APPENDIX B

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Energy Division Study for Proceeding R.21-10-002

Loss of Load Expectation and Slice of Day Tool Analysis for 2024

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List of Acronyms

AAEE – Additional Achievable Energy Efficiency	LOLH – Loss of Load Hours
BAA – Balancing Authority Area	MW – Megawatt
BTM PV – Behind the Meter Photovoltaic	NQC – Net Qualifying Capacity
CAISO – California ISO	PRM – Planning Reserve Margin
CEC – California Energy Commission	PU Code – Public Utilities Code
ELCC – Effective Load Carrying Capability	RA – Resource Adequacy
EUE – Expected Unserved Energy	SERVM – Strategic Energy Risk Valuation Model
IEPR – Integrated Energy Policy Report	SOD - Slice of Day
LCR – Local Capacity Requirements	TAC – Transmission Access Control

LOLE – Loss of Load Expectation	UCAP – Unforced Capacity
LSE – Load Serving Entity	WECC – Western Electric Coordinating Council

1. Introduction

Consistent with D.20-06-031, D.21-06-029 and D.22-06050, Energy Division puts forward the assumptions and results of its 2024 Loss of Load Expectation (LOLE) study for party comment and CPUC consideration. These studies are meant to complement other LOLE work done for the Integrated Resource Planning Proceeding (IRP) in R.20-05-003 including the Proposed Decision related to Transmission Planning Portfolios issued on January 13, 2023.[1] This report provides study results intended to mirror the current monthly construct, in contrast to the annual results presented in the IRP Proceeding.

The current RA proceeding, R.21-10-002 adopted a Slice-of-Day (SOD) framework and directed further development of the implementation details including calibration and translation of a LOLE study into a SOD PRM. These implementation details are still under Commission consideration, however, given the adopted timing of implementing the SOD framework in 2024 as the test year, Energy Division staff (ED Staff) thought it prudent to include an estimate of the translation of the LOLE results into the SOD framework as part of this report and proposal. Doing so will allow parties to see how the LOLE study results could be applied to the SOD framework using the calibration workbooks that were considered in the RA Reform Track workshops.

In recent years, the electric grid has been impacted by a rapidly changing generation fleet that includes a dramatic increase in variable generation from wind and solar power, significant demand side programs such as Behind the Meter (BTM) solar, energy efficiency, electric vehicles, and other programs and skyrocketing battery storage investments. In addition, variability in electric demand patterns related both to climate change as well as economic and demographic changes and increased variability around net peak versus gross peak demand require a reevaluation of adequate effective capacity needed to protect reliability. These transformations to the electric market, both on the demand side and supply side, have impacted how RA obligations are determined, the efficacy of past methods (such as the 15% PRM) and general conceptions about what time of the day is the most critical for electric reliability. All this has had significant impacts on the use of the residual electric generation fleet, as it transitions to a balancing and integration role in lieu of a primary energy production role. Both the level of adequate effective resources needed as well as the evolving ability of certain types of resources to provide effective reliability contribution are changing as the overall grid changes.

Setting PRM values based on LOLE studies constitutes an integrated framework for reliability analysis and offers a crosswalk with IRP planning portfolios. The results herein could also be used to help guide discussions regarding what assumptions should be utilized in setting PRM levels beyond the minimum 17 percent level for compliance year 2024 that was adopted in D.22-06-050. Compared to prior LOLE studies done in 2022 for 2024, ED staff chose to model the existing fleet of resources updated for recent development and IRP filings, and to make revisions to methodologies that were the subject of

[1] IRP Proposed Decision Ordering Supplemental Mid-Term Reliability Procurement and Transmitting Electric Resource Portfolios to California Independent System Operator for 2023-2024 Transmission Planning Process order linked here; https://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=501102663

comments by parties earlier in 2022 related to previous LOLE studies. ED staff no longer included any RESOLVE build out in the study. Staff also calibrated the model to identify LOLE events using the import constraint as the tuning variable instead of retiring thermal generation. Since the existing and planned additions to the fleet already achieved better than target LOLE during the study period, no Perfect Capacity additions were needed, and the adjustments considered in scenarios that used the import constraint as a varied variable were very minor. For all of these reasons, very little calibration to the model was needed. In addition, prior to the commencement of the study, ED staff made other significant updates to the model since earlier in 2022, which are explained in more detail in Section 5.

2. Summary of Study Results

The monthly results of ED staff's 2024 LOLE study and SOD translation are provided below. The results also are expressed using current NQC rules as well as translated into the SOD Tool to communicate how the study results may inform the new RA construct. As is normal for installed capacity (ICAP) resource counting, forced outages are not accounted for in the Net Qualifying Capacity (NQC) values of resources including thermal and storage. However, NQC methodologies that utilize ELCC or historical performance account for outage in their methodologies. ED staff also prepared a proposal to incorporate heat events into the NQC calculations for thermal resources that are often affected by extreme heat; however, that proposal is not implemented in these study results. In addition, moving towards a perfect capacity- (PCAP) or unforced capacity- (UCAP) based approach can likely improve the accuracy of reliability studies, as all generation is used within its real operational constraints.

ED staff performed LOLE studies of a the current SERVM dataset used for LOLE studies which uses the 2021 IEPR demand forecast and the new 2022 baseline resource file.[2] Table 1 reflects the results of four different 2024 scenarios that examine different import and Path 26 constraints. The reference scenario, S0, scenario represents the 4,000 MW unspecified simultaneous import constraints in the late afternoon to early evening hours currently assumed in general IRP reliability modeling and the Path 26 constraint that has been a factor in the RA proceeding until recently. The Path 26 constraint is primarily impacting flows in the PGE to SCE direction (PGE>SCE constraint). Both have been set to 4,000 MW in the Base Sensitivity but were varied in other sensitivities studied. ED staff performed sensitivities, S1 and S2, around the Path 26 and simultaneous import constraint. Finally, ED staff performed a sensitivity, S3, showing what would happen if significant amounts of "in development" resources do not come online in 2024 as planned. The scenario defined as S2 was chosen for use in the SOD tool, as it resulted in more balanced LOLE across the CAISO while not changing the PGE>SCE constraint or the simultaneous import constraint, compared to the other scenarios. In all sensitivities, the portfolio of resources is the same, except S3 which has about 4,000 MW of the "in development" capacity removed.

Table 1 CAISO 2024 LOLE results for three sensitivities

Regions	S0: Base Case Import at 4,000 MW and	S1: Import at 3,000 MW and PGE>SCE at 5,500 MW	S2: Import at 3,500 MW	S3: Import at 3,500 MW and PGE>SCE at 4,750

[2] Link to 2022 Updated Baseline file on CPUC website HERE

	PGE>SCE at original level	(1,500 above original level)	and PGE>SCE at 4,750 MW	MW, 4,000 MW InDev Delayed
CAISO	0.1045	0.08970	0.09533	0.28767
PGE	0.02919	0.08299	0.05411	0.24197
SCE	0.0695	0.08299	0.07220	0.27227
SDGE	0.10290	0.08970	0.09455	0.28767

The 2024 LOLE study S2 resulted in a probability-weighted average LOLE of 0.095 total across all 12 months of the year. Since this an annual LOLE study, most reliability risk is concentrated in the peak months (July through September) and margins seen in off-peak months are not reflective of actual resource need, just the annual installed capacity divided by worst peak day in those months. An important takeaway is that in the modeled 2024 system, CAISO relies heavily on large amounts of storage, solar and other hybrid generators that are under development (as shown in Table 4). This study is for 2024 study year, meaning that the Diablo Canyon Nuclear Power Plant remains online though all the Once Through Cooling plants such as Alamitos, Redondo Beach, and Ormand Beach are offline or retired in this model. The Diablo plant remains online in this study simply because it is prior to the earliest, original retirement date of Diablo.

This section illustrates three means of calculating a PRM and RA compliance obligation, as well as proposing a PRM to ensure reliability in 2024. These three methods include:

1. Current NQC counting for all types of resources to show how the portfolio required to maintain 0.1 LOLE would total across each month of the year.
2. Translating the SOD framework using the Natural Resources Defense Council (NRDC) tool which compares the hourly demand on the "Worst Day" profile and an exceedance based hourly profile of firm resources, batteries, wind, and solar resources; and
3. SOD Framework using the NRDC SOD tool, with the same hourly day demand profile from the IEPR and using solar/wind exceedance values derived from the NRDC workbook published on the CPUC website in preparation for ED workshops in the summer of 2022.[3]

The Table 2 below reports the monthly total Net Qualifying Capacity (NQC) required to achieve a LOLE of 0.1, and the median CAISO coincident managed peak by month from the 23 weather years in SERVM and the 2021 IEPR forecast produced by the CEC. Total NQC by month was compared to the median managed peak to calculate PRM.

Of particular note on Table 2, the resource portfolio included in the NQC MW row is the same portfolio, with only limited new units reaching COD at some point during the calendar year based on estimated commercial online dates specified by month in the baseline units file. There are no resources removed in order to calibrate to LOE targets. This is strictly an annual study, which is the reason for the large reserve

[3] See https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/ra-reform-excel-workbooks/2022_04_29_slice-of-day-nrdc.xlsx.

margins in off-peak months. Those values do not represent need, just existing portfolio and lower managed peak demand.

It is apparent from the table that managed peak demand in the SERVM model is not the same as the monthly peak demand from the CEC Hourly Load Model. Most importantly, September managed peak demand in SERVM is lower than the corresponding monthly managed peak from the IEPR demand. There is also a decline in NQC values in September relative to July and August, merely reflecting the declining ELCC of solar resources between those months. While the decline in solar ELCC is less dramatic in the recently adopted ELCC values than in prior years, where September ELCC would decline nearly 50% relative to August, there is still a small decline with leads to a decline in available NQC. Those two factors together lead to the appearance of a drop in necessary PRM in September when looking at NQC divided by CEC managed peak demand.

ED staff is weighing a variety of concerns in proposing this PRM for 2024 RA compliance year. ED staff is proposing a PRM that ensures reliability is met by preserving LOLE at or below 0.1 though ED staff is also concerned with the availability of RA resources sufficient to meet these RA procurement obligations. Given the heavy reliance on new and in development capacity, any delay could result in the inability for LSEs to meet RA obligations. We note that the proposal described in this paper based on LOLE modeling should be considered in conjunction with Energy Division Proposal 1 which discusses options for both the PRM and a potential extension of the effective PRM.

