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Decision 25-06-048 June 26, 2025

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 23-10-011

DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2026-2028, FLEXIBLE CAPACITY OBLIGATIONS FOR 2026, AND PROGRAM REFINEMENTS

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DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2026-2028, FLEXIBLE CAPACITY OBLIGATIONS FOR 2026, AND PROGRAM REFINEMENTS

Summary

This decision adopts Local Capacity Requirements for 2026-2028, Flexible Capacity Requirements for 2026, and refinements to the Resource Adequacy (RA) program. The RA program refinements include adopting a 18% planning reserve margin (PRM), with an extension of the effective PRM procurement target of 1,260-2,300 megawatts (MW) for June-October months, for the 2026 and 2027 RA compliance year, modifying the RA measurement hours to align with the California Independent System Operator's (CAISO) availability assessment hours, and incorporating the central procurement entity data reporting requirements into the annual RA compliance filing process.

This proceeding is closed.

1. Background

On October 12, 2023, the California Public Utilities Commission (Commission or CPUC) issued the Order Instituting Rulemaking (OIR) to oversee the Resource Adequacy (RA) program, consider program reforms and refinements, and establish forward RA procurement obligations applicable to Commission-jurisdictional load-serving entities (LSEs). Additional information on the procedural history of this proceeding is provided in the OIR.

A Scoping Memo and Ruling (Scoping Memo) for this proceeding was issued on December 18, 2023. The Scoping Memo identified the issues to be

addressed in this proceeding, set forth a schedule and process for addressing those issues, and established three tracks for this proceeding (Tracks 1, 2 and 3). Issues scoped as Track 1 were addressed in Decision (D.) 24-06-004 and issues scoped as Track 2 were addressed in D.24-12-003.

On July 19, 2024, Energy Division issued its Loss of Load Expectation (LOLE) study, titled "Loss of Load Expectation Study for 2026, Including Slice of Day Tool Analysis," which was attached to an Administrative Law Judge's (ALJ) ruling on July 22, 2024. On July 25 and 26, 2024, Energy Division held workshops on the LOLE study results.

On August 30, 2024, Energy Division issued "Appendix A to LOLE Study for 2026: Revised Slice of Day Tool Analysis," attached to an ALJ's ruling on the same day. Opening comments on Energy Division's Appendix A were filed on September 9, 2024 by: Alliance for Retail Energy Markets (AReM), Ava Community Energy (Ava), California Community Choice Association (CalCCA), California Environmental Justice Alliance/Sierra Club (jointly, CEJA/Sierra Club), CAISO, California Municipal Utilities Association (CMUA), Calpine Corporation (Calpine), Middle River Power LLC (MRP), Pacific Gas and Electric Company (PG&E), Protect Our Communities Foundation (PCF), Public Advocates Office at the California Public Utilities Commission (Cal Advocates), San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE), and Western Power Trading Forum (WPTF).

Reply comments on Energy Division's Appendix A were filed on September 16, 2024 by: American Clean Power–California (ACP-CA), AReM,

CalCCA, Cal Advocates, Microsoft Corporation (Microsoft), MRP, PG&E, PCF, SCE, SDG&E, Shell Energy North America (US). L.P. (Shell Energy), and WPTF.

On November 1, 2024, an Amended Scoping Memo and Ruling was issued that designated issues as Track 3 of the proceeding.

On December 23, 2024, an ALJ's ruling was issued that attached Energy Division's Appendix B to Loss of Load Expectation Study for 2025. Track 3 proposals were filed on January 17, 2025 by: ACP-CA, CalCCA, Cal Advocates, California Energy Storage Alliance (CESA), Form Energy, Hydrostor, Inc. (Hydrostor), OhmConnect, Inc. and Leapfrog Power, Inc. (jointly, OhmConnect/Leap), MRP, PG&E, SCE, and WPTF. Energy Division's Track 3 proposals were filed by an ALJ's ruling on January 21, 2025, along with a Demand Response Qualifying Capacity Proposal Status Update from Joint Staff of the Commission and the California Energy Commission (CEC).

A workshop on Energy Division's revised LOLE study was held on January 23, 2025. A workshop on Track 3 proposals was held on February 13 and 14, 2025. An ALJ's ruling attached Energy Division's workshop slides, titled "Hour Offset CalCCA QA Issue and PRM Implications," as well as Energy Division's Load Migration Update under the Slice of Day framework.

Opening comments on Track 3 proposals were filed on March 3, 2025 by: ACP-CA, AES Clean Energy Development, LLC (AES), AReM, CAISO, Cal Advocates, CalCCA, CEJA, Calpine, CESA, Clean Energy Buyers Association (CEBA), Center for Energy Efficiency and Renewable Technologies (CEERT), Form Energy, GreenGenStorage, LLC (GreenGen), Hydrostor, Independent

Energy Producers Association (IEP), Leap, Microsoft, MRP, PG&E, PCF, REV Renewables LLC (REV), SCE, SDG&E, Shell Energy, Terra-Gen, LLC (Terra-Gen), and WPTF.

Reply comments on Track 3 proposals were filed on March 17, 2025 by: ACP-CA, AReM, CAISO, Cal Advocates, CalCCA, Calpine, CEBA, CEERT, CEJA, Central Coast Community Energy and San Jose Clean Energy (jointly, CCCE/SJCE), California Efficiency + Demand Management Council (Council) and Leap (jointly, Council/Leap), Form Energy, Hydrostor, Large-scale Solar Association (LSA), Microsoft, MRP, PG&E, SCE, SDG&E, Shell Energy, and WPTF.

On January 17, 2025, Cal Advocates filed a motion to seal its Track 3 proposals. On March 17, 2025, Cal Advocates filed a motion to seal its reply comments. The motions to seal were granted on May 12, 2025.

2. Submission Date

The matter for this decision was submitted on May 21, 2025.

3. Issues Before the Commission

The scope of issues in Track 3, as adopted in the November 1, 2024 Amended Scoping Memo, is summarized as follows:

1. Adoption of 2026-2028 Local Capacity Requirements (LCR). The CAISO performs an annual LCR study, which is submitted into the RA proceeding and used to adopt local RA procurement requirements for the next three compliance years. For Track 3, this will be for the 2026-2028 RA compliance years.

2. Adoption of 2026 Flexible Capacity Requirements (FCR). Similar to the LCR process, the CAISO performs an annual FCR study, which is used to adopt flexible RA requirements for the following compliance year.
3. Planning Reserve Margin (PRM) for 2026. In D.24-12-003, the Commission deferred consideration of the 2026 PRM to Track 3 to allow additional time for Energy Division to submit a revised LOLE study analysis and translation of the PRM.
4. Slice of Day (SOD) Framework. The Commission will consider time-sensitive modifications to the SOD framework, which has begun full implementation for the 2025 RA compliance year.
5. Unforced Capacity (UCAP) Evaluations. Energy Division will coordinate with the CAISO to develop a UCAP accreditation methodology for thermal power plants and battery electric storage systems.
6. Refinements to the CEC's incentive-based supply-side demand response (DR) qualifying capacity (QC) proposal. To be submitted in December 2024, as authorized by D.23-06-029, the Commission will consider Energy Division's and the CEC's joint proposal, including testing requirements and requirements to integrate investor-owned utility DR programs.
7. Synchronization of Integrated Resource Planning (IRP) data collection with Central Procurement Entity (CPE) data requirements. In D.24-12-003, the Commission stated that parties should submit proposals in Track 3 on how to synchronize the existing IRP data collection process with the data requirements adopted for the CPE framework in order to minimize duplication and administrative burden on Commission Staff.

8. Other time-sensitive issues identified by Energy Division or by parties in proposals.

4. Discussion

4.1. 2026-2028 Local Capacity Requirements

In D.06-06-064, the Commission established the local RA framework and adopted local procurement obligations for 2007. The Commission determined that a study of the LCR, performed by the CAISO, would form the basis for the local RA program and that the local requirements should be based on a level of reliability described as "Option 2" in the CAISO's LCR study report.[1] The CAISO conducts an annual LCR study and the Commission resets local procurement obligations each year after review and approval of the CAISO's recommendations. A series of subsequent decisions (most recently in D.24-06-004) established local procurement obligations for 2008 through 2027. In D.19-02-022, multi-year local RA requirements were adopted for a three-year duration beginning with the 2020 compliance year.

In PG&E and SCE's service territories, beginning for the 2023 RA compliance year, a CPE framework was adopted and local requirements were no longer allocated to LSEs in PG&E's and SCE's distribution service areas. In SDG&E's service area, local RA requirements are still allocated to Commission-jurisdictional LSEs and each LSE must procure sufficient RA capacity in each local area to meet its obligations.

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[1] D.06-06-064 at 17.

The CAISO's Draft 2026 Local Capacity Technical Report (Draft LCR Report) was submitted on April 3, 2025. No comments were filed on the Draft LCR Report. The CAISO's 2026 Final Local Capacity Technical Report (Final LCR Report) was submitted on May 1, 2025. No comments on the Final LCR Report were filed.

The CAISO's recommended 2026-2028 LCR values are summarized in the following table, with the adopted 2025-2027 LCR values provided for comparison.

2026 - 2028 Local Capacity Requirements			
Local Area Name	**2026**	**2027**	**2028**
Humboldt	136	150	167
North Coast/North Bay	848	732	558
Sierra	1354*	1493*	1633*
Stockton	756*	760*	774*
Greater Bay	7558*	7558*	7558*
Greater Fresno	2100*	2226*	2352*
Kern	452*	460*	324*
Big Creek/Ventura	1369	1536	1621
LA Basin	5812	6176	6541
San Diego/Imperial Valley	2631	2800	2968
Total	23016	23891	24496
* CAISO note: Details about magnitude of deficiencies can be found in the applicable section [of the LCR Report]. Resource deficient areas and sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.			

2025 - 2027 Local Capacity Requirements			
Local Area Name	**2025**	**2026**	**2027**
Humboldt	164	166	169
North Coast/North Bay	967	836	844
Sierra	1532*	1620*	1709*
Stockton	735*	736*	737*
Greater Bay	7441*	7441*	7441*
Greater Fresno	2532*	2527*	2522*
Kern	434	422*	410*
Big Creek/Ventura	2145	2172	2200
LA Basin	4123	4361	4600
San Diego/Imperial Valley	2709	2812	2915
Total	22782	23093	23547
* CAISO note: Details about magnitude of deficiencies can be found in the applicable section [of the LCR Report]. Resource deficient areas and sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.			

The Commission finds the recommended LCR values for 2026–2028 to be reasonable. Accordingly, the CAISO's recommended 2026–2028 LCR values set forth in the table above are adopted.

4.2. 2026 Flexible Capacity Requirements

D.13-06-024 and D.14-06-050 adopted a flexible capacity requirement to begin in 2015 and defined implementation guidelines. D.13-06-024 recognized a need for flexible capacity in the RA fleet and defined flexible capacity need:

> "Flexible capacity need" is defined as the quantity of resources needed by the CAISO to manage grid reliability during the greatest three-hour continuous ramp in each month. Resources will be considered as "flexible capacity" if

> they can sustain or increase output, or reduce ramping needs, during the hours of "flexible need."[2]

This year, the CAISO notified the Commission that the final Flexible Capacity Needs Assessment for 2026 (Final FCR Report) would not be filed by early May but would be targeted to be filed on May 16. On May 2, an ALJ ruling was issued that shortened the time for comments on the Final FCR Report. The ruling stated that once the CAISO filed the Final FCR Report into the proceeding, parties would have until the end of the second business day to file responsive comments.

The Final FCR Report was submitted by the CAISO on May 16, 2025. No comments were filed on the Final FCR Report.

The Final FCR Report contains the following figures for 2026, with the 2025 FCR figures provided for comparison.

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[2] D.13-06-024 at 2.

2026 Flexible Capacity Requirements					
NOTE: All numbers are in Megawatts	**CAISO System Flexible Requirement**	**CPUC Flexible Requirement**	**CPUC**		
			Category 1 (minimum)	**Category 2 (100% less Cat. 1 & 3)**	**Category 3 (maximum)**
January	24697	23629	6280	16167	1181
February	24979	23901	6352	16354	1195
March	23403	22505	5981	15399	1125
April	27348	26207	6965	17932	1310
May	26326	25083	10024	13805	1254
June	27559	26329	10522	14491	1316
July	25038	24086	9626	13256	1204
August	26112	24927	9962	13719	1246
September	27388	26256	10493	14450	1313
October	25471	24571	6530	16812	1229
November	25065	24034	6388	16445	1202
December	23386	22531	5988	15416	1127

2025 Flexible Capacity Requirements					
NOTE: All numbers are in Megawatts	**CAISO System Flexible Requirement**	**CPUC Flexible Requirement**	**CPUC**		
			Category 1 (minimum)	**Category 2 (100% less Cat. 1 & 3)**	**Category 3 (maximum)**
January	22704	21830	6238	14500	1091
February	22568	21783	6224	14469	1089
March	20533	19708	5631	13091	985
April	25191	23818	6806	15821	1191
May	24740	23501	9568	12759	1175
June	23317	22128	9009	12013	1106
July	22869	21863	8901	11869	1093
August	23469	22492	9157	12211	1125
September	27010	25709	10466	13957	1285
October	25920	24708	7060	16412	1235
November	24987	23831	6810	15830	1192
December	21880	20945	5985	13913	1047

The CAISO maintains a must-offer obligation (MOO) under which an RA resource must be available for dispatch during standard hours under the CAISO's Resource Adequacy Availability Incentive Mechanism (RAAIM). The CAISO is required to annually determine the daily five-hour range for the standard hours, known as the "availability assessment hours" (AAH). AAHs are intended to correspond with the hours in which high demand conditions typically occur and thus, when RA resources are most critical to maintain system reliability.

Likewise, the Commission identifies RA "measurement hours," which are used to establish QC values for select resources, particularly demand response and non-dispatchable resources. The current RA measurement hours were adopted in D.10-06-036, and revised in D.18-06-030, D.22-06-050, and D.23-06-029. The RA measurement hours for the summer months (June to October) and winter months (November to February) are 4:00-9:00 pm, or Hour Ending (HE) 17-HE 21. For the spring months (March to May), the RA measurement hours are 5:00-10:00 pm, or HE 18–HE 22. These hours were also previously used to determine when use-limited resources are required to be available under the maximum cumulative capacity (MCC) bucket structure. In D.23-04-010, the Commission eliminated MCC buckets 1-4 for use with the SOD framework, while retaining the MCC DR bucket. The DR bucket limit applies equally to each slice of day, where resources must be available at least 24 hours per month from May to September.

In the CAISO's 2026 Final FCR Report, the CAISO states that, based on its analysis of the distribution of the top 5% of load hours within each month from 2026 to 2028, it continues to see a winter increase and a shift to later hours during January to February and October to December.[3] Given these observations, the CAISO recommends changing the winter month (November to February) AAHs to align with 5:00-10:00 pm or HE 18–HE 22, while retaining the spring month

[3] CAISO Final Flexible Capacity Needs Assessment for 2026, May 16, 2025, at 30.

(March to May) and summer month (June to October) AAHs of 5:00-10:00 pm, or HE 18–HE 22, and 4:00-9:00 pm, or HE 17-HE 21, respectively. The CAISO states that it will continue to monitor the AAHs for future years.

The CAISO's recommended changes to the AAHs were vetted through its FCR stakeholder process, which included opportunities for stakeholder participation. No comments were filed in the CAISO's FCR process.

The Commission reviewed the FCR figures and finds them to be reasonable. Accordingly, the CAISO's recommended values set forth in the table above are adopted.

The Commission also finds the modification of the AAHs to be reasonable. The one-hour discrepancy in the hours the Commission uses to assess RA for DR and non-dispatchable resource valuation purposes would minimally affect the current valuation of resources. Adopting this modification would ensure that the Commission's RA measurement hours remain aligned with the CAISO's AAHs.

Accordingly, beginning with the 2026 RA compliance year, the RA measurement hours shall be 5:00-10:00 pm, or HE 18-HE 22, for the winter months (November to February). The current RA measurement hours for the spring months (March to May) of 5:00-10:00 pm, or HE 18-HE 22, and for the summer months (June to October) of 4:00-9:00 PM, or HE 17-HE 21, will remain unchanged. The adopted modification will not affect the existing MCC DR bucket hours, which only apply for the months of May to September. The changes adopted in this decision are reflected in the table below.

Resource Adequacy Measurement Hours		
Months	**Hours**	**Hour Ending**
November – February	5:00 pm – 10:00 pm	18 – 22
March – May	5:00 pm – 10:00 pm	18 – 22
June – October	4:00 pm – 9:00 pm	17 – 21

The Commission notes that, because Load Impact Protocol filings for demand response resources are submitted annually on April 1, there will be a one-year lag in implementation of the newly adopted measurement hours for demand response resources. This will mean that the hours as adopted in this decision will be incorporated in the Load Impact Protocol studies launched in the fall of 2025, with final reports submitted to the Commission on April 1, 2026, for valuation of 2027 demand response resources.

4.3. Planning Reserve Margin

On July 19, 2024, Energy Division issued its LOLE study, titled "Loss of Load Expectation Study for 2026, Including Slice of Day Tool Analysis."[4] The LOLE report included results from the LOLE study, implementation of the study results into a SOD PRM setting tool, and recommendations for a 2026 PRM level.

On August 6, 2024, an ALJ ruling was issued that stated:

[4] ALJ Ruling on Energy Division's Loss of Load Expectation Study, July 22, 2024, Appendix A.

> It has come to the Commission's attention that the Slice of Day (SOD) Planning Reserve Margin (PRM) calibration tool, distributed by Energy Division on July 19, 2024, requires revisions to correct several logic calculations that were identified by parties following the release of the workbooks and discussed in the SOD Office Hours. Energy Division expects to issue a revised SOD PRM calibration tool and translation of the annual LOLE study results by the end of August.[5]

On August 30, 2024, Energy Division issued "Appendix A to LOLE Study for 2026: Revised Slice of Day Tool Analysis" (Appendix A).[6] Parties filed comments on Appendix A on September 9 and September 16, 2024.

In D.24-12-003, the Commission determined that additional vetting and further analysis of Energy Division's PRM analysis was necessary, based on numerous issues raised by parties. The Commission stated:

> Energy Division is authorized to undertake a further revision of the 2026 PRM analysis to correct identified errors raised in comments, and distribute it to the service list in this proceeding in early December 2024. Following the release of the revised PRM analysis, Energy Division will conduct workshops to explain the analysis and supporting data. Energy Division may solicit informal comments on the analysis and parties will have an opportunity to submit formal comments. Following that process, the Commission

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[5] ALJ Ruling on Energy Division's Slice of Day Calibration Tool, August 6, 2024, at 2.

[6] ALJ Ruling on Revised Slice of Day Calibration Tool and Comment Schedule, August 30, 2024, Appendix A.

