Appendix B to Loss of Load Expectation Study for 2026: Revised Slice of Day Tool Analysis

December 20, 2024
Prepared for CPUC Rulemaking (R.) 23-10-011

California Public
Utilities Commission

Executive Summary

Energy Division issued a Loss of Load Expectation (LOLE) and data update report on July 19, 2024, in support of decision making in the RA proceeding.[1] To correct errors in the SOD PRM setting tool, Appendix A was released on August 30, 2024.[2] Staff here present this Appendix B with a revised and updated SOD PRM setting tool, new monthly SOD stress test results, and a revised reliability margin assessment for each month of the 2026 RA compliance year. This information is presented in support of Track 3 of the RA proceeding R.23-10-011.

Key Updates

In Appendix B, Energy Division Staff (Staff) present a response to comments and questions about Appendix A released on August 30, 2024. Upon review of that feedback, Energy Division was able to make updates to the logic of the SOD PRM setting tool to correct formula errors that incorrectly identified the most constrained hour, added additional missing hydro resources and removing incorrectly included imports, identify changes to the stress test modeling including removal of the Thermal Derate functionality and removing maintenance rates from modeling, and show a final revised stress test PRM requirement translation into RA PRM requirements. Overall, the results for the peak months remain about the same as the revised results in Appendix A (decreasing by about 1%) while the modeled PRM requirements in off-peak months are significantly lower (about 5% reduced) relative to the Appendix A.

Key Results

Results of the LOLE reliability analysis for the entire CAISO footprint show that all months have acceptable, i.e. minimal or zero, loss of load expectation (LOLE) events if each month is calibrated to a planning reserve margin (PRM) requirement of 21% for the months of October to March and 22.5% for the months of June to September. Months April and May showed a higher PRM of 24.5% resulting from higher variability of peak demands relative to the annual peaks, but these months continue to have lower absolute MW requirements, so it is not expected we will see reliability issues from those events. Staff recommend that April and May can also require 21% same as off-peak months. This report also provides a comparison of the revised study results to the previous 2024 LOLE study showing that required capacity reserve margins have increased in August and September by 2-4.5% relative to the 2024 LOLE study results. Total LOLE across all months was acceptable, and across the whole year totaled 0.157.

Key Recommendations

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

[2] Link to Appendix A on the CPUC website RA History page: updated-results_appendix-a_v1.pdf

The PRM Recommendation section considers how the Appendix B revised CAISO area LOLE study results for 2026 should be considered for implementation as CPUC jurisdictional RA program requirements in RA program year 2026. Energy Division staff puts forward for consideration two high-level proposals aimed at balancing reliability and affordability. These proposals will be further developed and released in line with the Track 3 schedule.

Proposal 1: 17% PRM as an RA requirement paired with effective PRM (extending the 2025 status quo)

Proposal 2: 22.5% PRM as an RA requirement and System Waiver

Next Steps

Alongside this Appendix B, Energy Division staff is providing a revised calibrated SOD PRM setting tool on the CPUC RA history page website[3]. The new tool shows the monthly modeled SOD PRM requirement results. Staff is also posting a tool showing initial results before adding demand blocks. These workbooks now include a listing of individual resources, demand, added blocks of load, and the resulting modeled SOD PRM requirements. Table 9 of this report shows the updated monthly SOD PRM levels as well as blocks of demand added in each month.

While the Appendix B analysis and recommendations will receive formal comment in Track 3 of the RA proceeding, staff recognize that any analytical concerns should be reviewed as soon as possible. Therefore, Staff encourages parties to send informal comments and feedback anytime by email to Donald Brooks (donald.brooks@cpuc.ca.gov) or Behdad Kiani (behdad.kiani@cpuc.ca.gov). Staff will host a workshop in early 2025 to discuss this report in detail with parties.

[3] Resource Adequacy History

Introduction and Results Summary

In June 2024, the Commission decided in D.24-06-004 to move forward with implementation of the slice of day (SOD) RA program in 2025, adopted a 17% PRM level for RA compliance year 2025, and extended the summer reliability effective PRM mechanism (originally adopted in the Extreme Weather Proceeding) through 2025. In doing so, the Commission found that a 17% SOD PRM level is more appropriate than the 15.43% level for the 2025 RA compliance year, given concerns with lower levels of reliability across non-September summer months and the lower 2023 Integrated Energy Policy Report (IEPR) demand forecast (that is used in setting 2025 RA obligations).

As part of the current proceeding, Staff published proposals in January 2024 to implement the SOD program, update the underlying dataset, and conduct an updated LOLE study for 2026 study year. These proposals also intended to produce a modeled PRM requirement for consideration as an RA Program Requirement for each month of the year that would satisfy LOLE requirements by keeping total LOLE at 0.1 or below and use the SOD PRM setting tool to implement a monthly SOD PRM requirement. The monthly PRM adopted as an actual RA program compliance requirement could be set at one or more values by season or month. Translating the PRM from the monthly peak RA construct to the hourly SOD Framework has proven a complex analytical task.

In the Spring of 2024 and in preparation for a LOLE Study for the 2026 study year, Energy Resource Modeling staff in Energy Division, in collaboration with CPUC consultants, performed multiple updates to the inputs and assumptions for the LOLE model and issued a proposed Inputs and Assumptions document to the RA proceeding. These updates included:

- Updating the CAISO baseline generating fleet using the current CAISO Master Generating Capability List, vintage January 2024.
- Updating existing or under construction non-CAISO units from the 2032 WECC Anchor Data Set (ADS) and available Load Serving Entity (LSE) IRPs from balancing authority areas external to CAISO
- Incorporating the California Energy Commission (CEC) 2023 Integrated Energy Policy Report (IEPR) California Energy Demand Forecast
- Updating weather and hydroelectric data to include historical years 2021 and 2022
- Revising the weather normalization model for synthesizing hourly demand shapes
- Revising the hourly wind generation model
- Updating scheduled (maintenance) and unscheduled (forced) outage rates for several resource classes
- Incorporating ambient temperature output derating for thermal generating units.

On July 19th 2024, Staff released a report detailing the process of implementing the Inputs and Assumptions updates listed above for 2026, results from the LOLE study, implementation of the LOLE results into a modeled SOD PRM-requirement setting tool and recommending a PRM requirement level for considerations as a RA requirement for 2026.[4] Following the release of the July 19th report, Staff held workshops on July 25 and 26, where the study results were discussed with parties and staff held a subsequent SOD Office Hours for additional review of the materials.

On August 6, 2024, an Administrative Law Judge (ALJ) ruling was released, notifying parties that the SOD PRM setting tool required revisions to correct several logic calculations identified by parties following the release of the workbooks and discussion in the SOD Office Hours. The ruling noted that Energy Division would issue a revised SOD PRM setting tool and translation of the annual LOLE study results by the end of August. On August 30, 2024, Energy Division sent to the service list of the RA proceeding: (1) Appendix A to LOLE Study for 2026: Revised Slice of Day Tool Analysis and (2) the SOD PRM setting tool and (3) a notification that parties would be provided an additional comment period in September to review results including revised monthly stress test results that levelize the PRM requirements across the year.

Appendix A already highlighted that there was an over-counting of storage charging requirements by deducting charging energy from the hourly energy requirement twice, effectively reducing storage energy capabilities. Additionally, the storage optimization routine minimized variance in excess capacity rather than maximizing PRM. These corrections resulted in an increase in the PRM in the SOD PRM-setting tool.

Within Track 2 of the proceeding parties were provided an additional period on September 9, 2024, and September 16, 2024, to file comments regarding Appendix A. In September parties identified accounting errors in the PRM setting tool and consequently Appendix A contained an incorrect PRM requirement. Parties recommended publishing all underlying input data from the SOD calibration process, including a breakdown of capacity used for the SOD PRM setting tool to ensure that correct amounts were included.

In the recent Track 2 Decision, D.24-12-003, the Commission agreed with parties and authorized Energy Division to undertake a further revision of the 2026 PRM analysis to correct additional identified errors raised in comments and distribute it to the service list in this proceeding in early December 2024. In response to this direction, Energy Division has updated the study results to review and identify all issues with the SOD PRM Setting Tool, correct and vet the SOD PRM setting tool, and rerun the stress test to arrive at new PRM results. While preparing stress test results, staff also reviewed maintenance outages in stress test modeling and noted that this input also increased PRM requirements in off-peak months incorrectly. Therefore, staff removed the maintenance rates from the stress tests to correct for this issue.

More detail is provided in the body of this Appendix B regarding the revisions made to the stress test as well as the SOD requirement setting. The purpose of this Appendix B is to demonstrate effort made to present corrected analysis, provide further explanation of issues identified, present final study PRM requirements results and attempt to increase credibility in the revised study results so that they can be considered as inputs into the RA program requirements process.