Table 2 : 2024 Monthly NQC as a PRM over Peak Demand

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NQC MW Capacity	51,818	52,474	52,327	53,032	53,894	55,427	55,747	54,949	54,202	52,553	52,161	52,135
SERVM Median Managed Peak	31,319	30,539	29,467	31,073	34,024	40,885	44,840	45,643	44,839	36,076	31,683	32,189
CEC Median Managed Peak	32,538	31,478	30,307	33,366	37,517	42,707	45,908	46,500	47,325	38,861	32,411	33,895
SERVM PRM, Median SERVM Managed Peak	165.5%	171.8%	177.6%	170.7%	158.4%	135.6%	124.3%	120.4%	120.9%	145.7%	164.6%	162.0%
CEC PRM, CEC Monthly Managed Peak	159.3%	166.7%	172.7%	158.9%	143.7%	129.8%	121.4%	118.2%	114.5%	135.2%	160.9%	153.8%

Alternatively, the PRM can be calculated using a “worst day” heuristic. This method compares the required monthly NQC capacity to the highest monthly managed peak across all 23 weather years simulated in SERVM, or the 24 hour day in the CEC IEPR Hourly load model and imposing constraints in storage dispatch, available energy, and other features of the NRDC SOD tool. Since the load used in this method is higher in SERVM, and resources are used in the SOD tool according to production profiles, not NQC or PMax, the PRM in this scenario is lower. In essence, since the calculation uses the highest possible expected demand, this PRM reflects only the reserves needed to address forced outage risk and operating reserve requirements.

Finally, the PRM can be calculated using a "Slice-of-Day" method. This method compares the total capacity of the 0.1 LOLE compliant portfolio, adjusted for hourly availability for renewable resources, to managed load scaled by a single multiplier for every hour in a month.[4] The size of the multiplier is determined such that the scaled load matches the capacity of the portfolio. The multiplier is reported as the PRM. Essentially, this demonstrates that before considering weather variability, forced outages, or operating reserve requirements, the capacity of the 0.1 LOLE compliant portfolio would be able to serve the managed load from the median peak day scaled up by the PRM. The SOD method also considers energy constraints and ensures that the energy used by the pumped storage and battery fleet does not exceed what is available. The SOD method would be expected to produce a PRM similar to the NQC divided by the managed peak but can be different to the extent resource modeled capacities in the slice-of-day tool differ from their NQC.

Table 3 PRM Margin over Worst Day or from SOD Tool

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NQC MW Capacity	51,789	52,313	52,218	52,815	53,442	54,884	55,856	55,102	54,421	52,446	52,179	52,096
SERVM Worst Day Managed Peak	31,909	30,873	34,591	37,530	43,090	45,852	52,011	49,196	52,289	44,736	35,200	34,318
CEC Median Managed Peak	32,538	31,478	30,307	33,366	37,517	42,707	45,908	46,500	47,325	38,861	32,411	33,895
Draft SOD PRM, SERVM Worst Day Managed Peak	168.3%	179.6%	160.3%	149.1%	134.1%	130.3%	115.9	116.4%	108.9%	125.6%	151.5%	156.9%
Draft SOD PRM, using Worst Day CEC Managed Demand	170.0%	179.0%	182.5%	168.7%	154.2%	139.6%	133.3%	126.4%	120.4%	144.8%	163.4%	159.6%

For the PRM determination, the 2024 RA study year model was ultimately calibrated to result in a probability-weighted average LOLE of 0.095 total across all 12 months of the year. Since this an annual LOLE study, most risk is concentrated in the peak months (July through September) and margins seen in off-peak months are not reflective of actual resource need, just the annual installed capacity divided by worst peak day in those months. ED staff performed sensitivities around some important Path 26 assumptions which is explained elsewhere in this report. Due to significant retirements and new investment, in 2024 CAISO will rely heavily on large amounts of storage, solar and other hybrid generators that are currently under development (as shown in Table 4). This table illustrates the MW nameplate and number of units that have been added to the Baseline but are currently under development. These projects largely reflect firm projects reflected in LSE contracting in IRP filings most recently updated on November 1, 2022.

[4] SOD framework was developed using the NRDC SOD tool, with electric demand shapes from the IEPR and using solar/wind exceedance values derived from the NRDC workbook published on the CPUC website in preparation for ED workshops in the summer of 2022.

3. Summary of Recommendation and Proposed PRM

For 2024 RA compliance year, the SOD tool is not adopted for full implementation and the PRM will be set using the historical (I.e. existing and current) method of determining a margin of resources needed over managed peak demand. The results of the LOLE study show that a PRM based on NQC over median SERVM managed peak demand (median monthly peaks over the 23 weather years 1998-2020) results in a PRM between 120.9% and 124.3% , while the same resource fleet compared to the monthly peaks from the CEC monthly managed peaks out of the Hourly Load Model is between 114.5% and 121.4% depending on month (with September being the lowest value for both SERVM and CEC forecasts). These values are highlighted in yellow in Table 2.

ED staff propose a PRM for the 2024 RA compliance year of 118% to 120% for all 12 months of the year would be highly reliable based on these study results. This is reasonable since the LOLE study was performed with the same portfolio of resources in each of the 12 months. For that reason, RA obligations that ultimately require that same portfolio of installed capacity will result in a reliable system. Heat maps showing expected unserved energy (EUE) by hour and month back up the finding that July through September contain the primary periods of reliability risk. ED Staff have also proposed to base the 2024 RA obligations off a "Effective PRM" proposal, which is also being presented to parties for their comment.

Table 4 Capacity (MW nameplate) In Development Between end of 2022 and August 2024

Region	PGE		SCE		SDGE	
Unit Category	Sum of Capmax	Unit Counts	Sum of Capmax	Unit Counts	Sum of Capmax	Unit Counts
Battery Storage	1029.7	9	810	6	306	3
DR			11.6	1		
Hybrid_BattStorage	80	1	237	2		
Hybrid_Solar_1Axis			474	2		
Paired_BattStorage	438	9	280	1		
Paired_Solar_1Axis	969.9	9	715	2		
Solar_1Axis	100	1	258	5		
Solar_Fixed						
Wind	80	1	33.74	1		
Grand Total	**2697.6**	**30**	**2819.34**	**20**	**306**	**3**

4. Background

Decision D.05-10-042 adopted a monthly Resource Adequacy (RA) program that required Load Serving Entities (LSEs) to sign contracts with suppliers of RA capacity that commit net qualifying capacity (NQC in MW) to the California Independent System Operator (CAISO) market each month totaling their calculated share of the monthly coincident peak load plus a Planning Reserve Margin (PRM) of 15 percent. The supplier then confirms that contract to the CAISO, resulting in the supplier having a Must

Offer Obligation (MOO) into CAISO energy markets which requires the resource to bid or self-schedule into CAISO's energy markets.

In D.20-06-031, the Commission stated that given the extensive changes to the grid and the mix of generating resources since the PRM was established in D.04-01-050, it is appropriate to review the PRM through a LOLE study performed by Energy Division. In response to this direction, Energy Division submitted a 2024 LOLE study into the Phase 2 Implementation Track of this proceeding on February 18, 2022[5]. In its 2024 LOLE study submitted in 2022, Energy Division staff assumed a high penetration of variable and use-limited resources (built by the capacity expansion model RESOLVE) and removed Diablo Canyon and some cogeneration resources from the system in order to surface LOLE events.

In response to the LOLE study submitted in 2022, parties raised concerns with the inputs and assumptions used in the model and requested adjustments prior to adopting changes to the PRM. The key concerns parties raised included: the composition of base portfolio (particularly, the inclusion of new resources selected by the RESOLVE capacity expansion model, not just contracted in-development resources), the lack of recent weather data in the model, and the limit of imports to 4,000 megawatts (MW) during peak hours. Other concerns included the compatibility with the slice-of-day framework and the Commission's decisions in its Summer Reliability Proceeding R.20-11-003 which adopted an effective PRM of 20-22.5% to be met by the IOUs in 2022 and 2023 (D.21-12-015 OP 3).

Ultimately D.22-06-050 concurred with parties that further vetting of the model inputs and assumptions was necessary and encouraged parties to participate in the IRP process (including the Modeling Advisory Group), where modeling updates, that would address some of party's concerns, were taking place. The Commission also agreed with several parties that supported increasing the PRM for 2023, as the results of the study directionally supported the effective PRM of 20 to 22.5 percent adopted in the Summer Reliability Proceeding (D.21-12-015).

In D.22-06-50 the Commission concluded that "[t]o balance the recognized and urgent need to increase the PRM for 2023 with the acknowledgement that additional LOLE modeling must be undertaken, the Commission finds it prudent to adopt a marginally increased PRM for 2023 and 2024 that falls within the 15 to 17 percent PRM range initially adopted in D.04-01-050." The Commission adopted a 16 percent PRM for 2023 and a minimum 17 percent PRM for the 2024 RA year and noted that the "PRM for the 2024 RA year may be further revised in a June 2023 decision, after a review of Energy Division's updates to the LOLE modeling by stakeholders and the Commission".

D.22-06-050 also clarified that the summer reliability contingency resource procurement targets for 2023, adopted in D.21-12-015, will not change with the adoption of the increased PRM for 2023 which overlapped with the summer reliability emergency procurement period.

In addition to adopting a minimum 17 percent PRM for 2024, the Commission recognized this PRM could not be calibrated to a slice of day framework "as the 17 percent does not match the current LOLE modeling output". In recognizing this the Commission noted that converting the results of the LOLE

[5] Available at Results (ca.gov).

study to a slice-of-day framework should await the outputs of a refreshed LOLE study and this conversion process should leverage NRDC's "proof of concept" template.

On September 2, 2022, an Amended Scoping Memo and Ruling was issued by the assigned Commission office, setting forth the scope of issues and schedule for Phase 3 of the Implementation Track and Phase 2 of the Reform Track. In this Ruling the Commission clarified that the Implementation Track will consider modifications to the PRM for 2024 and beyond, which may include a future LOLE study for RA to be submitted into this proceeding no later than January 2023. The Reform Track will consider how to convert/calibrate the results of a LOLE study to the slice-of-day RA framework.