> will consider the revised PRM analysis in Track 3 of this proceeding.[7]

4.3.1. Energy Division's Proposal

On December 20, 2024, Energy Division served "Appendix B to Loss of Load Expectation Study for 2025: Revised Slice of Day Tool Analysis" (Appendix B).[8] In Appendix B, Energy Division summarizes that:

> …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, identifying 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 PRM requirements.[9]

Energy Division states that "[o]verall, 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 (above 5% reduced) relative to the Appendix A."[10] Energy Division further states that:

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[7] D.24-12-003 at 11.

[8] ALJ Ruling on Energy Division's Appendix B to LOLE Study for 2026 (LOLE Appendix B), December 23, 2024, Attachment A.

[9] LOLE Appendix B at 2.

[10] *Id*.

> 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 [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 for those events.[11]

In its Track 3 proposal, Energy Division states that:

> Adopting a PRM that is higher than the current 2025 17% PRM could potentially exacerbate market tightness, increase market power dynamics, and further impact RA prices. Notably, as shown in Figure 2 below, 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. Data collected from Quarter 1 through 3 for 2024 shows price trends continue to increase, with preliminary results showing a weighted average of $19.28/kW-month….[12]

Energy Division reports that "[a]nother reference point for price trends is the most recent Power Charge Indifference Adjustment (PCIA) RA market price benchmark data that shows System RA prices between 2023 and 2024 have

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[11] *Id*.

[12] Energy Division Track 3 Proposal at 11.

nearly doubled, increasing from $14.37 to $26.26/kW-month."[13] Energy Division states:

> Also of concern to Energy Division is some LSEs have indicated that in recent procurement solicitations, generators are offering multi-year contracts that would lock in these high prices for the mid-term time horizon, most notably for existing capacity in exceedance of going forward fixed costs. With these price concerns in mind, Staff believes it's 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.[14]

Energy Division put forth two PRM proposals. Proposal A recommends a 17% PRM for 2026 and an extension of the effective PRM with investor-owned utilities (IOU) procuring a MW amount equivalent to the 22.5% PRM LOLE results.[15] The proposal follows the approach from D.23-06-029, which extended the effective PRM through 2025. Energy Division recommends a modification that the effective PRM for 2026 would have IOUs procure a non-binding MW amount only in peak months (June-September), rather than June-October as adopted in D.23-06-029. Energy Division notes that although Emergency Load

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[13] *Id*. at 12.

[14] *Id*.

[15] *Id*. at 14.

Reduction Program (ELRP) resources are currently eligible to count towards the effective PRM, residential ELRP resources are only authorized through 2025.

Proposal B recommends a 22.5% PRM for June-September and 21% PRM for October-May, with a temporary system waiver process.[16] A temporary system waiver process would allow LSEs to request waivers in peak months (June-September) for RA requirements above 17%, if certain requirements are met, such as the inability to procure below a certain price threshold. For eligibility, an LSE that procured at least a 17% PRM must demonstrate that it made all commercially reasonable efforts to procure to meet requirements, including that an LSE issued Request for Offers (RFOs), bid into other market participant RFOs, and other means of bilaterally procuring capacity. The temporary waiver would be for the 2026 and 2027 RA years. Proposal B also provides that the CAISO Capacity Procurement Mechanism (CPM) backstops RA deficiencies with procurement costs to be paid by LSEs with deficiencies.

Energy Division asserts that the benefits of Proposal B are higher reliability requirements and the inclusion of a price mitigation mechanism, as well as the CAISO having greater ability to address individual LSE reliability needs up to the higher PRM levels. Energy Division recognizes that a shortcoming of Proposal B is that resources may not accept a CPM designation or be available to the CPM process, which could result in the CAISO not fulfilling the full amount

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[16] Energy Division Track 3 Proposal at 15.

of the solicitation. Another shortcoming is that the CAISO may choose not to use the CPM for all deficient LSEs, which would result in some LSEs paying more for reliability than others.

During the February 13 and 14, 2025 Track 3 workshops, Energy Division notified parties that it had identified an error in the Commission's historical demand that resulted in demand being shifted one hour later compared to the CAISO's Energy Management System data.[17] Energy Division reported that after correcting the hour offset issue and using an updated demand model, the preliminary results show "negligible overall change to LOLE across entire year."[18] Energy Division states that "summer months show increased reliability apart from May and October which show higher LOLE."[19] After updating the Appendix B LOLE study and using the SOD calibration tool, the proposed PRM was reduced from the previous 22.5% to 21% for summer months.

Based on the corrected demand model, Energy Division revises Proposal A so that the effective PRM would have IOUs procuring a non-binding MW amount up to the 21% PRM LOLE results for June-October (Revised Proposal A). Energy Division also revises Proposal B to a 21% PRM for June-October and a

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[17] ALJ Ruling on Energy Division's Hour Offset Workshop Slides and Load Migration Update, February 25, 2025, Appendix A.

[18] *Id*. at 8.

[19] *Id*.

20% PRM in all other months (Revised Proposal B).[20] System waiver eligibility would be for June-September, as with the prior proposal.

4.3.2. WPTF's Proposal

WPTF proposes a PRM of 22.5% for May-October and 21% for November-April.[21] WPTF states that its proposal is consistent with the results of Energy Division's revised analysis and stress testing (from Appendix A of the LOLE study), which shows a 21% PRM in off-peak months and a 22.5% PRM in summer months achieves a level of reliability close to a 0.1 LOLE target. WPTF states that its proposal is consistent with Energy Division's observation that grouping April, May, and October with the peak summer months would be prudent.

4.3.3. Comments on Proposals

Multiple parties support Proposal A, including 3CE/SJCE, AReM, Cal Advocates, CEJA, CEERT, SDG&E, and Shell Energy.[22] 3CE/SJCE, Cal Advocates, CEJA, and SDG&E generally contend that the proposal best addresses affordability concerns by avoiding unnecessary procurement and that given uncertainty around the LOLE study and SOD implementation, it is

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[20] *Id*. at 11.

[21] WPTF Track 3 Proposal at 1.

[22] 3CE/SJCE Reply Comments at 2, AReM Opening Comments at 2, Cal Advocates Opening Comments at 2, CEJA Opening Comments at 3, CEERT Opening Comments at 2, SDG&E Opening Comments at 2, Shell Energy Opening Comments at 2.

premature to move away from the 17% and effective PRM without a credible analysis. AReM states that the 17% PRM with the effective PRM has been working sufficiently for a few years and modifying it would be unnecessarily disruptive. Shell Energy states that the flexibility of the effective PRM should be maintained to allow resources to count towards the effective PRM that do not currently qualify as RA. CEJA notes that the PRM analysis does not include all resources, which mitigates reliability concerns for a lower PRM, and also recommends IOUs be allowed to include other clean resources in the effective PRM by advice letter, such as distributed energy resources (DER).

SDG&E supports Proposal A for the 2026 RA year but for 2027, suggests Energy Division should complete additional analysis and develop other PRM options.[23] Cal Advocates asserts that after conducting an analysis with a more conservative worst-case supply stack, its analysis resulted in a shortfall of resources at HE 23 in September 2026 when batteries were no longer available, and concluded that PRM requirements above 20% would be difficult to achieve due to lack of resources. The CAISO and Microsoft disagree with Cal Advocates' analysis, with the CAISO stating that the PRM should cover uncertainty across the year, and Microsoft stating that the stack analysis was introduced without an

[23] SDG&E Reply Comments at 4.

opportunity to review the data and that HE 23 has not been a constrained hour in LOLE modeling.[24]

PG&E supports Proposal A with modifications.[25] PG&E agrees that increasing the PRM from 17% could exacerbate high RA prices and notes that the emergency reliability effective PRM framework was adopted to address similar price concerns. While PG&E supports Revised Proposal A's 21% effective PRM in summer months, PG&E states that procurement responsibility should eventually be transferred to LSEs with a gradual PRM increase until the full PRM is met without the effective PRM. PG&E proposes an initial 17% PRM for 2026 and an increase to an 18% PRM once market price benchmark issues have been resolved in the PCIA proceeding, which would give LSEs an opportunity to prepare for an increased PRM without higher RA costs.

Multiple parties oppose Proposal A, or aspects of the proposal, including ACP-CA, Calpine, CEBA, CESA, CAISO, IEP, Microsoft, MRP, PCF, SCE, Terra-Gen, and WPTF.[26] Several parties, including ACP-CA, CAISO, Calpine, CEBA, CESA, Microsoft, MRP, PCF, and SCE, oppose extending the effective PRM,

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[24] CAISO Reply Comments at 2, Microsoft Reply Comments at 13.

[25] PG&E Opening Comments at 2.

[26] ACP-CA Opening Comments at 8, Calpine Opening Comments at 4, CEBA Opening Comments at 4, CESA Opening Comments at 8, CAISO Opening Comments at 3, IEP Opening Comments at 3, Microsoft Opening Comments at 4, MRP Opening Comments at 7, PCF Opening Comments at 3, SCE Opening Comments at 5, Terra-Gen Opening Comments at 2, WPTF Opening Comments at 3.

generally stating that it gives IOUs too much discretion on procurement, allows procurement of less reliable non-RA capacity, does not guarantee an RA portfolio meets a 0.1 LOLE target, and harms the ability to use backstop mechanisms as the CAISO only has authority to backstop up to the Local Regulatory Authority's adopted PRM, not the effective PRM levels. Other parties, such as Microsoft, CEBA, and IEP, oppose Proposal A because they state that it results in a PRM that results in a greater than a 0.1 LOLE reliability metric and violates Assembly Bill (AB) 2368.

SCE states that a 21% effective PRM is unreasonable and lacks foundation. SCE states that it performed its own preliminary LOLE study, which shows that a 15.5% PRM achieves a 0.1 LOLE target and that an effective PRM is unnecessary because a 17% PRM provides a 1.5% buffer to safeguard system reliability. SCE claims that absent reliable evidence supporting Proposal A or B, continuing what has been a successful 17% PRM is appropriate and necessary. In reply comments, Shell Energy supports SCE's 17% PRM without an effective PRM.[27]

CEJA disagrees that Proposal A contradicts AB 2368 or D.24-12-003, arguing that Energy Division used the 0.1 LOLE standard to come up with a reliability metric that best balances reliability and affordability issues.[28] CEJA

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[27] Shell Energy Reply Comments at 2.

[28] CEJA Reply Comments at 6.

states that in D.24-12-003, the Commission discussed needing analysis on how a higher PRM may "have downstream impacts that result in substantially higher costs to ratepayers and higher market prices…" and thus Energy Division conducted an LOLE analysis that considered costs and affordability.[29] CEJA asserts that while a 0.1 LOLE metric is widely used, there is no consistent way to apply it, as some jurisdictions layer effective load carrying capacity (ELCC) differently with the PRM, some include energy resources, and some include minimum number of hours or unserved energy to count as a loss of load event. CEJA states that the Commission's baseline LOLE assumptions are more conservative than other jurisdictions, as Energy Division assumes a LOLE is triggered if 6% of operating reserves are not retained such that the system must maintain at least 106% of load to avoid a loss of load event.

Some parties oppose relying on SCE's preliminary LOLE analysis, including CAISO, Calpine, CEBA, Microsoft, and MRP.[30] These parties generally express concern that SCE did not provide details about the results of its preliminary LOLE study and parties have been unable to evaluate it, and that the study was submitted in opening comments months after Track 3 proposals were due. Based on a cursory review, Calpine observes errors such as ignoring load

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[29] *Id*. (citing D.24-12-003 at 8).

[30] CAISO Opening Comments at 2, Calpine Reply Comments at 2, CEBA Reply Comments at 7, Microsoft Reply Comments at 7, MRP Reply Comments at 5.

forecast errors and assuming the availability of non-RA imports. In response to SCE's assertion that the import constraint in Energy Division's LOLE study is inconsistent with the one used in IRP, MRP notes that IRP considers the LOLE analysis very differently from the RA proceeding.

CalCCA and CEBA support Proposal B, with modifications.[31] CalCCA supports a system waiver but with several modifications, including: adoption of a permanent waiver process, a rebuttable presumption that a waiver should be granted, a standard waiver template with an attestation, application of the waiver to year-ahead and month-ahead showings, and that the waiver should relieve LSEs of penalties, point accumulation, expansion limits, and strategic reserve payments. In reply comments, CalCCA asserts that given SCE's LOLE study and conclusion that a 15.5% PRM meets the 0.1 LOLE standard, a system waiver should apply for any quantity above 15.5%.[32] CEBA claims that Proposal B is in line with AB 2368's requirement to utilize a 1-in-10 LOLE or similarly robust standard; however, it also recommends that a waiver based on capacity availability is more appropriate than a price-based waiver.

Numerous parties oppose Proposal B, or aspects of Proposal B, including: ACP-CA, AReM, CAISO, Calpine, Cal Advocates, CESA, IEP, Microsoft, MRP,

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[31] AES Opening Comments at 7, CEBA Opening Comments at 3, CalCCA Opening Comments at 4.

[32] CalCCA Reply Comments at 17.

PCF, SDG&E, SCE, Shell Energy, Terra-Gen, and WPTF.[33] Several parties, including ACP-CA, AReM, Calpine, CESA, MRP, Microsoft, Shell Energy, and Terra-Gen, oppose a system waiver process. Cal Advocates, IEP, MRP, Terra-Gen, and ACP-CA generally state that a system waiver potentially introduces distortions in the RA market, reduces incentives for long-term RA contracting, and increases the risk of LSEs leaning on compliant LSEs. CESA observes that the issues the Commission previously raised in declining to adopt a system waiver about reliability, unintended market power, and LSE leaning have not yet been resolved.

AReM states that a waiver disadvantages LSEs that entered into long-term contracts over LSEs that entered into short-term contracts. Calpine argues that a waiver is not necessary given the large amounts of new capacity being added to the CAISO system. Microsoft recommends deferring a waiver process unless new capacity currently included in the modeling does not show up by the October filing and Energy Division can assess whether an LSE is deficient by comparing available system resources to modeled resources.

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[33] ACP-CA Opening Comments at 6, AReM Opening Comments at 2, CAISO Opening Comments at 3, Calpine Opening Comments at 3, Cal Advocates Opening Comments at 9, CESA Opening Comments at 8, IEP Opening Comments at 3, Microsoft Opening Comments at 8, MRP Reply Comments at 8, PCF Opening Comments at 6, SCE Opening Comments at 7, SDG&E Opening Comments at 4, Shell Energy Opening Comments at 3, Terra-Gen Opening Comments at 2, WPTF Opening Comments at 3.

The CAISO expresses concern that system waivers with a price threshold well below current RA prices would make it easy for LSEs to meet waiver requirements, potentially resulting in a large number of waivers, an RA portfolio falling short of levels to meet a 0.1 LOLE, and significant reliance on the CAISO backstop mechanisms. CAISO, Cal Advocates, and MRP state that the proposal does not address how it comports with Public Utilities (Pub. Util.) Code Section 380(h)(7), requiring the Commission to minimize the need for CAISO backstop procurement. If a waiver is adopted, Calpine recommends a higher threshold price that aligns closer to market prices to discourage utilizing a waiver process.

Several parties recommend modifications to Proposal B's PRM levels. Calpine prefers a 21% PRM for summer months but states that a higher PRM for non-summer months is needed to ensure the annual target is met. Microsoft states that only Proposal B is related to the LOLE results but recommends a 21.5% PRM for May-October as an alternative. ACP-CA supports a 21% PRM in summer months but notes that there is ambiguity as to the appropriate PRM for non-summer months. WPTF states that Energy Division's updated analysis of a 22.5% and 21% PRM, for summer and non-summer months respectively, would produce a portfolio with 0.155 LOLE, which is more reliable than previously proposed but still exceeds the 0.1 LOLE target. SDG&E states that Proposal B would require additional RA procurement which would increase ratepayer costs. SCE claims that its own LOLE study suggests a lower PRM and that there are modeling assumptions that artificially reduce available resources or increase energy needs in Energy Division's study.

Parties that support WPTF's proposal are CESA, MRP, and Terra-Gen; with Microsoft and AES supporting with modifications.[34] MRP supports WPTF's proposal, although it acknowledges it is outdated because it was proposed prior to identification of data errors. MRP reasons that it results in a LOLE that is more reliable than Energy Division's proposals. CESA states that WPTF's proposal promotes transparency in returning procurement to LSEs and does not have a system waiver. Microsoft claims WPTF's proposal is a reasonable alternative due to the inability to perfectly calibrate the PRM to 0.1 LOLE, except that 21.5% PRM for May-October may be sufficient as 21% PRM does not appear to meet 0.1 LOLE. AES supports a 22.5% PRM for only June-September as the LOLE study confirms these months have the greatest reliability risk and this ensures LSEs procure without unnecessary cost during low-risk months.

PG&E and SCE oppose WPTF's proposal.[35] PG&E and SCE state that it is based on an outdated Energy Division analysis from December 2024 and it is unreasonable to adopt a PRM based on flawed data and without regard to cost impacts. Cal Advocates shows a comparison between Energy Division and WPTF's proposals to demonstrate that WPTF's proposal would be the most

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[34] AES Opening Comments at 8, CESA Opening Comments at 9, MRP Opening Comments at 8, MRP Reply Comments at 3, Microsoft Opening Comments at 8, Terra-Gen Opening Comments at 1.

[35] PG&E Reply Comments at 3, SCE Reply Comments at 4.

costly when comparing total annual 2026 procurement costs above the status quo.[36]

Several parties express concern with Energy Division's LOLE analyses and with basing a PRM increase on the study results, including 3CE/SJCE, CalCCA, SDG&E, and PG&E.[37] These parties generally argue that the insufficiency of and lack of confidence in the LOLE study is apparent from parties' wide-ranging, inconsistent PRM recommendations. These parties recommend Energy Division continue developing and vetting the LOLE modeling and update the PRM options for 2027. MRP recommends a transparent, formal process for setting the PRM, to help build confidence in Energy Division's study process.[38]

Several parties support a PRM that meets a 0.1 LOLE target, including ACP-CA, Calpine, CAISO, CEBA, IEP, MRP, Microsoft, and Terra-Gen.[39] Many of these parties state that significant amounts of new capacity have come online in recent years and that there is adequate supply to meet higher PRM

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[36] Cal Advocates Opening Comments at 8.

[37] SDG&E Reply Comments at 4, CalCCA Reply Comments at 15, 3CE/SJCE Reply Comments at 11, PG&E Reply Comments at 4.

[38] MRP Reply Comments at 7.

