Decision 24-06-004 June 20, 2024

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 2025-2027, FLEXIBLE CAPACITY OBLIGATIONS FOR 2025, AND PROGRAM REFINEMENTS

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DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2025-2027, FLEXIBLE CAPACITY OBLIGATIONS FOR 2025, AND PROGRAM REFINEMENTS

Summary

This decision adopts Local Capacity Requirements for 2025-2027, Flexible Capacity Requirements for 2025, and refinements to the Resource Adequacy program scoped as Track 1.

This proceeding remains open.

1. Background

On October 12, 2023, the California Public Utilities Commission (Commission) 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). This proceeding is the successor to Rulemaking (R.) 21-11-002, which addressed these topics over the preceding two years. 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 will be addressed in this decision.

1.1. Procedural History of Track 1

Track 1 proposals were filed on January 19, 2024 by: Alliance for Retail Energy Markets (AReM); American Clean Power Association – California (ACP-CA); California Community Choice Association (CalCCA); California Efficiency + Demand Management Council and Center for Energy Efficiency and

Renewable Technologies (jointly, Council/CEERT); California Energy Storage Alliance (CESA); California Independent System Operator Corporation (CAISO); the Public Advocates Office at the California Public Utilities Commission (Cal Advocates); City of San Jose, Administrator of San Jose Clean Energy (SJCE); Form Energy; Pacific Gas and Electric Company (PG&E); Southern California Edison Company (SCE); and Western Power Trading Forum (WPTF). The Commission's Energy Division's Track 1 proposals were filed by an Administrative Law Judge's (ALJ) ruling on January 22, 2024.

On January 19, 2024, PG&E submitted the Load Impact Protocols (LIP) Simplification Working Group Report on behalf of the LIP Simplification Working Group. On February 6, 2024, Energy Division's Report on Resource Adequacy Slice-of-Day (SOD) Implementation and Year-Ahead Showings was issued via an ALJ ruling. Workshops on all Track 1 proposals were held on February 14, 2024 and February 28, 2024.

On February 23, 2024, revised Track 1 proposals were filed by: ACP-CA; AReM; CAISO; CalCCA; CESA; California Wind Energy Association (CalWEA); Middle River Power LLC (MRP); PG&E; and SCE.

Opening comments on Track 1 proposals were filed on March 8, 2024 by: ACP-CA; AES Clean Energy Development, LLC (AES); AReM; Bonneville Power Administration (BPA); CAISO; CAISO's Department of Market Monitoring (DMM); Cal Advocates; CalCCA; Calpine Corporation (Calpine); CESA; Hydrostor, Inc. (Hydrostor); Microsoft Corporation (Microsoft); MRP; PG&E; REV Renewables LLC (REV); San Diego Gas & Electric Company (SDG&E); SCE; Shell Energy North America (US). L.P. (Shell Energy); Sierra Club and California Environmental Justice Alliance (jointly, Sierra Club/CEJA); Silicon Valley Clean

Energy Authority (SVCE); Terra-Gen, LLC (Terra-Gen); Vistra Corporation (Vistra); and WPTF.

Reply comments on Track 1 proposals were filed on March 22, 2024 by: AReM, BPA, CAISO, Cal Advocates, CalCCA, Calpine, CalWEA, CEERT, CESA, Form Energy, Hydrostor, MRP, Natural Resources Defense Council (NRDC), PG&E, Sierra Club/CEJA, SCE, SDG&E, Shell Energy, Terra-Gen, and WPTF.

2. Submission Date

The matter for this decision was submitted on May 13, 2024.

3. Issues Before the Commission

The scope of issues in Track 1, as adopted in the December 18, 2023 Scoping Memo, is summarized below:

1. Adoption of 2025-2027 Local Capacity Requirements (LCR). 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 1, this will be for the 2025-2027 RA compliance years.
2. Adoption of 2025 Flexible Capacity Requirements (FCR). Similar to the LCR process, CAISO performs an annual FCR study, which is used to adopt flexible RA requirements for the following compliance year.
3. 24-Hour Slice-of-Day (SOD) Framework. The Commission will consider priority modifications to the SOD framework, including issues identified in the Energy Division report summarizing party comments after the year-ahead test showings (to be submitted by February 1, 2024), as well as other proposals submitted into this proceeding.
    a. SOD Planning Reserve Margin (PRM). The Commission will consider the translation of the adopted 17 percent PRM for the 2025 RA compliance year to the SOD framework. Parties may submit proposals on a calibration methodology to determine how the adopted 17 percent PRM can be translated into the SOD

framework for 2025, as well as proposals to refine the SOD PRM calibration tool for use in the translation of future Loss of Load Expectation (LOLE) studies.

4. Unforced Capacity Methodology (UCAP). In Decision (D.) 23-04-010, the Commission expressed interest in exploring comprehensive application of a UCAP for resource counting that would account for ambient derates and forced outages. In addition to consideration of UCAP, parties should consider modifications to the RA product that would penalize LSEs if their contracted RA capacity underperforms or is not available for CAISO dispatch due to forced outage.
5. Demand response (DR) Load Impact Protocols (LIP). The Commission will consider potential simplifications to LIPs, as discussed in D.23-06-029, with consideration for the LIP Simplification Working Group's report to be filed in January 2024.
6. Resource Adequacy Compliance and Penalties. The Commission will consider modifications to the RA penalty structure and other ways to incent compliance with RA requirements, as well as to identify potential opportunities to increase the availability of RA resources.
7. Other time-sensitive issues identified by Energy Division or by parties in proposals. While structural changes to the central procurement entity (CPE) structure will be addressed in Track 2, parties and Energy Division may raise proposals in Track 1 on time-sensitive refinements to the CPE process that can be implemented in sufficient time to impact 2025 CPE procurement process.

As provided in the Scoping Memo, Track 1 is expected to conclude by the end of June 2024, with the caveat that if there are scheduling delays or scoped issues that cannot be addressed in a June 2024 final decision, those issues may be incorporated into a later track of this proceeding.

4. Discussion

4.1. 2025-2027 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 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 CAISO's LCR study report.[1] CAISO conducts an annual LCR study, and the Commission resets local procurement obligations each year after review and approval of CAISO's recommendations. A series of subsequent decisions (most recently in D.23-06-029) established local procurement obligations for 2008 through 2026. 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's and SCE's service territories, beginning for the 2023 RA compliance year, a CPE framework was adopted, and local requirements are 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 resources in each local area to meet its obligations.

CAISO's Draft 2025 Local Capacity Technical Report (Draft LCR Report) was submitted on April 4, 2024. Comments on the Draft LCR Report were filed on April 18, 2024 by the Protect Our Communities Foundation (PCF).

CAISO's 2025 Final Local Capacity Technical Report (Final LCR Report) was submitted on May 1, 2024. Comments on the Final LCR Report were filed

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

on May 8, 2024 by PCF. Reply comments on the Final LCR Report were filed on May 13, 2024 by CAISO.

PCF comments that CAISO states that the reliability standards to which it cites are not binding.[2] In reply comments, CAISO clarifies that it must apply all established reliability standards in the LCR Technical Study process and that the reliability standards are mandatory.[3] CAISO also states that PCF did not participate in in CAISO's stakeholder process to develop the local capacity requirements in the Final Report, which is the appropriate forum to discuss changes to CAISO's LCR study.

CAISO's recommended 2025-2027 LCR values are summarized in the following table, with the adopted 2024-2026 LCR values provided for comparison.

[2] PCF Comments on CAISO Final LCR Report at 3.

[3] CAISO Reply Comments on CAISO Final LCR Report at 2.

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.			

