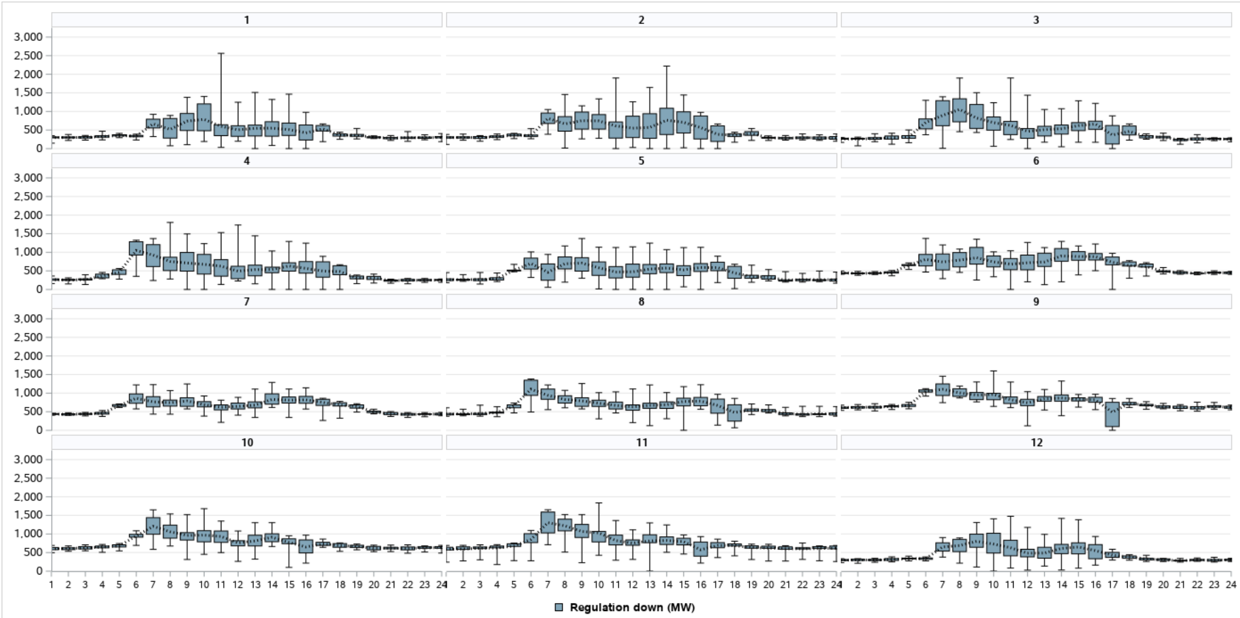


Figure 7.2 Hourly distribution of regulation down requirements (2025)



7.2 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. Figure 7.3 and Figure 7.4 show hourly distributions of load following up and down requirements for each month of 2025.

Figure 7.3 Hourly distribution of load following up requirements (2025)

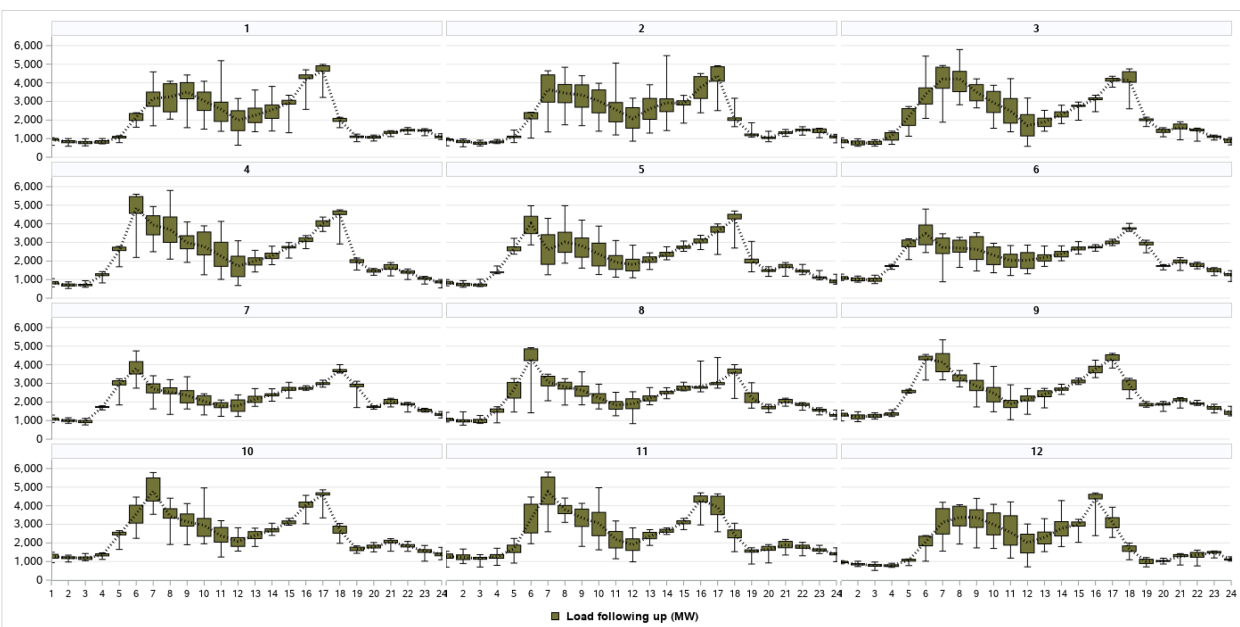
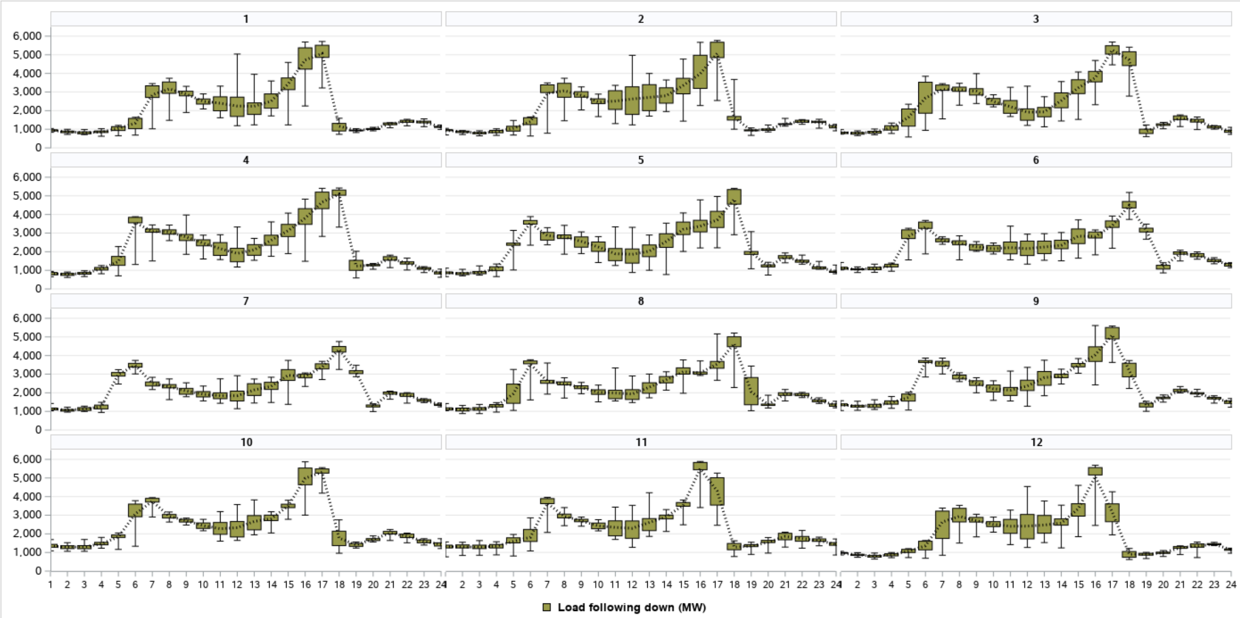