[39] ACP-CA Opening Comments at 8, Calpine Opening Comments at 4, CAISO Opening Comments at 8, CEBA Opening Comments at 4, IEP Opening Comments at 2, MRP Opening Comments at 6, Microsoft Reply Comments at 3, Terra-Gen Opening Comments at 1.

requirements.[40] The CAISO opposes Energy Division's proposals because it states that they fail to meet a 0.1 LOLE target and that there is sufficient supply available to justify increasing the 2026 binding PRM above 17%. While Calpine states that a PRM should achieve a 1-in-10 LOLE target, it is unclear which proposal meets this criterion.[41]

4.3.4. Discussion

The Commission acknowledges and appreciates Energy Division's efforts over the past year to develop the 2026 LOLE study, including efforts to revise the analysis multiple times in response to stakeholder input, modeling refinements, and data errors. As we stated in D.24-12-003, the "data gathering and reconciliation for the LOLE modeling process is a time-intensive, significant undertaking for Commission Staff. We underscore that Commission Staff is gaining experience as to how long the data development and modeling process will take for the new SOD framework, and we appreciate parties' patience as Staff develops and refines the modeling timelines."[42]

As parties have noted, there is no consensus among stakeholders as to which PRM proposal should be adopted and parties advocate for a wide range of

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[40] *See, e.g.,* CEBA Opening Comments at 5, Microsoft Opening Comments at 9, Calpine Opening Comments at 4, ACP-CA Opening Comments at 7, CAISO Opening Comments at 8, MRP Reply Comments at 8, WPTF Reply Comments at 2.

[41] Calpine Reply Comments at 1.

[42] D.24-12-003 at 18.

solutions. Several parties express uncertainty and a lack of confidence in Energy Division's LOLE study results and revisions, and recommend that Energy Division continue developing and vetting the LOLE modeling. These robust stakeholder discussions about Energy Division's LOLE studies further demonstrate the complexity of the LOLE modeling, as well as how these types of studies are highly sensitive to inputs.

Under Proposal B, Energy Division proposes a temporary system waiver process in conjunction with a higher PRM. A large number of parties oppose the temporary system waiver. The Commission concurs with parties' concerns that a system waiver process: (1) raises fairness concerns in that deficient LSEs may lean on LSEs that procure sufficient RA capacity, (2) adds administrative burden on Energy Division's resources to process waivers, particularly if a large number of LSEs submit waivers, and (3) increases the need to rely on the CAISO's backstop mechanism if sufficient RA capacity is not procured by LSEs. For these reasons, we decline to adopt Proposal B.

As to SCE's preliminary LOLE analysis, we agree with parties that there is insufficient information to consider and evaluate the study, as SCE did not submit the analysis into the record and raised it for the first time in opening comments. As such, the Commission and stakeholders have not had an opportunity to evaluate the results. In the future, the Commission intends to establish a deadline for submission of studies or analyses for consideration, as well as requirements for transparency and submission of documentation sufficient for stakeholders to evaluate the assumptions and results. The

establishment of similar deadlines and transparency requirements for Energy Division Staff, as well as parties, will be included in the scoping memo for future phases of the RA proceeding.

Given stakeholders' reservations about Energy Division's LOLE methodology and the lack of consensus on a proposed PRM, one viable option is to maintain the status quo 17% PRM with the effective PRM approach for the 2026 RA year. The current 17% PRM with the effective PRM has been in place since the 2024 RA year and we concur with parties' assertions that it has been successful thus far. That said, the Commission observes that all of Energy Division's LOLE studies indicate a need for a higher PRM. While there have been revisions to Energy Division's PRM recommendations these past few months, the updated and corrected proposal recommends a binding PRM higher than 17%.

The Commission also agrees with PG&E that full procurement responsibility should eventually be transferred to individual LSEs and that a gradual PRM increase would give LSEs more certainty and an opportunity to prepare. PG&E recommends an initial 17% PRM in 2026 and an 18% PRM once PCIA price benchmark issues have been resolved. The Commission finds that increasing the PRM to 18% and extending the effective PRM for the 2026 RA year would achieve several benefits: (1) it would increase the PRM above its current level, as has been demonstrated as needed by Energy Division's LOLE studies; (2) it would move in the direction of transferring additional procurement responsibilities to LSEs; and (3) it would provide more time to review the need

for additional PRM increases once the SOD framework is better established and modeling capabilities and input processes have further matured.

The Commission finds it appropriate to move cautiously with increases to the PRM and notes that some parties expected that the transition to the SOD framework would provide for a lower PRM (perhaps even below 15%) once the reliability cushion across net peak hours was more carefully managed via the hourly obligations.

As we stated in D.23-06-029 when adopting the 17% PRM and effective PRM:

> Extending the effective PRM is beneficial in that it provides non-binding targets for IOUs to procure contingency resources, including resources that are not subject to strict RA counting rules and resources that fewer entities are competing for, such as imports procured after the RA showing date and firm energy from co-generation facilities. This allows procurement of resources that provide reliability benefits without unnecessarily inflating RA prices and costs to ratepayers, and without reducing the pool of available RA resources.[43]

We affirm our rationale from D.23-06-029 that extending the effective PRM would allow for the procurement of resources that provide reliability benefits, without unnecessarily inflating prices and costs to ratepayers and without reducing the pool of available RA resources. As mandated by Pub. Util. Code

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[43] D.23-06-029 at 23.

380, the RA program must be designed to maintain reliability of electrical service while also minimizing costs to ratepayers.

The Commission estimates that based on the CEC's 2024 California Energy Demand forecast, increasing the binding PRM by 1% in 2026 would increase CPUC-jurisdictional RA requirements by approximately 400 MW in September 2026.[44] The 1% PRM increase combined with the ~500 MW peak load forecast increase from 2025 to 2026 would result in an increase of ~900 MW of additional resource need for CPUC-jurisdictional LSEs for 2026.[45]

For all of these reasons, we find that adopting a 18% PRM, and extending the effective PRM target for June-October, for the 2026 RA year is a reasonable and prudent approach that helps ensure grid reliability by increasing the PRM as indicated by the LOLE studies while minimizing costs to ratepayers. Accordingly, for 2026 RA year, the Commission adopts an 18% PRM and extends the effective PRM framework for June-October.

The Commission extends the effective PRM framework adopted in D.21-12-015, and further extended in D.23-06-029, for the 2026 RA year. In D.23-06-029, the Commission adopted effective PRM targets that translated to 4 to 6.5%,

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[44] *See* CEC's "California Energy Demand (CED) 2024 Peak Forecast." The additional procurement is based on 1% of the 2026 CAISO coincident annual peak forecast (46,751 MW) and a 90% CPUC-jurisdictional load share.

[45] The CAISO annual coincident peak increase from 2025 to 2026 is 467 MW, based upon a July 2025 forecast peak of 46,284 MW and September 2026 forecast of 46,751 MW.

in addition to a 17% binding PRM.[46] To maintain an equivalent level of reliability for the 2026 year, as was adopted for the effective PRM in D.23-06-029, an effective PRM target of 1,260 MW to 2,300 MW would translate to an effective PRM range of 3 to 5.5%, in addition to the 18% binding PRM. The 1,260 MW to 2,300 MW effective PRM procurement target is based on the estimated CPUC-jurisdictional load share of the 2026 CAISO coincident peak demand forecast.[47]

Accordingly, consistent with the effective PRM framework adopted in D.23-06-029, an effective PRM target of 1,260 MW to 2,300 MW for June-October is adopted for the 2026 RA year. This procurement target will be divided between the three IOUs based on the approximate Transmission Access Charge (TAC) area CAISO load share, resulting in the following effective PRM targets: 120-220 MW for SDG&E and 570-1,040 MW each for PG&E and SCE. The effective PRM will follow the approach adopted in D.23-06-029, with the exception that LSEs are no longer required to submit non-binding month-ahead RA filings.[48]

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[46] D.23-06-029 at 24.

[47] The 2026 CAISO coincident peak forecast (46,751 MW) is from the "California Energy Demand (CED) 2024 Planning Forecast LSE and BAA Tables," Form 1.5b, available at: https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2024-integrated-energy-policy-report-0. The CPUC-jurisdictional load share is estimated to be 90% (i.e., 42,075 MW) and a 3 to 5.5% effective PRM procurement target is approximately 1,260 to 2,300 MW.

[48] *See* D.23-06-029 at 25.

As several parties have commented, it would be ideal if Energy Division could develop and complete a new LOLE study with new PRM proposals for the 2027 RA year. It is not possible, however, for Energy Division to further analyze the data issues that arose in the current LOLE study cycle and complete a new LOLE study prior to the 2027 RA year. As the Commission stated in D.24-12-003, "the data gathering and reconciliation process for the inputs and assumptions that underlie the LOLE study is very time-consuming and resource intensive. The Commission therefore determines that it is not feasible to run an updated LOLE study each year. It is more realistic and reasonable for Energy Division Staff to update an RA LOLE study at least every two years."[49]

Energy Division is expected to submit proposed Inputs and Assumptions for a new LOLE study in March 2026, and complete a new RA LOLE study for the 2028 RA year in July 2026. The 2028 LOLE study will be submitted into the successor RA proceeding for stakeholder evaluation and consideration. A more detailed LOLE study schedule may be included in a scoping memo in the successor RA proceeding.

Thus, for the 2027 RA year, the Commission finds it is reasonable to maintain the 18% PRM, and extend the effective PRM target for June-October, as is adopted for the 2026 RA year. As with the 2026 RA year, an effective PRM procurement target of 1,260-2,300 MW translates to an effective PRM range of 3

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[49] D.24-12-003 at 17.

to 5.5%, in addition to the 18% binding PRM. Accordingly, for the 2027 RA year, the Commission adopts an 18% PRM and extends the effective PRM target of 1,260 MW-2,300 MW for June-October. The procurement target will be divided between the IOUs as follows: 120-220 MW for SDG&E and 570-1,040 MW each for PG&E and SCE. The Commission authorizes Energy Division to publish the 2028 LOLE study in July 2026 for evaluation and consideration by stakeholders. The Commission will monitor market conditions and impacts of the adopted PRM framework and reevaluate the PRM requirements for the 2028 RA year in 2026.

Lastly, the Commission disagrees that the PRM adopted in this decision is inconsistent with AB 2368. Pub. Util. Code § 380(h) provides that the Commission "shall determine and authorize the most efficient and equitable means for achieving" multiple goals, one of which is "[e]nsuring that the resource adequacy program can reasonably maintain a standard measure of reliability, such as a one-day-in-10-year loss-of-load expectation or a similarly robust reliability metric adopted by the commission, and use it for planning purposes."[50] In D.24-12-003, we stated that: "we maintain that a 0.1 LOLE

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[50] Pub. Util. Code Section 380(h), which provides:

> The commission shall determine and authorize the most efficient and equitable means for achieving all of the following:

reliability target is the general industry standard, that using the standard helps align the RA requirements with the IRP process, that a 0.1 LOLE target is currently used by Energy Division in RA LOLE modeling, and that the Commission plans to continue using the standard in modeling going forward."[51] AB 2368 also adds an objective to the RA program: "Consideration of mitigation measures, if the commission determines they are needed, to reduce costs to ratepayers."[52]

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(1) Meeting the objectives of this section.

(2) Ensuring that investment is made in new generating capacity.

(3) Ensuring that existing generating capacity that is economical is retained to ensure reliability.

(4) Ensuring that the resource adequacy program can reasonably maintain a standard measure of reliability, such as a one-day-in-10-year loss-of-load expectation or a similarly robust reliability metric adopted by the commission, and use it for planning purposes.

(5) Ensuring that the cost of generating capacity and demand response is allocated equitably.

(6) Ensuring that community choice aggregators can determine the generation resources used to serve their customers.

(7) Ensuring that investments are made in new and existing demand response resources that are cost effective and help to achieve electrical grid reliability and the state's goals for reducing emissions of greenhouse gases.

(8) Minimizing the need for backstop procurement by the Independent System Operator.

[51] D.24-12-003 at 66.

[52] Pub. Util. Code Section 380(b)(5).

For the 2026 LOLE modeling, Energy Division used a 0.1 LOLE target. In determining its recommended PRM values, Energy Division put forward two PRM proposals as "Staff believes it's 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."[53] Here, we determine that a PRM slightly higher than Revised Proposal A is the most efficient and equitable means to reasonably maintain a standard measure of reliability for planning purposes, while minimizing ratepayer costs, as mandated by Pub. Util. Code Section 380.

4.4. Unforced Capacity

Energy Division and CESA put forth UCAP proposals for consideration. Additional information and the history of the UCAP framework proposals can be found in past Commission decisions, such as D.22-06-020, D.23-04-010, D.24-06-004, and D.24-12-003.

4.4.1. Energy Division's Proposal

Energy Division proposes to apply UCAP for capacity accreditation of storage and dispatchable thermal resources, and for reliability modeling.[54] The UCAP framework would not affect resources subject to probabilistic QC methodologies, such as wind and solar, and hybrid resources featuring storage

[53] Energy Division Track 3 Proposal at 11.

[54] Energy Division Track 3 Proposal at 2.

and solar components would require further consideration. UCAP calculations would utilize each unit's recorded performance whenever possible, and substitute class-based median values when necessary. For the most basic case, Energy Division proposes the following:

1. Evaluate forced outage rates for each resource and hour within the evaluation period;
2. Identify the most constrained hours systemwide for each season;
3. Filter the hourly forced outage rates for the most constrained hours;
4. Apply adjustments for ambient temperature conditions, if applicable, during monthly peaks; and
5. Calculate forced outage rates with weighting and aggregation for each resource and season.

Three complete prior years would be used to evaluate UCAP values with each year weighted so that recent data contributes more significantly than earlier data. When aggregation across resources is required, such as for class-aggregated outage rates in lieu of historic resource-level data, capacity-weighted medians would be applied using resource-level Pmax values.

The proposal applies two UCAP values for each resource, corresponding to the Equivalent Forced Outage Rates (EFORd) for a set of peak hours in two seasons. Peak hours for each season would be selected using a supply cushion approach, as outlined in the CAISO's Resource Adequacy Enhancements Draft Final Proposal. The formula would be adapted from the North American Electric Reliability Corporation's (NERC) Generating Availability Data system

(GADS) manual for Equivalent Forced Outage Deration Hours (EFDH) to determine the outage rate for each hour. Energy Division proposes sourcing outage data from the CAISO's Prior Trade Day Curtailment Reports, which are public summaries of Outage Management System (OMS) data.

Energy Division states that using a model that accounts for ambient temperatures, rather than relying only on outage data, will mitigate effects of extreme weather events. The resource-level derating curves can be used to calculate derations due to ambient temperatures based on historic, normalized, or forecasted weather data.

Energy Division reports that it has been coordinating with the CAISO's staff and the CAISO's Department of Market Monitoring to increase consistency between the organizations' approaches to a UCAP framework. Energy Division has worked with the CAISO to identify a public data set to base formulations and relevant records within the CAISO's curtailment data. As there are unique requirements for each organization and distinctions between the accreditation and modeling processes, the goal has been to unify the UCAP framework to the greatest extent possible.

4.4.2. CESA's Proposal

CESA recommends guiding principles for developing a UCAP methodology, which are that a viable methodology should: (1) be developed in coordination with the CAISO, (2) be adopted in conjunction with changes to the CAISO's RAAIM, (3) be aligned with the PRM so outage uncertainty is reflected in the PRM or QC value, (4) be at the resource-specific level to avoid QC

distortions, (5) use a single public data source to ensure compatibility and verifiability, (6) allow for consultation between the Commission, the CAISO, and resource owners to validate accuracy of values, (7) feature reasonable timing for implementation, and (8) incorporate forced outages due to equipment failures, not outages used to manage state-of-charge (SOC) due to known technical characteristics.[55]

CESA proposes a resource-specific UCAP calculation for storage resources and states that the forced outage types to be considered for calculating UCAP values are: (1) forced outage/derate (immediate), (2) forced outage (delayed), and (3) forced outage (postponed). Suppliers should have an opportunity to verify the initial outage classification and provide corrections. CESA recommends parties consider which forced outage sub-types should lead to a UCAP reduction, whether separate performance indices should be calculated, and how indices will be combined to form a UCAP value, for the following forced outages: (1) impacting maximum discharge level, (2) impacting maximum charge level, (3) impacting maximum continuous energy limit, and (4) impacting minimum continuous energy limit.

CESA recommends resource-specific EFORd values be developed for storage, because EFORd values are proposed for thermal resources. The performance index values would be calculated using the best three years in the

[55] CESA Track 3 Proposal at 5.

four-year historical review period, with equal weighting. New resources would use a class average value until available for at least one year. CESA recommends the CAISO's WebOMS as the single outage data source.

4.4.3. Comments on Proposals

CEERT supports Energy Division's proposal and urges prompt implementation.[56] Numerous parties support Energy Division's proposal with further development needed in workshops, such as ACP-CA, AES, AReM, CalCCA, Calpine, CAISO, MRP, and PG&E.[57] These parties generally state that additional work needed for a final UCAP framework includes: (1) developing a clear forced outage definition and nature-of-work outage types, (2) aligning design and implementation schedules between the Commission's and the CAISO's RA processes, (3) determining how hybrid resources will be treated, (4) developing the methodology for applying ambient derates, (5) evaluating which historical years apply, and (6) refining the definition of supply cushion hours.

ACP-CA states that instead of a ten-year average for new resources, a rolling tranche of recent resources should be established from which data can be drawn. ACP-CA recommends including CESA's proposal for an ex post outage review to ensure outages are appropriately calculated. AES expresses concerns

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[56] CEERT Opening Comments at 2.

[57] ACP-CA Opening Comments at 4, AES Opening Comments at 2, AReM Opening Comments at 5, CalCCA Opening Comments at 14, Calpine Opening Comments at 2, CAISO Opening Comments at 8, MRP Opening Comments at 13, PG&E Opening Comments at 13.

with Energy Division's supply cushion approach, arguing that it does not account for RA resources that are available but not shown on a supply plan. AReM agrees that supply cushion incorporation is essential to incentivize generators to maintain reliability and that the supply cushion should be incorporated into the UCAP framework, and in addition, it can be implemented as part of a penalty mechanism to incentivize short-run participation in the market.

The CAISO sees merit in parts of Energy Division's proposal, including a resource-specific UCAP, forced outage information based on the CAISO's OMS data, and applying UCAP derates to resource types not subject to other performance or probabilistic counting methodologies, such as thermal and storage. CalCCA states that continued development of a UCAP methodology should include verifying PRM impacts through an LOLE study, applying UCAP to all eligible RA resources regardless of whether they were shown for RA during a forced outage, minimizing impacts to existing contracts, and developing a methodology for new resources without a class average. AReM and PG&E recommend a pilot program in the 2027 RA year before full implementation in 2028. Calpine states that UCAP should not be implemented before 2028 to allow for recalculation of the PRM to reflect UCAP counting, allow time for contracts to adjust to new counting rules, and give suppliers an opportunity to update QCs.

Several parties support CESA's proposal, or aspects of it, including Cal Advocates, Calpine, CEJA, IEP, MRP, PCF, REV, and Terra-Gen.[58] IEP and MRP support CESA's guiding principles. Cal Advocates supports the principle to exclude outages from technology limits not explicitly modeled in the CAISO's market model, but states that outages due to storage SOC limitations within an operator's control should be included in the UCAP calculation. Calpine agrees with excluding outages that reflect normal operating limits that cannot be reflected in the CAISO resource data templates. CEJA concurs with CESA that it is important for storage to receive equitable treatment under a UCAP framework.