2024 - 2026 Local Capacity Requirements			
Local Area Name	**2024**	**2025**	**2026**
Humboldt	133	137	141
North Coast/North Bay	983	989*	853
Sierra	1212*	1263*	1314*
Stockton	750*	750*	750*
Greater Bay	7329*	7498*	7667*
Greater Fresno	2028*	2203*	2378*
Kern	427*	427*	427*
Big Creek/Ventura	1971	1110	1146
LA Basin	4413	4795	5177
San Diego/Imperial Valley	2834	3019	3205
Total	22080	22191	23058
* 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 2025–2027 to be reasonable. Accordingly, CAISO's recommended 2025–2027 LCR values set forth in the table above are adopted.

4.2. 2025 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."[4]

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

This year, CAISO notified the Commission that the final Flexible Capacity Needs Assessment for 2025 (Final FCR Report) would not be filed by early May but would be targeted to be filed on May 13. On May 2, an ALJ's ruling was issued that shortened the time for comments on the Final FCR Report. The ruling stated that once 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 CAISO on May 13, 2024. No comments on the Final FCR Report were filed.

The Final FCR Report contains the following figures for 2025, with the 2024 FCR figures provided for comparison.

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

2024 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	23583	22554	6065	15361	1128
February	23925	22909	6160	15604	1145
March	24446	23246	6251	15833	1162
April	23817	22643	6089	15422	1132
May	23485	22293	8303	12875	1115
June	23897	22776	8483	13154	1139
July	20651	19836	7388	11456	992
August	22018	21087	7854	12179	1054
September	23135	22226	8278	12837	1111
October	22655	21745	5847	14811	1087
November	23081	22145	5955	15083	1107
December	20900	20093	5403	13685	1005

Despite the brief review period available for the Final FCR Report, the Commission reviewed the FCR figures and finds that the figures appear reasonable. Accordingly, CAISO's recommended values set forth in the table above are adopted.

4.3. Delay of Slice-of-Day Implementation

In D.22-06-0250, the Commission determined that 2024 would be the test year for the SOD framework, with full program implementation to begin for the 2025 RA year.[5] In D.23-04-010, the Commission affirmed that it intended to move forward with SOD implementation in 2025.[6] CalCCA and AReM offer

[5] D.22-06-050 at Ordering Paragraph (OP) 15.

[6] D.23-04-010 at 73.

proposals on delaying the 2025 implementation of the SOD framework, as summarized below.

AReM proposes three options for delaying implementation.[7] Under the first option, AReM proposes a full year delay with 2025 as another test year. AReM states that this proposal provides more time to develop SOD tools and for LSEs to become familiar with the tools. AReM acknowledges that the downsides of this option are that RA reform to ensure reliability is delayed, there are no guarantees a delay would lead to a smooth 2026 rollout, and that LSEs that planned for a 2025 implementation may face financial consequences by a delay.

Under a second option, implementation would be delayed to July or some other point in 2025. AReM cites an advantage of this option is that RA reform moves forward in 2026 with a few extra months for development. A disadvantage is that SOD tools would still be required for year-ahead filings in 2024. AReM adds that because year-ahead filings have lower penalty risk (based on points and LSE expansion), this option gives more time to develop tools and templates before LSEs face the risk of full penalties.

Under a third option, LSEs would be permitted to choose between the current RA framework and the SOD framework for 2025 compliance with full SOD implementation in 2026. AReM cites one advantage of this option as fairness to LSEs by giving optionality, while a disadvantage is the burden on Commission Staff to juggle two RA frameworks for compliance, while still working on full SOD implementation. AReM notes that this option may raise concerns that LSEs select a preferred framework that harms reliability.

[7] AReM Revised Proposal at 5.

CalCCA proposes to delay SOD implementation to 2026 at the earliest, or until exit criteria have been met.[8] CalCCA reasons that there are issues with the showing tools that require resolution and a SOD PRM for 2025 has not yet been selected, adding uncertainty to LSE procurement. CalCCA recommends adopting exit criteria before implementation to include: that showing template issues have been resolved to Energy Division and LSEs' satisfaction, the showing template has been finalized one year before the first showing, LSEs have been trained on and successfully used the template for a test year filing, and a PRM for the first year has been adopted with sufficient time for LSEs to procure. CalCCA recommends that LSEs continue to show storage in Maximum Cumulative Capacity (MCC) Bucket 4 in 2025 by showing excess capacity to charge storage.

4.3.1. Comments on Proposals

Several parties support delaying SOD implementation until 2026, including CAISO, CalWEA, Calpine, REV, SDG&E, SCE, and SVCE.[9] CAISO sees merit in delaying implementation because it would allow time for the SOD PRM process to be solidified, to consider proposals based on the 2024 test year, and to analyze LSEs' monthly test year showings in 2024 to identify enhancements. SDG&E contends that a delay is not likely to negatively impact system reliability and may in fact avoid unintended harm by relying on an uncertain reliability metric and incomplete SOD framework. CalWEA supports a delay to 2026 so long as waivers are adopted.

SVCE supports a delay to 2026 if a temporary waiver process is not adopted. SVCE remarks that marketers are not yet selling SOD products and

[8] CalCCA Revised Proposal at 9.

[9] CAISO Opening Comments at 7, CalWEA Reply Comments at 2, Calpine Opening Comments at 3, REV Opening Comments at 7, SDG&E Opening Comments at 2, SCE Opening Comments at 3, SVCE Opening Comments at 4.

contracts are not yet designed for the new framework but acknowledges that marketers may not transition to the SOD framework until it is binding. SCE only supports delaying to 2026 if other measures are not adopted, such as a waiver process, an appropriate SOD PRM, and allowing resources to count for RA if a commercial operation date (COD) is after the start of the RA month.[10]

CalCCA opposes a partial delay as LSEs would have to comply with two sets of requirements, one for year-ahead and one for month-ahead with different counting rules.[11] CalCCA states this will create uncertainty and potential excess costs on LSEs to comply with two RA programs. CalCCA also opposes AReM's optionality proposal because it complicates compliance and raises concerns about how to equitably allocate costs for backstop procurement.

Parties that oppose delaying the SOD framework are Sierra Club/CEJA, MRP, PG&E, and Shell Energy. PG&E argues that the test year was intended to address issues with the showing tools and that the process is ongoing and will likely result in significant progress throughout 2024; thus, it is premature to conclude the tools and processes will not be ready for 2025.[12] PG&E points out that LSEs have had sufficient time to adjust their portfolios and that since test year filings were not binding, it is unsurprising that LSEs failed to meet their test year obligations. PG&E also states that a delay is unfair to LSEs that have proactively procured the right mix of resources for SOD requirements, that a delay will likely have adverse consequences for other high-priority changes (like UCAP and multi-year RA), and that resolving "all" issues is an arbitrary

[10] SCE Opening Comments at 3.

[11] CalCCA Opening Comments at 16.

[12] PG&E Opening Comments at 14.

standard that prevents implementation of any new program.[13] PG&E states that 2025 implementation would allow the Commission see how capacity needs can be met at a granular level.

MRP opposes a delay, stating that Energy Division's SOD Report did not find significant flaws in the framework and that Energy Division and parties are working through issues raised by parties this year.[14] Shell Energy contends that a delayed implementation discriminates against LSEs that have been diligently working towards SOD compliance.[15] Shell Energy states that the Commission must maintain regulatory certainty around the transition and that a delay does not guarantee issues with the framework will be resolved. Shell Energy instead recommends 2025 implementation with greater leniency to address challenges with the SOD framework. Sierra Club/CEJA agree that implementation should not be delayed, and the program should continue to be refined in 2024.[16]

4.3.2. Discussion

The Commission began exploring a broad reform of the current RA program in 2020. Over nearly four years, Energy Division Staff and stakeholders have worked together to develop and refine every aspect of the new SOD framework. Through numerous working group meetings, workshops, and office hours, and the submission of a substantial volume of proposals, comments, and reports, the Commission recognizes and appreciates the significant undertaking by Energy Division Staff and parties to develop this new RA framework.