[4] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M536/K273/536273741.PDF

The summary of the specific changes incorporated in Appendix B that differ from the Appendix A (August 30, 2024) study results are:

1. Adding monthly net qualifying capacity (NQC) of hydro units from the Master Resource Database (MRD) and replaced aggregated hydro capacity for a more accurate hydro counting. Removing remote generators from SOD PRM-setting tool to avoid double-counting of imports. These changes resulted in a net reduction of the PRM.
2. Removing maintenance rates from SERVM to be consistent with SOD PRM setting tool (blocks of load added for stress test are higher than capacity impacts of maintenance rates). This resulted in a reduction in PRM in off-peak months.
3. Corrected formula errors in the SOD PRM setting tool (in addition to the errors identified in Appendix A). Staff corrected formula references which incorrectly identified the most constrained hour, and thus correctly matched demand to exceedance hours for the PRM calculation.
4. Staff provided in the SOD PRM-setting tool a total list of all generators included in the CAISO region, and separated pumping load from DR. The added data had no effect on the PRM but is provided for transparency and stakeholder review.
5. Removing ambient derates from revised stress test runs. This had the effect of lowering the PRM by about 1%.

After making these corrections or modifications, staff recalculated demand block levels in the SOD PRM-setting tool, adjusted the demand blocks by month, and ran SERVM to identify the demand blocks and resource levels needed to arrive at 0.1 LOLE across the year, and the appropriate PRM level to apply to the RA program. Staff recalculated both the SOD equivalent of the initial August LOLE study (which was not rerun) then based on those initial LOLE SOD results, staff redid the stress tests (including a revised SERVM LOLE run) to surface the LOLE and determine the required PRM values in each month.

Review of Updated Capacity Amounts in Appendix B

After review of Appendix A (issued August 30, 2024) and party comments on it, staff reviewed the tabulation of capacity included in the SOD PRM-setting tool that totals CAISO area generation. The total of capacity by tech type is not meant to include imported resources, which are part of the import constraint. Therefore, some remote generators needed to be removed from SOD PRM-setting tool as they were already part of the import constraint amount (4,000 MW in initial study, lowered to 2,500 MW to surface LOLE). Likewise, the CAISO total is meant to reflect NQC capacity that is then compared to worst day peak demand to result in the PRM level needed for maintaining LOLE targets. Upon reviewing the SOD PRM-setting tool, staff noticed hydro totals did not include all the NQC provided by hydro in the RA program. Staff added those capacities to be consistent with SERVM hydro accounting. The changes are summarized in

Table 1. These corrections resulted in a net decrease in capacity required to meet RA requirements of 2,075 MW NQC in the September month which is equivalent to 4.5% decrease in PRM.

Table 1 Resources removed and added to SOD PRM-setting tool to properly account for imports and hydro units

	Resources Removed and Added (September NQC)	Unit
Remote Generators Removed from SOD	(4,126)	MW
Hydro Resources removed from NQC Baseline	(2,905)	MW
Hydro Resources Added to NQC Baseline	4,956	MW
Total Changes (reduction) in required resources list	(2,075)	MW
Managed Load in September	46,395	MW
Effect on % PRM decrease	-4.5%	

Staff also removed the Thermal Derate functionality for this 2026 LOLE study, due to unexpected results on the PRM. Staff will continue to test this functionality during Track 3 and return with a proposal regarding it when discussing UCAP. This change led to a further decrease in the PRM by about 1%.

Additionally, staff made other formula corrections to the SOD PRM-setting tool which resulted in increasing the PRM which partially offset the decrease seen by correcting the resource capacity totals. The previous PRM setting tool, that supported the Appendix A results, included two PRM settings: one without negative operating units (NOUs) and one with NOUs. These settings have now been split into two separate workbooks: one calculating PRM with NOUs and the other without. Several formulas in the PRM Setting tab and the Monthly Constrained tab were referencing the wrong constrained hour (from the Without NOU Annual LOLE workbook), leading to incorrect PRM values being displayed. Specifically, Column I in the PRM Setting tab was referencing the constrained hour from a table intended for the PRM setting without NOUs, and a similar issue affected the Monthly Constraints. This mistake in constrained hour led to higher credit given to resources, whose exceedance is based on hour of day, but whose credit decreases as the hour moves later (especially solar) and when demand is lower. After these corrections, the PRM values in the new workbook are now accurately displayed, properly aligned with the correct tables, and now reflect higher PRM values than those shown previously.

Removal of Maintenance Rate to avoid double counting

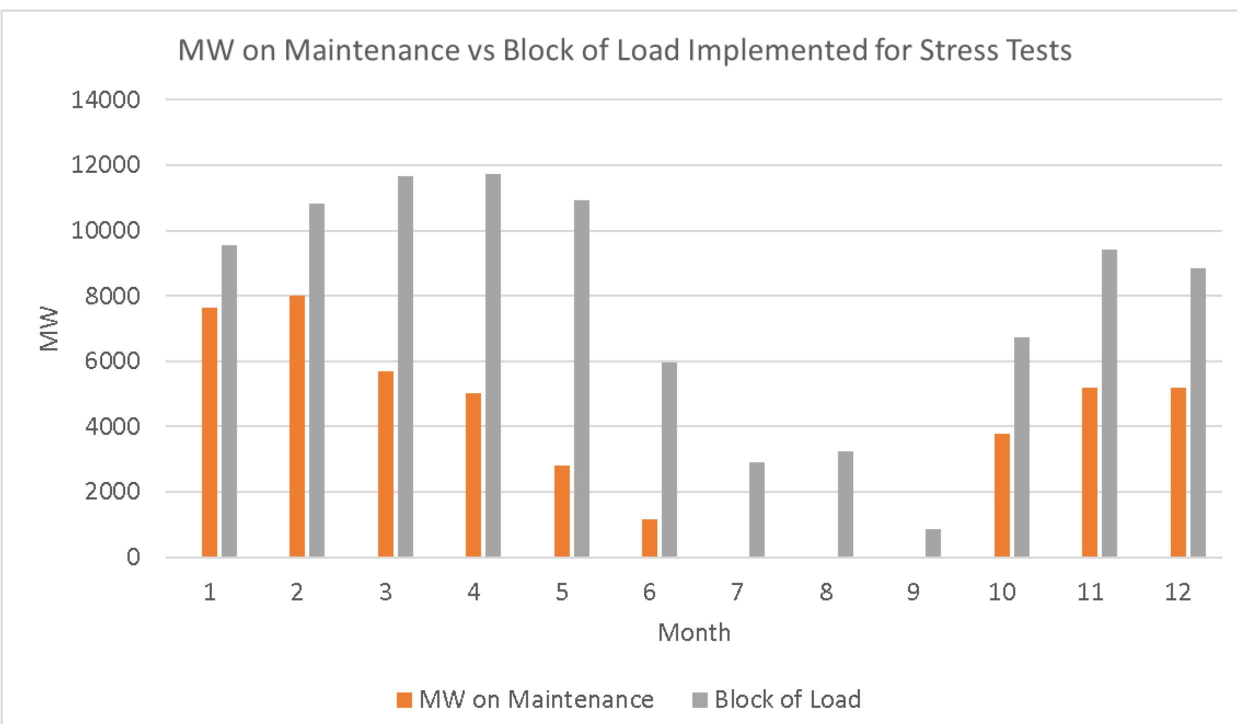
As staff was evaluating PRM results by month and conducting stress test results staff reconsidered the inclusion of a maintenance rate for each unit in the modeling in addition to adding demand blocks to surface LOLE. Staff realized this created an unrealistic situation where resources were forced into maintenance by the model, even when the added demand narrowed the excess resource margins in off-peak months that usually generally allow for maintenance. This artificially created scarcity in the model and inappropriately increased PRM. CAISO tariff and RA program rules require that units shown for RA are replaced, so this model change is consistent with that tariff expectation that RA units are replaced.

To reinforce this observation staff compared planned maintenance scheduled by the model with the required blocks of demand for the stress test runs. Figure 1 shows that these amounts are fairly close, demonstrating why the model scheduled maintenance in these months – that there was excess capacity in these months which enabled maintenance to occur without increasing LOLE. But when extra demand was added, the model no longer was able to schedule the maintenance without increasing LOLE. Staff removed maintenance rates in SERVM stress tests so blocks of loads are not double counted. In other words, the demand blocks added in SERVM now include capacity on maintenance and additional amounts of margin of demand added to increase LOLE to 0.1 target.

Staff also observed that the anomalous results in February are now gone. Removal of maintenance rates resulted in even LOLE across most of the off-peak months and resolved the situation in the initial study where February LOLE results appeared anomalous.

Figure 1 shows a comparison between added blocks of demand (Negative Operating Unit or NOU) and capacity in maintenance. As it is seen, most maintenance happens during non-summer months and the capacity in maintenance remains lower than the block of demand required to keep the LOLE at the 0.1 margin. The difference between NOU and capacity in maintenance will be the margin of demand required to increase LOLE to the 0.1 target.

Figure 1 Comparison between added blocks of demand and capacity in maintenance



Revised 2026 LOLE Results

On an annual basis, staff was able to achieve LOLE of 0.1 with a sizable surplus of capacity in off-peak months. Focusing on the peak months of the summer only, staff found that the baseline resource fleet was over reliable, allowing for a decrease in the evening CAISO simultaneous import constraint from 4,000 MW to 1,700 MW. Table 2 shows the PRM in each month needed to provide sufficient reliability to minimize loss of load, and the amount of additional load (24-hour static blocks) added to each month to levelize the PRM in summer and off-peak months. These extra blocks of demand were then added to SERVM and the study was rerun to ensure that with these PRM levels (and demand blocks) CAISO still achieves a LOLE of 0.1 across the months of the year.