REV and Terra-Gen generally support CESA's methodology over Energy Division's, with Terra-Gen stating that CESA's proposal is more equitable and accurate. MRP agrees with CESA's EFORd approach, which it states may better identify hours of reliability concern, as supply cushion hours include outages and factors that may skew data. Calpine, MRP, and REV support using CESA's recommended best three out of four years, while IEP recommends using the best three of six years. CalCCA supported using Energy Division's proposal for

[58] Cal Advocates Opening Comments at 18, Calpine Opening Comments at 2, CEJA Opening Comments at 10, IEP Opening Comments at 3, MRP Opening Comments at 13, MRP Reply Comments at 10, PCF Opening Comments at 11, REV Opening Comments at 4, Terra-Gen Opening Comments at 3.

weighting historical years. PCF suggests that individual plant level data be used as much as possible.

SDG&E and SCE generally recommend further development of the UCAP proposals in workshops.[59] SCE notes that when UCAP is adopted, the PRM will have to be reduced to reflect the shift of forced outages from the PRM to the UCAP QC. SDG&E states that there should be sufficient time to develop proposals prior to 2028 and that a final UCAP approach should be adopted by end of 2025. IEP and SCE generally claim that upon implementing UCAP, RAAIM is not necessary and will require elimination through the CAISO.

4.4.4. Discussion

In D.24-12-003, the Commission stated that "Energy Division should coordinate with CAISO to develop a UCAP accreditation methodology for thermal power plants and battery electric storage systems for consideration in advance of the 2028 RA compliance year and to submit a revised UCAP proposal in Track 3 of this proceeding."[60] While a broad range of parties support the Track 3 UCAP proposals, numerous parties comment that additional work is needed on several key elements of the framework. The Commission notes that Energy Division's proposal does not mention the application of UCAP for hybrid resources, such as solar plus battery storage.

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[59] SCE Opening Comments at 14, SDG&E Opening Comments at 7.

[60] D.24-12-003 at 21.

The Commission supports some of CESA's proposed guiding principles, including that a viable UCAP framework should be developed in coordination with the CAISO, that it should use a single public data source to ensure compatibility and verifiability, and that it should incorporate forced outages due to equipment failure. However, the Commission finds that CESA's proposal is not sufficiently developed when compared to Energy Division's proposal. CESA's qualification on equipment failure to exclude outages used to manage SOC is inappropriately tied to a specific technology and it is unclear what SOC-driven outages may be under operator control.

In terms of passing on the intended performance incentives associated with a UCAP framework to the resource owners, there is insufficient record as to how existing qualifying capacity terms may be applied in contracts, or whether new terms may be needed. In addition, the impacts to the CAISO's tariffs and operations must be understood, which would allow for better coordination with the CAISO on UCAP implementation. For example, if the existing QC term is calculated using UCAP, then the must-offer obligation will need a different definition because the resource, when not subject to a forced outage or temperate derate, should offer what the resource is capable of delivering.

The Commission concurs that further development of Energy Division's UCAP proposal is needed. A final UCAP framework should utilize the CAISO's OMS system as the source for outage information because it is a public database and includes data for battery storage, which the NERC GADS database does not. In D.24-12-003, the Commission stated that: "it may not be feasible for a final

UCAP methodology to be at a resource-specific level unless a procedure is developed to correct anomalous or missing data from specific plants, and therefore, additional class groupings should be considered."[61] The Commission has a preference for resource-specific values but remains concerned about the data quality issues. We authorize Energy Division to publish resource-specific and class average UCAP values with the forthcoming UCAP proposal in 2026 for consideration.

The Commission authorizes Energy Division, in coordination with the CAISO, to further develop a final UCAP framework to address the following areas: (1) establish a definition(s) for the types of "forced outage" that will be applicable to the UCAP calculation; (2) refine the ambient temperature derate methodology to address any Staff-identified issues; (3) develop UCAP for hybrid resources containing battery storage; (4) address how the incentives for UCAP should be transferred to the resource owner via the RA contract and identify whether any modifications are needed to the CAISO tariff; and (5) calculate the estimated impact of UCAP on resource counting and to the PRM for procurement.

The Commission finds parties' assertions about the use of the best three out of four years for the UCAP calculation to be reasonable, rather than using Energy Division's proposed weighting of the most recent year in a three-year

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[61] *Id*. at 23.

average. As guidance in further developing the UCAP methodology, the Commission endorses the use of the best three out of four years to calculate the UCAP.

The Commission targets the 2028 RA compliance year as the implementation year for a UCAP framework. In addition to publishing preliminary resource-specific and class average UCAP values, we authorize Energy Division to publish estimated impacts to the PRM without a forced outage rate in advance of adopting a final UCAP framework. Energy Division is authorized to hold a workshop with stakeholders on its refined UCAP proposal before the end of 2025.

As discussed above with the PRM, Energy Division will be preparing a LOLE study for the 2028 RA compliance year. We anticipate that the final UCAP framework will be incorporated into the 2028 LOLE study and will reflect a PRM that moves the forced outage rate out of the PRM and into the resource accounting.

4.5. Accreditation for Solar and Wind Resources

ACP-CA recommends adopting a probabilistic counting methodology for solar and wind resources, as previously proposed in Tracks 1 and 2.[62] This proposal would align data inputs used for RA accreditation with those in IRP accreditation and leverage Energy Division's work to develop simulated load

[62] ACP-CA Track 3 Proposal at 7.

and resource production across twenty years of historical weather data. ACP-CA asserts that this method more accurately associates resource performance with reliability risk and identifies the highest risk days across a more complete weather dataset. ACP-CA claims that this method would bring more stability to QC values, as the values would be grounded in expected performance through extended weather history, rather than a small sample of recent years.

ACP-CA expresses concern with the exceedance methodology, including its use of a limited and moving dataset, introduction of sampling error and unpredictability with each refresh of the historical review window, and the use of equal weighting for unequal years. ACP-CA states that the exceedance translation step approximates output during peak hours, which fails to retain shapes throughout the day, and undercounts performance while doubling the weight of overcounting errors.

ACP-CA also recommends changing the methodology for turning SOD QC values into a single monthly value for the CAISO from using the peak hour value to a different method, arguing that the peak value fluctuates too much year-over-year, the peak value overvalues summer net qualifying capacity (NQC) and undervalues non-summer NQC, and the peak value undermines the CAISO's ability to backstop.[63] ACP-CA considers a few alternatives, such as using net peak or ELCC values.

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[63] ACP-CA Opening Comments at 3.

CEJA and Calpine support this proposal.[64] Calpine states that exceedance focuses on peak load days that may not correspond to stressed system days, and uses limited historical data that may not account for system stress events. CEJA comments that under-counting solar and wind can have adverse consequences on ratepayers as it may require procurement of more resources, and environmental consequences in retaining unnecessary fossil facilities.

Terra-Gen supports translating QC values into a different single monthly value for transmitting to the CAISO, as the current framework omits key aspects of RA provisions such as outage and substitution impacts.[65] PG&E suggests creating a working group to consider different options for solar and wind QC calculations in a new track of the proceeding.[66] MRP posits that changes to QC counting for wind and solar benefited non-CPUC-jurisdictional LSEs because the QC values increased when compared to ELCC-derived values.[67] MRP states that because non-CPUC-jurisdictional local reliability areas did not modify PRMs to account for increased capacity, those LSEs now have surplus "paper capacity" without changes to physical operations.

4.5.1. Discussion

In D.24-12-003, the Commission stated:

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[64] Calpine Opening Comments at 6, CEJA Opening Comments at 10.

[65] Terra-Gen Opening Comments at 11.

[66] PG&E Reply Comments at 10.

[67] MRP Reply Comments at 7.

> The Commission sees merit in modifying the QC values for wind and solar resources using SERVM weather profiles, rather than using exceedance profiles, as this would better align SOD RA values with how SERVM stochastic datasets are used in the RA LOLE studies. However, we find that there is insufficient record at this time to consider this change and that more analysis is needed.[68]

The Commission then "authorize[d] Energy Division to conduct an analysis comparing exceedance profiles for wind and solar resource against SERVM weather profiles to be considered in Phase 3 of this proceeding."[69] At this time, Energy Division has been unable to complete an analysis comparing exceedance values for wind and solar against SERVM weather profiles. Energy Division is authorized to continue working on this analysis and submit it into the successor RA proceeding.

While the Commission continues to see merit in SERVM weather profile-based QC values for wind and solar resources, there is still insufficient record to modify the current methodology. It is important to develop a thorough record to carefully consider an alternative to the exceedance methodology for variable energy resources (VER). Modifying the VER counting methodology repeatedly can contribute to market uncertainty and instability. One year ago, in D.24-06-004, the Commission adopted the requirement to lock in exceedance levels for a

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[68] D.24-12-003 at 18.

[69] *Id*.

three-year period. Therefore, current exceedance levels are locked in for 2025 through 2027. In addition to Energy Division's aforementioned analysis, additional work is needed regarding changes to the single monthly value sent to the CAISO for NQC purposes. Energy Division is authorized to include this topic in its analysis for submission into the successor RA proceeding. The Commission also authorizes Energy Division to hold a workshop in Fall 2025 on the QC accreditation for wind and solar resources and the QC methodology for CAISO showings.

4.6. Energy Storage Resources

Parties submitted multiple proposals on charging sufficiency requirements and accreditation for long-duration energy storage (LDES), including proposals for multi-day storage (MDS) and pumped storage hydropower (PSH) resources.

4.6.1. Accreditation Proposals

CESA proposes that to the extent a resource is procured to meet long-duration storage compliance for mid-term reliability (MTR) purposes in the IRP process, the RA program should establish an 8-hour minimum duration for such resources in their QC calculation, and establish an "IRP-LDES" classification and accompanying QC methodology.[70] CESA states that storage technologies are competing to allow LSEs to meet MTR obligations but there are concerns as to how shorter-duration technologies may be counted to provide 8-hour services.

[70] CESA Track 3 Proposal at 17.

CESA also proposes to define Extended Duration (ED)-LDES in the SOD framework as those resources "where it would take longer than 24 hours to complete a single cycle" and to use annually calculated ELCC values as the ED-LDES QC values.[71] Currently, resources that have more than 12 hours of continuous discharge duration are not able to fully charge in the SOD tool as they are not able to charge and discharge at the same time. CESA states that an annually calculated ELCC value would accurately represent the resource's contribution to reliability. Energy Division would calculate ELCC values for each storage class that meets the definition of an MDS resource, as well as a resource whose discharge is 12-24 hours, and is commercially operational in the upcoming year. Because ELCC values incorporate SOC limitations, ED-LDES resources should not be required to be "charged" to meet RA requirements.

Form Energy proposes that MDS resources should be accredited at their Pmax over the 24-hour period shown and not be required to show daily charging sufficiency, similar to the current treatment of PSH which are the longest duration energy storage resources currently participating in the RA program.[72] This methodology would recognize actual capabilities of these resources, similar to other resources in the SOD framework. Form Energy states that it would be unreasonable to require a charging showing for MDS since these resources are

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[71] *Id*. at 20.

[72] Form Energy Track 3 Proposal at 5.

able to be discharged continuously for the 24-hour period shown on an LSE's showing without recharging. Hydrostor likewise proposes that the charging sufficiency requirement should be eliminated for LDES as these resources are not as likely to follow charge/discharge patterns like shorter-duration resources, and may charge more incrementally over multiple days (potentially holding a charge beyond the 24-hour timeframe).[73]

MRP proposes that for LSEs with load served by PSH resources, the RA requirements should include pumping energy MW and MWh requirements, analogous to the charging requirements that apply for battery storage resources.[74] MRP states that just as energy storage systems must first be charged with electrical energy before they can be discharged to serve load, PSH resources require electrical energy to pump water from a lower reservoir to an upper reservoir to allow energy production. MRP notes that while the pumping energy requirement is captured in Energy Division's LOLE study, the RA program does not require securing energy charging sufficient for PSH resources.

4.6.1.1. Comments on Proposals

ACP-CA, SDG&E, and SCE oppose adopting an IRP-LDES classification.[75] SCE asserts that the IRP process has several policy objectives whereas RA has a

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[73] Hydrostor Track 3 Proposal at 8.

[74] MRP Track 3 Proposal at 1.

[75] ACP-CA Opening Comments at 17, SDG&E Opening Comments at 13, SCE Opening Comments at 13.

singular reliability purpose, and thus the RA program should determine what a resource can contribute to reliability. ACP-CA likewise states that as MTR requirements are established in IRP, it is unclear what incremental value is offered with an additional resource class in the RA program. SDG&E argues that an IRP-LDES classification would unnecessarily constrain LSEs' ability to procure LDES suited for specific needs and add complexity to the RA program.

CEERT and Hydrostor support an IRP-LDES classification, with Hydrostor stating that the designation should attach only to LDES that can deliver at a resource's maximum capacity for at least eight hours to be consistent with the RA/IRP programs.[76]

ACP-CA and Cal Advocates oppose CESA's proposal to use ELCC values for ED-LDES resources.[77] Cal Advocates contends that this creates an unequal footing between LDES and other non-variable resources if ED-LDES is the only resource using ELCC, while other resources are accredited based on capability to provide power each hour of the day. Cal Advocates adds that ELCC factors for LDES would change year to year, while values for other resources would be fixed. ACP-CA states that applying ELCC requires an LOLE study to determine whether energy sufficiency issues arise and it would be difficult to determine whether energy contributed to the LDES is not already being shown for

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[76] CEERT Opening Comments at 3, Hydrostor Opening Comments at 9.

[77] ACP-CA Opening Comments at 14, Cal Advocates Opening Comments at 17.

compliance with another LSE's energy sufficiency requirement. GreenGen contends that before considering ELCC for ED-LDES, the Commission should provide study results as it is unclear whether a study would provide actionable information.[78]

CEJA supports Form Energy's proposal to credit MDS, as these resources provide reliability attributes to help transition away from fossil fuel reliance.[79]

Several parties oppose exempting LDES resources from the charging sufficiency requirement, including ACP-CA, Calpine, Cal Advocates, and Terra-Gen.[80] ACP-CA and Terra-Gen contend that an exemption for eight-hour LDES is not justified and disadvantages 4-hour storage. ACP-CA states that Hydrostor's proposal appears premised on a single-day reliability event when the RA program is designed to prepare for multiple stressed days.

Cal Advocates states that Form Energy's proposal does not provide assurances there will be sufficient excess energy to charge MDS to meet its obligation as a firm resource. Cal Advocates observes that one difference between large PSH and MDS is that the two largest PSH facilities in California have large storage reservoirs that are fed by natural water inflow, in addition to

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[78] GreenGen Opening Comments at 3.

[79] CEJA Opening Comments at 10.

[80] ACP-CA Opening Comments at 14, Calpine Opening Comments at 6, Cal Advocates Opening Comments at 21, Terra-Gen Opening Comments at 7.

pumped water.[81] Therefore, unlike MDS, these plants can provide at least 24 hours of discharge at full capacity even during stressed conditions. SCE opposes exempting 8-hour LDES from the charging requirement as 8-hour storage can be completed within a single day but SCE agrees in part to exempting 12-hour LDES due to its unique charging/discharging patterns.[82]

In comments, Cal Advocates recommends adopting a MDS counting methodology that includes a multi-day energy sufficiency requirement (MDESR).[83] An MDESR would allow for determining energy sufficiency needs over multiple days to facilitate dispatch patterns on SOD showings. Cal Advocates states that for simplicity, the MDESR could be based on excess energy available for the MDS on the monthly SOD compliance plan. Excess energy would be multiplied by the amount of days provided for charging the MDS (3 days to charge would mean 3 times the excess MWh). Cal Advocates comments that an advanced charging period by month should be adopted, which may require further stakeholder input. Cal Advocates alternatively suggests that LSEs may use historical data or contractual provisions that MDS will have enough SOC to discharge its capacity.

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[81] Cal Advocates Opening Comments at 22.

[82] SCE Opening Comments at 12.

[83] Cal Advocates Opening Comments at 25.

Terra-Gen supports a charging requirement for PSH resources, stating that it ensures technical consistency and reliability, and does not discriminate against storage resources.[84] Cal Advocates supports the proposal but notes that in California, PSH resources are not entirely closed-loop systems as they are not solely dependent on charging energy from the grid to maintain SOC.[85] ACP-CA recommends the development of a monthly or seasonal energy sufficiency framework that can address both MDS and PSH resources, as well as seasonally constrained hydro resources.[86] CalCCA states that storage resources should not have different charging requirements, as it creates an uneven playing field and unreliable grid, and suggests addressing this in a future phase of the proceeding.[87]

Parties that oppose a charging sufficiency requirement for PSH resources are Form Energy, GreenGen, Hydrostor, SCE, and PG&E.[88] The parties generally state that it is not appropriate to apply charging sufficiency to PSH, as the proposal does not account for differences between PSH and battery storage technologies. Form Energy contends that while PSH might be shown as

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[84] Terra-Gen Opening Comments at 4.

[85] Cal Advocates Opening Comments at 24.

[86] ACP-CA Opening Comments at 14.

[87] CalCCA Opening Comments at 25, CalCCA Reply Comments at 32.

[88] Form Energy Opening Comments at 5, GreenGen Opening Comments at 2, Hydrostor Opening Comments at 6, SCE Opening Comments at 13, PG&E Opening Comments at 5.

discharging in all 24-hour slices, the charging energy could be consolidated in fewer hours, which is a drastic departure in how those resources operate. GreenGen states that some PSH resources do not have charging requirements analogous to lithium batteries, as PSH can charge from non-grid resources (i.e., streamflows) to refill the upper reservoir and discharge for several days without grid charging if sufficient upper reserves exist. Hydrostor claims that the proposal is an attempt to undercut other proposals to extend the PSH charging treatment to LDES.

SCE agrees that MRP's proposal should apply for closed-loop PSH but not to open-loop PSH that has inflows that can provide capacity without using energy to pump water back to the reservoir. PG&E comments that different QC methodologies for PSH and 4-hour battery reflect the large technology variations, as PSH can be open or closed-loop, be short or long durations, and have higher or lower round-trip efficiencies.

Some parties, such as CalCCA, Hydrostor, PG&E, and SCE, state that LDES accounting and charging sufficiency rules should be addressed in a future phase of the RA proceeding.[89]

[89] CalCCA Opening Comments at 25, Hydrostor Opening Comments at 4, SCE Reply Comments at 9, PG&E Reply Comments at 6.

4.6.1.2. Discussion

Regarding CESA's proposed IRP-LDES classification, the Commission agrees with parties that it is unclear what value would be added by including an 8-hour+ classification in the RA program, as 4- to 12-hour batteries are already accommodated in the Master Resource Database (MRD) and SOD compliance tool with regards to temporal charging constraints. We decline to adopt this proposal.