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[13] PG&E Reply Comments at 3.

[14] MRP Opening Comments at 13.

[15] Shell Energy Opening Comments at 3.

[16] Sierra Club/CEJA Reply Comments at 7.

In D.23-04-010, the Commission identified that in the 2024 test year, "LSEs have a penalty-free opportunity to prepare for and provide feedback on the SOD framework rules, compliance and showing tools, and processes. Subject to minor adjustments and modifications to the SOD framework rules and compliance and showing tools, the Commission fully intends to move forward with implementation of the SOD framework for the 2025 RA compliance year."[17]

In considering parties' concerns about moving forward with 2025 implementation, the Commission is not persuaded that delaying implementation of the SOD framework is warranted. Given the multiple years that the SOD framework has been under development, we find that LSEs have had ample time to prepare their RA portfolios for implementation of the SOD framework in 2025. The Commission also agrees with parties that state that delaying SOD implementation would be unfair to those LSEs that have been adjusting their RA portfolios to meet the SOD requirements.

We recognize parties' concerns about whether the showing tools and processes will be ready for 2025 implementation. Energy Division has spent the past year developing and modifying the SOD showing tools in response to party input and will continue doing so in the months following the issuance of this decision. The Commission is confident that the showing tools will be ready for 2025 implementation. However, as we stated in D.23-04-010, we "anticipate that minor adjustments to the compliance tools and program rules may be necessary following the test year."[18]

The Commission is not convinced by arguments that an additional test year is necessary to give Energy Division Staff sufficient time to refine the

[17] D.23-04-010 at 71.

[18] *Id.*

showing tools. An additional 2025 test year will mean that Energy Division Staff yet again will be required to run two RA programs simultaneously – the current RA program and the SOD test year process. Overseeing two distinct RA programs in 2025 would not necessarily free up Commission Staff resources and time to develop the SOD showing tools. The Commission agrees with parties that state that delaying implementation by one year does not guarantee that all issues with the SOD framework will be resolved to all parties' satisfaction.

Moreover, even if SOD implementation is delayed, parties have requested that standalone storage resources continue to be shown in MCC Bucket 4, as was permitted during the 2024 test year, so long as LSEs can demonstrate excess capacity above their requirements to charge the storage. As more LSEs have been using use-limited resources to meet RA requirements, more LSEs would need to use the SOD showing tools to show excess energy in an additional test year. In other words, Energy Division would still be expected to complete the SOD showing tools and LSEs would still need to become familiar with the SOD showing tools for the 2025 RA year.

For these reasons, we maintain that the 2025 RA compliance year will be the first year for the new SOD framework. The Commission expects that the first year of implementation of an entirely new RA framework will be imperfect and that there will be hurdles, just as could be expected for any major regulatory program rollout. The Commission will continue to monitor the readiness of the SOD showing tools throughout 2024 and monitor LSEs' compliance with the SOD requirements in 2025 and will consider adjustments to the program as needed.

Lastly, Energy Division will continue to host office hours and trainings prior to the 2025 year-ahead filing deadline to assist LSEs with using the SOD template. We encourage LSEs to use these trainings and resources.

4.4. SOD Planning Reserve Margin

In January 2023, Energy Division published the annual 2024 LOLE study that reflected monthly PRM levels using the California Energy Commission's (CEC) 2021 Integrated Energy Policy Report (IEPR) managed demand.[19] For the summer months (July-September), the PRM levels ranged from 14.5 percent to 21.4 percent. In D.23-06-029, the Commission adopted a 17 percent PRM, taking both the LOLE study and other factors into account, including increases to the demand forecast and reliance on a large amount of under-construction resources. The Commission adopted a 17 percent PRM for the 2024 and 2025 RA years, stating that "[g]iven the realities of available RA supply and persistent delays in development projects, it is prudent to retain the status quo 17 percent PRM for the 2024 and 2025 RA years."[20]

In addition, in D.22-06-050 (and reaffirmed in D.23-04-010), the Commission determined that a single PRM will apply to all hours of the year for initial implementation of the SOD framework.[21] In D.23-04-010, the Commission authorized Energy Division to integrate the PRM calibration tools, as proposed by NRDC and SCE, to translate the results of the 2024 LOLE study to the SOD framework.

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[19] Energy Division Study for Proceeding R.21-10-002, Loss of Load Expectation and Slice of Day Tool Analysis for 2024, issued January 20, 2023 (January 2023 LOLE Study), available at: 3_study-for-ra-proposals-2023.pdf (ca.gov).

[20] D.23-06-029 at Finding of Fact 4.

[21] D.22-06-050 at OP 27; D.23-04-010 at 59.

As stated in the Scoping Memo, the Commission "will consider the translation of the adopted 17 percent PRM for the 2025 RA compliance year to the SOD framework. Parties may submit proposals on a calibration methodology to determine how the adopted 17 percent PRM can be translated into the SOD framework for 2025, as well as proposals to refine the SOD PRM calibration tool for use in the translation of future Loss of Load Expectation (LOLE) studies."[22] Below we consider proposals to translate the 17 percent PRM for the SOD framework.

We note that additional PRM-related proposals were submitted by WPTF, ACP-CA, and CAISO with variations on effectively re-running the LOLE study or modifying the adopted 17 percent PRM for 2025. Based on the Scoping Memo, such proposals are out of scope for Track 1 of this proceeding, which is focused on translation of the adopted 17 percent PRM for 2025 and are therefore not discussed in this decision. The Scoping Memo provided that Track 2 will include consideration of a revised LOLE study and PRM for the 2026 and 2027 compliance years, and parties are encouraged to discuss such proposals in Track 2.

4.4.1. Summary of Proposals

For the 2025 RA year, Energy Division recommends two options for translating the 17 percent PRM into a SOD PRM.[23] Under Option 1, Energy Division notes that to translate the results of the 2024 RA LOLE study to a SOD PRM, Energy Division utilized the methodology adopted in D.23-04-010, which authorized Energy Division to integrate the PRM calibration tools, as proposed by NRDC and SCE. This methodology included using the current SOD counting

[22] Scoping Memo at 4.

[23] Energy Division Proposal at 3.

rules for resources and the 2021 IEPR worst-day load forecast (both of which reflect September values). In fall of 2023, Energy Division published an initial draft of its SOD PRM calibration tool using the portfolio results of the 2024 RA LOLE study and presented the results in an October 2023 workshop. After correcting errors, Energy Division then calculated a 15.43 percent SOD capacity margin for the September peak month.

Option 1 is to apply the 15.43 percent PRM, provided by translation of the 2024 LOLE portfolio, to the 2025 SOD compliance year. Energy Division states that a 15.43 percent PRM suggests that a 17 percent PRM calibration is fulfilled, given that the results from the 2024 RA LOLE study (published in January 2023) show a 15 percent PRM for September using the 2021 CEC 1-in-2 IEPR demand forecast.[24] Energy Division observes that there is a question of whether a 15.43 percent SOD PRM for all summer months ensures the same level of reliability adopted in D.23-06-029 with the 17 percent PRM.

Under Option 2, Energy Division recommends maintaining the status quo 17 percent PRM for the 2025 SOD PRM to apply to RA program obligations. Energy Division states that this option applies a slightly higher SOD PRM than the 15.43 percent LOLE results translated to September but may also be lower than the SOD PRM required in other months, given the monthly exceedance levels. Energy Division states that a 17 percent PRM will decrease LOLE slightly in September but will potentially increase LOLE in other months of the year, which will result in a more balanced LOLE across summer months. Energy Division also notes that the 15.43 percent September calibration result is very

[24] The SOD PRM derived from the January 2023 LOLE study used the 2021 IEPR forecast. *See* Energy Division January 2023 LOLE Study.

close to the CEC's monthly managed September PRM of 14.5 percent, which was used to inform the 17 percent PRM for 2024 and 2025 in D.23-06-029.