Figure 7.4 Hourly distribution of load following down requirements (2025)



In addition to ancillary service and load following requirements, the model also enforces a frequency response reserve with a minimum provision of 376 MW to satisfy a NERC requirement. The model enforces a constraint such that only internal combined cycle and battery energy storage resources provide this reserve. This reserve product requires that generators providing it be able to maintain the required response for 30 minutes.

8 Resource and Transmission Constraints

Table 8.1 provides details on any resource specific and transmission constraints enforced in the model.

Table 8.1 Generic constraints enforced in the PLEXOS model

Constraint Category	Description
RETier	Tiered price solar and wind curtailment constraint
USELE3350	Ensure the maximum unserved energy in an hour is less than 30,000 MW
CAISO Import	A net import limit of 5,500 MW is used from June through September during hours 16 – 22. In all other hours, a limit of 11,665 MW is used in the model. This constraint in enforced on imports from external tie-generators and imports/exports from "rest of WECC" region
NetExport CAISO	Constrain CAISO net export to less than 5,000 in any hour
Path 15	Flow limit of 5,000 MW enforced between PG&E Valley and SCE zones in the model
Hydro Pumped Storage End Volume	Daily end-of-period storage volume limits on CAISO PSP units (Eastwood, Helms, Lake Hodges and San Luis)
Hydro Pumped Storage Starts	Limit Pumped Storage starts to one per day
Helms Pump Gen Limits	Constraint to ensure the coordination of Helms 1, 2, 3 generation and pumping modes
Humboldt Min Gen	Humboldt minimum generation in the winter (November - February, 9 am-9pm) must be at least 100 MWs
Reg - Spin Limit	Limits Reg and Spin contributions to ramp * 10 specifically for CAISO dispatchable hydro, Helms, Pio Pico and SCE LCR CCGT and LMS100 units
CAISO Unit Starts	Limit CAISO natural gas unit daily starts to less than or equal to 1
50PCTLFDRisk	Constraints on solar and wind so that they cannot provide more than 50 percent of load following down requirement

50PCTWindSolarProfile	Constraints on solar and wind so that they cannot provide more than 50 percent of their rated capacity for load following down reserve
CCGT HeadRoom	Constraint to ensure headroom (frequency response) reserves provided by CAISO combined cycle units is less than or equal to 8 percent of the rated capacity of the unit
BTMPV	Constraint to ensure behind-the-meter PV generation is greater or equal to its rated capacity
DR_hpd	Limit DR operating hours per day
Battery Storage End Volume	Daily end-of-period storage volume limits on CAISO battery resources
Battery Storage Non-Spin	Enforce a constraint that battery needs to have 0.5 MWh (30 minutes) of ending volume in order to provide 1 MW of non-spin reserve
Hybrid and Co-located limits	Constraints to ensure hybrid and co-located resources generation are within their Pmax and aggregate capability constraint (ACC) limits, respectively