With respect to an accreditation methodology for ED-LDES resources, no detail was provided by CESA as to how an ELCC study would be performed for ED-LDES counting purposes. We also agree with Cal Advocates' concerns that applying ELCC would mean that ED-LDES is the only resource using ELCC, while all other resources would be accredited based on ability to provide capacity in each hour of the day. Further, the proposal would require an LOLE study to calculate ELCC values, which would require significant effort by Energy Division Staff and would deviate from the SOD framework. As such, we decline to pursue further development of this proposal.

Form Energy proposes that MDS resources should be accredited at their Pmax value over the shown 24-hour period without a charging sufficiency test. The Commission sees some merit in Form Energy's proposal, as these resources are being developed to provide long durations of discharge similar to PSH and may be able to charge/discharge when needed. However, we agree with Cal Advocates that the proposal does not provide assurances that there will be sufficient excess energy to charge the MDS to meet its obligation as a firm

resource. We also agree with several parties that note that open-loop PSH resources (the large majority of pumped storage hydro MW) have storage reservoirs that are fed by natural water inflow, in addition to pumped water, and therefore do not present the same energy sufficiency charging concerns as MDS. At this time, the Commission finds insufficient record to adopt Form Energy's proposal. We, however, outline several questions below for further consideration and discussion, before adopting an accreditation methodology for LDES resources.

The Commission sees merit in Cal Advocates' MDESR proposal in that it would establish a charging requirement for LDES resources but allow flexibility for resources that cannot charge in a single 24-hour period. However, the proposal lacks necessary detail for consideration, such as the specific day-multiplier. Additionally, this recommendation raises concerns about compliance beyond 24 hours, which could undermine the SOD program. The Commission encourages further development of this proposal.

With respect to PSH resources, the Commission notes that these resources can be either closed-loop or open-loop systems, which will affect the charging patterns of these resources and should be considered for future changes to the PSH counting rules. Additional record is needed to determine the necessary charging sufficiency requirements for different designs to PSH systems. As such, we agree with parties that further examination of seasonal charging requirements for PSH (and MDS) resources is needed. We also see merit in potential application of Cal Advocates' MDESR proposal for PSH resources.

Before adopting, or modifying, accreditation methodologies for LDES resources, several questions regarding charging sufficiency requirements and accreditation require further discussion. The outstanding issues include, but are not limited to, the following:

1. Whether MDS and/or PSH should have limitations on their ability to charge storage resources;

2. As MDS (24-hour+) and ED-LDES (12-24 hour) batteries are not able to fully charge in a 24-hour period, how can these batteries fit into the SOD framework;

3. As MDS and other ED-LDES resources may have different attributes, should these resources be treated differently from each other and how;

4. Whether a MDESR test, as proposed by Cal Advocates, could work in the SOD framework, including how much extra time should be allowed for charging and what types of multi-day resources should this apply to;

5. How a seasonal PSH or MDS charging requirement could work, including how many months in advance should be permitted and how this would fit into the SOD framework;

6. For PSH accreditation in particular: (1) an analysis of reliability issues with the current methodology, (2) the different treatments for different designs of PSH (considering loop design, duration in number of hours, and round-trip efficiencies), and (3) whether PSH charging rules should be based on historical data.

The Commission authorizes Energy Division to hold a workshop in the Fall of 2025 on LDES issues. The above outlined issues will assist in informing the workshop agenda. Parties are encouraged to further develop LDES proposals following the workshop and submit proposals into the successor RA proceeding.

4.6.2. Other LDES Proposals

To ensure that LDES is properly incentivized and resource attributes are better captured, Hydrostor proposes introducing minimum capacity buckets, as compared to the previous maximum cumulative capacity buckets that are storage attribute specific.[90] Hydrostor states that a minimum obligation for LDES is critical to improving reliability by ensuring a single asset is not overly relied on, such as short-duration storage. This would ensure that LSEs contracting to meet IRP mandates will maintain contracts with LDES beyond IRP obligations. The proposal is also designed to reward LSEs that have acted in good faith to procure LDES resources.

Hydrostor also proposes eliminating the ability for storage resources to count for multiple cycles under the SOD framework.[91] Hydrostor states that while shorter-duration resources count for multiple cycles, this creates a

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[90] Hydrostor Track 3 Proposal at 5.

[91] *Id*. at 8.

disconnect for longer-duration resources that only count for a single cycle. Because shorter-duration storage has a lower cost, LDES resources may be disadvantaged even though the resources have greater reliability benefits and provide diversification of storage. Hydrostor requests the Commission issue statistics to understand the prevalence and reliability impacts of multi-cycling in a 24-hour period.

Numerous parties oppose a procurement carve-out for LDES resources, including ACP-CA, Calpine, CalCCA, Cal Advocates, MRP, SDG&E, and SCE.[92] These parties generally argue that this topic is outside the scope of the RA proceeding and should be raised in the IRP proceeding, and that the IRP process already has LDES procurement requirements. CalCCA and Calpine assert that the RA program was intended to ensure LSEs achieve reliability through technology-neutral requirements, and CalCCA adds that LSEs should be able to optimize portfolios with technologies that are most cost-effective and aligned with an LSE's objectives.

Form Energy supports Hydrostor's minimum capacity proposal as potentially appropriate in the future to meet multi-day reliability needs.[93]

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[92] ACP-CA Opening Comments at 18, Calpine Opening Comments at 6, CalCCA Opening Comments at 24, Cal Advocates Opening Comments at 15, MRP Reply Comments at 12, SCE Opening Comments at 12, SDG&E Opening Comments at 12.

[93] Form Energy Opening Comments at 7.

Multiple parties oppose limiting 4-hour storage to a single cycle, such as ACP-CA, CalCCA, SDG&E, SCE, and Terra-Gen.[94] These parties generally reason that if 4-hour storage is physically and contractually able to cycle multiple times per day and has charging sufficiency, this reflects the resource's capability to provide reliability. ACP-CA and SDG&E state that this issue was already litigated and the Commission made a determination in D.23-04-010 to allow multiples cycles for 4-hour storage. ACP-CA and Terra-Gen disagree that multi-cycling disadvantages 8-hour storage and state that the IRP process mandates procurement of these resources.

4.6.2.1. Discussion

The Commission declines to adopt an LDES minimum procurement requirement in the RA program. We concur with parties that state that the RA program is designed to ensure that LSEs procure capacity to maintain system reliability with cost-effective resources and that issue should be addressed in the IRP proceeding.

In D.23-04-010, the Commission adopted the following:

> Storage resources that are operationally and contractually able to provide multiple cycles in a 24-hour cycle are allowed to be shown for multiple cycles per day, provided that the load-

[94] ACP-CA Opening Comments at 17, CalCCA Opening Comments at 25, SDG&E Opening Comments at 15, SCE Opening Comments at 14, Terra-Gen Opening Comments at 5.

serving entity (LSE) shows sufficient excess energy and time between discharge cycles to charge the battery.[95]

The Commission finds insufficient basis to modify its position from D.23-04-010. We agree with parties that contend that if 4-hour batteries are able to cycle multiple times per day and have sufficient charging, this reflects the batteries' contribution to reliability. As such, we decline to limit 4-hour storage to a single cycle.

4.6.3. Shorter-Duration Energy Storage Resources

CESA proposes to allow LSEs to include energy storage resources with durations less than four hours at values up to, but no greater than, the resource's deliverability allocation, limited by the resource Pmax.[96] CESA states that currently, resources with less than 4-hour duration with deliverability allocation greater than NQC have showing values artificially limited by the resource NQC. CESA cites the example that a 100 MW 2-hour battery with a 100 MW deliverability allocation has a 50 MW NQC. An LSE is only able to show that resource for a maximum of 50 MW each hour. CESA claims that updating the rule for the SOD tool will ensure LSEs will be able to show the resource within its operational ability and would be consistent with the way the CAISO can operate the resource.

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[95] D.23-04-010 at Ordering Paragraph (OP) 9.

[96] CESA Track 3 Proposal at 22.

ACP-CA, CEERT, and SCE support the proposal.[97]

Based on our understanding of CESA's proposal, we note that the SOD showing tool already accounts for energy storage resources in the manner CESA proposes.[98] The SOD showing tool already accounts for energy storage with durations less than four hours at values up to, but no greater than, the resource's deliverability allocation, limited by the resource Pmax in the manner. As such, CESA's proposal is not necessary.

4.6.4. Voluntary Charging Sufficiency Groups

CESA states that because the SOD framework sets 24 requirements and 24 NQC values but requires LSEs to transact resources monthly, there is a transactability issue that limits the amount of excess capacity an LSE can use to meet charging sufficiency requirements.[99] CESA proposes allowing two or more LSEs to form a voluntary charging sufficiency group, in which a group-wide charging sufficiency test would be performed. A group administrator would be responsible for verification of membership and each LSE can be a member of one group per year. Energy Division would collect LSEs' RA plans, aggregate the shown deliverable resources in each group, calculate excess energy that is not storage, and determine if aggregate excess energy is sufficient to meet the

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[97] ACP-CA Opening Comments at 17, CEERT Opening Comments at 3, SCE Opening Comments at 13.

[98] *See* D.23-04-010 at Appendix A-5.

[99] CESA Track 3 Proposal at 14.

aggregate deficiency considering the group's storage fleet. If the group's storage charging is sufficient, non-compliance with the charging sufficiency requirement is not assessed. If there is a charging deficiency, Energy Division would determine each individual LSEs' deficiency and assess penalties.

AES supports the proposal because it is a pragmatic approach that ensures storage is utilized efficiently and compliance barriers are mitigated.[100]

ACP-CA, MRP, PG&E, and SDG&E oppose the proposal.[101] These parties generally assert that the proposal adds complexity and significant administrative burden on Energy Division, as well as to the SOD framework, to track groups with separate RA filings and obligations, calculate aggregate resources and excess energy, and determine individual LSE deficiencies and penalties. PG&E observes that while CESA cites test year data to support the proposal, test year submissions were not binding and thus it is unclear if similar results would be seen in 2025. ACP-CA states that the proposal is inequitable in that only LSEs open to sharing their portfolio details could participate. MRP states that allowing LSEs to combine RA requirements is a departure from the longstanding practice of assessing RA compliance on an LSE level.

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[100] AES Opening Comments at 5.

[101] ACP-CA Opening Comments at 18, MRP Opening Comments at 20, PG&E Opening Comments at 12, SDG&E Opening Comments at 18.

SDG&E argues that the proposal lacks clarity regarding cost allocation with group administration and verification in terms of how costs would be distributed to and recovered from customers. SDG&E states that relying on aggregate group performance raises concerns of masking LSE deficiencies and leaning by deficient LSEs. SDG&E adds that the proposal lacks clarity regarding interactions with RA counting methodologies, such as UCAP.

The Commission agrees with parties that express concerns with the proposal, including that it would be administratively burdensome on Commission Staff to implement and would shift RA requirements away from individual LSEs to aggregate group compliance. There is also insufficient evidence that the proposal would resolve the problem CESA claims to address. While CESA claims the proposal would help address transactability challenges, there is no evidence that a groupwide charging sufficiency test would be an efficient, tailored, or necessary means of resolving that issue. The Commission declines to adopt this proposal.

4.7. Co-Located Resources

CalCCA and SCE put forth proposals for co-located resource counting. CalCCA first proposes to formally adopt a counting methodology for co-located deliverable resources, which Energy Division Staff has clarified through office hours.[102] For 2025 year-ahead showings, Energy Division included a

[102] CalCCA Track 3 Proposal at 18.

"Deliverability MW" column in the MRD to represent maximum capacity or proportion of a resource considered deliverable if less than its nameplate. The Deliverability MW value would cap the amount an LSE could show in its RA showing. Initially, Deliverability MW was defined as the lower of:

1. A deliverability reduction due to a resource's deliverability status and, if applicable, the 2025 NQC deliverability status limits; or

2. A Point of Interconnection (POI) limit for co-located resources that share a POI and for which the limit was binding. For a co-located solar resource, the Deliverability MW was calculated as the POI limit minus the NQC of its paired storage.

After consulting with stakeholders and the CAISO, Energy Division updated the Deliverability MW value for resources in the second category to allow the affected co-located solar to count up to the full deliverable capacity. CalCCA asserts that the change allows LSEs to show co-located generation with Partial Capacity Deliverability Status (PCDS) or Full Capacity Deliverability Status (FCDS) for RA or charging sufficiency requirements up to the deliverable POI, so long as the combination of generation plus storage does not exceed the deliverable POI in an individual hour. CalCCA recommends formally adopting this change.

CalCCA next recommends reevaluating the SOD counting methodologies for co-located resources where a portion or all of the generation is energy-only (EO) , which would unlock additional capacity that can be shown for RA and

charging requirements.[103] CalCCA recommends addressing the following concerns: to ensure that (1) the showing of the two co-located resources in any hour does not exceed the POI, (2) must-offer obligations are imposed on both resources, and (3) deliverability limits at the POI are not exceeded when the co-located resources have multiple off-takers.

SCE states that the RA program has been automatically prorating energy sufficiency from co-located energy-only resources with full deliverability status based on the storage resources' NQC.[104] SCE recommends eliminating the rule and adopting the following: for existing projects that may have contracted for the sale of all capacity attributes, or that may seek to monetize attributes, "energy sufficiency" should be defined as "a capacity attribute that is created by a project that is eligible to count towards an LSE's energy sufficiency showing." The capacity attribute should stay with the project unless and until it is allocated or sold by that project. For any hybrid or co-located VER that is behind a POI with full deliverability status but allocated zero deliverability, the VER's charging sufficiency should stay with the applicable VER. SCE recommends workshops to assess and identify RA-eligible storage resources that are eligible to purchase VER's charging sufficiency capacity attributes.

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[103] CalCCA Track 3 Proposal at 20.

[104] SCE Track 3 Proposal at 6.

4.7.1. Comments on Proposals

Parties that support CalCCA's proposal to formalize the SOD counting rules for PCDS and FCDS co-located resources up to their deliverable capacity and POI limit are AES, CAISO, LSA, and Terra-Gen.[105] AES and Terra-Gen comment that this would give LSEs certainty in their RA showings and ensure consistency in compliance. The CAISO states that this ensures LSEs are able to show deliverable resources that are not otherwise limited due to POI constraints, recognizing reliability contributions under the SOD framework.

CEJA supports CalCCA's proposal to allow co-located EO resources to count as RA, while ACP, CESA, and LSA support the proposal but state that further development is needed.[106] CESA states that discussion is needed on several issues, such as determining the quantity subject to and enforcement of the MOO. SCE supports the proposal so long as the co-located resources are behind the same POI and have a single off-taker, the SOD tool ensures that the total output of the co-located resources does not exceed the POI in any hour, and the CAISO enforces a MOO on the resources.[107]

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[105] AES Opening Comments at 7, CAISO Opening Comments at 10, LSA Reply Comments at 2, Terra-Gen Opening Comments at 12.

[106] ACP-CA Opening Comments at 11, CESA Opening Comments at 14, CEJA Opening Comments at 9, LSA Reply Comments at 2.

[107] SCE Opening Comments at 14.

Parties that oppose CalCCA's proposal to allow co-located EO resources to count as RA are CAISO, MRP, PG&E, and Terra-Gen.[108] The CAISO states that the proposal would require changes to the CAISO's rules, as the CAISO's tariff and systems do not support applying a MOO on EO resources. Further, the CAISO notes that the proposal may require the CAISO to revisit how it studies and establishes deliverability for RA resources as the CAISO does not study whether EO resources can serve the aggregate of the CAISO load or award deliverability status to co-located resources at the POI level. MRP agrees that significant work at the CAISO would be required and the CAISO's process for allocating deliverability does not align well with the SOD framework. Terra-Gen comments that several issues require further discussion, including coordination with the CAISO's processes, cost-shifting between suppliers with deliverability allocations and off-takers of EO resources, and impact on deliverability allocations if there are different resources owners at the same POI.

CAISO, PG&E, and Terra-Gen oppose SCE's proposal.[109] The CAISO agrees with SCE that it is unclear which resources could use the VER's charging sufficiency capacity attributes in their showings and more clarification is needed; otherwise a resource could be located outside of the POI in which the VER is

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[108] CAISO Opening Comments at 11, Terra-Gen Opening Comments at 14, MRP Reply Comments at 12, PG&E Reply Comments at 7.

[109] CAISO Opening Comments at 2, PG&E Reply Comments at 7, Terra-Gen Opening Comments at 9.

located. Terra-Gen argues that the proposal treats charging sufficiency as a standalone capacity attribute, fails to address the complexities of co-located and hybrid resources, and disregards that many existing projects have contracted for the sale of specific attributes, including charging sufficiency. ACP-CA supports development of SCE's proposal but notes that it would be beneficial to pursue a fulsome solution to unlock EO contributions, such as CalCCA's proposal.[110]

4.7.2. Discussion

The Commission agrees that formalizing the resource counting rules for PCDS and FCDS co-located resources under the SOD framework is reasonable for the sake of consistency and certainty. Accordingly, the variable energy component of a co-located resource with PCDS or FCDS will count for RA requirements and off-site charging sufficiency requirements up to its deliverable capacity as long as the combination of shown generation plus storage does not exceed the POI in the same hour.

For grid charging-restricted storage resources, energy available for on-site charging is calculated based on the VER exceedance profile and is irrespective of the VER's deliverability status. Additionally, energy used for charging on-site grid charging-restricted storage is subtracted from the energy available for charging grid-connected storage. This counting methodology was incorporated

[110] ACP-CA Opening Comments at 11.

into the SOD showing template prior to the 2025 year-ahead SOD compliance filings.

The Commission finds that CalCCA's proposal to count co-located energy-only resources as RA resources is not adequately developed and would require substantial modifications with the CAISO's tariff and systems, as the CAISO does not currently support applying a MOO to EO resources. Further, we agree with the CAISO that "[a] core tenet of the RA program is that RA resources must be capable of serving the aggregate of CAISO load."[111]

The CAISO's Transmission Plan Deliverability (TPD) and Distributed Generation Deliverability (DGD) processes serve as a structured method for assessing the deliverability of resources within the CAISO system. Through the TPD/DGD Allocation Process, resources receive deliverability allocations that grant them the ability to provide RA to LSEs. The CAISO's annual deliverability study then evaluates these awarded TPD/DGD resources to ensure they can reliably deliver power under peak conditions. The annual deliverability assessment process does not include EO resources because these resources were not evaluated and provided TPD/DGD in the TPD/DGD Allocation Processes. Expanding the scope of the CAISO deliverability process to include EO resources would require significant analysis and discussions within the CAISO stakeholder

[111] CAISO Opening Comments at 11.

process, as it would fundamentally alter the framework for how deliverability is determined across the grid.

Regarding SCE's proposal, D.24-06-004 states that an EO resource may count towards the storage charging sufficiency requirement only if the EO resource is charging exclusively paired storage.[112] As the decision emphasizes that the energy sufficiency benefit of the EO would remain bundled with the storage component, the value is therefore realized only through the paired storage. Further, because EO resources are not able to submit supply plans to the CAISO, SOD compliance could not be assessed to confirm the charging sufficiency value shown by an LSE, if not bundled with the paired storage resource. We decline to adopt this proposal.