Energy Division also notes that it plans to perform a set of stress tests in its 2026 LOLE study (as part of Track 2 of this proceeding) to assess the effectiveness of imposing an annual PRM based on a peak month's result, and if needed, explore the necessity of levelized annual PRM or unique monthly PRMs for purposes of maintaining reliability.[25]

4.4.2. Comments on Proposals

Ava, CalCCA, and PG&E support a 15.43 percent SOD PRM for 2025.[26] CalCCA and Ava state that the 15.43 percent should be adopted if the SOD framework is implemented in 2025 but that the 17 percent should be retained if there is another test year.

Microsoft argues that neither PRM calibrates for reliability but prefers 17 percent and recommends Energy Division's proposed stress tests.[27] Vistra supports an initial PRM of 17 percent for 2025 and either maintaining the effective PRM or performing stress tests to identify if the PRM needs to be increased.[28] CAISO states that for 2025, a PRM less than 17 percent should not be adopted and a 15.43 percent SOD PRM should not be used, as this may introduce loss of load risk in months outside of the peak month.[29] SCE disagrees with CAISO that a PRM of less than 17 percent would introduce LOLE risk in months

[25] Energy Division Proposal at 10.

[26] Ava Opening Comments at 4, CalCCA Opening Comments at 18, PG&E Opening Comments at 11.

[27] Microsoft Opening Comments at 5.

[28] Vistra Opening Comments at 4.

[29] CAISO Opening Comments at 3.

outside of the peak month, arguing that CAISO is incorrectly treating single PRMs and SOD PRMs as the same.[30]

SCE, MRP, and WPTF oppose both of Energy Division's options for the SOD framework.[31] SCE views a 17 percent PRM as more problematic because it does not account for differences in the two frameworks with respect to resource counting and applying PRM to load. MRP opposes both PRMs due to a lack of evidence either can maintain 0.1 LOLE and states if either is adopted, the Commission should commit to understanding the level of reliability the option yields.

WPTF is concerned with a single PRM based on September or a 17 percent PRM that will increase LOLE in other months. WPTF commissioned Astrape Consulting to stress test both options and calculate the lowest PRM that produces a 0.1 LOLE. WPTF states that the analysis shows that a 15.43 percent PRM increases LOLE to 0.372, a 17 percent PRM produces a LOLE of 0.229, and a 19.7 percent PRM is the lowest PRM to produce a portfolio meeting 0.1 LOLE. In reply comments, PG&E observes that WPTF's analysis does not include the impact of the effective PRM for SOD, which when combined with a base PRM of 15.43 percent produces a range of 19.13-22.43 percent PRM.[32]

Calpine supports a 17 percent PRM for 2025 after reviewing WPTF's analysis, as a 15.43 percent PRM yields a LOLE far above the 0.1 LOLE target.[33]

[30] SCE Reply Comments at 4.

[31] SCE Opening Comments at 5, WPTF Opening Comments at 3, MRP Opening Comments at 5.

[32] PG&E Reply Comments at 5.

[33] Calpine Reply Comments at 3.

CEERT supports Energy Division's proposal for stress tests to analyze monthly reliability when applying a single PRM.[34]

4.4.3. Discussion

As discussed above, we maintain that the first year of the SOD framework will be the 2025 RA year. As described in the Scoping Memo, the Commission "will consider the translation of the adopted 17 percent PRM for the 2025 RA compliance year to the SOD framework."[35]

In considering the appropriate translation of the 17 percent PRM for the 2025 RA year, we are concerned that the results of Energy Division's 15.43 percent PRM calibration analysis demonstrate that a 17 percent PRM calibration is fulfilled only in September.[36] We agree with Energy Division that this raises the concern that a 15.43 percent SOD PRM for all summer months does not ensure the same reliability level the Commission intended when adopting the 17 percent PRM for 2025 in D.23-06-029. Alternatively, under Energy Division's proposed 17 percent SOD PRM for 2025, Energy Division states that the adopted 17 percent PRM was initially informed by a PRM reflecting about 15 percent for September using CEC's managed peak demand forecast and thus, a 17 percent SOD PRM may have a comparable level of reliability as intended by D.23-06-029.

The Commission observes that the CEC's 2023 IEPR demand forecast for 2025 shows decreased demand compared to previous years, and a shift in the peak to July (rather than September). Several parties, including SDG&E, Microsoft, and Cal Advocates, express concerns with the uncertainty associated with a lower demand forecast and changing peak loads, as the IEPR forecast is

[34] CEERT Reply Comments at 4.

[35] Scoping Memo at 4.

[36] Energy Division Proposal at 4.

closely tied to the RA requirements.[37] The Commission is concerned that the reduced demand and shift in peak to July, under which solar exceedance values are significantly higher than in September, may result in a restrictively lower PRM for procurement purposes. A 15.43 percent PRM level runs the risk of less total resources procured by LSEs. However, maintaining a 17 percent PRM level builds in a safety margin in the event the modifications to the 2025 RA forecast do not materialize. The Commission finds that applying a 17 percent SOD PRM for 2025 is a more prudent approach that would help offset uncertainty with the decreased load forecast.

In considering the 2023 IEPR forecast for 2025, it appears that a PRM of 17 percent (as opposed to 15.43 percent) in the SOD framework would result in an increase in procurement of 726.66 megawatts (MW) in July, 706.59 MW in August, and 698.38 MW in September. On balance, this additional level of procurement is reasonable, considering that the 2025 RA forecast has decreased considerably, particularly for the tightest supply months of August and September. For these reasons, the Commission is persuaded that a 17 percent PRM is a more appropriate PRM to be applied to the SOD framework for the 2025 RA compliance year and we adopt it here.

4.5. Compliance and Penalties

The Scoping Memo provides that the Commission "will consider modifications to the RA penalty structure and other ways to incent compliance with RA requirements, as well as to identify potential opportunities to increase the availability of RA resources."[38] We consider such proposals below.

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[37] SDG&E Opening Comments at 10, Microsoft Opening Comments at 8, Cal Advocates Reply Comments at 3.

[38] Scoping Memo at 4.

4.5.1. Temporary System Waivers

CalCCA recommends a temporary waiver process for system and flexible RA from 2025-2027 to align with SOD implementation and assist with a smooth transition.[39] CalCCA suggests a partial waiver that gives an LSE a waiver of penalty points and other non-financial consequences if an LSE demonstrates tight market conditions, similar to the local waiver process. CalCCA also suggests a full waiver that would give an LSE a waiver of financial penalties, points, and other consequences. The LSE would need to show: (1) highly constrained market conditions (similar to the local waiver process) and that it received insufficient bids and/or offers to meet its obligations, (2) that COD delays for new projects contributed to the deficiency, and (3) that the LSE made reasonable efforts to meet RA obligations but could not due to SOD implementation issues. CalCCA proposes a workshop to further develop criteria for a waiver.

SCE recommends a temporary system waiver for summer 2024 (July–September) and for the 2025 RA year.[40] For a deficient LSE, SCE proposes the LSE demonstrate that it made all "best commercial efforts" to secure capacity through solicitations and the broker market. Despite these efforts, the LSE must show a lack of capacity for procurement. SCE states that other factors that should be considered are excessive pricing (although not sufficient on its own) and project delays outside of an LSE's control.

ACP-CA recommends limited system waivers when it is clear that an LSE exercised commercially reasonable efforts to secure capacity but circumstances

[39] CalCCA Proposal at 9.

[40] SCE Proposal at 2.

beyond the LSE's control resulted in non-compliance.[41] ACP-CA suggests the LSE must show it held solicitations, actively developed new resources, and actively attempted to procure capacity. ACP-CA states that a waiver should also be granted when the cause of a deficiency is due to a delay in allocation of deliverability or maximum import capability.