Consistent with this direction, Energy Division Staff participated in the PRM RA reform workshops and provided a methodology to calibrate the results of a LOLE study to a slice-of-day framework utilizing the NRDC template. Energy Division's participation and proposal are summarized in the RA Reform Workshop Report submitted into the proceeding on November 15, 2022. A decision on the implementation details of slice-of-day, including the PRM calibration, is expected in Q1 2023.

While Energy Division understands that the Commission has yet to adopt a final proposal regarding the calibration of the LOLE study results to a slice-of-day framework, it is including an estimated translation of the current LOLE results into the SOD tool developed by NRDC as a test of the translation pending the outcome the RA Reform decision.

5. Model Inputs and Conventions

Aggregate system reliability is measured by a stochastic model that analyzes generation and electric demand patterns for each hour over thousands of individual simulations that together calculate a probability weighted expected average across all scenarios simulated. Reliability metrics from stochastic reliability modeling include LOLE as well as Expected Unserved Energy (EUE) and Loss of Load Hours (LOLH).[6] Contribution to reliability is measured in terms of ability to reduce LOLE or EUE by adding resources then rerunning the analysis.

For this analysis, ED staff used a 0.1 LOLE target (equivalent to one loss-of-load event every ten years) to determine the level of RA resources needed for adequate system reliability. The 0.1 LOLE target, although not officially adopted by the Commission, is in common use around the country and in past LOLE studies performed for CPUC proceedings, including the RA and IRP proceedings.

ED staff used the Strategic Energy and Risk Valuation Model (SERVM) developed by Astrapé Consulting. SERVM is a probabilistic system reliability planning and production cost model. ED staff configured SERVM to analyze a target study year (2024) under a range of uncertainty including weather conditions (23 historical weather years, 1998-2020), economic output (5 weighted levels), and multiple runs of unit

[6] LOLE equals the expected number of loss-of-load events, regardless of length, in a given year. LOLH equals the expected number of hours with loss-of-load in a year. EUE equals the total MWh of unserved energy in a year. LOLE is a measure of frequency, not duration or magnitude. LOLH is a measure of duration, not frequency or magnitude. EUE is a measure of magnitude, not frequency or duration.

performance. SERVM simulates hourly economic unit commitment including reserves and dispatch for individual generating units over all 8,760 hours of the study year. The model currently is configured to represent a simplified set of external regions in the Western Interconnect using a zonal representation of the transmission system, grouped into seven zones for California and 16 for the rest of the Western Interconnect, roughly equating to actual Balancing Area boundaries.

Data Updates and Major Changes Since February 2022 LOLE Proposal

Many of the inputs and assumptions for this study are the same as those used for modeling work in the IRP proceeding (R.20-05-003) and the LOLE and ELCC proposal released into the RA proceeding on February 18, 2022. ED staff have performed some significant data and methodology updates the earlier RA LOLE modeling including those described below. The overall LOLE dataset included three major parts: the electric demand forecast, existing electric generation resources, and new electric generation resources projected to be built. The electric demand forecast used in this study is the California Energy Commission's (CEC) adopted 2021 California Electricity Demand Forecast Update,[7] which is often referred to as the 2021 Integrated Energy Policy Report (IEPR) demand forecast Mid-Mid Managed Scenario but paired with the High Electric Vehicle demand forecast (rather than Mid).

The 2021 IEPR demand forecast includes an annual peak and energy forecast for California and the balancing areas within. It also includes hourly profiles for the TAC areas that comprise the CAISO balancing area for each year of the forecast, disaggregated into consumption demand and several demand modifiers. ED staff used the annual peak and energy forecast to size SERVM's 23 historical year (1998-2020) set of weather-normalized consumption demand shapes.

ED Staff did not use the IEPR demand forecast's hourly consumption profiles because they are only a single average year, rather than a multiple weather year distribution. ED staff did use the demand modifier profiles for Additional Achievable Energy Efficiency (AAEE), Light and Heavy Duty Electric Vehicles (EVs), and Time-Of-Use (TOU) rate impacts that are included with the IEPR because those demand modifiers are assumed weather independent and can be paired with any of the 23 weather year consumption profiles. For BTM PV, ED staff used its 23 historical year set of solar shapes, sized to the BTM PV energy production forecasted in the IEPR. For BTM battery storage, ED staff backed out its impact on the IEPR annual peak and energy forecast and then modeled it like a dispatchable utility-scale battery storage unit, but with 2.5 hour duration in order to be consistent with the IEPR forecast.

The demand side resources forecasted in the IEPR have clearly shifted the distribution of the hour of day when managed peak demand occurs, especially in summer months. This is captured in the LOLE analysis results in this report and manifests as resources that are use-limited or unable to generate during evening peak hours are less able to reduce LOLE and hence offer less reliability benefit. For demand forecast assumptions outside of California, ED staff used the information included in the WECC 2032 Anchor Data Set.[8]

[7] Insert link to 2021 IEPR

[8] System Stability Planning Anchor Data Set (ADS) (wecc.org)

In both the case of CAISO internal generation and the 2032 Anchor Data Set, ED staff performed extensive updates since previous LOLE modeling. Projections for new planned and in development resources to serve CAISO demand were compiled from LSE IRP filings (updated most recently on November 1, 2022) as well as the 2032 Anchor Data Set V2.0.

ED staff modeled the Baseline electric system, reflecting only what was installed or likely to become operational before 2024. No new RESOLVE portfolios or resources considered "planned_new" or "review" from IRP plans were included. A complete list of generation resources assumed in the studies along with other key input data are available on the CPUC's website.[9] Operating parameters such as heat rate, ramp rate, minimum capacity and other information were drawn from the confidential CAISO Masterfile which lists operating parameters for all generators serving CAISO's electric market. For existing and new generators outside the CAISO balancing area, all generation information including max capacity, online dates and operating parameters, was also drawn from the WECC 2032 Anchor Data Set.

Major Data Updates

ED staff made several major changes and updates to our SERVM dataset since the RA LOLE and ELCC study performed in early 2022 including:

Baseline Reconcile and 2032 Anchor Dataset

1. Major baseline resource update was as follows[10]:
    - 1.1. CAISO Master Generating Capability List as of 11/8/2022 was utilized
    - 1.2. 11/1/2022 LSE IRP compliance filings were used to identify in development resources
    - 1.3. 10/2022 NQC List was utilized
    - 1.4. RPS database was utilized
    - 1.5. EIA data was utilized
    - 1.6. WECC Anchor Dataset 2032 was utilized

ED staff updated the baseline list of generators during summer 2022 and finalized it 11/23/22. This baseline replaces the prior list dated Sept. 2021. ED staff added new generators that have come online or were in development as of summer 2022. The new units were from the CAISO Master Generating Capability list through 10/31/22 and data drawn from 11/1/22 LSE IRP filings.

The baseline update also involved making additions and updates to individual units, including updates to operating parameters and maximum capacity. ED staff also updated regions, unit types, and unit categories to correct errors and oversights. ED staff consolidated planned capacity with newly online capacity if a planned project came online, separated hybrid units into LESR and SUN units and appended "LESR" or "SUN" to the SERVM UnitIDs. And made other minor corrections from other sources we found, including EIA data. We combined PG&E Bay and PG&E Valley regions into one PGE region and combined the demand and demand modifiers since the separation was no longer maintained in CAISO and CEC modeling. Finally, ED staff updated some solar and wind unit categories to make sure they were consistent with the RPS database.

Calibration of imports, simplification of external regions

[9] Unified RA and IRP Modeling Datasets 2022 (ca.gov)

[10] Link to 2022 Updated Baseline file on CPUC website HERE

ED staff performed reconciliation between the SERVM dataset of demand and generating resources and the 2032 WECC ADS, as well as an overall consolidation of external regions in order to produce a realistic pattern of import exchanges between CAISO and external areas. Another advantage was to simplify modeling runs and data processing, and to speed up modeling time. ED staff used the 2032 WECC Anchor Data Set (ADS) as the source for existing and new generation units, and for planned investments to Balancing Authorities all over WECC. Those regions closest to California, listed in Table 5 were maintained in the model while regions further from California were left out. In addition, regions in the Northwest and Southwest were grouped as a coregion in order to simplify their dispatch patterns. Despite that some calibration and shifting of capacity between regions was needed in order to tune all regions towards 0.1 LOLE target. ED staff worked to equalize reliability level across regions and model realistic transfer amounts between regions. NW regions were found to be short and SW regions plus LADWP were found to be long on capacity in 2024 through 2032 given the 0.1 LOLE target and the 2032 ADS, reflecting additional need for development before reaching 2032 and evolving procurement targets for non-CAISO Balancing Authorities in meeting their reliability needs.

Table 5 Consolidated External Regions

Co-dispatch group	Modeled Regions
CAISO	PGE, SCE, SDGE
NW	BPAT, PACW
SW	AZPS, NEVP, SRP, WALC
none	IID, LADWP, SMUD, TID, PortlandGE
Not Modeled	PSCO, IPCO, CFE, BCHA-AESO, TEPC, EPE, NWMT-WAUW, PACE,

Addition of 2018-2020 weather year to our stochastic data set

During the course of 2022, ED staff performed the detailed updates to add more recent weather years (2018-2020) into our overall ensemble of weather data for use in the SERVM model. ED staff gathered data including hourly and monthly actual historical sales demand from CAISO and from EIA, BPA and Pacificorp for areas outside of California. Second, ED staff gathered the necessary demand modifier data to "add back" to create consumption demand, including modeled BTMPV data and actual observed demand response event data. Lastly, ED staff performed weather normalization using the Monash model to create a trained algorithm that predicted electric demand given temperature and humidity data.

This effort was extremely helpful given the heat observed in 2020 and the ability to add that new extreme event into the overall ensemble of conditions tested in SERVM. Likely more extreme heat years will appear in the future weather years (including 2022) however ED staff are currently constrained to using available historical weather years to forecast future.