4.8. Demand Response Resources

OhmConnect/Leap state that under the SOD framework, LSEs now prefer 24-hour resources due to their ability to meet obligations in any hour, which has constrained demand for DR due to its smaller availability window.[113] OhmConnect/Leap state that DR requirements are tied to the AAH window due to the MCC buckets, and DR providers are allowed to choose which four of the five AAHs to provide load reductions in. DR resources are only given QC values

[112] D.24-06-004 at OP 9.

[113] OhmConnect/Leap Track 3 Proposal at 3.

during the AAHs and therefore DR is prohibited from meeting RA demand outside of the AAHs, even if they can provide capacity outside of the window.

OhmConnect/Leap recommend Energy Division consider the underlying technologies and load profiles of the resources in a DR provider's portfolio to award QC outside of the AAHs during the QC process. Awarding QC should account for different DR resource profiles (type, duration, dispatch timing) to enable DR providers to satisfy RA market demand.

Parties that support the proposal are AReM, CalCCA, CEJA, CESA, and CEERT.[114] PG&E supports the proposal as long as DR resources available in hours of critical need are not sacrificed in operational or counting terms with expanded eligibility.[115] PG&E notes that the Commission has referenced a DR OIR that has not yet been launched and should consider whether that is a better venue for these changes. Calpine is not opposed to the proposal provided the capacity is subject to appropriate measurement and verification.[116]

While the Commission sees merit in the proposal, there are several questions that need to be addressed before further consideration. In particular, the proposal does not address how the Commission should ensure that the load reduction capability of DR resources during the AAHs is not compromised with

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[114] AReM Opening Comments at 8, CalCCA Opening Comments at 24, CEJA Opening Comments at 9, CEERT Reply Comments at 2, CESA Opening Comments at 12.

[115] PG&E Opening Comments at 16.

[116] Calpine Opening Comments at 8.

expanded eligibility, and what the measurement and verification process should be for estimating QC outside the AAHs.

As such, we encourage further refinement of the proposal to address the following issues: (1) how to ensure that the availability and load reduction capability of the DR resource during the AAHs is not compromised with expanded offerings outside of the AAHs, (2) the measurement and verification methodology for estimating QC values outside of the AAHs, (3) any updates needed for the application of DR resources' MCC bucket cap, and (4) implications on the CAISO's operational requirements and constraints (including the interaction with the CAISO MOO and supply plan showings).

4.9. Other Slice of Day Modifications

4.9.1. Hourly Load Obligation Trading

As proposed in previous tracks of the RA proceeding, CalCCA recommends allowing LSEs to transact load obligations on an hourly basis under the SOD framework.[117] CalCCA states that because the SOD framework requires monthly transactions, if an LSE contracts for a resource, it must do so for the resource's NQC in all 24 hours of the month even if the LSE only has an open position in one hour. CalCCA contends that the proposal is an administratively simple way to allow LSEs with open positions in some hours to pay another LSE with long positions to cover these positions. CalCCA argues that this proposal

[117] CalCCA Track 3 Proposal at 3.

has no impact on the CAISO processes and does not involve generators. LSEs would document trades on the RA showings and the Commission would validate trades to ensure no double-counting or loss of total RA across hours.

Trading a load obligation would not relieve an LSE of its obligation to serve load, and the obligation would remain with the underlying guarantor. If, for example, an LSE that accepted a load transaction stops providing LSE services unexpectedly, the responsibility for showing sufficient resources for the transaction reverts back to the original LSE. CalCCA states that the proposal will promote affordability by reducing RA shortages and minimizing over-procurement by allowing LSEs to procure to meet load shapes. LSEs could meet RA requirements through resource swaps but CalCCA states there is difficulty in getting all the necessary transactions to align through the bilateral market. CalCCA provides an analysis of its members' first binding year-ahead RA showings to show that hourly load obligation trading would have increased compliance with year-ahead RA requirements.

In opening comments, CalCCA amends its proposal as follows: initially implement the proposal with a 25% limit on how much load each LSE can trade and treat defaults on hourly trades no differently than defaults on RA agreements.[118]

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[118] CalCCA Opening Comments at 10.

4.9.1.1. Comments on Proposals

Cal Advocates, CEERT, Hydrostor, Microsoft, Shell Energy, and 3CE/SJCE support the proposal.[119] These parties generally agree that the proposal could improve affordability issues by reducing costs for LSEs and customers, and give LSEs needed flexibility to meet RA obligations. Cal Advocates recommends that LSEs with hourly trading be responsible for CPM costs due to a non-collective deficient RA showing at the CAISO.

ACP-CA, AReM, CEJA, and MRP support the proposal in concept but recommend modifications or further development.[120] ACP-CA recommends identifying the scale and necessity of hourly obligation trading and parse out benefits that can be achieved through existing trading paths. If adopted, ACP-CA suggests guardrails on the quantity of trades (capacity and duration) and the horizon of trades to ensure the tool is narrowly used in situations that cannot be addressed through standard trades. CEJA supports exploring how to include transactability in the SOD framework and ensuring that the loading order is followed via public oversight. AReM recommends capping the amount of load or number of transactions, creating a tab in the SOD showing template to log

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[119] Cal Advocates Opening Comments at 10, CEERT Opening Comments at 3, Hydrostor Opening Comments at 9, Microsoft Opening Comments at 17, Shell Energy Opening Comments at 4, 3CE/SJCE Reply Comments at 13.

[120] ACP-CA Opening Comments at 16, AReM Opening Comments at 3, CEJA Opening Comments at 11, MRP Reply Comments at 9.

transactions, and requiring attestations. Similarly, MRP expresses concern that many consequences have not been considered, including limits on how many hours an LSE can sell, whether hourly load sales can be used in lieu of procuring additional capacity to ensure sufficient charging capacity, and the burden on Energy Division to track transactions.

PG&E, SCE, and SDG&E oppose the proposal.[121] PG&E states that the proposal fails to address outstanding implementation issues (such as penalty attribution and point accrual), fails to implement guardrails, and that it is premature to know whether the mechanism is needed. PG&E states that the proposal significantly increases the complexity of the RA program, and recommends at least one year of SOD experience and an evaluation by Energy Division before adopting.

SDG&E asserts that the proposal lacks critical detail, is unduly complex, results in further divergence from the CAISO's RA program, and potentially creates perverse incentives for market participants. SDG&E states that the proposal omits consideration for transmission constraints, as allowing LSEs to contract load outside their designated service areas could exacerbate transmission bottlenecks. SDG&E adds that it is imprudent to add a new market

[121] PG&E Opening Comments at 10, SCE Reply Comments at 8, SDG&E Opening Comments at 16.

for an untested product while the SOD framework is being implemented. SCE agrees that the proposal lacks sufficient detail for implementation in 2026.

4.9.1.2. Discussion

Proposals for load obligation trading in the SOD framework were first raised prior to D.22-06-050. In that decision, the Commission identified several reasons why hourly load obligation trading would add significant complexity to the RA program and declined to adopt the proposal. The Commission stated that "[h]owever, if transactability and inefficiency concerns arise once the new 24-hour framework is implemented, the Commission may consider proposals to include hourly obligation trading.[122] The Commission noted that "[u]nder the 24-hour framework, LSEs are not precluded from transacting or swapping with other LSEs to optimize their positions."[123]

In D.23-04-010, the Commission affirmed its position, stating that it "maintains the rationale outlined in D.22-06-050 and thus, sees no reason to apply a test year assessment that considers the need for inter-LSE hourly transactability. As stated in D.22-06-050, should these concerns arise once the SOD framework is implemented – after the test year – the Commission may consider such proposals."[124] In D.24-06-004, the Commission again declined to

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[122] D.22-06-050 at 97.

[123] *Id*.

[124] D.23-04-010 at 72.

consider CalCCA's load obligation trading proposal and determined that "[o]nce the SOD framework is implemented, and LSEs' RA showings are binding, the Commission can evaluate whether transactability concerns exist."[125]

As we have previously stated, load obligation trading would add both complexity to the new SOD framework and substantial administrative burden on Energy Division Staff to track transactions and verify compliance. The first binding year of the SOD framework is currently underway with the 2025 RA year. The Commission has yet to consider whether transactability concerns exist because we are mere months into the first year of binding RA filings, and Energy Division Staff and LSEs are adjusting to the first year of SOD implementation. Therefore, it is premature to determine that transactability concerns exist under the SOD framework and that there is a need for CalCCA's proposal.

The Commission also agrees with parties that state that the proposal fails to fully address critical issues, such as whether CalCCA's concerns could be addressed through existing trading mechanisms, what types of guardrails should be added to limit the use of hourly trading, and how the RA penalty regime will interact with the proposal. As such, we decline to adopt the proposal at this time.

To evaluate whether transactability issues exist under the SOD framework, Energy Division should conduct an evaluation after a full year of SOD

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[125] D.24-06-004 at 73.

implementation to assess the need, benefits, and feasibility of an hourly load obligation trading mechanism. We caution that one year of compliance data for a new RA program may not be sufficient to effectively evaluate whether an hourly load obligation trading mechanism is needed. That said, Energy Division is authorized to prepare a report on whether transactability issues exist in 1st Quarter (Q1) 2026.

4.9.2. Penalties for Deficiencies Cured by T-1 Deadline

Pursuant to D.24-06-004, for June-September month-ahead filings and on an interim basis, new resources with a commercial operation date (COD) after T-30 and before the start of the RA compliance month (T-1) can count towards that month's RA compliance.[126] SCE states that deficient LSEs can be penalized $5,000 to $20,000 depending on the deficiency and number of occurrences, even if they cure within five days of the T-1 deadline. SCE recommends that if an LSE cures its deficiency with a new resource by T-1, penalties should not be assessed. SCE argues that this is reasonable because it will continue to incentivize LSEs' compliance and is consistent with D.24-06-004's decision to extend the cure timeline to T-1 for new resources.

[126] SCE Proposal at 5 (citing D.24-06-004 at OP 6).

AES and SDG&E support the proposal.[127] AES states that the penalty structure imposes an unnecessary financial burden on LSEs that ultimately fulfill compliance obligations within the extended deadline.

The Commission finds SCE's proposal to be reasonable and that an LSE that cures its deficiency with a new resource coming online before the T-1 deadline should not be assessed penalties. We agree that adopting this proposal will continue to incentivize an LSE to meet its RA requirements to avoid penalties. Accordingly, if an LSE cures its RA deficiency by the T-1 deadline with a new resource that meets the rule established in Ordering Paragraph (OP) 6 in D.24-06-004, penalties will not be assessed on the LSE.

4.9.3. Q3 Import Counting Rule

SCE states that pursuant to D.24-06-004, for 3rd Quarter (Q3) 2025 only, an LSE may count off-peak import energy that is not available during the AAH window towards meeting RA requirements, regardless of whether the import is paired with the on-peak import on a specific branch group, as long as the off-peak energy meets other existing requirements.[128] SCE recommends extending the off-peak import counting process for Q3 2026 and Q3 2027 until a full solution is developed. SCE reasons that given the current state of the RA market, it is important for LSEs to procure and count not only off-peak imports with on-

[127] AES Opening Comments at 6, SDG&E Opening Comments at 20.

[128] SCE Track 3 Proposal at 6.

peak imports, but also to provide excess deliverable energy to ensure sufficiency for storage.

Cal Advocates supports the proposal because LSEs may have challenges complying with SOD requirements in off-peak hours considering the available volumes of dispatchable RA resources.[129] Cal Advocates states that this may help with affordability as off-peak imports are likely to be lower-cost than on-peak imports.

The Commission agrees that it is reasonable to extend the off-peak import counting rule, as the rule may help with affordability issues with off-peak imports that are lower cost than a 24 x 7 product. However, as the rule adopted in D.24-06-004 has not yet been utilized for 2025, the Commission deems it reasonable to only extend the import counting rule to Q3 2026, in addition to Q3 2025. After Q3 2025, the Commission will reevaluate the counting rule and determine whether it is necessary and feasible to extend it beyond 2026. Accordingly, the off-peak import counting rule adopted in OP 12 of D.24-06-004 is modified to apply to 3rd Quarter of 2025 and 3rd Quarter of 2026.

4.9.4. Load Migration Update

Energy Division put forth a proposal on the load migration update process under the SOD framework.[130] In D.23-06-029, an annual load migration update

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[129] Cal Advocates Opening Comments at 15.

[130] Appendix B to ALJ's Ruling on Energy Division's Hour Offset Workshop Slides and Load Migration Update (Appendix B), February 25, 2025, at 1.

process was established that permitted an LSE to submit a revised load migration update in mid-February to cover load migration from May-December. Other than the load migration update, the decision stated that an LSE's load forecast would be locked in for the January-April and the May-December timeframe in each RA year. The Commission further clarified that "the quarterly [Cost Allocation Mechanism (CAM)]/[Reliability Must Run (RMR)] processes will be modified to only provide LSEs refreshed CAM/RMR credits for June-December based on CAM resource information and updated June-December forecasts."[131]

Energy Division states that in D.23-04-010, the Commission adopted the new LSE Showing Tool in which Energy Division sets requirements and allocations in the workbook and distributes those to LSEs for completion and submission for year-ahead and month-ahead RA filings.[132] Under the former RA framework, LSEs directly inputted load migration into the showing template beginning with the May month-ahead filings. Energy Division states that due to the timing for the load migration update established in D.23-06-029, it has become burdensome for Staff to recalculate load forecast requirements and CAM/RMR allocations based on the mid-February load migration submissions and incorporate the revised values into the individual LSE SOD showing templates by mid-March. The process involves cleaning and processing the

[131] D.23-06-023 at 143.

[132] Appendix B at 1.

CAM allocation data, creating new templates for LSEs, and verifying the output values, which can take several weeks to complete. Energy Division asserts that there is insufficient time for Staff to update and redistribute templates to LSEs ahead of the May month-ahead deadline (due mid-March).

For the 2025 RA year only, Energy Division offered a process for LSEs to manually update load requirements within the SOD showing templates. Once the revised load forecast values are updated in the template, LSEs would submit May month-ahead filings and the process would still be subject to verification against finalized revised load requirements.

For future years, Energy Division proposes shifting the timeframe for the updated load forecast from May-December to June-December. Aligning the load migration update with the CAM/RMR allocation update will likely give Staff sufficient time to recalculate and issue updated requirements and allocations to LSEs. This avoids the potential for errors that may occur using the 2025 manual process and gives LSEs more time to incorporate changes into the showings to meet adjusted requirements and complete the updated showing template ahead of the June month-ahead filing deadline. No parties commented on the proposal.

The Commission finds that Energy Division's timing shift for the mid-year load migration update is reasonable, as it addresses the burden on Staff to apply load migration updates within the designated timeframe. The proposal not only simplifies the update and distribution process for revised SOD requirements and allocations but avoids the need for LSEs to manually update load requirements

in filings. The process also gives LSEs more time to incorporate necessary changes to their showings to meet the adjusted requirements.

Accordingly, the requirement in OP 22 of D.23-06-029 is modified as follows: an LSE is permitted one load migration update in mid-February to cover June to December load migration. Other than the one load migration update, an LSE's load forecast is locked in for the January-May timeframe and the June-December timeframe for each RA compliance year.

4.10. Local CPE Framework Modifications

4.10.1. CPE Timeline and Requirements

SCE recommends reconsidering the timeline adopted in D.24-12-003 that locked in the Year 2 requirement and proposes to revert back to the previous requirement that CPEs procure 100% of the prompt year and Year 1, and 50% of Year 2 requirements.[133] SCE also proposes eliminating all self-showing options, non-compensated and compensated. SCE posits that requiring CPEs to lock in procurement two years before the compliance year increases the risk of over- or under-procurement, which can be costly and perpetuate uncertainty for LSEs and CPEs. SCE asserts that the requirement undermines the benefits of eliminating the self-show attestation, by forcing the CPEs to estimate need and make procurement decisions based on availability three years forward.

[133] SCE Track 3 Proposal at 3.

SCE also recommends defining the CPE's requirement based on the result of the LCR Technical Study less the local capacity determined from the data Energy Division collects for each of the CPE's local areas (Net Requirement) and provide LSEs with the CPE's Net Requirement on a monthly aggregated level. SCE states that D.24-12-003 eliminated the self-showing option in favor of a data request procedure but did not explicitly state that the CPEs should use the data to determine procurement targets.

Calpine and Cal Advocates support more clarity around the CPE's procurement objective, and Calpine agrees the CPE's requirements should reflect local requirements net of the local capacity LSEs have contracted.[134] MRP supports removing the lock-in requirement, stating that the rule undermines the CPE's purpose to meet local capacity requirements and turns the CPE framework into a front stop mechanism where a deficient CPE passes procurement to CAISO's backstop procurement.[135]

Parties that oppose SCE's proposal, or aspects of it, include CalCCA, MRP, Microsoft, Shell Energy, and PG&E.[136] Microsoft, Shell Energy, and CalCCA generally contend that it is premature to reverse the adopted timing that will be assessed at the end of the 2027, and Shell Energy states that SCE provides no new

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[134] Calpine Opening Comments at 7, Cal Advocates Opening Comments at 13.

[135] MRP Opening Comments at 18.

[136] CalCCA Opening Comments at 18, Microsoft Opening Comments at 13, MRP Opening Comments at 19, PG&E Opening Comments at 15, Shell Energy Opening Comments at 5.

facts or analysis to justify a change. CalCCA argues that that over- and under-procurement risks result from the failure to resolve timing issues and that if CPE allocations are provided well in advance, LSEs have time to adjust procurement.

MRP, CalCCA, and PG&E state that reducing the CPE's requirement in response to a non-binding data request would fundamentally change the original CPE design that allows any LSE to sell local RA to the CPE with equal opportunity of being procured and that there is no guarantee resources remain under contract. MRP opposes eliminating the compensated self-show option, as this is the only option to recover premiums for new clean resources in local areas. CalCCA recommends instead asking LSEs in the data request which contracted local RA capacity LSEs do not plan to offer to the CPE.

4.10.1.1. Discussion

The Commission declines to reverse the timing procedure adopted in D.24-12-003, including elimination of the compensated self-showing option. The issues raised by SCE were considered in Track 2 in D.24-12-003, approximately six months ago, and no new evidence has been provided to justify reversing the decision. As provided in D.24-12-003, the rule will be effective in 2025 for the 2027 RA year and will be reevaluated by the end of 2027.[137] The Commission agrees that under a proposed Net Requirement, there is no guarantee that local resources remain under contract and netting the local requirements will restrict LSEs' ability to bid local resources into the CPE solicitation.

Parties seek clarification as to how the data collected by Energy Division should be used by the CPE. The Commission affirms what it stated in D.24-12-003:

> To clarify, the Commission is not directing the CPEs to reduce the CPE requirement based on the aggregated data provided by Energy Division as to what local resources have been contracted by LSEs. Reducing the CPE's requirement in this manner would result in LSEs being unable to compete in the annual solicitation process, as those resources would have reduced the CPE's local requirement.[138]

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[137] D.24-12-003 at OP 5.