When performing the monthly SOD stress tests, staff reduced LOLE and spread LOLE across the summer by raising the import constraint back up to 2,500 MW (raising the PRM in September) and added blocks of demand to other months to increase LOLE while decreasing PRM to the same level as September. Thus, overall PRM levels of 21.0% for the months of October through March and 22.5% for June through September allow for reliable operation of the CAISO system. April and May also had 24.5% PRM requirements in the study, which reflect significant variability in peak demand across the weather years simulated in the LOLE study. Staff are comfortable combining April and May with the off-peak months and maintaining PRM of 21% in these off-peak months as it is expected CAISO can manage these off-peak months with dispatch and operational actions. The overall MW requirements in April and May are far lower than August and September, so this will not pose a risk. Study results show that 21.0% PRM in off-peak months and 22.5% PRM in summer meets the 0.1 LOLE target.

The revised monthly results of staff's 2026 LOLE study and SOD translation are provided in Table 2 below. The Supply column represents the hourly value for generating resources used in the PRM setting tool, including exceedance for wind and solar resources. The column reflects capacity identified in the Generating Resource Baseline posted to the System Reliability Modeling Datasets 2024 page of the CPUC website.[5] This includes installed capacity, expected new capacity, and imports of up to 2500 MW per month. Importantly, this level of installed infrastructure is considered likely achievable by 2026 RA compliance year. Therefore, it is conceivable that the PRM recommendations in Table 2 can be achieved given the available supply shown. However, staff offer a recommendation section at the end of this document for how to apply these PRM results to RA Program Requirements in 2026.

[5] The Generating Unit Baseline List, updated in August of 2024, is posted on this page. [System Reliability Modeling Datasets 2024]

Table 2 Summary of Revised Results - Levelized PRM levels Expected to Ensure Low or No Reliability Events in 2026

Month	Planning Reserve Margin	Constraining Hour Ending	Managed Load (MW)	NOU (MW)	Supply (MW)
Jan	21.00%	19	30,003	9,558	47,868
Feb	21.00%	19	29,419	10,817	48,686
Mar	21.00%	20	29,412	11,652	49,688
Apr	24.50%	19	31,688	11,270	53,483
May	24.50%	20	33,897	10,442	55,202
Jun	22.50%	19	41,906	5,964	58,641
Jul	22.50%	19	45,588	2,916	59,417
Aug	22.50%	19	44,125	3,229	58,008
Sep	22.50%	18	46,395	867	57,896
Oct	21.00%	18	37,720	6,742	53,799
Nov	21.00%	18	31,645	9,433	49,705
Dec	21.00%	22	28,855	8,843	45,615

For comparison purposes, Table 3 shows the previous results from Appendix A where maintenance rate was implemented in SERVM. With maintenance rates included, PRM needed to be at higher values to keep the LOLE at or below 0.1 particularly in off-peak months. As noted above, staff removed the maintenance rates from SERVM runs to avoid double counting. Due to this change the PRM reduced in winter months, and the study now correctly reflects the CAISO RA tariff requirement that capacity reported for reliability in supply plans must be substituted if it is on maintenance. The added demand blocks allow for levelizing LOLE and PRM in individual months. The added demand helps to levelize the LOLE events throughout the year and thereby helps establish a stable modeled PRM requirement across the year. Adding demand to September initially lowered the PRM slightly and raised LOLE to 0.1 across the summer. Previous to that, the summer was slightly overly reliable.

Table 3 Results summarized from Appendix A showing higher non-summer PRM due to including maintenance in SERVM

Month	PRM	Constraining Hour Ending	Managed Load	Added Block of Load	Supply (MW)
1	26.49%	19	30,003	5,920	45,438
2	26.49%	19	29,419	8,120	47,485
3	26.49%	20	29,412	8,690	48,194
4	26.48%	19	31,688	10,400	53,234
5	26.50%	19	34,546	8,770	54,793
6	23.49%	19	41,906	5,390	58,408
7	23.51%	19	45,588	2,490	59,381
8	23.52%	19	44,125	2,540	57,641
9	23.50%	18	46,395	130	57,458
10	23.49%	18	37,720	5,170	52,964
11	23.47%	18	31,645	7,950	48,886
12	23.50%	19	30,392	6,970	46,142

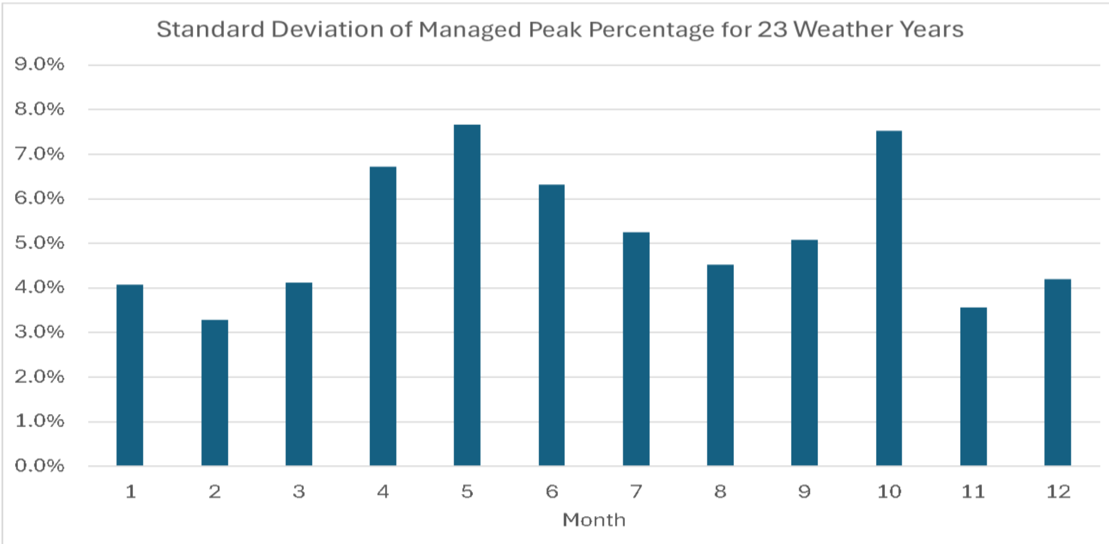
The table shows LOLE results by month for this revised Appendix B stress test results. As reflected, LOLE is now lower in winter, with the removal of maintenance requirements, but is elevated in April, May and October outside the summer. LOLE totals 0.159 across the whole year, with significant LOLE outside of the summer in April, May and October. LOLE totals 0.11 during the four summer months of June through September.

Table 4 Monthly LOLE and EUE 21.5% PRM off-peak and 22.5% PRM in peak (Appendix B Results)

Month	LOLE	EUE	LOLH	PRM
1	0.00024	0.10306	0.00024	21.00%
2	0.00000	0.00000	0.00000	21.00%
3	0.00052	0.88240	0.00076	21.00%
4	0.00765	6.11105	0.00879	24.50%
5	0.02648	42.47178	0.04669	24.50%
6	0.01462	12.23719	0.01462	22.50%
7	0.00382	3.23502	0.00505	22.50%
8	0.02198	24.54513	0.02946	22.50%
9	0.07708	80.49484	0.09243	22.50%
10	0.00672	2.45889	0.00672	21.00%
11	0.00000	0.00000	0.00000	21.00%
12	0.00000	0.00000	0.00000	21.00%
Total	0.15912	172.53937	0.20476	

Higher model PRM requirements in Table 2 are driven by the underlying variability of demand and resource performance, not just sheer magnitude (volume) of demand and resources. Figure 2 shows the standard deviation of variability as percent deviation in ratio of peak monthly demand to total annual demand across all 23 weather years. April, May and October show the highest standard deviation of ratio of monthly managed peaks to annual peaks across weather years, meaning those months show the greatest variability in their contribution to the total need in those years. The standard deviation in ratio of monthly peak to annual peak is well above 5% in those months which could lead to greater PRM need in those months. April, May and June do in fact require higher PRMs while October has a lower PRM but still shows elevated LOLE. Peak demands in winter and summer months fall within a narrower band of variability, thus they require lower PRM requirements, Though PRM is expected to be highest in those months, total MW reliability need is still lower in those months than the MW capacity needed during the summer. This explains why months with higher variability (and thus higher uncertainty) result in higher modeled PRM requirement. Due to the lower overall MW need, and ability of CAISO to manage situations like this when they arise because of the lower overall MW requirement off-peak, staff believes it prudent to group the fall months with winter and propose a 21% PRM for the months of April, May and October despite higher LOLE. If parties disagree with this approach and instead prefer to group these three months with the summer and require higher 22.5% PRM, that is also prudent. Parties are encouraged to comment on that issue.

Figure 2 Standard Percentage Deviation of ratio of monthly peak to annual peak demand within 23 weather years show high variations in months April, May, June and October resulting in higher LOLE during these three months



Comparison of Revised SOD results with the "old method" stress test from SERVM

Upon reviewing Track 2 opening and reply comments, staff noticed that some parties misunderstood how the modeled PRM requirements are calculated within the stress test procedure. To help clarify this misunderstanding, staff would like to make clear that although blocks of load are added to the managed load to simulate the situation of removing the resources to surface loss of load, when calculating modeled PRM requirements, monthly PRM levels should be added to the managed load only (and not to the blocks of added load).