4.5.1.1. Comments on Proposals

ACP-CA, REV, Shell Energy, SJCE, and SVCE support CalCCA's proposal.[42] ACP-CA supports a full waiver proposal for COD delays. Shell Energy states that the current penalty price should be the benchmark to determine whether bid prices received were too high. SVCE recommends adopting CalCCA's proposal starting for the 2024 compliance year.

SCE supports a temporary waiver but disagrees that the waiver should extend to 2027; instead, SCE states that any extension beyond 2025 should be deferred.[43] Calpine supports a temporary waiver but notes that a significant amount of capacity is scheduled to be added in the next few years.[44] Calpine supports a waiver for delayed COD of a new resource but states that it should be time-limited as LSEs must pursue other options to meet obligations. AReM supports a partial waiver of non-financial penalties for 2025-2027 but objects to a full waiver of financial penalties, as a full waiver allows an LSE to escape any payment for procurement obligations, which is unreasonable even in a tight market.[45] AReM opposes a waiver for delays of new resource development since

[41] ACP-CA Proposal at 11.

[42] ACP-CA Revised Proposal at 10, REV Opening Comments at 6, Shell Energy Comments at 1, SJCE Proposal at 3, SVCE Proposal at 2.

[43] SCE Opening Comments at 3.

[44] Calpine Opening Comments at 3.

[45] AReM Opening Comments at 13.

LSEs can avoid penalties if it contracts with existing resources rather than delayed new resources.

MRP and PG&E oppose waivers and generally state that determining whether an LSE exercised commercially reasonable efforts can be a very subjective process, resulting in inequitable application of the criteria.[46] MRP contends that a waiver cannot be aligned with Public Utilities (Pub. Util.) Code Section 380's requirement to minimize backstop procurement and that a waiver process would allow deficient LSEs to avoid procuring capacity, significantly eroding grid reliability and the value of the RA program. MRP highlights that the Commission adopted a 17 percent PRM in part due to concerns about the lack of supply from new project delays, and thus, the PRM includes an implicit system waiver because the Commission may otherwise have adopted a higher PRM.

PG&E states that waivers are highly inequitable for LSEs that do not use the process, as those LSE potentially contract at higher prices and LSEs that use the waiver process avoid contracting. PG&E adds that LSEs that fail to meet system obligations put all customers at greater risk of outages, even customers of LSEs that paid the price of meeting system obligations. PG&E argues that none of the proposals offer sufficient safeguards to ensure reliability, such as a cap on how much of an LSE's obligation can be waived.

In opening comments, PG&E proposes temporary system waivers for new resource development delays.[47] PG&E recommends that LSEs that experience new project delays for mid-term reliability (MTR)-related resources should receive a waiver, if the delayed resource was the difference between a month-

[46] MRP Opening Comments at 10, PG&E Opening Comments at 5.

[47] PG&E Opening Comments at 7.

ahead showing passing or failing compliance. If yes, the LSE would be eligible for a waiver; if not, the LSE would receive a penalty based on the deficiency, net the impact of the delayed resource. PG&E states that this approach caps the volume eligible for a waiver, addresses concerns about new resource delays, and is more equitable for all LSE experiencing delays. Further, the Commission has set criteria for granting MTR procurement waivers and this process would eliminate duplicative administrative work.

4.5.1.2. Discussion

The Commission has considered and rejected adoption of system RA waivers a few times in recent years. In D.19-06-029, the Commission rejected system waivers, stating that "there remain significant, unresolved issues that required further consideration before allowing such waivers, including potential leaning by LSEs and market power issues. Such market power issues may include potential gaming by generators that may, for example, withhold capacity during more expensive peak months."[48] In D.20-06-031, we again rejected adopting of system RA waivers, stating that the "waiver process requires further development and study," and reiterating our position in D.19-06-029.[49]

While the Commission understands concerns regarding high prices for RA resources in recent years, the Commission concludes that a system waiver process is not the solution. The Commission is persuaded by those that argue that a system waiver process is highly inequitable for those LSEs that procure to meet their RA obligations at market prices, while LSEs that use a system waiver process would potentially avoid both procuring RA capacity and paying penalties for non-compliance. We also agree that an LSE's failure to meet its

[48] D.19-06-026 at 18.

[49] D.20-06-031 at 59.

system obligations increases the risk of outages for all ratepayers, even the customers of LSEs that complied to meet their RA obligations.

As we concluded in past Commission decisions, for any system waiver process, we continue to be concerned that system waivers raise system reliability issues and leaning concerns, whereby LSEs that fail to procure sufficient capacity and receive a waiver lean on the procurement of compliant LSEs, resulting in reliability risk to all ratepayers. These issues have yet to be resolved. For these reasons, we decline to adopt a system waiver process.

With respect to new project development delays, MRP points out that the 17 percent PRM adopted in D.23-06-029 was adopted in part due to the Commission's concerns about the amount of new RA resources facing development delays and thus, the PRM implicitly includes a temporary system waiver. The Commission agrees with MRP that the adoption of the 17 percent PRM helps to account for development delays for new resources.[50] That said, in this decision, the Commission addresses new resource development delays through extended cure periods, as discussed below.

4.5.2. Extension of Cure Periods

CalCCA, CESA, and SCE put forth proposals to address new resource development delays and extended cure periods.

The current RA rules require LSEs to make month-ahead showings 45 days prior to the start of the compliance month. Due to that requirement, CalCCA argues that new resources that reach COD, or existing resources that contract with LSEs, between the month-ahead deadline and the start of the compliance month are not accounted for when assessing compliance.[51] CalCCA proposes

[50] *See* D.23-06-029 at 23.

[51] CalCCA Proposal at 8.

that the cure period be extended such that LSEs may cure their year-ahead and month-ahead RA deficiencies up to the start of the operational RA month. For example, if an LSE has a September deficiency for its year-ahead filing due on October 31 or its September month-ahead filing due on July 15, but the deficiency is resolved before September 1, the Commission should find the LSE compliant and not subject to penalties.

CalCCA also proposes that if the LSE resolves a deficiency between the start and end of the compliance month, the penalty amount should be derated. That is, the penalty dollar amount would be prorated by the percentage of days the LSE was deficient. CalCCA posits that the proposal would unlock new and existing capacity that becomes available between the showing deadline and the RA compliance month.

SCE recommends allowing LSEs to use new contracted resources to count towards RA obligations even if they do not become operational by the T-45 or T-30 RA deadlines so long as they come online before the start of the compliance month.[52] SCE states that this process, known as "proxy RA," is used in the context of MTR and system reliability procurement. SCE contends that this would enhance grid reliability by increasing the availability of resources that are online before the start of the month with contractual obligations that match the must-offer obligation (MOO) and would avoid long lead times needed to meet formal RA requirements.

CESA similarly proposes that resources with CODs prior to the start of the RA month should be eligible to be shown on an LSE's RA plan for that month.[53] CESA states that, for example, large resources that reach COD in August cannot

[52] SCE Proposal at 5.

[53] CESA Proposal at 6.

count towards RA requirements in September and thus do not have a MOO even if the LSE contracted capacity for September and the resource is online in September. CESA states that CAISO should have access to as much capacity with a MOO as available and LSEs should likewise get credit for procuring such resources. CESA proposes two implementation options: (1) a cure process, whereby after receiving a deficiency notice, the LSE provides the contract of the new resource with the scheduled COD or (2) a waiver process, whereby after the start of a compliance month, an LSE can seek relief by showing it contracted a new resource with a COD before the start of the month and penalties may be adjusted after verification.[54]

4.5.2.1. Comments on Proposals

Ava, AReM, PG&E, CESA, and Vistra support CalCCA's proposal.[55] AReM states that while the benefits of an extended cure period are limited, it could be useful for new resources and for flexibility with SOD implementation issues. PG&E supports an extended cure period if it gives CAISO sufficient time to evaluate system needs and exercise backstop procurement authority that does not result in a cost shift.