Hydro performance disconnected from other weather impacts

For this LOLE study, ED staff no longer assume that hydroelectric performance (and hydro abundance in general) are tied to other weather dynamics, such as overall temperature, wind and solar performance. This will allow ED staff to further assess variability of hydroelectric availability across the full distribution of other weather variables. The new effect is large increase in combinations tested in the model, where instead of 23 weather years correlated together times 5 Load Forecast Error (LFE) values resulting in 115 distinct combinations of weather hand demand, now we have 23 weather years times 23 hydro availability scenarios times 5 LFE points, or 2,645 distinct combinations to test. This represents a greater testing of more variability, making the overall result more robust and durable. Hourly hydroelectric dispatch in SERVM is still driven by weather information drawn from 1998-2020 rainfall and hydroelectric historical production, and sample hydro profiles are posted to the CPUC website.[11]

Updates to Electric Demand shapes to Reconcile SERVM and IEPR Hours 17:00-22:00 Patterns

Demand shapes included in the SERVM model were not completely consistent with the 2021 IEPR shapes. In comparison, the IEPR demand shapes showed slightly higher demand in the early evening during peak months.

Figure 1 shows daily average CAISO demand in September 2025 (unadjusted to add the late afternoon bump) to compare IEPR with an unadjusted demand shape from SERVM and IEPR with and without Load Modifiers (LM). Blue and red lines represent IEPR hourly load forecast with LMs and without LMs. Green and orange lines represent SERVM hourly demand with and without LMs.

In comparing the SERVM and IEPR shapes, it is seen that between hours 18:00 to 22:00 there is a difference in electric demand patterns. ED staff are currently investigating this difference and are cognizant of the likely impacts increased demand in these hours would have on LOLE results.

To ensure consistency with the RA program which uses the IEPR to set RA requirements and to more fully understand the impacts of this difference, ED staff adjusted the SERVM demand shapes to account for these observed differences in pattern seen during these critical hours. In SERVM, hourly demand shapes were adjusted during the period affected (HE 17-22 hours) to generally match the IEPR demand patterns.

[11] 2024 sample hydroelectric generation profiles posted HERE

Figure 1 Load bump shown in IEPR daily average September 2025 Demand

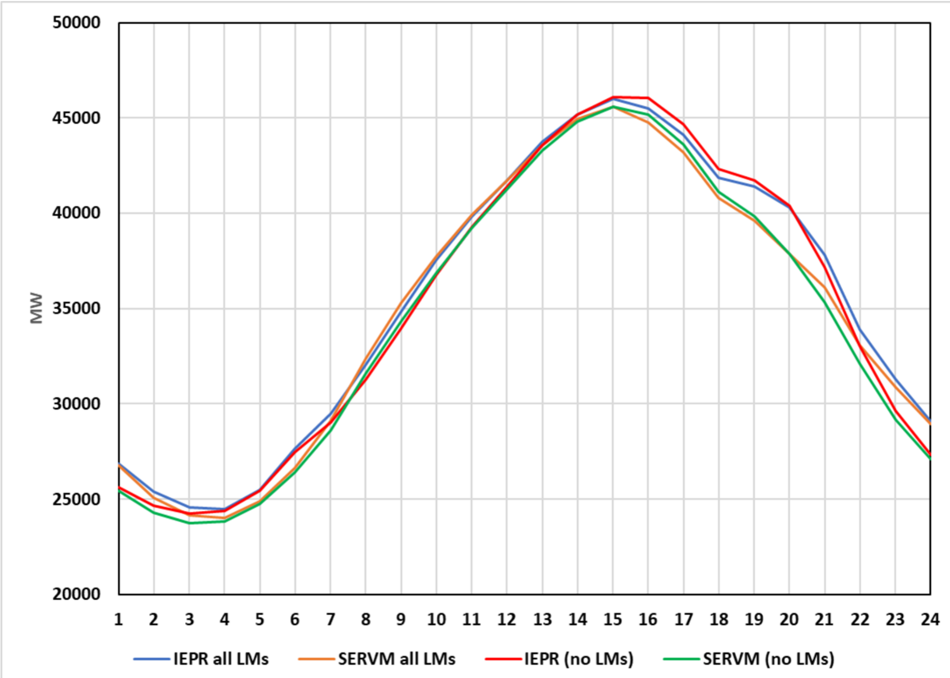


Figure 2 shows the results of this adjustment for 2024 hourly demand shapes and the resulting closer match to IEPR demand patterns.

Figure 2 Comparison of adjusted demand profile for September 2024

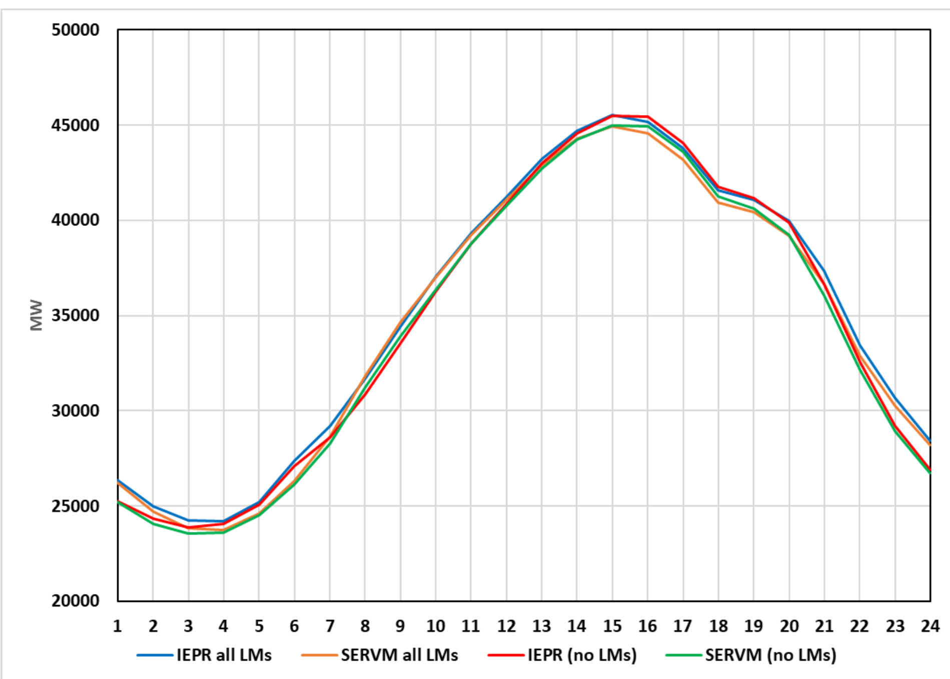
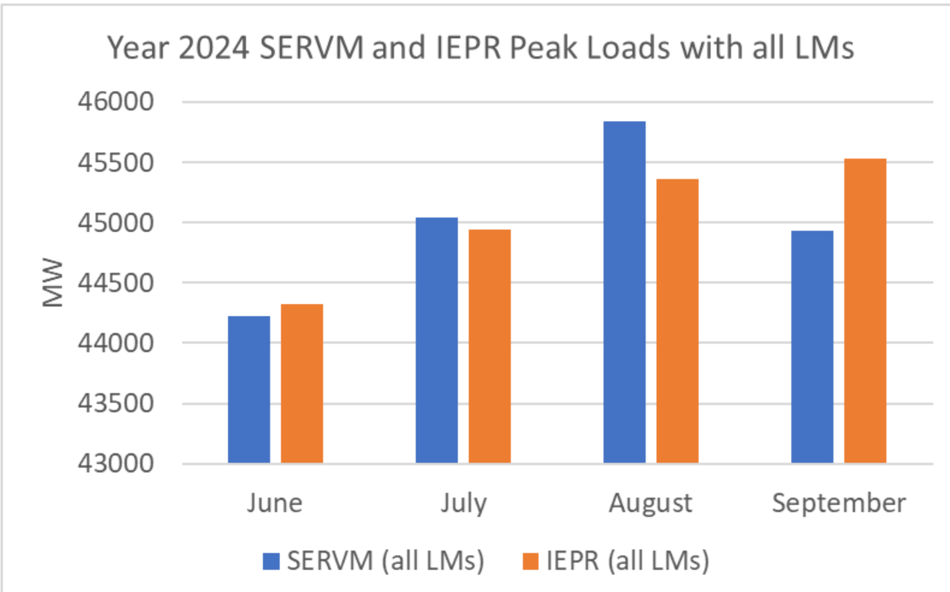


Figure 3 shows a comparison of managed peak demand between the IEPR and SERVM demand shapes for summer months of 2024. The larger stochastic dataset used in SERVM (containing more than one year of hourly demand, wind, and solar) shows a different pattern of demand peaks than the single Hourly Load Model from the CEC IEPR which peaks in September. While SERVM uses the IEPR peak and energy forecast as median forecast for the annual peak, meaning the annual peaks are only slightly different between SERVM and IEPR, SERVM allocates demand to summer months based on the pattern of demand over the historical dataset (representing 1998-2020 hourly demand patterns) versus the single Hourly Load Model which allocates peak load to September instead. This affects the overall PRM calculation for each month, and also has effects on LOLE studies.

Figure 3 Managed Peak Demand Comparison IEPR to SERVM, Summer 2024



ED staff continue studying the main factors causing the differences in demand shapes produced for SERVM and in the IEPR. ED staff will continue to collaborate with the CEC to bridge this difference.

Loss of Load Study Scenarios and Results

Using the Baseline dataset described in this report, ED staff completed a LOLE study of the 2024 RA compliance year to determine the quantity of resources needed to maintain reliability in the CAISO area. Since the SOD framework is not adopted or to be implemented for 2024, this LOLE study is intended to inform a conventional PRM calculation, whereby capacity is quantified as NQC and compared the monthly median managed peak to determine the percentage in excess of peak need to meet CAISO aggregate demand plus operating reserves, forced outages, and other operational needs as simulated in an hourly stochastic reliability model.

ED staff calculated an “Annual” PRM, whereby resources are flat across the year (meaning resources that operate during peak summer months are also able to operate in off-peak months) which leads to excessive PRM levels in off-peak months. Since demand is so much lower in off-peak months, and even varies somewhat during the summer, PRM levels may appear erratic and an average or minimum is needed. Likewise it is important to remember that a 50% PRM in February using this approach doesn’t translate to resource need of 150% of demand in that month, just that NQC divided by much lower peak demand gives that result.