Figure 3 shows Appendix B modeled PRM requirements versus available resources in each month across the year during the most constrained hours. The yellow line is available NQC based on existing and planned capacity, including 2,500 MW of imports, Diablo Canyon extended to 2030, but without inclusion of once-through-cooling (OTC) plants in the Strategic Reliability Reserves. In off-peak months the orange line reflects what the modeled PRM requirements would require if adopted as the RA program requirements, i.e. the modeled PRM requires from LSEs a volume of resources which is much lower than available installed resources, reflected in the yellow line. It should be noted that only 2,500 MW of simultaneous import assumption is included in the yellow line as available NQC, whereas the RA program has historically seen higher import levels at between 4,000 – 6,000 MW. The LOLE studies that have been done for both IRP and RA have historically limited the simultaneous import assumption to 4,000 MW to ensure that that from a planning perspective there is not an overreliance on imports available to meet RA needs. Parties should note that results of the study show that 2,500 MW of simultaneous imports, alongside other existing or planned capacity, would be sufficient to achieve a 0.1 LOLE throughout the year. With the current 4,000 MW simultaneous import limit imposed in the model during peak hours HE 17-22 in the model, CAISO is already reliable and existing resource development should be sufficient. These modeling results suggest that in 2026 there should be surplus of RA capacity in the market provided that the resources under construction or in development that are part of the

Baseline reach COD as scheduled. Staff has reviewed the Baseline resources versus CAISO active new resources and notes that while the Baseline resources are online in large part, a small portion are still pending but well underway; furthermore, the modeled baseline represents a list of expected resources from a point in the past and thus is not inclusive of all known contracts currently reported that could potentially come online by 2026.

Figure 3 PRM calculated from SOD PRM-setting tool using exceedance

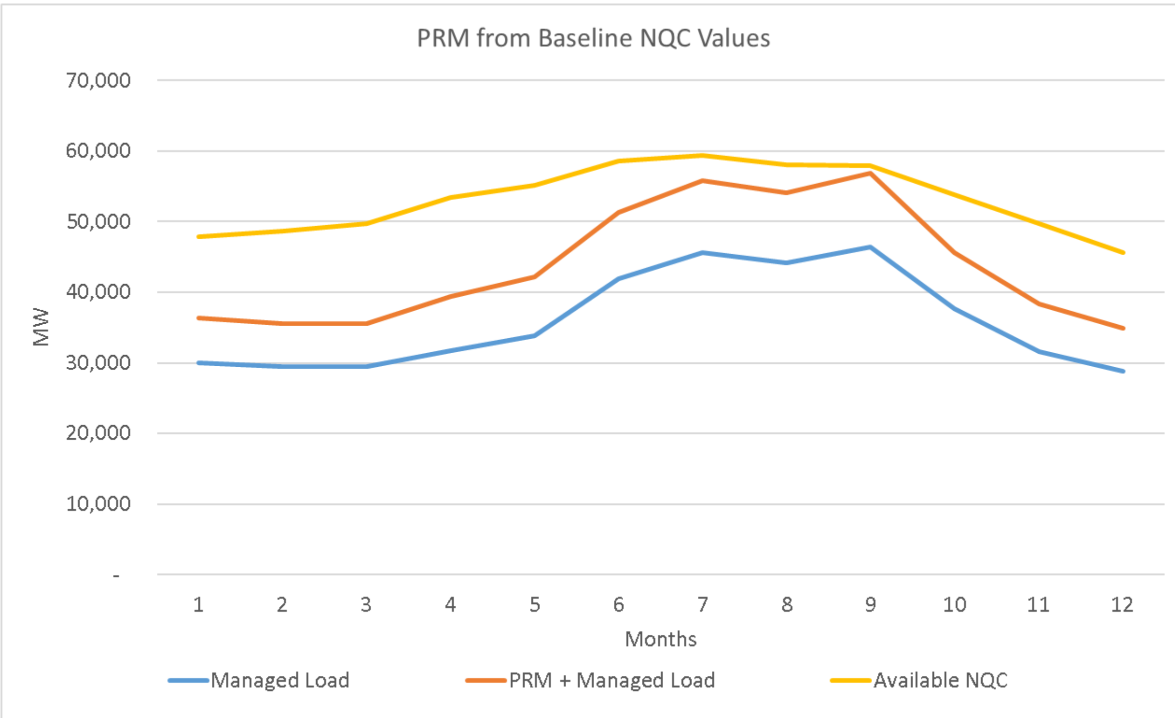


Figure 4 shows the RA requirements by calculating the monthly PRM using ELCC (Effective Load Carrying Capability) instead of exceedance for solar and wind resources. This is compared to the monthly peak demand, rather than the most constrained monthly hour (as reflected in Figure 3). The orange line reflects estimated RA requirements calculated using ELCC for wind and solar. The yellow line reflects all available NQC, also calculated using ELCC. Comparing Figures 3 and 4, staff observe that the modeled PRM requirement percentages mostly match between methods through summer months. However, higher modeled PRM requirement levels are seen during the winter months since ELCC values are higher than exceedance capacity values in winter months.

Figure 4 PRM calculated from non-SOD ELCC Stress Tests

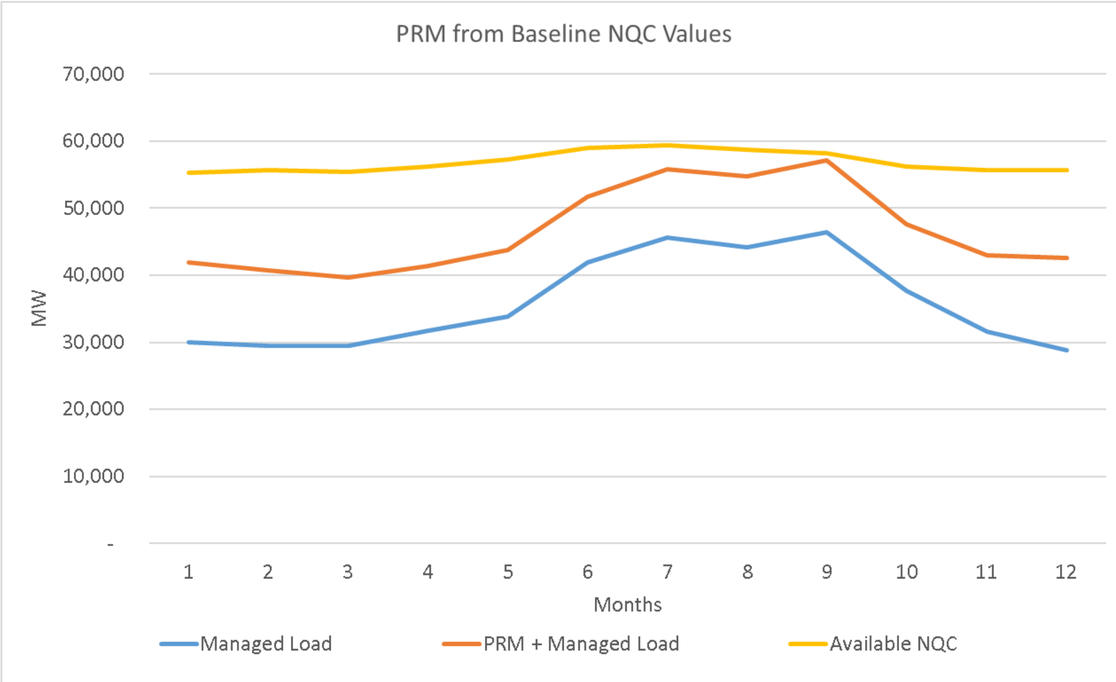


Table 5 provides a comparison between 2024 RA Study results (published in February 2023) and the 2026 revised RA Study results from December 2024 (shown here in Appendix B). This comparison shows that the modeled PRM requirements needed to maintain reliability increased from one study to the next by about 2-4.5% points in Aug-Sep but reduced in all other months. This reflects greater effort to reduce PRM in off-peak months through stress tests, so it does not reflect reduction in reliability need, just reduction in excess capacity. Neither set of results reflected in Table 5 include Demand Response (DR) Resources, which is why the modeled PRM requirements proposed in this Appendix B are greater than shown below. While there are small differences in summer months (18.5% in 2024 study year vs 20.6% in August for example) the differences in off-peak months are far larger reflecting ELCC values that are far higher than exceedance values.

Table 5 Comparison between 2024 Study year and 2026 study year (current) PRM Results (both studies are compared using ELCC, not exceedance)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2024 LOLE Study	Effective Capacity: NQC current, new Portfolio ELCC + 4000 MW import	51,789	52,313	52,218	52,815	53,442	54,884	55,856	55,102	54,421	52,446	52,179	52,096
	2022 IEPR 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
	NQC divided by CEC Monthly Manag ed Peak	159.2%	166.2%	172.3%	158.3%	142.4%	128.5%	121.7%	118.5%	115%	135%	161%	153.7%
2026 LOLE Study	NQC equivalent Bas eline 2026 LOLE portfolio+2500 MW Import	54,307	54,653	54,413	55,038	55,895	57,358	57,791	57,088	56,574	54,896	54,703	54,730
	2023 IEPR Managed Peak + NOU	39,561	40,236	41,064	42,958	44,339	47,870	48,504	47,354	47,262	44,462	41,078	37,698
	Modeled PRM Requirements with ELCC values	137.3%	135.8%	132.5%	128.1%	126.1%	119.8%	119.1%	120.6%	119.7%	123.5%	133.2%	145.2%

Revised Results and PRM calculations

Translation of Annual LOLE Study into SOD Modeled PRM Requirements

This section details how the LOLE study results were translated to a SOD modeled PRM requirements. As documented in the background section, Energy Division staff revised the previous SOD PRM-requirement tool, including updating the exceedance profiles. Then, Staff went through the same steps as before to translate and test the LOLE study results. Staff used the following inputs in the revised SOD PRM requirement tool.