Parties that support SCE's and/or CESA's proposals include AES, AReM, Ava, Hydrostor, Microsoft, REV and Vistra.[56] Microsoft states that resources should count for RA as soon as they come online up to T-15. Vistra suggests modifying the month-ahead deadline to after all CAISO showings and manual

[54] CESA Revised Proposal at 7.

[55] Ava Opening Comments at 5, AReM Opening Comments at 10, PG&E Opening Comments at 9, CESA Opening Comments at 3, Vistra Opening Comments at 11.

[56] AES Opening Comments at 2, AReM Opening Comments at 18, Ava Opening Comments at 5, Hydrostor Opening Comments at 2, Microsoft Opening Comments at 12, REV Opening Comments at 4, Vistra Opening Comments at 11.

additions have occurred, up to T-15. AReM supports both proposals but is concerned that they do not include a way to verify the scheduled COD or address consequences if a generator fails to meet the COD. AReM states that CAISO needs to verify resources that came online to know how much backstop procurement is needed. Hydrostor generally supports CESA's proposal as it would avoid unnecessary, costly delays in attributing new online capacity to an LSE. AES and REV support both proposals, and Ava supports SCE's proposal.

CAISO notes that the Commission does not have authority to change CAISO showing timelines and any changes must go through CAISO's stakeholder process.[57]

4.5.2.1. Discussion

In D.23-06-029, the Commission noted that "in recent years, development projects have faced significant delays due to a host of issues, including supply chain delays, labor shortages, interconnection queue limitations, and rising costs."[58] In addition, a large volume of new mid-term reliability projects are expected to come online as directed in the Integrated Resource Planning (IRP) proceeding.

The Commission finds it reasonable to allow new resources with a COD after T-30 and before the start of the RA compliance month (T-1) to count towards that month's RA compliance, on an interim basis. This proposal will not only increase the number of resources an LSE can count towards its RA obligations, but also increase the number of resources with a MOO that are available to CAISO's markets to enhance grid reliability.

[57] CAISO Opening Comments at 8.

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

We find, however, that this interim extension of the cure period should be limited to the critical summer months for RA capacity availability. As such, for June-September month-ahead filings, new resources with a COD after T-30 and before the start of an LSE's RA compliance month (T-1) may count towards curing an LSE's identified RA deficiencies for that compliance month, if the LSE provides the following documentation to Energy Division: (1) the new resource contract verifying that the resource will be providing a MOO into CAISO energy markets consistent with an RA product, and (2) a COD notice that confirms the resource was online and deliverable before the start of the compliance month (T-1). Additionally, the MWs associated with the identified resource must not accept any CAISO Capacity Procurement Mechanism (CPM) designation for the associated compliance month, which will ensure there is no double-counting of the resource for RA purposes.

To implement this extended cure period, Energy Division Staff will continue to issue deficiency notices prior to T-30, as is the current practice. If an LSE procures a new resource that reaches COD after T-30 and before the start of the RA compliance month, the LSE must submit to Energy Division Staff the COD notice and underlying RA contract for the new resource. After the RA compliance month, Energy Division Staff will refer any remaining outstanding deficiency to the Consumer Protection and Enforcement Division. If the new resource with a COD after T-30 cures the LSE's deficiencies, the LSE's deficiencies will be considered cured within five business days. This rule will be effective upon the issuance of this decision and may be utilized by LSEs for compliance beginning with their July 2024 month-ahead showing.

We recognize that CAISO will continue to assess collective and individual LSE backstop needs based on the timelines identified in its tariff. Currently,

CAISO locks supply plan submittals at T-30. Therefore, the extended cure period will not be accounted for in CAISO's current monthly CPM process. While we recognize CAISO's current system has limitations, we encourage CAISO and Energy Division to coordinate to ensure that the additional new confirmed RA resources for the compliance month are visible to CAISO markets and are considered in any CPM designation. In addition, as this extended cure period is adopted on an interim basis, the Commission will monitor the use of the cure period and will reevaluate the need for it in the future.

The Commission finds that CalCCA's proposal to allow LSEs to cure year-ahead and month-ahead deficiencies up to the start of the compliance month with both new and existing resources is overly broad and introduces uncertainty and risk to the RA program's goal of ensuring grid reliability. We decline to adopt this proposal.

4.5.3. Residual Capacity Auction

Cal Advocates submits a Residual Capacity Auction (RCA) proposal that would allow the existing CPE to procure system RA capacity on behalf of deficient LSEs through a blind reverse auction.[59] The RCA includes a waiver process for LSEs that demonstrate good faith efforts to procure system RA. The proposal is intended to be a mechanism to procure sufficient capacity to cure individual LSE deficiencies at competitive prices. The proposal recommends the following components:

1. Develop and implement a reverse blind auction, called the RCA.
2. The RCA would request system RA offers and procure up to the aggregate amount of LSEs' system RA deficiencies, select offers in the auction, and pay bidders the bid price.

[59] Cal Advocates RCA Proposal at 4.

3. The Operator of the RCA (ORCA) will be the local RA CPE.
4. The ORCA will allocate system RA credits and costs to deficient LSEs.
5. The ORCA will remain the contractual counterparty and be responsible for submitting procured resources on RA supply plans to the Commission and CAISO.
6. A system waiver process for May-September would be needed for LSEs to demonstrate good faith and commercial reasonable efforts.

Cal Advocates states that the RCA provides a venue where suppliers can submit reasonably priced bids to a single buyer, if the suppliers were unable to find buyers at higher bids. Cal Advocates states that where there is true market scarcity, the RCA allows the Commission to weigh trade-offs between very high procurement costs against non-compliance risks or alternative procurement, as LSEs currently have no ability of assessing trade-offs.

4.5.3.1. Comments on Proposal

Numerous parties raise concerns about the RCA proposal. CalCCA and PG&E assert that in order to take a position on the proposal, there are many outstanding questions and implementation details that need to be developed.[60] PG&E and SVCE generally state that it is unclear whether the proposal would be implementable by 2026, that a more immediate solution is needed, and that it is unclear that the RCA would even be needed in 2026 and beyond due to the large volume of resources expected to come online through the IRP proceeding.[61] PG&E and SVCE also state that the RCA does not address compatibility and integration with the SOD program, such as how the ORCA would procure for deficiencies across slices of hours and multiple LSEs.

[60] CalCCA Opening Comments at 22, PG&E Opening Comments at 20.

[61] SVCE Opening Comments at 7, PG&E Opening Comments at 20.

SVCE, WPTF, and MRP question whether the proposal addresses what may be the source of problems in the current RA market.[62] SVCE comments that the proposal incorrectly asserts that market concentration is to blame for the current RA market, rather than tight supply, and that the RCA may lead to more market distortions due to LSE and marketer incentives. MRP states that the proposal relies on an assumption that a seller that previously offered a price that an LSE found unreasonable would offer a much lower price to the ORCA, which MRP argues is contrary to a rational seller's behavior in a tight market. WPTF argues that the proposal will lead to LSEs deferring system RA procurement to the RCA, and that it presents a permanent solution for a temporary problem.

SVCE, Vistra, and SCE oppose expanding the scope of the CPE's role, given that the current local CPE framework has experienced challenges with procurement obligations.[63] SCE states that the proposal will add significant administrative complexity to the RA program and the CPE's role, which is currently much more limited and less costly than the RCA proposal.

CAISO supports elements of the proposal, including limiting reliance on backstop procurement and that the proposal is not solely a waiver.[64] CAISO and SCE assert, however, that it will add significant work to an already compressed monthly showing timeline.[65] PG&E contends that allocating the ORCA's administrative costs to all LSEs regardless of whether they relied on the ORCA is inconsistent with cost-causation principles and inequitable to LSEs that did not

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[62] SVCE Opening Comments at 5, MRP Opening Comments at 14, WPTF Opening Comments at 10.