[138] *Id*. at 67.

As further stated in D.24-12-003, we affirm that "the aggregated information will be provided to the CPEs to better assess the state of the overall local portfolio before initiating the CPEs' annual solicitations and the CPEs would use this information to better assess the actual needs for short-term and long-term procurement for the three-year forward requirements and beyond."[139]

4.10.2. CPE Data Collection Proposals

SCE, PG&E, and CalCCA submit proposals on how to incorporate the local CPE data request process. PG&E states that the existing IRP Request Data Template (RDT) contains all of the required data requested in D.24-12-003, except for the monthly contracted NQC value.[140] PG&E suggests modifying the IRP RDT to add a new tab requiring LSEs to provide the monthly contracted NQC for local resources and the resource technology type for the applicable years of the local RA compliance period. PG&E recommends Energy Division send the information to the CPEs within 45 days of submittal by LSEs so CPEs can make informed procurement decisions during the solicitation process.

Alternatively, PG&E recommends incorporating a modified template into the annual RA filing process that mirrors the current Multiyear Capacity Documentation Summary to collect information from LSEs and limit duplicative efforts by stakeholders and Energy Division. CalCCA similarly proposes

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[139] *Id*.

[140] PG&E Track 3 Proposal at 2.

incorporating the local RA CPE data request process into the existing RA compliance filing, rather than into the IRP data process.[141] CalCCA asserts that it does not see how consolidating the local CPE reporting requirements into the IRP process minimizes duplication and administrative burden more than consolidating it into the RA process.

SCE proposes a standard template that uses the same definitions for both CPE and IRP data, and that the CPE data process maintain the current timing of issuing the data request in mid-January with responses due January 31 so that the CPE has the data before it launches the CPE RFO.[142]

AReM supports CalCCA's proposal and agrees that including the reporting in RA showings is more predictable and administratively efficient.[143] CalCCA supports PG&E's alternative proposal and states that the data collection timing is predictable and consistent with the year-ahead filing deadline.[144] CalCCA adds that contracted local RA capacity is already part of the same LSE data reporting so this is administratively efficient for reporting entities. To increase transparency between the IRP and RA proceedings, CEJA suggests LSEs complete data reporting for the CPEs and IRP at the same time, and certain

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[141] CalCCA Track 3 Proposal at 25.

[142] SCE Track 3 Proposal at 5.

[143] AReM Reply Comments at 6.

[144] CalCCA Opening Comments at 21.

information be aggregated for public disclosure (such as amount of contracted resources in each local area for RA and IRP, planned transmission projects that impact local needs, and projected LCR needs and CAISO analysis of the LCR area).[145]

The Commission finds CalCCA's proposal and PG&E's alternative proposal – to incorporate the CPE data collection process into the year-ahead RA filing – to be a reasonable approach. The approach is efficient, more familiar to LSEs, and streamlines the data collection timeline with one filing deadline on October 31. Accordingly, the CPE data reporting requirements will be incorporated into the annual RA compliance filing process. Energy Division is authorized to use the data request template sent out in January 2025 to be incorporated in the annual RA compliance filings due October 31.

4.11. Residual Unit Commitment Bids

SCE states that consistent with D.05-10-042, the current CAISO tariff provides that RA resources must bid into the CAISO's residual unit commitment (RUC) process with a zero dollar bid and are not eligible for RUC revenue.[146] SCE notes that the CAISO is making changes to accommodate expansion of the day-ahead market to non-CAISO entities with the Day-Ahead Market Enhancements (DAME) and Extended Day-Ahead Market (EDAM) initiatives in

[145] CEJA Opening Comments at 12.

[146] SCE Track 3 Proposal at 7.

2026.[147] The changes include replacing RUC with new products that serve the same purpose but are bidirectional (called Reliability Capacity Up (RCU) and Reliability Capacity Down (RCD) products). Another new product the CAISO has created is called Imbalance Reserves. SCE states that when EDAM begins operation, the CAISO will remove the requirements for RA resources to submit zero dollar RUC bids and remove language that RA resources are ineligible to receive revenue from the RUC market.

SCE asserts that with the move to the EDAM and changes to the CAISO rules, CPUC-jurisdictional LSE RA resources may provide these products for free to other balancing authorities, by bidding zero prices for RUC (or RCU and RCD) or Imbalance Reserves to the EDAM market. SCE states that this is because jurisdictional LSEs must contract for RA resources that accept the zero bid requirement and will not receive RUC revenues; thus, the potential lost revenues are likely factored into future RA prices for CPUC LSEs. SCE proposes reconsidering the RA rules from D.05-10-042 to ensure the rules are fair and consistent with upcoming changes to the CAISO market.

[147] *Id*. At 8 (citing CAISO Day-Ahead Market Enhancements and Extended Day-Ahead Market Tariff Amendment, FERC Docket ER23-2686-000, August 22, 2023).

Numerous parties support this proposal, including CAISO, CalCCA, CEBA, Cal Advocates, SDG&E, and Shell Energy.[148] The CAISO agrees the Commission should align its rules on RA bids into the CAISO's RUC market and RUC compensation with the new DAME and EDAM policies. Cal Advocates states that adopting the proposal before the EDAM launches would not materially impact RA RUC requirements since the CAISO tariff would continue to enforce current RUC rules. Cal Advocates adds that the proposal would facilitate the appropriate contract changes to existing and future RA contracts, and that because existing contracts are valued in part to provide zero dollar RUC bids and receive no RUC revenue, a modified rule would give additional revenue for resources where existing language may not allow.

CalCCA states that D.05-10-042 was intended to prevent multiple payments for the same capacity (through RA contracts and again through RUC revenues). CalCCA notes that the CAISO developed the DAME Transitional Measures to allow LSEs/resource pairs to mutually elect for the CAISO to automatically transfer RUC payments to LSEs using functionality similar to that used for inter-scheduling coordinator trades.

4.11.1. Discussion

In D.05-10-042, the Commission stated:

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[148] CAISO Opening Comments at 2, CalCCA Opening Comments at 23, CEBA Opening Comments at 7, Cal Advocates Opening Comments at 11, SDG&E Opening Comments at 20, Shell Energy Reply Comments at 6.

> We hereby reiterate that an RA resource must submit a zero dollar ($0) bid for RA capacity bid into RUC and that an RA resource will not be eligible for any RUC availability payment or revenue. As we said in Resolution E-3955: "It is not the intention of this Commission to simply provide needless revenue streams, or the ability to double-recover costs, to generators. It is the Commission's position that an RA resource that receives an RA payment should not also receive a RUC availability payment through the CAISO." Accordingly, LSE contracts with RA resources should reflect these policy determinations.[149]

D.05-10-042 was intended to align with the CAISO tariff, by providing that RA resources must bid into the RUC process with a zero dollar bid and must not be eligible for RUC revenue. When the EDAM begins operation, the Commission concurs that the CAISO tariff and D.05-10-042 will no longer be consistent regarding RUC bidding restrictions and payments for RA resources.

However, eliminating the prohibition from D.05-10-042 that "an RA resource will not be eligible for any RUC availability payment or revenue" raises a concern about excess payment for capacity from both the RA contract and from the CAISO charges ultimately passed onto load for the RCU/RCD and Imbalance Reserve products. As stated in D.05-10-042, the Commission's intent is to avoid "simply provid[ing] needless revenue streams, or the ability to double-recover costs, to generators."

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[149] D.05-10-042 at 16.

The Commission is concerned that RA contracts that do not provide that the RUC (or successor) revenues will be credited back to the LSE will result in a potential double payment for capacity benefits already included in the RA contract price. It is unclear, however, whether the Imbalance Reserve product is similar to the RUC process to obtain additional capacity for uncertainty between day-ahead and real-time markets. SCE's proposal only recommends removal of the zero dollar bid requirement for RCU/RCD and Imbalance Reserve products, but does not address eligibility or allocation of revenues of those products to the buyer or seller. As such, there is insufficient record to consider SCE's proposal at this time.

Because the zero dollar bid requirement was adopted in conjunction with the prohibition on RA resources receiving RUC revenue in D.05-10-042, the Commission defers consideration of the zero dollar bid requirement for RCU/RCD and Imbalance Reserve products, and the appropriate allocation method for revenues collected, and whether those revenues should be credited back to the LSE that has procured the RA capacity value of the resource.[150] The Commission will consider these issues in the successor RA proceeding.

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[150] *See* General Order 96-B, Industry Rule 7.

4.12. RA Brokerage Firms

Cal Advocates asserts that brokers play a prominent role in the bilateral RA market to contract for RA capacity, as brokers can influence LSEs' RA position optimization and RA pricing.[151] Cal Advocates points out, however, that the broker market has limitations in evaluating cost-effectiveness. Cal Advocates states that brokers' fees are structured in a variety of ways, including (1) as a percentage of the notional transaction cost, (2) as a rate adder for a certain amount of dollars per kilowatt-month, and/or (3) as a flat fee for each transaction. Cal Advocates argues that a flat fee incentivizes brokers to increase the number of transactions regardless of price and volume, while under a percentage-based approach, brokers make more money when RA prices are higher. Cal Advocates contends that a rate adder offers a superior incentive structure for ratepayers and LSEs, as the broker is compensated based on the amount of capacity moved, indifferent to pricing.

Cal Advocates proposes ordering IOUs to negotiate rate-adder fees with brokers, between $0.01/kW-month to $0.02/kW-month as a recommended rate-adder. IOUs would submit a Tier 2 Advice Letter within three months of this decision to update Bundled Procurement Plans (BPP) to reflect the flat rate broker fees, and would inform Procurement Review Groups of the broker fee renegotiations. Cal Advocates also proposes negating any broker agreement

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[151] Cal Advocates Track 3 Proposal at 3.

with IOUs that allows the brokerage firm to be a counterparty to a product for which the firm provides brokerage services. Cal Advocates reasons that the dual roles create conflicting incentives, where the broker may have financial incentives to reserve favorable offers for clients they represent. Further, Cal Advocates proposes that IOUs immediately stop transactions with brokers with dual roles and amend brokerage agreements to eliminate these risks.

SDG&E opposes the proposal and states that it does not address the apparent problem.[152] SDG&E notes that information on broker transactions are included in IOUs' quarterly compliance reports (QCRs), which ensures IOUs do not enter transactions above or below market based on perverse incentives. SDG&E states that it uses multiple brokers, decreasing the likelihood that one broker with perverse incentives can enter a transaction harmful to ratepayers. The proposal may reduce liquidity and increase RA compliance costs if brokers are unwilling to agree to a rate-adder fee and stop transacting with IOUs, as IOUs are just three of 38 LSEs and non-IOU LSEs would not be subject to these requirements. SDG&E states that a more reasonable approach is to require additional information on QCRs, such as a broker fee reporting requirement.

The Commission finds that Cal Advocates' proposal has merit in concept. However, there is insufficient record support as only one party commented on the proposal and two of the three IOUs provided no comment. Further, BPP

[152] SDG&E Opening Comments at 9.

rules are not generally addressed in the RA proceeding, as the venue for BPP rule modifications is the IRP proceeding and the Advice Letter process. As such, we decline to adopt the proposal. To the extent any IOU agrees with the proposal, it may file a Tier 2 Advice Letter to update their BPP.

5. Comments on Proposed Decision

The proposed decision of ALJ Chiv in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on June 11, 2025 by: ACP-CA; AES; AReM; Cal Advocates; CAISO; CalCCA; CEBA; CEJA; CESA; Council and CPower Energy Management (CPower) (jointly Council/CPower); Form Energy; Hydrostor; IEP; OhmConnect/Leap; Microsoft; MRP; PCF; PG&E; SCE; SDG&E; Shell Energy; Terra-Gen; WPTF, and 3CE. Reply comments were filed on June 16, 2025 by: CAISO, CalCCA, CEERT, CEJA, Council/CPower, OhmConnect/Leap, PG&E, SCE, SDG&E, and Shell Energy.

All comments have been carefully considered. Portions of the proposed decision that have been revised in light of comments are mentioned in this section. However, additional changes have been made to the proposed decision in response to comments that may not be discussed here. We do not summarize every comment but focus on major arguments made in which the Commission did or did not make revisions in response to party input. We remind parties that under Rule 14.3(c), comments on a proposed decision must focus on factual,

legal, or technical errors in the proposed decision; comments that fail to meet the requirements will be accorded no weight.

At least one party exceeded the page limit for submission of comments, under Rule 14.3 of the Commission's Rules of Practice and Procedure. In the future, the Commission will direct parties to disregard comments on pages that exceed the Rule 14.3 limit.

The CAISO states that the proposed decision includes values for the 2026 final flexible capacity requirement that differ from the results of the CAISO's final report.[153] The Commission acknowledges that the FCR values in the proposed decision were incorrect and the decision has been modified to include the CAISO's corrected FCR values.

Several parties comment that the modification to the AAHs in the proposed decision was incorrect and should be corrected to reflect changes made in CAISO's Final FCR Report.[154] Parties state that the conversion is incorrect where HE 17 is hour ending at 17:00, which begins at 16:00 or 4:00 pm. The Commission acknowledges that the AAH modification in the proposed decision was incorrectly converted, and the decision has been modified to correct this.

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[153] CAISO Comments on Proposed Decision at 12.

[154] PG&E Comments on Proposed Decision at 6, SCE Comments on Proposed Decision at 4, CAISO Comments on Proposed Decision at 12, OhmConnect/Leap Comments on Proposed Decision at 3.

ACP-CA seeks clarification that revising the AAHs will not impact locking in of exceedance values from 2025-2027 and will take effect at the subsequent profile re-evaluation.[155] We clarify that the AAH modification will not impact the 2025-2027 QC exceedance values for solar and wind.

Several parties oppose the 18% PRM, including AES, CEBA, CESA, Microsoft, MRP, PCF, SDG&E, Terra-Gen, and WPTF, and state that it does not satisfy Section 380(h)(4) and/or is not adequately supported by the record.[156] As to what PRM should be adopted, CEBA, CESA, and Terra-Gen state that a PRM that meets a 0.1 LOLE must be adopted. AES reiterates support for Energy Division's 22.5% PRM for June-September and 21% for other months. MRP and WPTF reiterate support for WPTF's PRM proposal, stating that it is closer to achieving a 0.1 LOLE than the 18% PRM. PCF recommends the status quo 17% PRM alone and SDG&E recommends the 17% PRM with the effective PRM.

Microsoft, CAISO, and CEBA state that a PRM for 2027 should not be adopted. The CAISO states that supply/demand conditions and RA prices should be monitored for 2025 and 2026, and in 2026, it should be determined whether the PRM should be increased.

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[155] ACP-CA Comments on Proposed Decision at 10.

[156] AES Comments on Proposed Decision at 5, CEBA Comments on Proposed Decision at 3, CESA Comments on Proposed Decision at 10, Microsoft Comments on Proposed Decision at 3, MRP Comments on Proposed Decision at 6, PCF Comments on Proposed Decision at 10, SDG&E Comments on Proposed Decision at 2, Terra-Gen Comments on Proposed Decision at 4, WPTF Comments on Proposed Decision at 3.

3CE, CEJA, PG&E, SCE, and Shell Energy support the 18% PRM with the effective PRM and support a PRM for both 2026 and 2027.[157] Parties generally state that the 18% PRM framework appropriately balances reliability and affordability concerns. 3CE supports the minimal increase above the current 17% PRM in that it moves cautiously and gives LSEs more certainty. Shell Energy supports the PRM as reasonable given the uncertainty with Energy Division's LOLE modeling. CEJA states that the lower PRM does not violate AB 2368, as the Commission has broad discretion to define the LOLE standard and there is no consistent way to apply the standard. CEJA disagrees that there is a reliability issue with a lower PRM/effective PRM given that the framework has been in place since 2024 and has not resulted in any reliability issue. SCE urges rejection of arguments from financially-interested parties that favor a higher PRM on the grounds that the Commission cannot consider affordability under Section 380.

SCE states that setting an inflated PRM would be arbitrary and result in unjust, unreasonable rates. SCE disagrees with reevaluating the PRM in 2027, noting that Energy Division cannot complete a new LOLE study before the 2027 RA year and that continued market speculation and uncertainty may result in

[157] 3CE Comments on Proposed Decision at 2, CEJA Reply Comments on Proposed Decision at 2, PG&E Comments on Proposed Decision at 1, SCE Comments on Proposed Decision at 3, SCE Reply Comments on Proposed Decision at 2, Shell Energy Comments on Proposed Decision at 2.

LSEs being unable to procure to meet obligations, in reduced incentives to contract past a few months, and in higher costs and prices. The CAISO states that while an 18% PRM in 2026 is an incremental improvement over the status quo, it is below the 0.1 LOLE level in Energy Division's LOLE studies.[158]

CalCCA and 3CE support the 18% PRM but recommend reducing the effective PRM to 3%, from 3 to 5.5%, since Energy Division's Revised Proposal B recommended a PRM up to 21%. 3CE states that the effective PRM target should be based on the most updated LOLE study, not based on historical figures.

While several parties oppose an 18% PRM with the effective PRM, the Commission observes that there is still no consensus among these parties as to what the appropriate PRM should be. Some insist that the PRM must meet a 0.1 LOLE standard without identifying what that PRM should be. Some reiterate support for Energy Division's Proposal B, while others urge that the status quo 17% PRM be adopted. MRP and WPTF reiterate that WPTF's proposed 22.5% PRM for May-October should be adopted, despite acknowledging that it does not meet a 0.1 LOLE metric.

In addition to a lack of consensus on the PRM, the Commission underscores stakeholders' uncertainty and lack of confidence in Energy Division's LOLE study results and revisions. The Commission maintains that the 18% PRM with the effective PRM - a PRM slightly higher than Revised Proposal

[158] CAISO Comments on Proposed Decision at 3.

A - is the most efficient and equitable means for achieving the multiple objectives mandated by Section 380, which include ensuring that the RA program can reasonably maintain a standard measure of reliability for planning purposes, and minimizing costs to ratepayers. We agree with CEJA that AB 2368 also adds an objective to the RA program: "Consideration of mitigation measures, if the commission determines they are needed, to reduce costs to ratepayers."[159] We disagree that the effective PRM framework presents reliability concerns, and agree with CEJA that parties have provided no instance where the effective PRM (that has been in place since 2024) resulted in reliability issues.

With respect to CalCCA and 3CE's concerns about the effective PRM, the Commission maintains that extending the effective PRM framework adopted in D.23-06-029 (translated to an effective PRM of 3 to 5.5%) is appropriate here, particularly given parties' concerns about Energy Division's LOLE study results.

With respect to the 2027 RA year, the Commission reiterates that it is not possible for Energy Division to complete a new LOLE study prior to the 2027 RA year. This is consistent with our determination in D.24-12-003 that "it is not feasible to run an updated LOLE study each year. It is more realistic and reasonable for Energy Division Staff to update an RA LOLE study at least every two years."[160] In response to the CAISO, the Commission consistently monitors

[159] Pub. Util. Code Section 380(b)(5).