1. Managed Worst Day Load Forecast - Staff used the 2023 California Energy Commission IEPR Hourly Load Model to identify the managed peak worst day load profile for each month in 2026. Those monthly managed peak worst day load profiles were then entered into the SOD PRM requirement tool as a table on the Managed Load worksheet.
2. The annual resource portfolio is extracted from SERVM and translated into monthly values using monthly QC before being input into the SOD PRM requirement tool. Each technology category of resources is quantified according to its QC calculation guidelines. The profiles tab contains QC values by unit category and profiles for each resource type, with solar and wind profiles based on the exceedance values for each month determined in the exceedance workbook. The pump

storage hydro (PSH) and DR shapes follow RA rules, and the simultaneous import constraint is entered into the SOD PRM tool across all 24 hours of the day as a flat profile.
3. The Dashboard tab reflects the MW values of each unit category, as well as managed load and supply with and without storage.
4. The PRM Setting worksheet, includes two tables that organize data from the input worksheets to setup a root-finding problem for Excel's built-in Solver tool to determine the maximum modeled PRM requirement. The PRM requirement is evaluated as the minimum reserve margin across all 24 slice-of-day hours for a given month, which is the hourly supply capacity divided by the total load minus 100%. This worksheet allocates storage capacity to meet hourly excess capacities, defined as total load multiplied by 1+PRM minus total supply without storage while ensuring that the overall capacity of storage is not exceeded in any given hour and that the available energy in the batteries is not exceeded in any given day while guaranteeing there is sufficient energy to charge the batteries.

Staff used the revised SOD requirement workbook to translate the initial resulting annual portfolio of resources into the SOD PRM requirement-setting tool and recalculated monthly required modeled PRMs. As expected, off-peak modeled PRM requirement levels were excessive due to lower electric demand relative to the annual capacity portfolio (calculated for each month using hourly SOD NQC values). As expected, LOLE equaled zero outside of September presenting an opportunity for levelizing LOLE across the months to remove some of that excess. Table 6 illustrates the initial modeled SOD PRM requirement results showing that the required PRM in September is the minimum for the whole year and is equal to 23.12%. The other months show significant excess capacity relative to their much lower managed peak demand, which explains their minimal or zero LOLE.

Changes to the SOD PRM Setting tool

The Slice-of-Day PRM-setting tool consists of an Excel workbook that determines monthly maximum planning reserve margins for California's grid based on input monthly load forecasts and net qualifying capacities (NQC) for each unit category. The tool provides an interactive dashboard for inspecting a single month's profile.

Changes present in the PRM Setting Tool used in Appendix B relative to the version used in the initial 2026 results version (published in July 2024) are summarized below.

- Whereas the previous version of the SOD PRM-Setting Tool required separate Excel files for each month of data, the new version combines all months to allow the user to view a full year's inputs and results.
- The previous version solved so that storage was dispatched to minimize the variance among hourly PRM values for each most constrained day, while the new version dispatches storage to maximize the PRM (i.e., the minimum hourly margin for each most constrained day), allowing the storage allocations to equal exactly any negative excess between the system requirements (i.e., total load forecast with PRM) and capacities shown by all non-storage resources. The same constraints on storage are applied in each month in this revised Appendix B. These revised constraints ensure either the full energy capability (daily MWh) or the full instantaneous capacity (MW) are leveraged, or both.
- The excess vs. charging energy constraint on storage resources has been corrected for various errors that had resulted in over-counting charging requirements for storage resources.

Changes in this Appendix B version, relative to the Appendix A (August 2024 version) are summarized below.

- This latest version of the SOD PRM setting tool includes all inputs in the same workbook so parties can review the resource list.
- Several formulas were corrected in this latest SOD PRM-setting tool. In previous versions of the tool, the determination of constrained hour was mistakenly referring to the constrained hour before adding demand blocks, meaning it was incorrect and led to the wrong (lower) PRM calculation. Fixing this reference had the effect of increasing the modeled PRM requirements, offsetting the effect of correcting the supply to remove imports.

Exceedance Values – Exceedance values are profiles for different technology types calculated for variable renewable energy resources based on six years of historical energy production. These values are based on exceedance levels, which provide the likelihood that a resource will produce more energy than the value given. In the previous values posted in the original 2026 LOLE study (published in July 2024), it was identified that the exceedance profiles were not adjusting CAISO settlement data to correct for Daylight Savings Time. Staff made corrections to the exceedance calculation to correct for this error. Staff also removed the year 2017 from the data set to accurately reflect the 6-year historical data set (as opposed to a 7-year historical data set). Staff reposted the revised exceedance profiles to correct for both errors. The new exceedance values are being used in the tool producing the Appendix B results.

Exceedance levels indicate the output of a resource (% nameplate) on at least X% of observations (e.g. 70%) for each month-hour pair are the reverse of percentiles, with 70% exceedance meaning that the number given is the 30th percentile of production (i.e., a higher exceedance level is a more conservative number). Staff use historical CAISO settlement quality data and/or modeled data where historical data is insufficient to derive both exceedance levels and values. To derive exceedance levels, staff use historical production data during the top five CAISO load days, as well as days where a Flex Alert, EEA 1-3, or Emergency Alerts are called. Staff also uses a solver function to identify the exceedance level that minimizes LOLE in the worst days to identify unique exceedance levels for each month and for each technology type. The exceedance levels are then applied to historical monthly production and a production profile for each technology type by region is produced and can then be applied hourly to the variable resource's nameplate MW.

Table 6 Initial Monthly Modeled SOD PRM Requirements resulting from Annual LOLE Portfolio (Appendix B Results)

Month	Planning Reserve Margin	Constraining Hour Ending	Managed Load (MW)	NOU (MW)	Supply (MW)
1	**59.98%**	19	30,003	0	47,998
2	**67.13%**	19	29,419	0	49,169
3	**71.17%**	20	29,412	0	50,345
4	**71.68%**	19	31,688	0	54,402
5	**63.91%**	19	34,546	0	56,625
6	**39.62%**	19	41,906	0	58,511
7	**29.02%**	19	45,588	0	58,820
8	**30.18%**	19	44,125	0	57,442
9	**23.12%**	18	46,395	0	57,122
10	**42.97%**	18	37,720	0	53,927
11	**58.54%**	18	31,645	0	50,170
12	**57.57%**	19	30,392	0	47,888

The primary differences in inputs across the months are the managed load and resource values in different months of the year. The managed load forecast input is derived from the CEC's 2023 IEPR hourly managed system (1-in-2) demand forecast and uses the worst day hourly load shape for each month. The hourly resource values for each month are derived from the 2025 master resource database ("VER Exceedance Profiles" tab) which provides exceedance profiles for wind and solar resources. using the updated exceedance methodology adopted in D.24-06-004. Hydro and non-dispatchable resources also vary by month and are quantified by their appropriate NQC methodologies, some of which depend on hour of day such as Demand Response. The resource values used in the SOD PRM setting tool are reflective of the RA values that will be used for the 2025 RA compliance year.

The translation of the annual LOLE study resulting in monthly modeled SOD PRM requirements show September as having the lowest PRM requirement due to having the highest peak demand and the lowest exceedance production levels for solar and wind. However, other summer months (June, July and August) are fairly similar in overall reliability despite higher PRM requirement levels. The other summer months are supported by the same portfolio of baseline supply resources, despite the differing exceedance production profiles, and have only slightly different managed demand levels.

As shown in Table 6, the modeled PRM requirement levels for the most stressed summer months (July-September) varied significantly. The modeled PRM requirement was approximately 23.12% in September, 30.18% in August and 29.02% in July. This variation in Appendix B modeled PRM requirements shown in Table 6 is primarily driven by monthly fluctuations in resource NQC values and hourly managed demand during the most constrained hour. On the demand side, there is a load variation of about 2,270 MW between August and September, compared to only about 800 MW between July and September. This is updated since the original LOLE study report (July 2024), due to corrections made to the SOD PRM setting tool that corrected the calculation of the initial PRM requirement from the annual LOLE study. On net, the same effects impacted this updated table as effected the rest of the SOD translation, namely removal of imports, correction of NQC totals (hydro and imports) listed in the tool, and correction of cell references and formulas in the workbook.

Table 7 details the supply and load values used in the SOD PRM Setting Tool by month and resource technology during the most constrained hour of each summer month from Appendix B results. On the supply side, we observe a difference of over 2,000 MW in resource values (excluding storage) between July and September during the most constrained hour, with almost no difference between August and September. In the most constrained hours—HE 19 in July and HE 18 in September—there is a significant change in production from variable renewable resources. That difference is why the constrained hour is later in the day in July than September. With the exceedance profiles and SOD PRM-setting tool used in the July 2024 Appendix A results, some summer months had a constrained hour as late as HE 20. Between July and September, wind and solar QC drops by over 1,980 MW, while the hourly managed load during the most constrained hour decreases by over 2,200 MW between August and September. These reductions in wind and solar between July and September and in managed load between August and September contribute to the lower PRM in September.