[63] Vistra Opening Comments at 12, SCE Opening Comments at 8, SVCE Opening Comments at 5.

[64] CAISO Opening Comments at 8.

[65] CAISO Opening Comments at 8, SCE Opening Comments at 8.

use the ORCA.[66] SCE opposes giving LSEs a waiver due to excessive prices, as it would relieve LSEs of their procurement obligations.[67]

WPTF, MRP, and Vistra argue that the proposal is outside the scope of Track 1.[68]

4.5.3.2. Discussion

The Commission appreciates Cal Advocates' efforts to put forth a creative proposal to address high prices in the RA market while balancing a mechanism to improve grid reliability. A wide range of parties, however, express numerous concerns with the structure of the RCA proposal, as well as the amount of time and work that would be required to further develop the proposal.

The Commission finds that the proposal would require significant stakeholder discussion and development before it could be considered for implementation. In addition, as parties have highlighted, the current RA compliance review timeline is very compact – from LSEs' submission of year-ahead filings to Energy Division's review of filings and issuance of deficiency notices to LSEs' submission of month-ahead filings. It is unclear how and whether a process as complex as the RCA proposal could be layered into the current RA timeline. As such, we decline to adopt the RCA proposal.

4.5.4. Allocation of Effective PRM or Strategic Reliability Reserve Capacity

AReM states that non-investor-owned utility (IOU) LSEs do not receive Cost Allocation Mechanism (CAM) credits for resources procured by IOUs to meet effective PRM targets, although costs are covered from non-IOU LSE

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[66] PG&E Opening Comments at 20.

[67] SCE Opening Comments at 8.

[68] WPTF Opening Comments at 10, MRP Opening Comments at 14, Vistra Opening Comments at 12.

customers through the CAM.[69] AReM thus argues that it is unfair that IOUs may show those resources on CAISO supply plans while non-IOUs cannot, potentially resulting in a cost shift where non-IOU LSE customers double pay for RA resources when CPM costs are allocated. AReM proposes that the Commission issue LSEs' allocations of "effective" capacity they may report on CAISO supply plans consistent with the CAM today. AReM notes that this would only impact reporting of supply to CAISO.

CalCCA supports this proposal, stating that allowing IOUs to mitigate risk of CPM costs, even though all LSEs pay for effective PRM resources, results in a cost shift to unbundled customers.[70]

In opening comments, PG&E recommends allocating capacity from Strategic Reliability Reserve (SRR)-procured resources to alleviate near-term tightness in the RA market.[71] PG&E proposes that the Commission coordinate with CAISO and the Department of Water Resources (DWR) to allocate 2,859 MW of capacity from once-through-cooling (OTC) gas resources under contract with DWR to all LSEs to use towards RA requirements. The allocation would focus on summer months of greatest concern (July-September) and apply through summer 2026 as DWR contracts are set to expire in December 2026.

PG&E recognizes SRR resources are not considered RA resources and are only to be "called upon to support grid operations during extreme" events; however, PG&E argues that this should not prevent the resources from being used towards RA requirements. PG&E points out that the IOUs' Base Interruptible Program (BIP) resources are only called on during CAISO

[69] AReM Proposal at 3.

[70] CalCCA Opening Comments at 21.

[71] PG&E Opening Comments at 12.

emergency events but are allowed to count towards LSEs' RA requirements. Thus, PG&E reasons that SRR-procured resources could be treated similarly as BIP resources on an interim basis. PG&E notes that this would require expeditious coordination between agencies and further development in Track 2.

AReM, SCE, SDG&E, and Shell Energy support further discussion of SRR allocation in Track 2.[72] AReM is concerned about the need to coordinate allocation with DWR and CAISO, which adds uncertainty that this would be feasible. Sierra Club/CEJA support PG&E's proposal but state that credits should be allocated based on peak load share, as all Californians (not just jurisdictional LSEs' customers) pay for these resources.[73]

CAISO, Calpine, and MRP oppose PG&E's proposal and generally state that SRR resources were intended for "extreme events" and not for use as RA resources.[74] MRP comments that SRR resources are meant to be used sparingly and using them as RA resources would be double-counting and result in such resources being unavailable for a 0.1 LOLE event. Calpine argues that counting SRR resources as RA resources is inconsistent with guidance from multiple agencies.

CAISO states that SRR resources are comprised of more than just OTC resources and were designed to assist with grid reliability beyond 1-in-10 events; therefore, the Commission should not use these resources to backfill LSEs' RA requirements. CAISO adds that because SRR resources are only called on in extreme events or grid emergencies, these resources do not regularly submit

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[72] AReM Reply Comments at 12, SDG&E Reply Comments at 6, SCE Reply Comments at 2, Shell Energy Reply Comments at 7.

[73] Sierra Club/CEJA Reply Comments at 6.

[74] CAISO Reply Comments at 5, Calpine Reply Comments at 1, MRP Reply Comments at 7.

offers in the CAISO market and are not subject to the same availability rules as RA resources. CAISO asserts that these resources should not be considered a substitute for RA capacity that is generally available to support the grid year-round.

WPTF opposes PG&E's proposal as it was not submitted with other Track 1 proposals and not subject to appropriate vetting.[75] WPTF also argues that affording special treatment to SRR resources would likely require significant changes to CAISO's tariff and RA processes.

4.5.4.1. Discussion

AReM expresses concern that if CAISO makes a CPM designation and needs to allocate costs to LSEs, effective PRM supply is counted towards the IOUs' RA requirements, but not towards non-IOUs' requirements, which may result in a cost shift. The Commission finds that AReM's proposal is not implementable due to timing issues with CAISO's processes and with the IOUs' effective PRM resource submissions. CAISO's systems require Local Regulatory Authority credits to be provided to CAISO five business days prior to the T-45 showing deadline, to be uploaded into the Customer Interface for Resource Adequacy (CIRA) system and count towards individual LSEs' showings. By contrast, the IOUs currently provide effective PRM showings to Energy Division at T-45, and then again at T-30, documenting the available supply being provided to count towards the effective PRM.

AReM's proposal would require Energy Division to provide effective PRM credits to CAISO ahead of the monthly backstop process (which begins at T-30), which is not possible at this time given the timing of receiving effective PRM resource supply from the IOUs and the restrictions on sending CAISO supply

[75] WPTF Reply Comments at 1.

credits for the CPM process. As such, we decline to adopt AReM's proposal. Energy Division is encouraged to coordinate with CAISO to look for potential solutions to address the current timing limitations of providing effective PRM supply credits to CAISO ahead of the monthly CPM process.

With respect to PG&E's proposal, the Commission agrees with parties that assert that SRR resources are meant to address extreme events and not meant to backfill RA requirements. We also agree with CAISO that SRR resources are comprised of more than OTC resources and such resources are not regularly offered to the CAISO market and are not subject to the availability rules of RA resources. We decline to adopt PG&E's proposal.

4.6. Modifications to Resource Counting Rules

4.6.1. Hybrid and Co-Located Resource Counting

CESA states that the current QC methodology for hybrid and co-located resources, as adopted in D.20-06-031, applied different treatment for resources with and without grid-charging restrictions.[76] Under the current methodology, the renewable component of a grid-charging restricted resource is given a reduced QC value to account for energy sufficiency of the storage component. CESA points out that under the SOD framework, the storage charging sufficiency verification eliminates the need for the current QC calculation for hybrid and co-located resources with grid-charging restrictions. CESA argues that it is no longer appropriate to reduce the QC of the renewable component because its energy is not restricted from serving onsite and offsite storage under the SOD framework. CESA therefore proposes that the renewable component's QC should be calculated the same as any other renewable resource's QC, the energy storage component be calculated the same way as any other energy storage's QC,

[76] CESA Proposal at 12.

and the total QC value of the resource should be the sum of the two components limited by the Point-of-Interconnection (POI) limit.