[160] D.24-12-003 at 17.

RA market supply/demand conditions and RA prices. As stated in the decision, the Commission will continue to monitor market conditions and impacts of the adopted PRM framework and reevaluate the PRM requirements for the 2028 RA year in 2026. The Commission declines to modify the PRM framework adopted in this decision. A more detailed LOLE study schedule may be included in a scoping memo in the successor RA proceeding.

AReM states that there is a calculation error in the 900 MW of resource need in September 2026, compared to September 2025, and that to capture year-over-year change, an additional 80 MW should be added.[161] The Commission reviewed the calculation for the ~900 MW increase of resource need and we clarify that the July 2025 annual peak forecast (46,284 MW) should be used for the calculation, instead of the September 2025 peak (46,204 MW). The decision has been modified to reflect the updated values, and the resulting resource need (~900 MW) remains unchanged.

PG&E recommends no longer requiring LSEs to file non-binding month-ahead RA filings for the effective PRM, which was adopted in D.23-06-029.[162] PG&E states that the original intent of the requirement was to give insight into RA contracted resources until state agencies were able to develop a better understanding of supply conditions but since then, state agencies have made

[161] AReM Comments on Proposed Decision at 2.

[162] PG&E Comments on Proposed Decision at 4.

significant progress in understanding supply conditions. SDG&E agrees with PG&E, stating that it burdens LSEs to put these reports together despite no longer serving a useful purpose.[163]

The Commission agrees that the non-binding month-ahead filings required in D.23-06-029 are no longer necessary and finds it reasonable to remove this requirement. We note that if such information is needed in the future, Energy Division is encouraged to request such information via a data request. As such, the decision has been modified to remove the non-binding RA filing requirement adopted in D.23-06-029.

Regarding Energy Division's publication of UCAP values, PG&E recommends releasing preliminary UCAP values for the 2027 RA year concurrently with the publication of the LOLE study inputs and assumptions to give LSEs visibility into resource values for 2027 prior to 2028 implementation.[164] The Commission clarifies that Energy Division is authorized to publish resource-specific and class average UCAP values with the forthcoming UCAP proposal for consideration in 2026. The decision has been modified to reflect this.

Some parties express concern with the revenue allocation approach for RCU, RCD, and Imbalance Reserve products, such as CalCCA, CAISO, and

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[163] SDG&E Reply Comments on Proposed Decision at 2.

[164] PG&E Comments on Proposed Decision at 2.

SDG&E.[165] Parties state that requiring these revenues to go back to the LSE would impact how scheduling coordinators bid into the day-ahead market, create disincentives for bidding costs accurately, and create market distortions.

Multiple parties express concern with the accreditation method for Imbalance Reserve products and with Imbalance Reserves being treated the same as RCU/RCD products, including AES, CESA, CEBA, IEP, SCE, Terra-Gen, and WPTF.[166] Parties generally state that it is incorrect to equate the Imbalance Reserve product to RUC/RCD capacity, as the Imbalance Reserve product is not a capacity product and more akin to an ancillary service or energy product, and Imbalance Reserves will not bid into the RUC process and instead be co-optimized in the day-ahead market along with ancillary and energy bids.

Several parties comment that revenue allocation should be left to counterparties to negotiate on their own terms. SCE supports RUC products' revenue being credited back to an LSE but only when the LSE is purchasing RA directly from the generator (as it is complex to track RCU/RCD resale revenue and important to have consistent pricing in the RA market).[167] The CAISO

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[165] CAISO Comments on Proposed Decision at 8, CalCCA Comments on Proposed Decision at 4, SDG&E Reply Comments on Proposed Decision at 4.

[166] AES Comments on Proposed Decision at 7, CESA Comments on Proposed Decision at 18, IEP Comments on Proposed Decision at 3, SCE Comments on Proposed Decision at 5, Terra-Gen Comments on Proposed Decision at 6, WPTF Comments on Proposed Decision at 12.

[167] SCE Comments on Proposed Decision at 5.

recommends recognizing that the DAME policy includes Transitional Measures that provide a temporary, optional payment allocation tool to scheduling coordinators and LSEs to allow time to renegotiate existing RA contracts.

Considering parties' comments, the Commission finds that SCE's proposal requires further development, as it did not address the eligibility and allocation of revenues for the RCU, RCD, and Imbalance Reserve products. The Commission finds that more record on the bidding impacts and revenue allocation process for RCU, RCD, and Imbalance Reserve products would be beneficial before adopting a requirement. As stated in the decision, we remain concerned that RA contracts that do not provide that the RUC (or successor) revenues will be credited back to the LSE will result in a potential double payment for capacity benefits already included in the RA contract price. We also affirm what we stated in D.05-10-042, that it is the Commission's intent to avoid "simply provid[ing] needless revenue streams, or the ability to double-recover costs, to generators."

The record should be further developed on these issues in the successor RA proceeding. Because the zero dollar bid requirement was adopted in conjunction with the prohibition on RA resources receiving RUC revenue in D.05-10-042, we also defer removal of zero dollar bid requirement at this time. As such, the decision removes the language that allows non-zero dollar bids, the language that "an RA resource may be eligible for any available RUC payment or revenue, including RCU, and RCD, and Imbalance Reserve product revenues,"

and the adoption of the revenue allocation process for RCU, RCD, and Imbalance Reserve products. The decision has been modified to reflect this.

ACP-CA recommends a working group to address multiple issues, including probabilistic solar and wind counting analysis, QC methodology for showings to CAISO, EO resources for charging sufficiency, UCAP, and LDES.[168] While the Commission does not agree that a working group is necessary for all of these issues, it is reasonable to authorize a workshop on solar and wind accreditation and the QC methodology for CAISO showings. As such, Energy Division is authorized to hold a workshop in Fall 2025 on these issues, and may schedule the workshop alongside the LDES workshop.

CESA comments that the decision mischaracterizes its proposal as a modification to the 4-hour duration requirement, and states that its proposal is only focused on conveying the factual operational/reliability capabilities on the SOD showing tool.[169] CESA states that its proposal would allow LSEs to show the resource on the SOD showing tool within its operational capabilities and deliverability allocation.

Based on CESA' comments, the Commission agrees that CESA's proposal was mischaracterized in the proposed decision. However, based on our revised understanding of CESA's proposal, we note that the SOD showing tool already

[168] ACP-CA Comments on Proposed Decision at 3.

[169] CESA Comments on Proposed Decision at 16.

accounts for storage resources in the manner that CESA proposes. D.23-04-010 provides that: "Energy storage resources will be assigned value based on Pmax, restricted to daily resource capabilities (e.g., maximum daily run hours, maximum continuous energy, and storage efficiency)."[170] For example, a battery storage resource that has a Pmax of 100 MW and produces 200 MWh per cycle would be allowed to show for 100 MW for two hours instead of 50 MW for four hours in the SOD tool. As such, CESA's proposal is not necessary, and the decision has been modified to reflect this.

Some parties reiterate support for hourly load obligation trading, including CalCCA, AReM, and 3CE.[171] CalCCA disagrees that there are critical issues that still need to be addressed and states, among other things, that it recommended a 25% limit in comments as a potential guardrail and that the complexity and administrative burden on Commission Staff have been overstated. CalCCA states that the Commission should commit to implementing hourly trading for 2027. AReM recommends Energy Division analyze RA filings in August and issue a report in Q4 2025 (with a supplemental report in Q3 2026) to inform proposals for hourly trading in summer 2027.

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[170] D.23-04-010 at Appendix A-5.

[171] AReM Comments on Proposed Decision at 8, CalCCA Comments on Proposed Decision at 2, 3CE Comments on Proposed Decision at 4.

The Commission disagrees with CalCCA that all of the critical issues have been addressed. While CalCCA posits that the complexity and administrative burden on Energy Division is overstated, we clarify that CalCCA's proposal would introduce additional verification steps for Energy Division Staff in the month-ahead review process, and Energy Division would be required to conduct these additional review steps of comparing and verifying trades (and issuing correction/deficiency notices) across LSE filings under very constrained timelines. With respect to the lack of guardrails, while CalCCA may have updated its proposal in comments to include a 25% cap on trades, other parties proposed differing limits on the amount of trading across hours and duration that necessitate further consideration by the Commission.

As stated in the decision, the Commission has yet to consider whether transactability concerns exist as we are mere months into the first year of binding RA filings, and thus, it is premature to determine that transactability concerns exist under the SOD framework and that there is a need for CalCCA's proposal. That said, we agree that Energy Division should provide a report on transactability issues in Q1 2026, rather than Q2 2026, so that parties can consider such a report to inform future proposals. The decision is modified to reflect this.

OhmConnect/Leap state that the decision does not identify a venue to address the questions posed about the DR process.[172] OhmConnect/Leap

[172] OhmConnect/Leap Comments on Proposed Decision at 3.

recommend the LIP process as a potential venue. The Commission clarifies that the DR questions may be addressed in the successor RA proceeding or a new DR rulemaking.

With respect to formalizing the co-located resource counting rules, AES recommends that Energy Division update the QC Manual to provide guidance on available capacity for co-located assets.[173] The Commission clarifies that Energy Division is authorized to update the RA Guide to include the formalized co-located resource counting rules.

6. Assignment of Proceeding

Alice Reynolds is the assigned Commissioner and Debbie Chiv is the assigned ALJ in this proceeding.

Findings of Fact

1. The CAISO recommended that the existing capacity needed for all local areas is 23,016 MWs for 2026, 23,891 MWs for 2027, and 24,496 MWs for 2028.

2. The CAISO recommended system-wide Flexible Capacity Requirements that range from 23,386 MWs in December to 27,559 MWs in June.

3. A modification of the RA measurement hours to 5:00-10:00 pm, or HE 18-HE 22, for winter months (November to February) would align with the CAISO's revised AAHs.

[173] AES Comments on Proposed Decision at 6.

4. Increasing the PRM to 18% and extending the effective PRM target for the 2026 and 2027 RA years would achieve several benefits: (1) it would increase the PRM above its current level, as has been demonstrated as needed by Energy Division's LOLE studies; (2) it would move in the direction of transferring additional procurement responsibilities to LSEs; and (3) it would provide more time to review the need for additional increases to the PRM once the SOD framework is better established and modeling capabilities and input processes have further matured.

5. We affirm our rationale from D.23-06-029 that extending the effective PRM would allow for the procurement of resources that provide reliability benefits, without unnecessarily inflating prices and costs to ratepayers and without reducing the pool of available RA resources.

6. A 18% PRM and an extension of the effective PRM target for June-October for the 2026 and 2027 RA years is a reasonable and prudent approach that helps ensure grid reliability by increasing the PRM as indicated by the LOLE studies, while minimizing costs to ratepayers.

7. Further development of Energy Division's UCAP framework proposal is needed.

8. Further consideration and discussion on an accreditation methodology for LDES resources is needed.

9. For the sake of consistency and certainty, it is reasonable to formalize the counting rules for PCDS and FCDS co-located resources under the SOD framework.

10. It is premature to determine that transactability concerns exist under the SOD framework and that there is a need for an hourly load obligation trading proposal. CalCCA's proposal fails to fully address critical issues, such as whether concerns could be addressed through existing trading mechanisms, what types of guardrails should be added to limit the use of hourly trading, and how the RA penalty regime will interact with the mechanism.

11. Adopting SCE's proposal to not assess penalties on an LSE that cures its deficiency with a new resource coming online before the T-1 deadline is reasonable and would continue to incentivize an LSE to meet its RA requirements to avoid penalties.

12. Extending the off-peak import counting rule to Q3 2025 and Q3 2026 may help with affordability issues as off-peak imports are lower cost than a 24 x 7 product.

13. Energy Division's proposal to shift the mid-year load migration update simplifies the update and distribution process for revised SOD requirements and allocations and addresses the burden on Staff to apply load migration updates within the designated timeframe.

14. Incorporating the CPE data collection process into the RA year-ahead filing process is efficient, more familiar to LSEs, and streamlines the data collection timeline with one filing deadline on October 31.

Conclusions of Law

1. The CAISO's recommended LCR study results for 2025-2027 are reasonable and should be adopted.

2. The CAISO's recommended systemwide FCR figures for 2026 are reasonable and should be adopted.

3. A modification to the RA measurement hours to 5:00-10:00 pm for winter months (November to February) is reasonable and should be adopted.

4. A 18% PRM with an extension of the effective PRM target for June-October should be adopted for the 2026 and 2027 RA years.

5. The Commission should authorize further development of Energy Division's UCAP framework proposal.

6. The Commission should authorize further discussion of an accreditation methodology for LDES resources.

7. The counting rules for PCDS and FCDS co-located resources under the SOD framework should be formalized.

8. The Commission should authorize Energy Division to prepare a report in Q1 2026 on whether transactability issues exist.

9. SCE's proposal that an LSE should not be assessed a penalty if it cures its deficiency with a new resource coming online before the T-1 deadline should be adopted.

10. The off-peak import counting rule should be extended to Q3 2026.

11. It is reasonable to shift the timing of the mid-year load migration update.

12. The proposals to incorporate the CPE data collection process into the year-ahead RA filing process are reasonable.

13. Motions made in this proceeding that are not expressly ruled upon are deemed denied.

14. The proceeding should be closed.

O R D E R

IT IS ORDERED that:

1. The Commission approves 23,016 megawatts as the existing capacity needed for the Local Capacity Requirement for 2026.

2. The Commission approves 23,891 megawatts as the existing capacity needed for the Local Capacity Requirement for 2027.

3. The Commission approves 24,496 megawatts as the existing capacity needed for the Local Capacity Requirement for 2028.

4. The California Independent System Operator's recommended Flexible Capacity Requirements for 2026 are adopted.

5. Beginning in the 2026 Resource Adequacy (RA) compliance year, the RA measurement hours for the winter months of November to February will be 5:00-10:00 pm, or Hour Ending (HE) 18-HE 22. The adopted changes are reflected in the table below:

Resource Adequacy Measurement Hours		
Months	**Hours**	**Hour Ending**
November – February	5:00 pm – 10:00 pm	18 – 22
March – May	5:00 pm – 10:00 pm	18 – 22
June – October	4:00 pm – 9:00 pm	17 – 21

6. For the 2026 and 2027 Resource Adequacy (RA) compliance years, a 18% planning reserve margin (PRM), and an extension of the effective PRM procurement target of 1,260-2,300 megawatts (MW) for June-October, is adopted. The procurement target will be divided between the three investor-owned utilities as follows: 120-220 MW San Diego Gas & Electric Company, and 570-1,040 MW each for Pacific Gas and Electric Company and Southern California Edison Company. The requirements adopted in Decision 23-06-029 pertaining to the effective planning reserve margin are applicable to the effective PRM adopted in this decision, with the exception that load-serving entities are no longer required to submit non-binding month-ahead RA filings.

7. The Commission authorizes Energy Division, in coordination with the California Independent System Operator (CAISO), to further develop a final Unforced Capacity (UCAP) framework that addresses the following areas: (1) establish a definition(s) for the types of "forced outage" that will be applicable to the UCAP calculation; (2) refine the ambient temperature derate methodology to address any Staff-identified issues; (3) develop UCAP for hybrid resources containing battery storage; (4) address how the incentives for UCAP should be transferred to the resource owner via the Resource Adequacy contract and identify whether any modifications are needed to the CAISO tariff; and (5) calculate the estimated impact of UCAP on resource counting and to the planning reserve margin for procurement.

8. Energy Division is authorized to publish preliminary resource-specific and class average Unforced Capacity (UCAP) values, as well as estimated impacts to

the planning reserve margin without a forced outage rate in advance of adopting a final UCAP framework. Energy Division is authorized to hold a workshop with stakeholders on its refined UCAP proposal before the end of 2025.

9. The Commission authorizes Energy Division to hold a workshop in the Fall of 2025 on long-duration energy storage (LDES) issues. The following questions regarding charging sufficiency requirements and accreditation require further discussion. Parties are encouraged to further develop LDES proposals following the workshop and submit proposals into the successor Resource Adequacy (RA) proceeding.

1. Whether multi-day storage (MDS) and/or pumped storage hydropower (PSH) should have limitations on their ability to charge storage resources;

2. As MDS (24-hour+) and Extended Duration (ED)-LDES (12-24 hour) batteries are not able to fully charge in a 24-hour period, how can these batteries fit into the Slice of Day (SOD) framework;

3. As MDS and other ED-LDES resources may have different attributes, should these resources be treated differently from each other and how;

4. Whether a multi-day charging sufficiency test, as proposed by Cal Advocates, could work in the SOD framework, including how much extra time should be allowed for charging and what types of multi-day resources should this apply to;

5. How a seasonal PSH or MDS charging requirement could work, including how many months in advance should be permitted and how this would fit into the SOD framework;

6. For PSH accreditation in particular, (1) an analysis of reliability issues with the current methodology, (2) the different treatments of different designs of PSH (considering loop design, duration in number of hours, and round-trip efficiencies), and (3) whether PSH charging rules should be based on historical data.

10. The variable energy component of a co-located resource with Partial Capacity Deliverability Status or Full Capacity Deliverability Status will count for Resource Adequacy requirements and off-site charging sufficiency requirements up to its deliverable capacity as long as the combination of shown generation plus storage does not exceed the Point of Interconnection in the same hour.

11. Energy Division is authorized to conduct an evaluation after a full year of Slice of Day implementation to assess the need, benefits, and feasibility of an hourly load obligation trading mechanism. Energy Division is authorized to prepare a report in the 1st Quarter of 2026 on whether transactability issues exist.

12. If a load-serving entity (LSE) cures its Resource Adequacy deficiency by the T-1 deadline with a new resource that meets the rule established in Ordering Paragraph 6 in Decision 24-06-004, penalties will not be assessed to the LSE.

13. The off-peak import counting rule adopted in Ordering Paragraph 12 of Decision 24-06-004 is modified to apply to 3rd Quarter of 2025 and 3rd Quarter of 2026.

14. The requirement in Ordering Paragraph 22 of Decision 23-06-029 is modified such that a load-serving entity (LSE) is permitted one load migration update in mid-February to cover June to December load migration. Other than the one load migration update, an LSE's load forecast is locked in for the January-May timeframe and the June-December timeframe for each Resource Adequacy compliance year.

15. The central procurement entity data reporting requirements will be incorporated into the annual Resource Adequacy (RA) compliance filing process. Energy Division is authorized to use the data request template sent out in January 2025 to be incorporated in the annual RA compliance filings due October 31.

16. Rulemaking 23-10-011 is closed.

This order is effective today.

Date June 26, 2025, Sacramento, California.

ALICE REYNOLDS
President
DARCIE L. HOUCK
JOHN REYNOLDS
KAREN DOUGLAS
Commissioners

Commissioner Matthew Baker recused himself from this agenda item and was not part of the quorum in its consideration.