Table 7 Monthly Demand and Supply during most constrained hours, Modeled SOD PRM Requirement (Appendix B Results)

Month	Jun	Jul	Aug	Sep	Oct
Constraining Hour Ending	19	19	19	18	18
Biogas	186	184	183	183	179
Biomass/Wood	423	422	411	415	391
CC	16,730	16,736	16,729	16,747	16,786
Coal	0	0	0	0	0
Cogen	1,753	1,738	1,746	1,720	1,734
CT	7,789	7,780	7,780	7,791	7,818
DR	2,319	2,319	2,319	2,438	2,438
ICE	255	255	255	255	255
Geothermal	1,078	1,083	1,083	1,085	1,077
Hydro	4,967	5,277	5,305	4,956	4,201
Interchange	2,500	2,500	2,500	2,500	2,500
Nuclear	2,915	2,915	2,915	2,915	2,915
PSH	1,419	1,418	1,418	1,417	1,418
Storage	11,616	12,148	12,622	12,496	11,274
Solar Fixed_Norcal	201	159	23	168	13
Solar Fixed_Socal	96	76	11	79	4
Solar Thermal_Norcal	0	0	0	0	0
Solar Thermal_Socal	132	105	40	92	19
Solar Tracking_Norcal	781	588	72	456	18
Solar Tracking_Socal	681	580	58	438	16
Wind_Norcal	860	987	719	581	214
Wind_Socal	1,939	2,145	1,820	1,165	528
Total Supply (NQC MW)	**58,641**	**59,417**	**58,008**	**57,896**	**53,799**
2023 IEPR Managed Load	**41,906**	**45,588**	**44,125**	**46,395**	**37,720**

Table 8 provides a heat map of the exceedance production profile differences between July and September for wind and solar, for the model results shown in Appendix B. Every red space is a decrease in production of greater than five percentage points relative to the prior month. The most constrained hours in September and August consistently have significant decreases in production from August to September. This means that all else being equal, the modeled PRM requirement levels from the SOD PRM requirement tool will be lower in September than in July and August, even if the capacity or nameplate margin of resources in excess of electric demand were the same. The decrease in exceedance production profiles contributes to significant variability in modeled PRM requirements during the summer months and explains the wide fluctuation in PRM requirements across the summer months. It would be easier to use the SOD PRM setting tool to set potential requirements if exceedance production profiles were set for the whole summer, possibly taking an average of each monthly profile to make a comparison easier.

Table 8 Exceedance production profile differences between July and September (Supply input for Appendix B Results)

Hour Ending	Solar Fixed_Norcal	Solar Fixed_Socal	Solar Thermal_Norcal	Solar Thermal_Socal	Solar Tracking_Norcal	Solar Tracking_Socal	Wind_Norcal	Wind_Socal
1	0%	0%	0%	0%	0%	0%	12%	20%
2	0%	0%	0%	0%	0%	0%	14%	17%
3	0%	0%	0%	0%	0%	0%	17%	14%
4	0%	0%	0%	0%	0%	0%	19%	16%
5	0%	0%	0%	0%	0%	0%	18%	14%
6	4%	6%	0%	0%	7%	8%	19%	10%
7	18%	9%	0%	8%	30%	20%	13%	7%
8	10%	1%	0%	8%	15%	6%	8%	3%
9	4%	-1%	0%	1%	8%	4%	3%	1%
10	3%	-1%	0%	0%	7%	4%	3%	-1%
11	4%	0%	0%	4%	8%	5%	3%	-1%
12	4%	0%	0%	1%	8%	4%	5%	0%
13	4%	0%	0%	-1%	8%	4%	8%	1%
14	4%	1%	0%	-7%	6%	4%	14%	4%
15	4%	2%	0%	-7%	5%	4%	20%	6%
16	8%	8%	0%	-2%	7%	7%	19%	12%
17	20%	23%	0%	8%	25%	29%	18%	16%
18	28%	20%	0%	29%	42%	34%	17%	18%
19	8%	3%	0%	11%	12%	6%	14%	17%
20	0%	0%	0%	0%	0%	0%	12%	17%
21	0%	0%	0%	0%	0%	0%	13%	19%
22	0%	0%	0%	0%	0%	0%	15%	21%
23	0%	0%	0%	0%	0%	0%	15%	22%
24	0%	0%	0%	0%	0%	0%	16%	21%

Due to the expectation that the LOLE will be uneven across the summer, even with an annual portfolio, Staff conducted a stress test to levelize LOLE across the summer months as part of evaluating the overall monthly SOD calculated PRM requirements needed to meet 0.1 LOLE. To do this, Staff first raised the import constraint from 1,700 MW to 2,500 MW. This had the effect of increasing the initial September PRM level from 23.12% to 24.5% and lowering the September LOLE risk. Second, staff levelized the modeled PRM requirements in the summer overall by adding demand blocks individually to each month, which lowered the modeled PRM requirements in the summer months to the Appendix B values of 22.5%. This modeled PRM requirements value was the target PRM for the whole summer, and when that PRM was used for the summer, staff arrived at a LOLE of .11 which was acceptable for the summer months. Higher or lower modeled PRM requirements would have resulted in either too much or not enough LOLE. Less LOLE occurred in September as a result, while greater LOLE occurred in July and August. Staff then added blocks of demand to the other months (outside of summer) to increase their LOLE and lower their PRM levels until LOLE across the entire year again totaled 0.1. Staff added blocks of demand to avoid the confusion of having to select resources to remove and is an optimal way to balance LOLE risk across CAISO. It is very important to calculate needed demand blocks using the modeled SOD PRM requirement-setting tool and record the PRM requirement levels and what hour becomes the constrained hour. This calculation effort is necessary since as batteries are optimized, energy is shifted around the day and what was a constraint on one hour can become a constraint on a different hour as optimization is refreshed. PRM requirement levels are confirmed by running the SOD PRM requirements tool for that month using that month's specific managed demand day profile and exceedance values. Staff repeated this calibration until annual aggregate monthly LOLE equaled 0.1.[6]

[6] RA proposals from January 2024 are discussed in this slide deck. SOD Stress Test proposals begin on slide 81. ra-oir-track-1-workshop-022924.pdf (ca.gov)

Revised Monthly Stress Test Results

Staff is posting the revised calibrated PRM workbooks supporting Appendix B on the CPUC RA history page website.[7] That workbook shows the monthly PRM SOD results, including a listing of individual resources, demand, added blocks of load, and the resulting SOD PRM. Table 9 shows the updated monthly SOD PRM levels as well as blocks of demand added in each month.

Staff arrived at a levelized PRM that resulted in LOLE at 0.1 with a modeled PRM requirement of about 22.5% for the months of June to December and 21% for the months of January to May. The other months showed acceptable LOLE, and across the whole year totaled 0.157.

Table 9 Proposed Levelized SOD PRM levels (Hours Ending are in PST time)

Month	Planning Reserve Margin	Constraining Hour Ending	Managed Load (MW)	Added Block of Load (MW)	Supply (MW)
Jan	21.00%	19	30,003	9,558	47,868
Feb	21.00%	19	29,419	10,817	48,686
Mar	21.00%	20	29,412	11,652	49,688
Apr	24.50%	19	31,688	11,270	53,483
May	24.50%	20	33,897	10,442	55,202
Jun	22.50%	19	41,906	5,964	58,641
Jul	22.50%	19	45,588	2,916	59,417
Aug	22.50%	19	44,125	3,229	58,008
Sep	22.50%	18	46,395	867	57,896
Oct	21.00%	18	37,720	6,742	53,799
Nov	21.00%	18	31,645	9,433	49,705
Dec	21.00%	22	28,855	8,843	45,615

Table 10 compares the demand blocks used for the results released in the original study results in July 2024) and the results in this revised SOD stress test. Non-summer months show bigger changes and higher blocks of demand requirements compared to the original July result. Recall in the original July results those months had nearly 0 LOLE and still continue to have very limited LOLE so the larger change in these four months does not have significant impact on LOLE.

[7] Resource Adequacy History

Table 10 Comparison of Demand Blocks initial July results to Appendix B revised results

Month	7/19 Demand Block level	Revised Demand Block level	Change (MW)	Change (%)
1	4,750	9,558	4,808	101%
2	8,000	10,817	2,817	35%
3	9,000	11,652	2,652	29%
4	8,900	11,270	2,370	27%
5	9,400	10,442	1,042	11%
6	5,842	5,964	122	2%
7	2,200	2,916	716	33%
8	2,425	3,229	804	33%
9	400	867	467	117%
10	4,800	6,742	1,942	40%
11	6,950	9,433	2,483	36%
12	4,650	8,843	4,193	90%

LOLE Results Summary (Appendix B Version)

Table 11 illustrates the LOLE, Expected Unserved Energy (EUE) and Loss of Load Hours (LOLH) levels by month from the stress test runs used in Appendix B results. The Appendix B results show that all months have minimal or zero LOLE at PRM levels of 21% for the months of October through March and 22.5% for the months of June through September. Months April and May have 24.5% PRM due to higher peak managed demand variability in these months. As mentioned above, current changes to our modeling method, such as removing maintenance rates and revisions to the SOD PRM setting tool resulted in fixing the February problem (that appeared in Appendix A results) that showed high LOLE values in February. The total LOLE for the year now equals 0.1591 and is close to the 0.1 target, particularly the summer months.