ED staff have made changes to the methodology employed for LOLE studies, partially in reflection of changes to the RA program and partially in reflection of comments made by parties in response to the February 18, 2022 LOLE studies. During workshops on the that study, ED staff proposed a new means to calibrate to the desired 0.1 LOLE level. In the past, ED staff either added and subtracted Perfect Capacity or retired existing aging thermal generation. Both of these methods created potential minor distortions on study results, either by the Perfect Capacity resources affecting how the rest of the fleet is dispatched, or by raising the question of whether ED staff's removal of aging thermal generation was arbitrary and could have led to different PRM results depending on which thermal was removed. Instead, ED staff raised or lowered the level of Simultaneous Import at peak hours in peak months (previously assumed to be static at 4,000 MW) to increase or decrease LOLE as desired.

Secondly, the CAISO is divided into three regions, each modeled independently but linked as a co-region. Each region in CAISO (PGE, SCE and SDGE) broadly represents the Transmission Access Control (TAC) areas within CAISO and are linked by the transmission network that makes up CAISO. In the past, staff separated PGE into PGE_Bay and PGE_Valley, but in 2022, ED staff combined PGE into a single region, thus simplifying a number of the study inputs. ED Staff no longer recognized any improved precision or accuracy from the separation of PGE into the two areas.

A key transmission limit in CAISO is the Path 26 constraint, which limits the flow of energy from north to south and vice versa. Path 26 is generally located along the boundary of PG&E's TAC to the north and SCE's TAC to the south. Path 26 has a NERC path rating of 4,000 MW of power south from PG&E's system to SCE's system, and 3,000 MW to flow north to PGE from SCE. After running the Base Case study, ED staff further investigated the different LOLE levels in each area within CAISO. The PGE TAC area reflected a much lower LOLE than the SCE and SDG&E areas, which prompted ED staff to look at alternative scenarios that included relaxing the Path 26 constraint to see the magnitude of this effect. As the Path 26 constraint was relaxed, LOLE decreased modestly. The effect on LOLE and number of hours where the Path 26 constraint was binding were both documented. The results indicate that location of resources between north and south to minimize Path 26 congestion may modestly influence the total amount of resources and RA obligations needed to achieve a desired level of LOLE.

ED staff was able to achieve a minimum level of resources to meet LOLE of 0.1 and evaluated transmission and Path 26 constraints. A base case and three sensitivities were completed, with the results discussed in further detail below.

Description of Study

A LOLE study was performed to determine the minimum PRM needed to maintain reliability in the CAISO. In order to perform this study, ED staff evaluated LOLE across 5 standard load forecast uncertainties (ED staff tests bands of +/- 2.5 percent with probability weighting on these bands, +/- 1.5% uncertainty with probability weighting, and 0% uncertainty with heaviest probability weighting) together with 23 historical weather years (from 1998 to 2020). Whereas in the past, this resulted in 115 cases total run with multiple unit outage draws, for this study ED staff decoupled the hydro generation from other weather-related variables as discussed earlier. That had the effect of expanding the number of cases run, now 23 weather years times 23 hydro scenarios times 5 load forecast uncertainty levels, totaling 2645 total cases. Keeping all other parameters such as electric demand and resource fleet constant, the simultaneous import constraint and the transmission limit for PGE>SCE were modified in each scenario to weigh the impacts and tradeoffs, as a means to both calibrate to 0.1 LOLE and to test the sensitivity of the PGE>SCE Path 26 constraint to differing LOLE levels in each IOU region in CAISO. Average hourly energy transfer across Path 26 and Binding Hours resulting from these simulations were statistically analyzed to check conformity with LOLE capacity increase/decrease for each region.

Table 6 totals capacity in MW of baseline resources by technology type. The Battery Storage category includes stand-alone and co-located systems, and the Firm category includes biomass, CC, Cogen, CT, geothermal, ICE, nuclear, and steam.

Table 6: Baseline Portfolio (MW Nameplate)

Category (Capmax MW)	AZPS	BPAT	IID	LADWP	NEVP	PACW	Portland GE	SMUD	SRP	TID	WALC	CAISO
Battery Storage	1,223	48	231	620	1,300	610	5	-	148	-	329	8,969
Firm	11,846	9,622	1,934	8,180	9,016	1,238	1,919	1,995	9,846	548	2,240	40,830
Hydro	-	29,586	84	290	-	987	553	2,611	91	158	2,502	9,175
PSH	-	500	-	1,460	750	-	-	-	176	-	44	1,683
Solar	4,375	1,457	770	2,526	6,658	1,478	142	488	884	120	1,648	18,820
Wind	924	6,339	-	429	150	2,501	659	-	-	-	485	7,670

Due to significant retirements and new resource development, CAISO will rely heavily on large amounts of storage, solar and other hybrid generators that are currently under development in 2024 (as shown in Table 7). This table illustrates the MW nameplate and number of units that have been added to the Baseline but are currently under development. These projects largely reflect contracted projects reported by LSEs in their November 1, 2022, IRP filings.

Table 7 Capacity (MW nameplate) In Development Between end of 2022 and August 2024, per CPUC November 2022 vintage baseline file

Region	PGE		SCE		SDGE	
Unit Category	**Sum of Capmax**	**Unit Counts**	**Sum of Capmax**	**Unit Counts**	**Sum of Capmax**	**Unit Counts**
Battery Storage	1029.7	9	810	6	306	3
DR			11.6	1		
Hybrid_BattStorage	80	1	237	2		
Hybrid_Solar_1Axis			474	2		

Paired_BattStorage	438	9	280	1		
Paired_Solar_1Axis	969.9	9	715	2		
Solar_1Axis	100	1	258	5		
Solar_Fixed						
Wind	80	1	33.74	1		
Grand Total	**2697.6**	**30**	**2819.34**	**20**	**306**	**3**

Scenario Description

Current LOLE modeling in IRP and RA studies over the past two years have used as a Base Case, a simultaneous import constraint of 4,000 MW imposed in Hour Ending (HE) 17-22 between June to September and a Path 26 PGE>SCE constraint at its current path rating of 4,000 MW. In keeping with workshop discussion over the course of summer 2022 and to avoid distorting dispatch from various resource classes, ED Staff calibrated LOLE to 0.1 by modification of the simultaneous import constraint, rather than retiring thermal generation or adding perfect capacity.

Base case S0 is compared to Sensitivities S1 and S2, each differing in modified import constraint and PGE>SCE Path 26 constraint assumption. S1 constrains simultaneous imports to 3,000 MW and relaxes Path 26 (North to South) to 5,550 MW. S2 constrains simultaneous imports to 3,500 MW and relaxes Path 26 (North to South) to 4,750 MW. S3 is a sensitivity similar to S2 with In Development resources removed in order to show the effects of delays in development.

Table 9 shows the LOLE results for each scenario by region. The first three scenarios (S0, S1, and S2) meet the LOLE target while S3 does not. In scenarios S1 and S2, ED staff was able to reduce the peak time simultaneous import constraint from 4,000 MW to 3,000 MW in S1 and 3,500 MW in S2, demonstrating that in 2024 the equivalent overall LOLE effect of Path 26 and similar amounts of additional imports were comparable to a point, as seen in S1 where at 5,500 MW (1,500 MW increase) the three regions in CAISO have equalized in LOLE and the marginal use of increased PGE>SCE Path 26 constraint would have no longer been significant. ED staff suspects this is caused by retirement of significant generation in SCE's area, resulting in the need for additional capacity from PGE's area to replace it.

To illustrate the imbalance in capacity between IOU service areas, Table 8 shows capacity compared to CAISO coincident peak demand in each service area, demonstrating that SCE area has the lowest margin of NQC over demand of any of the three IOU areas. This implies that future development ought to be weighed more heavily towards SCE's area than PGE's area.

Table 8 September breakdown per region of monthly NQC modeled compared to PRM

September breakdown	PGE	SCE	SDGE
Capacity using current NQC calculations	27,482	26,132	4,827
SERVM Worst Day Managed Peak	22,121	27,391	4,759
SERVM Median Managed Peak	19,945	22,626	3,987
PRM, NQC divided by Worst Day Managed Peak	124.2%	95.4%	101.4%

PRM, NQC divided by Median SERVM Sales Peak	137.8%	115.5%	121.1%

Due to its minimal overall fleet needed for LOLE while still maintaining more balance between the IOU areas, ED staff choose to use the results of the S2 Sensitivity to calculate the Slice of Day PRM.

Table 9 CAISO LOLE Results for Four Sensitivities

Regions	S0: Base Case Import at 4,000 and PGE>SCE at original level	S1: Import at 3,000 and PGE>SCE at 5,500 (1,500 above original level)	S2: Import at 3,500 and PGE>SCE at 4,750	S3: Import at 3,500 and PGE>SCE at 4,750 , 4,000 MW InDev Delayed
CAISO	0.1045	0.08970	0.09533	0.28767
PGE	0.02919	0.08299	0.05411	0.24197
SCE	0.0695	0.08299	0.07220	0.27227
SDGE	0.10290	0.08970	0.09455	0.28767

Table 10 reflects annual binding hours and summary statistics for Path 26 across three scenarios. Comparing these results with the LOLE values in Table 9, it is important to note that scenarios with higher maximum binding hours have higher LOLE. For a better visual demonstration, Figure 4 compares the distribution plot between binding hours and average MWh flowing across Path 26 for three scenarios.