Table 11 Monthly LOLE and EUE 21% PRM off-peak and 22.5% PRM in peak (Appendix B Results)

Month	LOLE	EUE	LOLH	PRM
1	0.00024	0.10306	0.00024	21.00%
2	0.00000	0.00000	0.00000	21.00%
3	0.00052	0.88240	0.00076	21.00%
4	0.00765	6.11105	0.00879	24.50%
5	0.02648	42.47178	0.04669	24.50%
6	0.01462	12.23719	0.01462	22.50%
7	0.00382	3.23502	0.00505	22.50%
8	0.02198	24.54513	0.02946	22.50%
9	0.07708	80.49484	0.09243	22.50%
10	0.00672	2.45889	0.00672	21.00%
11	0.00000	0.00000	0.00000	21.00%
12	0.00000	0.00000	0.00000	21.00%
Total	0.15912	172.53937	0.20476	

Table 12 shows the amount of energy (in GWh) generated by each unit type in CAISO in Appendix B model runs. This table illustrates total generation including contributions from demand modifiers, though they do not receive RA requirement credit. Battery storage and PSH are net negatives, as they require more energy to charge than they discharge. Larger negative numbers illustrate heavier use. Note that the 34,919 GWh of BTMPV energy generated per the model is substantial, constituting more than 15% of total CAISO energy to meet load (255,878 GWh). The total generation equals total demand and that total demand modifiers net out to a positive number (meaning more demand reducing modifiers than demand increasing). In future years, that number becomes negative as EV load begins to grow substantially.

Table 12 Annual Energy Generated by Unit Type in 2026 (Appendix B Results)

Annual Energy Balance		
	SERVM	
Category	2026	Units
Battery Storage	(2,777)	GWh
Biomass	4,219	GWh
BTMPV	34,919	GWh
CC	97,956	GWh
Coal	-	GWh
Cogen	15,713	GWh
CT	9,201	GWh
DR	9	GWh
Geothermal	12,731	GWh
Hydro	16,735	GWh
Hydro_NW_CAISO	10,152	GWh
ICE	529	GWh
Nuclear	25,692	GWh
OffshoreWind	-	GWh
OOSWind	-	GWh
PSH	(658)	GWh
Solar	65,459	GWh
Steam	-	GWh
Wind	20,183	GWh
Curtailed Energy	(361)	GWh
Net Imports	12,671	GWh
Total Demand Modifiers	5,921	GWh
Load	255,616	GWh
Total Generation	255,611	GWh

Figure 5 shows distribution of EUE in hours of the day and months of the year in the previous Appendix A model runs. Recall, Appendix A showed high LOLE and EUE in February, evidenced below with the dark red box in February at hour ending 22. The SERVM model was forcing maintenance in winter months and causing high EUE MWh to occur.

Figure 5 EUE MWh Original Appendix A Maintenance Forcing EUE in Winter

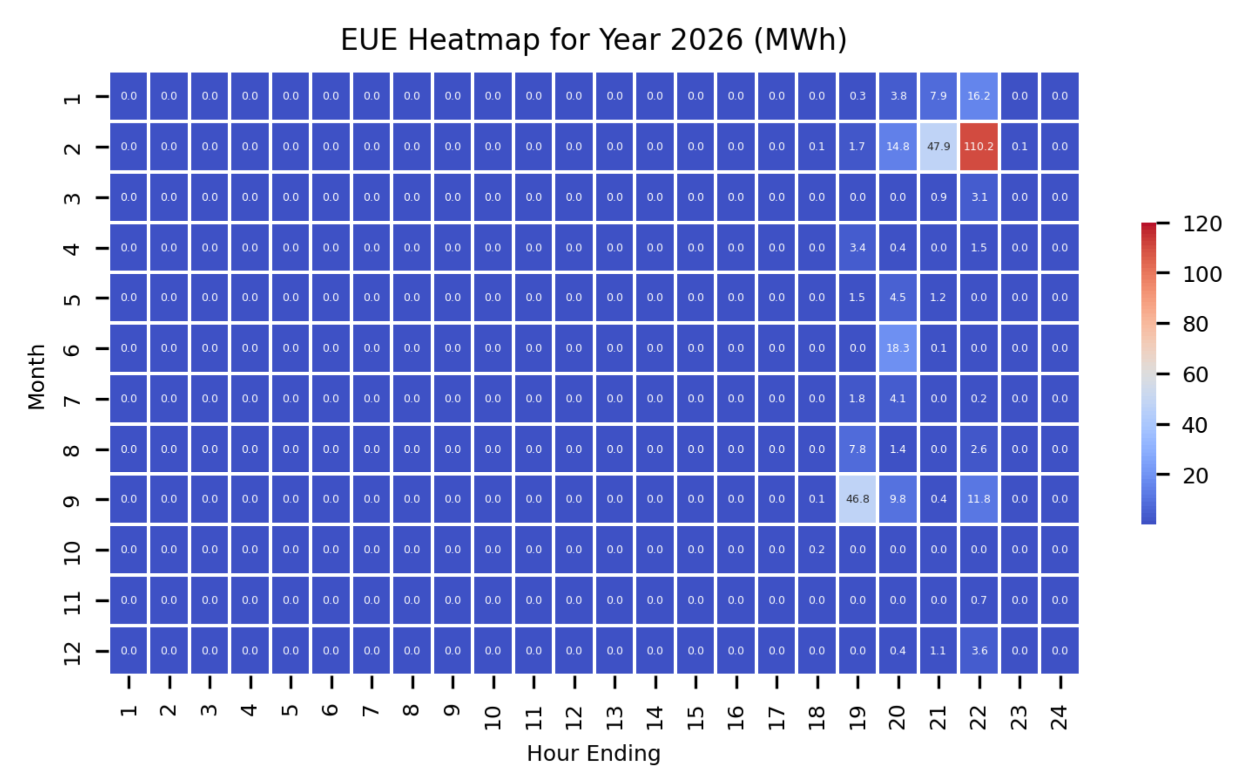
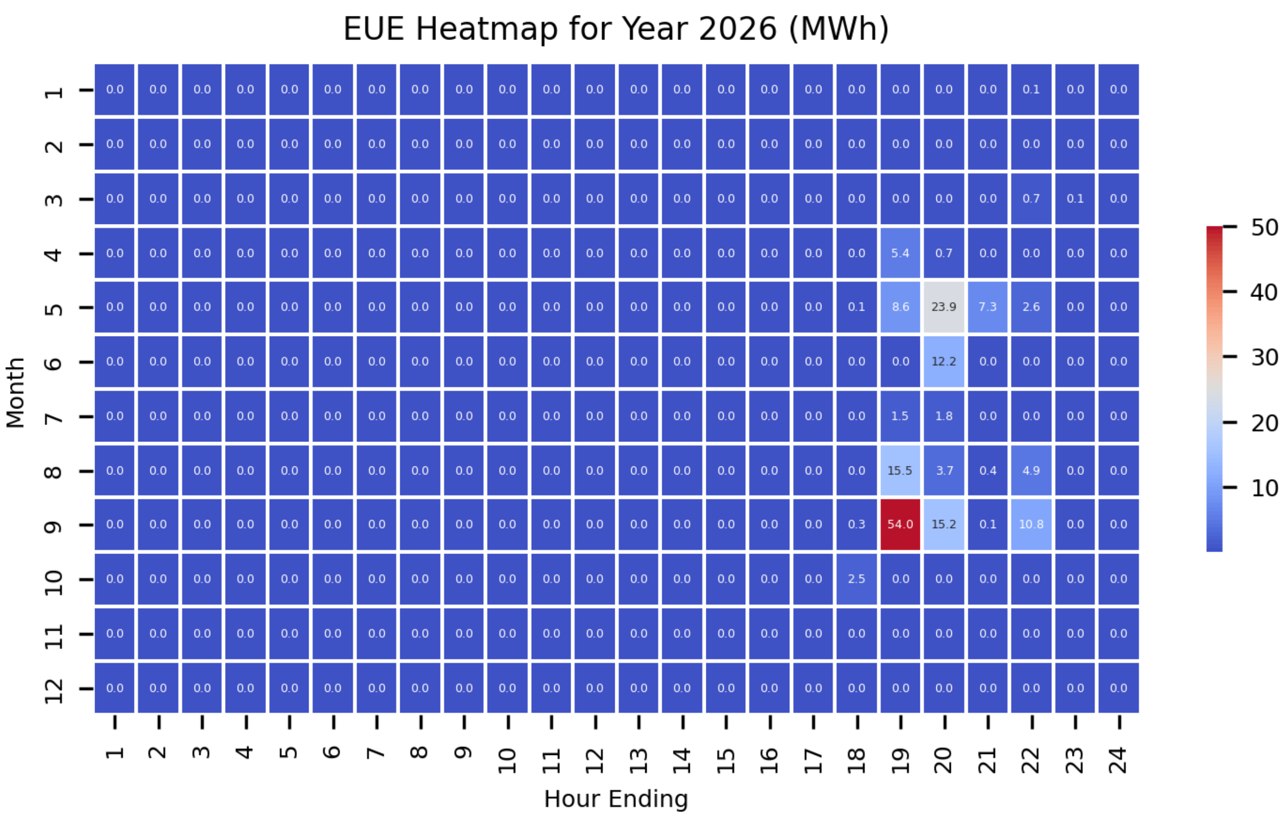


Figure 6 illustrates what hours and what times of year EUE occurs in the revised Appendix B final stress test results. In particular, when maintenance is removed, the high EUE amounts in winter disappear and EUE and LOLE are once again focused in the evening hours in the middle of the year. A levelized PRM would potentially reduce risk in September relative to the lower September PRM in the Annual LOLE Base case, but the tradeoff is increased LOLE risk in other summer months. Generally speaking, it is unlikely that off-peak months will be binding constraints in reality. However, a levelized PRM that has been created through monthly stress tests would theoretically be the minimum level needed to prevent LOLE events. Levelizing the PRM in off-peak months by increasing demand until it is nearly the same as supply creates artificial increased LOLE risk in off-peak months relative to the much higher margins of resources that are seen in the real CAISO market, particularly if that small margin of resources was also meant to include replacement for capacity on maintenance.

Figure 6 EUE MWh by hour of day and by month - SOD Revised Monthly Stress Test in Appendix B



PRM Recommendation

The 2026 RA LOLE Study results in Appendix B reflect that the baseline list of resources (existing and in development resources) plus a Simultaneous Import Constraint of 2,500 MW satisfies reliability needs for the 2026 RA compliance year. Based on these study results, staff recommend the CPUC consider a RA program requirement of 22.5% for the summer months (June through September) and a PRM of 21% for the other months (October through May) while also considering other alternatives, as outlined further below.

Balancing the need for reliability and affordability is key to the mission of the CPUC. In the current market of unprecedented RA prices, it is pertinent to discuss reliability planning and modeling results from this Appendix B in the full context of RA program requirements for LSE procurement compliance obligations.

RA prices have reached unprecedented levels that in many cases far exceed the marginal cost of new capacity. Notably, between 2017 and 2023 the weighted average price for RA capacity has increased by

349% from $2.46 kW-month to $11.05 kW-month.[8] Additionally, the most recent Power Charge Indifference Adjustment (PCIA) Final RA market price benchmark reflects that System RA prices between 2023 and 2024 have nearly doubled, increasing from $14.37 to $28.65 kW-month.[9] Equally concerning is some LSEs have indicated that in recent procurement solicitations, generators are offering multi-year contracts that would lock in these excessively high prices for the mid-term time horizon, most notably for existing capacity far in exceedance of its marginal cost.

Furthermore, RA program non-compliance has increased significantly in recent years.[10] Whether due to the increase in prices, the scarcity of supply, the increase in the number of LSEs serving load, or possibly the increase in the RA program PRM, the RA program has observed a concerning increase in non-compliance. As noted in the Resource Adequacy Citation Database published in February 2024, there have been 509 separate instances of RA program violations since 2010, resulting in 144 total RA Citations issued. As reflected in Table 2 of the Citation Database, since 2010 there have been three citations issued to investor-owned utilities (IOUs) with penalties totaling $26,000, 86 citations issued to Energy Service Providers (ESPs) totaling over $9.8 million dollars, and 54 citations issued to Community Choice Aggregators (CCA)s totaling over $54 million. Since 2010, RA citations have resulted in over $63 million in fine payments being remitted to the State of California General Fund. However, most importantly in this context, the RA program experienced a significant uptick in RA non-compliance from 2017 through 2023. An RA capacity deficient LSE may be cited by the CPUC but has avoided paying the actual cost of the RA capacity. Setting higher RA requirements under current market conditions may result in increased LSE penalties that may or may not provide LSEs the incentive to contract and/or enhance reliability.

Energy Division staff recognizes that adopting a PRM that is higher than the current 17% PRM could potentially exacerbate market tightness, increase market power dynamics, and further impact RA prices. In Track 2 of R.23-10-011, several parties expressed that higher RA requirements (a larger PRM value relative to existing RA requirements) will have downstream impacts that result in higher costs to ratepayers as LSEs need to procure additional resources to meet these requirements. The CPUC's IRP requirements for new resources were set in 2019, 2021 and 2023 with an expectation that the PRM would increase in future years. The IRP procurement mandates and other requirements have resulted in over 20 GW of new nameplate capacity since January 2020. In addition, there is a pipeline of over 19 GW of additional capacity expected in the next few years – some but not all of which is reflected in the

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8 2017 – 2022 Resource Adequacy Report (Table 6), along with internal analysis of 2023 RA price data that will inform the 2023 RA Report. Table 6 in each RA Report includes the current and previous years of contract execution (i.e., 2023 data includes contracts executed in 2022 and 2023 that are delivered in 2023).

9 Official RA Market Price Benchmarks (MPB) sent to the PCIA service list, R. 17-06-026, on October 4th, 2024. These figures reflect Final RA Market Price Benchmarks. On November 5th, 2024, Revised RA MPBs were sent to the PCIA service list, with weighted average System RA price being $26.26.

10 See RA Compliance Information, including list of RA citations, available at Resource Adequacy Penalties and Citations, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-penalties-and-citations.

modeling baseline. The Appendix B modeling baseline is largely underway and appears achievable, and the IRP procurement requirements are likely going to continue to inspire contracting beyond the baseline. Nonetheless, there remain concerns that market power will continue to grow and impact RA prices in the near to mid-term.

With these concerns in mind, Energy Division staff puts forward for consideration two high-level proposals aimed at balancing reliability and affordability. These proposals will be further developed and released in line with the Track 3 schedule. Staff also plan to include the most up to date 2024 draft IEPR demand forecast in considering the appropriate PRM level for 2026.

Proposal 1: 17% PRM RA Requirement paired with effective PRM (extending the 2025 status quo)

- Adopt 17% PRM for RA compliance year 2026
- Extend effective PRM framework with IOUs procuring a MW amount equivalent to the 22.5% PRM LOLE study results

Proposal 2: 22.5% PRM RA Requirement and System Waiver

- Adopt 22.5% PRM for RA compliance year 2026
- Allows LSEs to file system waivers for RA requirements above 17% if certain requirements are met, including inability to procure below a certain price threshold
- CAISO Capacity Procurement Mechanism (CPM) backstops RA deficiencies with procurement costs paid by LSEs with deficiencies

The Commission considered proposals for temporary systems waivers to address tight market conditions in D.19-06-026, D.20-06-031, and D.24-06-004. Ultimately, in these decisions, the Commission declined to adopt system waiver proposals stating that concerns about reliability, unintended market power, and LSEs leaning on other LSEs' procurement had not yet been resolved. The Commission encouraged further study and discussion of these issues. In October 2024 Governor Newsom issued Executive Order N-5-24 which directs the CPUC to evaluate electric ratepayer supported programs and the costs of regulations and make recommendations on additional ways to save consumers money. This directive makes clear that cost impacts and mitigation options should be further explored.

In light of affordability concerns, the results of the latest LOLE study, and the recent Executive Order, more discussion on price mitigation options is warranted and the proposals offered here are meant to initiate discussion on the appropriate approach. A driving force behind these proposals is persistently high RA prices. Ultimately thousands of MWs of new capacity have come online since 2020, yet it has not resulted in as much price relief or RA compliance as was anticipated. Therefore, Energy Division staff believe that it is prudent and necessary to discuss reliability planning (PRM study results and increases to the RA program PRM for CPUC jurisdictional LSEs) in the context of price impacts and balancing affordability goals.

The CPUC needs to consider the impacts of raising the PRM for CPUC jurisdictional entities in concert with how the CPUC PRM is utilized by the CAISO to trigger the contracting for backstop resources though the Capacity Procurement Mechanism (CPM), as well as the cost-allocation for such program. CPUC jurisdictional LSEs subject to any CPUC adopted PRM for RA program requirements account for roughly 90% of the load in CAISO. Over or undersupply of RA between the CPUC and non-CPUC entities can lead to reliability and/or cost shifting concerns. Non-CPUC jurisdictional LSEs are not subject to the CPUC's PRM and historically have demonstrated PRM levels of 15% or less for their own loads. Notably, the CPUC RA program does not allow liquidated damage energy contracts to count towards RA requirements due to their performance uncertainty (although such contracts can be used to hedge energy prices). While non-CPUC jurisdictional LSEs historically have used some quantities of non-RA eligible resources, including liquidated damage contracts, to meet their PRMs.

Given these concerns, the CPUC needs to consider the possibility that reliability may not be improved throughout the CAISO if there is an uneven application of the PRM. For example, this study shows that there is surplus/cushion identified if a 21% - 22.5% PRM is applied to the CAISO, such that the resource portfolio plus 2,500 MW of import resources can maintain a 0.1 LOLE; i.e., if imports are higher or built resources are lower – LOLE can be maintained, thus there is a cushion. However, if non-CPUC jurisdictional LSEs do not provide an adequate PRM alongside CPUC jurisdictional LSEs, the effect could lower the reliability cushion of the entire system. Furthermore, some resources in the baseline fleet may be resources dedicated to non-CPUC jurisdictional entities and not performed as modeled. There is a wide array of uncertainties in the supply and demand that serve as critical inputs to generate the modeled PRM results in Appendix B. The CPUC will consider the Appendix B results, alongside recommendations and proposals for the appropriate RA program requirements in Track 3 of R.23-10-011.