Table 10 Path 26 Sensitivities and Path 26 Binding Hours

PGE>SCE	**S0: Base Case – Original Levels**		**S1**		**S2**	
	Import at 4,000 MW and P26 at 4,000 MW		Import at 3,000 and P26 at 5,550 MW		Import at 3,500 MW and P26 at 4,750 MW	
	Average Purchase	Binding Hours	Average Purchase	Binding Hours	Average Purchase	Binding Hours
	MWh	hr	MWh	hr	MWh	hr
Mean	360.35	71.35	357.60	71.21	359.12	71.06
Minimum	192.88	9.00	189.26	9.00	193.48	9.00
Average Higher 95th Percentile		158.368		157.798		158.159

Figure 4 Path 26 statistical analysis for binding hours and average purchases

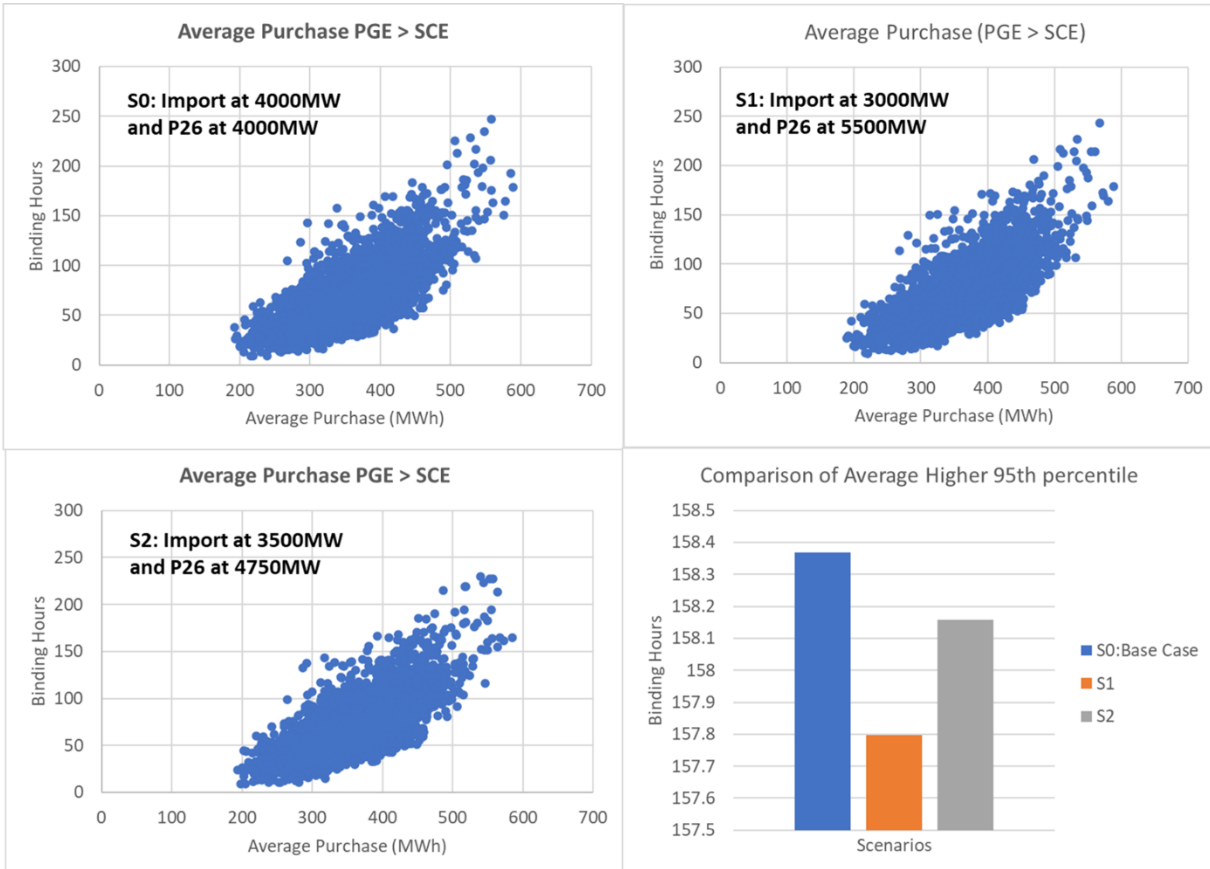


Figure 4 shows distribution plots of the number of hours Path 26 is binding in the PGE>SCE direction and the MWh of average purchases across Path 26 in the PGE>SCE direction for the three scenarios S0, S1 and S2. It is seen that scenarios that have more binding hours on the top right corner with higher maximum hours have higher LOLE. The bar chart is comparing 95th percentile binding hours for the three scenarios.

6. LOLE Results

Calibrated System with S2 Portfolio – PRM Results

The 2024 RA study year model was ultimately calibrated to result in a probability-weighted average LOLE of 0.105 total across all 12 months of the year, with all of it occurring in the July through September peak months. Significant new capacity reach operation in 2021 and 2022, representing nearly 4,000 MW of new online capacity and another 5,823 MW of capacity is under construction and in development. Contracted development resources were compared to LSE IRP plans and other CPUC data to create a realistic picture of new resource investments. The results of the LOLE study show that a PRM based on NQC over SERVM median managed peak demand results in a PRM between 120.9% and 124.3%, while the same resource fleet compared to CEC monthly managed peak is between 114.5% and

121.4% depending on month (with September being the lowest value for both SERVM and CEC forecasts).

Figure 5, Figure 6, and Figure 7 demonstrate the distribution of EUE in MWh in each IOU area. It is evident that EUE is moving later into the evening, now concentrated in the late evening and night of summer months, with much smaller amounts in other late-night hours in off-peak months. The shift to late hours broadly represents the saturation effects of large amounts of solar and storage added to the fleet. EUE events that in the past would have been in the middle of the day at peak consumption and even events in the early evening demand are now effectively met with solar and storage.

Figure 5 Heat Map of EUE in PGE Across Month and Day (MWh)

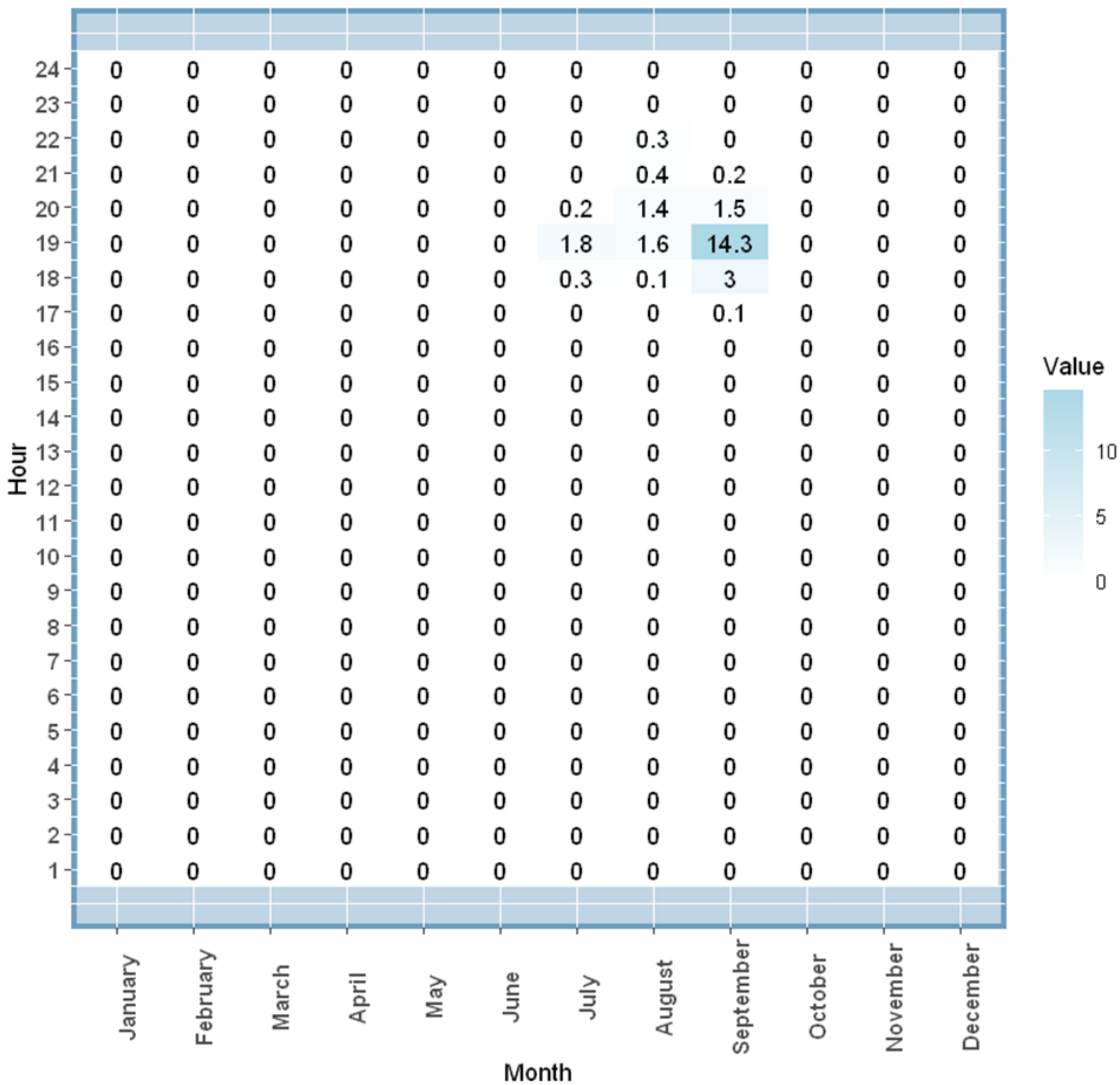


Figure 5 demonstrates the extent to which EUE is moving later into the evening, now concentrated in the late evening and night of summer months, with much smaller amounts in other late-night hours in off-peak months. The shift to late hours broadly represents the saturation effects of large amounts of solar and storage added to the fleet. EUE events that in the past would have been in the middle of the day at peak consumption and even events in the early evening demand are now effectively met with solar and storage.

Figure 6 Heat Map of EUE in SCE Across Month and Day (MWh)

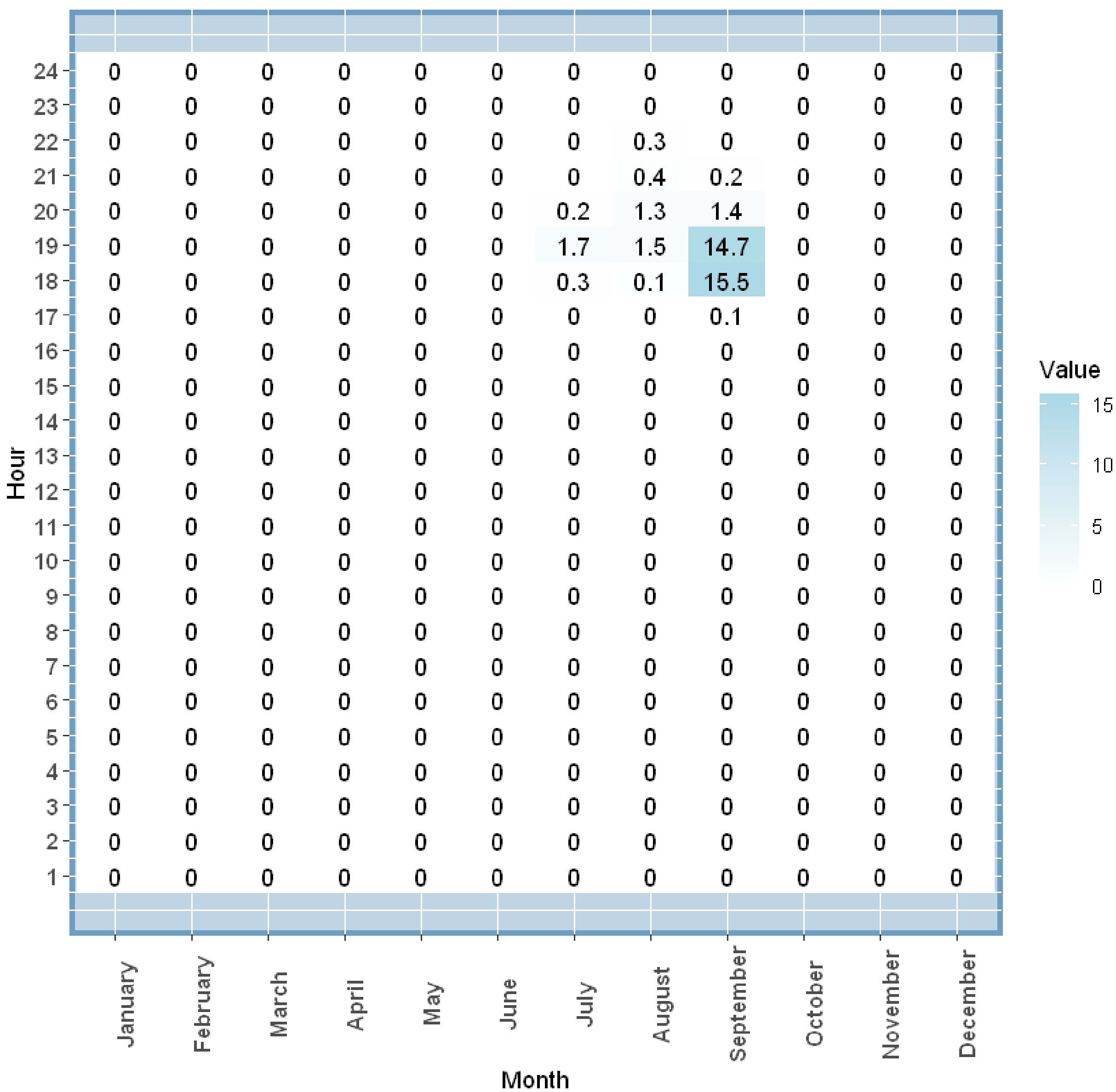
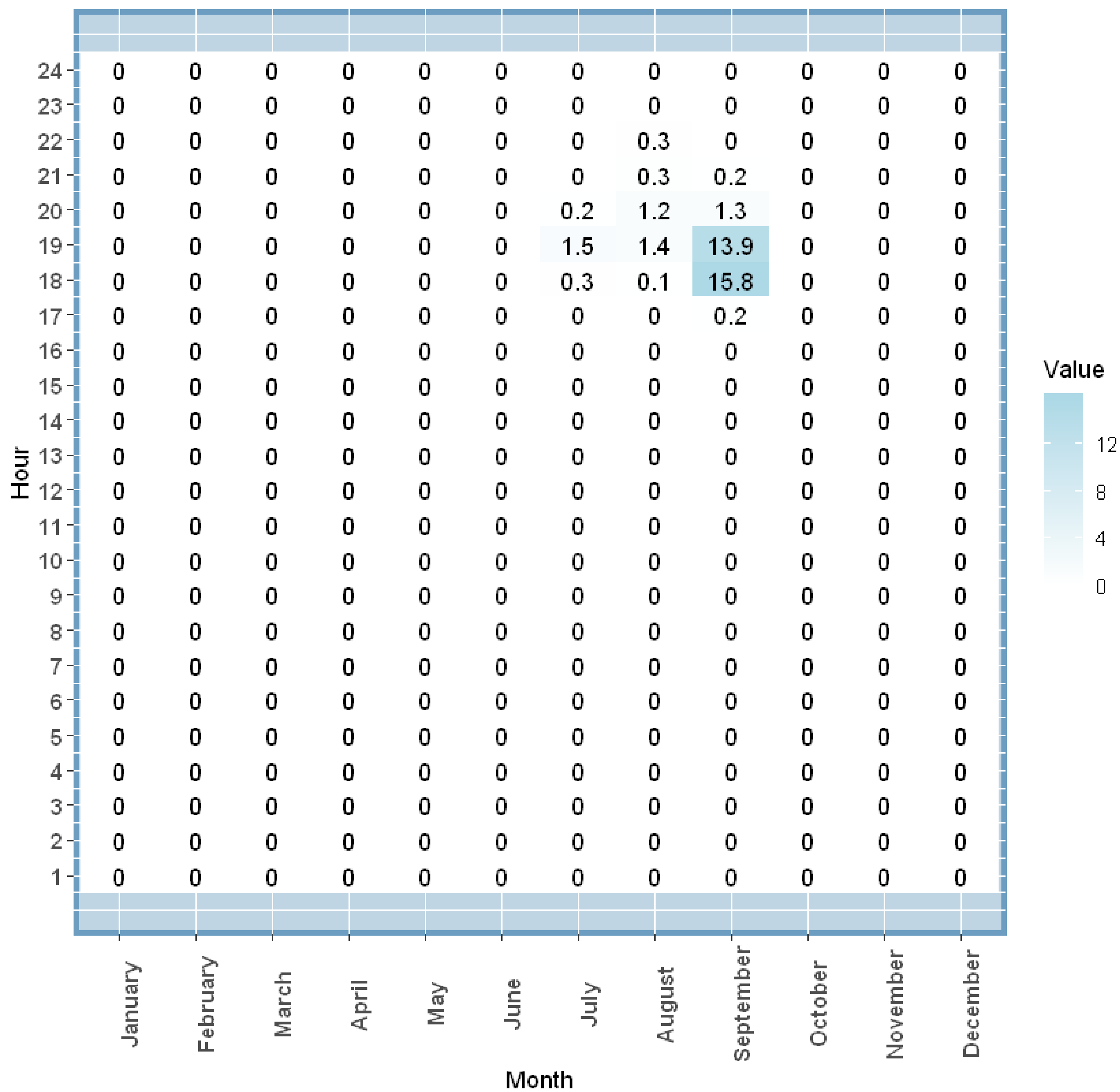


Figure 7 Heat Map of EUE in SDGE Across Month and Day (MWh)



The table below reports the monthly total Net Qualifying Capacity (NQC) required to achieve a LOLE of 0.1, and the median CAISO coincident managed peak by month from the 23 weather years in SERVM and the 2021 IEPER forecast produce by the CEC. Total NQC by month was compared to the median managed peak to calculate PRM.

Table 11 shows the results of the PRM calculation based on SERVM and CEC median peak managed demand. In both cases, the NQC MW available in the first row represents the same fleet of resources. There are some new resources reaching COD during 2024, but ED staff did not remove any resources in some months as in the past in calibrating to LOLE targets. This is strictly an annual LOLE study, not attempting to create a tuned fleet in each month individually. Thus, the NQC MW in the first row, though fluctuating, does not represent an increase or decrease in available Pmax MW capacity. The next two rows present the managed peak demand from SERVM and the CEC. Finally, the resulting PRM is displayed in the final two rows of the table, with the CEC managed forecast in September showing the biggest difference with the SERVM peaks at only 114.5% required PRM in excess of peak load. This apparent contradiction however results from different peak demand between SERVM and the CEC. Were CEC's September forecast about the same as August instead of being higher by 1,000 MW, the apparent PRM in September would be around 2% higher and more in line with August's PRM.

Secondly, declining ELCC values for solar in particular result in a general decline in the available NQC (the numerator in the PRM calculation) even as managed peak demand is larger in the IEPR (the denominator in the PRM calculation). While the decline in solar ELCC is less dramatic in the newer ELCC values adopted in 2022 than in the prior year's adopted ELCC values, where September ELCC would decline nearly 50% decline in ELCC relative to August, there is still a small decline which leads to a decline in available NQC and apparent PRM. Those two factors together lead to the appearance of a drop in necessary PRM in September when looking at NQC divided by CEC managed peak demand.

ED staff is weighing a variety of concerns in proposing this PRM for 2024 RA compliance year. ED staff is proposing a PRM that ensures reliability is met by preserving LOLE at or below 0.1 though ED staff is also concerned with the availability of RA resources sufficient to meet these RA procurement obligations. Given the heavy reliance on new and in development capacity, any delay could result in the inability for LSEs to meet RA obligations. ED staff has weighed these concerns in our proposal of PRM that is flat for all 12 months of the year, and that is sufficient to meet LOLE targets. Additionally, given the uncertainty of development timelines, ED staff is separately proposing consideration of an extension of the effective PRM beyond 2023 in lieu of adopting a higher PRM at this time (see ED Proposal 1).

Table 11 2024 Monthly NQC as a PRM over Peak Demand

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NQC MW Capacity	51,818	52,474	52,327	53,032	53,894	55,427	55,747	54,949	54,202	52,553	52,161	52,135
SERVM Median Managed Peak	31,319	30,539	29,467	31,073	34,024	40,885	44,840	45,643	44,839	36,076	31,683	32,189
CEC Median Managed Peak	32,538	31,478	30,307	33,366	37,517	42,707	45,908	46,500	47,325	38,861	32,411	33,895
SERVM PRM, Median SERVM Managed Peak	165.5%	171.8%	177.6%	170.7%	158.4%	135.6%	124.3%	120.4%	120.9%	145.7%	164.6%	162.0%
CEC PRM, CEC Monthly Managed Peak	159.3%	166.7%	172.7%	158.9%	143.7%	129.8%	121.4%	118.2%	114.5%	135.2%	160.9%	153.8%

Staff also performed the PRM calculation using the "Worst Day" managed peaks from the SERVM dataset. This method compares the required monthly NQC capacity to the highest monthly managed peak across all 23 weather years simulated in SERVM. The monthly peaks from the IEPR are already the "worst day" as there is only one weather year included in the IEPR Hourly Load Model. This is just NQC compared to peak demand forecast. Since the "worst day" peak is higher than the median managed peak in SERVM, the required PRM in this scenario is lower since less reserves are needed for demand variability.

Finally, the PRM can be calculated using a "Slice-of-Day" method. This method compares the total capacity of the 0.1 LOLE compliant portfolio, adjusted for an exceedance based hourly availability for renewable resources, to the "worst day" managed hourly demand profile.[12] The tool calculates a multiplier to apply to each hour's demand such that the scaled demand matches the capacity of the portfolio. The multiplier is reported as the PRM. Essentially, this demonstrates that before considering weather variability, forced outages, or operating reserve requirements, the capacity of the 0.1 LOLE compliant portfolio would be able to serve the managed demand from the "Worst Day" demand scaled up by the PRM. The SOD method also considers energy constraints and ensures that the energy used by the pumped storage and battery fleet does not exceed what is available. The SOD method would be expected to produce a total MW capacity amount equal to total NQC required in a LOLE study, but the PRM would look different to the extent the "Worst Day" demand is higher than the median demand, and that the resource modeled capacities in the slice-of-day tool differ from their unit specific NQC.

Table 12 PRM Margin over Worst Day or from SOD Tool

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NQC MW Capacity	51,789	52,313	52,218	52,815	53,442	54,884	55,856	55,102	54,421	52,446	52,179	52,096
SERVM Worst Day Managed Peak	31,909	30,873	34,591	37,530	43,090	45,852	52,011	49,196	52,289	44,736	35,200	34,318
CEC Median Managed Peak	32,538	31,478	30,307	33,366	37,517	42,707	45,908	46,500	47,325	38,861	32,411	33,895
Draft SOD PRM, SERVM Worst Day Managed Peak	168.3%	179.6%	160.3%	149.1%	134.1%	130.3%	115.9	116.4%	108.9%	125.6%	151.5%	156.9%
Draft SOD PRM, using Worst Day CEC Managed Demand	170.0%	179.0%	182.5%	168.7%	154.2%	139.6%	133.3%	126.4%	120.4%	144.8%	163.4%	159.6%

For the PRM determination, the 2024 RA study year model was ultimately calibrated to result in a probability-weighted average LOLE of 0.095 total across all 12 months of the year. Since this an annual LOLE study, most risk is concentrated in the peak months (July through September) and margins seen in off-peak months are not reflective of actual resource need, just the annual installed capacity divided by worst peak day in those months. ED staff performed sensitivities around some important Path 26 assumptions which are explained in this report. Due to significant retirements and new investment, CAISO will rely heavily on large amounts of storage, solar and other hybrid generators that are currently under development in 2024 (as shown in Table 4). This table illustrates the MW nameplate and number of units that have been added to the Baseline but are currently under development. These projects largely reflect firm projects reflected in LSE contracting in IRP filings most recently updated on November 1, 2022.

[12] SOD framework was developed using the NRDC SOD tool, with electric demand shapes from the IEPR and using solar/wind exceedance values derived from the NRDC workbook published on the CPUC website in preparation for ED workshops in the summer of 2022.

7. Results and Recommendations 2024 PRM

For 2024 RA compliance year, the SOD framework is expected to be implemented as a test year. Therefore, ED staff proposes a range of PRM for 2024 RA compliance year between 118% and 120% for all 12 months of the year, which is based on the current RA resource counting framework rather than the SOD resource counting framework. The results of the LOLE study show that a PRM based on NQC over SERVM median managed peak demand results in a PRM between 120.4% and 124.3%, while the same resource fleet compared to CEC monthly managed peak is between 114.5% and 121.4% depending on month (with September being the lowest value for both SERVM and CEC forecasts). The differences in September PRM results between SERVM and CEC reflect a slightly higher September managed peak demand in the CEC demand profiles than what is seen in the managed demand profiles in SERVM. ED Staff have also proposed to base the 2024 RA obligations off a "Effective PRM" proposal, which is also being presented to parties for their comment.

LOLE results show that 2024 portfolio baseline requires no additional capacity to be reliable (meets 0.1 LOLE standard) in addition to the significant MWs of new resources made available in the Baseline update and what is currently In Development. Significant Path 26 issues and differences between the CEC demand shapes and those developed for SERVM were analyzed and discussed. Significant new resources were added to the baseline, a large pool of resources is currently in development, and several new modeling methods were used for this study. In the future, when the RA program fully transitions to the SOD framework, ED staff will recommend a translation of this method into the SOD tool and propose a PRM based on SOD. ED staff evaluated implementation of this approach to the SOD framework, and that discussion follows.

8. Proposed Slice of Day Approach for Future Years

As the grid evolves to rely on a more complex and diverse portfolio of supply, the RA program and the corresponding PRM must evolve as well. In D.22-06-050, the Commission outlined a general framework for determining and applying the PRM under the Hourly SOD framework, including the following core steps. ED staff attempted to follow these steps in this proposal to express the results of the LOLE study and calculate a necessary PRM for SOD implementation.

1) Enter baseline portfolio from SERVM and calibrate to 0.1 via LOLE analysis, then the SERVM portfolio should inform the PRM used in RA program

2) Calibrate Convert Portfolio to PRM Requirements using Slice-of-Day resource counting

3) Apply PRM to Compliance Requirement

Slice-of-Day Tool

The Slice of Day Resource Adequacy framework should be calibrated to deliver the portfolio of resources that has been assessed as reliable through a Loss of Load Expectation (LOLE) study.
The objective of SOD tool is to create system-level 24-Hourly-Slice RA that achieves the maximum PRM possible on the highest load day while satisfying the capacity sufficiency constraint and storage constraints:
The objective function for SOD tool is: Maximize $\sum_{m=1}^{12} PRMm$

-Decision Variable is: Monthly $PRMm$
-Constraints:
Hourly Capacity (MW) > Hourly Load + PRM (MW)
Daily Storage Discharge + Roundtrip Efficiency Losses (MWh) < Daily Excess Energy (MWh)
Hourly Storage Dispatch (MW) < Installed Storage (MW)
Daily Storage Dispatch (MWh) < Installed Storage (MWh)

SOD Inputs:

SERVM specifically produces the following output reports, which are entered into the SOD tool.

1) Hourly Managed Load, Solar and Wind profiles.
2) Baseline portfolio that has been assessed as reliable through a Loss of Load Expectation (LOLE) study for the year 2024, the portfolio meets 0.1 LOLE. The S2 portfolio from our previous LOLE study was used, which constraints Path 26 to 4,750 MW and the CAISO simultaneous Import Constraint to 3,500MW.
3) Storage units in the Baseline portfolio (both PSH and battery).

SERVM Portfolio	Energy Division LOLE 2024 Baseline Portfolio
Load	CEC 1-in-2 Load (2024, TN241174), Peak Day Method
Solar Profile	GridPath_Solar
Wind Profile	GridPath_Wind

Process to Convert the portfolio to the appropriate PRM in SOD:

1. Upload SERVM portfolio into the SOD tool. The portfolio already meets 0.1 LOLE, Currently the S2 sensitivity portfolio used for the LOLE study results earlier in this report.
2. Upload CEC profiles that were taken from 2024 IEPR load shapes and create a monthly profile based on the day with the maximum peak load value, for example, the day with the maximum peak load value in January was selected as the January profile, and so on.
3. Upload Solar and wind profiles that came from GridPath and NP Energy.
4. Upload SERVM hourly managed Load, Solar and Wind profiles for 23 weather year, and create a monthly profile based on the day with the maximum peak load value, for example, the day with the maximum peak load value in January was selected as the January profile, and so on.
5. Upload SERVM Pondcap and Capacity for battery storage units. Impose an 8hr cap on duration which will cap the PSH units coded in the model with more than 8hr durations.
6. Selected either CEC or SERVM profiles to base the calculation on.
7. Select the Solar and Wind prolife with the desired exceedance value to be model. Exceedance determines the value that a resource is expected to produce at or above over a given percentage of observations. The 10th percentile is the 90% exceedance profile value and so on. For example, the day with its max solar output at the 10th percentile of output for all January days across the 23 weather years is used for the January 10th percentile profile, and so on.

8. Run the solver, which gives the new SOD required PRM % value. The Solver calculates the highest monthly load multiplier that the reliability compliant portfolio can support.

9. Questions to be Considered by Commission and Parties

ED staff proposes that the Commission and parties consider the following questions in reviewing the results of the LOLE studies for 2024.

1. What, if any changes should be made to the assumptions used to perform the LOLE study?
2. Is a LOLE study appropriate to calculate RA obligations for: 1.) a peak RA capacity framework, 2.) a slice of day reliability construct?
3. How should planned outages be treated in calculating an RA PRM using a LOLE study?
4. Would removing deliverability restrictions in the NQC calculation be an accurate translation of the way that resources provide reliability value to CAISO in most instances, outside of particularly constrained times? Would it be possible that certain resources would avoid making transmission upgrades because they have less of an incentive? Do parties have any other arguments pro or con about deliverability restrictions in the QC calculation?
5. Should ED staff perform LOLE studies for RA obligations and SOD targets every year, or is every other year enough?
6. Should the PRM be static across the year or vary monthly (or seasonally)? Is there a simpler or more accurate method to allocate LOLE risk to individual months? Is there a simple heuristic or is a monthly LOLE study the best approach?
7. Should forced outage rates on thermal resources be included in setting their QC value? In other words, should the PRM be set using a UCap or ICap framework? If an UCap framework is preferred should the forced outage rates also include ambient derates?

(END APPENDIX B)