CalCCA, WPTF, Sierra Club/CEJA, and Terra-Gen support CESA's proposal.[77] Cal Advocates opposes CESA's proposal, stating that the Commission addressed the methodology for hybrid and co-located resources in D.23-04-010.[78] CESA disagrees with Cal Advocates and argues that D.23-04-010 did not fully describe changes required for the QC methodology for hybrid and co-located resources to recognize the interactive effects of the SOD framework.[79]

The Commission agrees with CESA that derating the QC of hybrid and co-located resources based solely on grid restrictions does not reflect the actual capabilities of many of these resources. Further, if paired resources should be derated, the deration should apply to the storage resource that is not fully charged. However, paired resources with grid-restricted charging are potentially less reliable than paired resources which allow grid-charging because grid-restricted resources may not have sufficient charging capacity to fully charge the paired resource during certain months. The grid charging restriction is being addressed as part of a state-of-charge test in the current SOD templates, which will ensure that paired storage resources have enough energy to provide capacity from their paired resources.[80] Because the state-of-charge test addresses the paired resources' grid-restricted charging limitations, there is no longer a need to

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[77] CalCCA Reply Comments at 17, WPTF Opening Comments at 8, Sierra Club/CEJA Reply Comments at 3, Terra-Gen Opening Comments at 3.

[78] Cal Advocates Opening Comments at 14.

[79] CESA Reply Comments at 8.

[80] *See e.g.*, RA SOD Showing Template User's Guide at 19, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/rashowing_template_usersguide_rev27.docx.

derate the QC values of paired renewables in order to account for grid-charging restrictions on paired storage resources.

Accordingly, under the SOD framework, hybrid and co-located resources' QC counting methodology will be as follows: the renewable component's QC value will be calculated the same as other renewable resources' QC values, the storage component's QC value will be calculated the same as other storage resources' QC values, and the total QC value of the resource will be the sum of the two components limited by the POI limit and the compliance tool's state-of-charge test. This will be effective for the 2025 RA compliance year.

4.6.2. Monthly Exceedance Levels

CalWEA proposes that exceedance levels under the SOD framework should be set on a monthly basis, rather than a seasonal basis, using the same mean-squared error approach developed by Energy Division Staff in fall 2023 to calculate exceedance levels in accordance with Ordering Paragraphs 5 and 6 of D.23-04-010.[81] CalWEA asserts that this approach is more precise, avoids the subjective determination of seasons, and conforms to the monthly RA requirements. CalWEA also recommends that monthly exceedance numbers should be updated every five years, rather than annually, to provide stability and predictability, and recalculated in the event of a major change in circumstances (*e.g.*, substantial technology advancements).

Cal Advocates, MRP, Sierra Club/CEJA, and Terra-Gen support the proposal.[82] Cal Advocates states that monthly exceedance values would require little additional staff support and would ensure that wind and solar resources

[81] CalWEA Revised Proposal at 2.

[82] Cal Advocates Opening Comments at 2, MRP Opening Comments at 17, Sierra Club/CEJA Reply Comments at 8, Terra-Gen Opening Comments at 4.

receive full value for their expected reliability contributions. Terra-Gen argues that the benefits of improving accuracy for wind and solar resources outweigh the additional burden on staff resources. MRP supports CalWEA's proposal but recommends the issue be taken up in Track 2.

The Commission agrees that adjusting exceedance levels for wind and solar resources to a monthly level from the current seasonal level would improve accuracy in exceedance levels and would not be burdensome on Commission Staff resources. The Commission, however, finds that instead of an update every five years, an update every three years strikes an appropriate balance between stability of the exceedance values and inclusion of up-to-date data.

Accordingly, under the SOD framework beginning with the 2025 RA compliance year, the exceedance levels for wind and solar resources will be adjusted to monthly levels, with the next update to occur in 2024 and subsequent updates every three years thereafter. Each refresh will also use the most up-to-date rolling six-year historical data points, consistent with the methodology adopted in D.23-04-010 (*e.g.*, 2018-2023 for 2024 update, 2021-2026 for 2027 update).

4.7. Modifications to the Storage Charging Sufficiency Test

4.7.1. System-Wide Charging Sufficiency Test

CESA proposes an initial system-wide storage charging sufficiency test before assessing sufficiency at the LSE level.[83] Energy Division would collect LSEs' RA plans, aggregate the shown deliverable resources, and determine if the aggregate excess energy is sufficient to meet the aggregate energy deficiency. If the system is sufficient, individual LSEs would not be assessed for non-

[83] CESA Proposal at 9.

compliance with energy sufficiency requirements. If the system has a charging deficiency, Energy Division would allocate any system-wide storage charging benefit to deficient LSEs before assessing penalties.

AES, Hydrostor, REV, and Terra-Gen support the proposal.[84] Terra-Gen states that the proposal is consistent with how the RA program avoids prescribing how LSEs meet overall reliability needs and only sets minimum requirements.

DMM recommends that the Commission ensure LSEs properly submit their grid-charging constraints into the RA showing template when considering CESA's proposal.[85] DMM states that co-located and hybrid resources typically have constraints that limit their ability to charge from the grid due to federal investment tax credit and local property tax exemptions that require the storage resource to charge from onsite renewable generation output. DMM states that this negates the ability of these resources to benefit from excess system-wide energy generation for charging.

Cal Advocates, MRP, and PG&E oppose CESA's proposal.[86] These parties generally state that the proposal would allow LSEs to avoid penalties if they are deficient on their energy sufficiency determination, so long as all aggregate LSEs show enough charging sufficiency. This would result in leaning on LSEs that have procured sufficient capacity, and would be contrary to the SOD structure's intent that each LSE demonstrate sufficient capacity. PG&E states that the proposal removes incentives to meet requirements and could result in a cost

[84] AES Opening Comments at 3, Hydrostor Opening Comments at 2, Terra-Gen Opening Comments at 3, REV Opening Comments at 3.

[85] DMM Opening Comments at 9

[86] Cal Advocates Opening Comments at 15, MRP Opening Comments at 7, PG&E Opening Comments at 17.

shift. MRP counters that if CESA is correct that sufficient capacity exists on an aggregate basis, LSEs should not have difficulty meeting their requirements. If an LSE does not have sufficient charging, on the other hand, it can reduce the usage of storage to meet its RA requirements. MRP adds that overall sufficient charging energy is reviewed in the IRP proceeding and therefore, should be reflected in the effective load carrying capacity (ELCC) QC value of storage resources.

The Commission agrees with those parties that argue that a system-wide charging sufficiency test would allow LSEs that have not met their charging sufficiency requirement to lean on LSEs that have procured to meet those requirements. We concur that this would be contrary to the initial intent of the SOD framework, would eliminate incentives for LSEs to meet charging sufficiency requirements, and would undermine the RA program's LSE-based compliance program. For these reasons, we decline to adopt CESA's proposal.

4.7.2. Initial State-of-Charge Modification

CESA states that under the SOD framework, storage resources are considered as starting the "worst-day" at 0 megawatt-hour (MWh) state-of-charge.[87] CESA states that this assumption does not reflect the actual reliability value that storage provides and is overly restrictive. CESA cites CAISO data indicating that storage enters each summer day with between 4,000 MWh–7,500 MWh state-of-charge. CESA recommends that each resource's initial state-of-charge be determined by conservatively considering two worst days in a row, as follows:

1. First Day: an LSE first determines the maximum end-of-day state-of-charge that can be achieved while minimizing

[87] CESA Revised Proposal at 9.

its 24-hour RA requirement deficiencies given its resource portfolio with a starting state-of-charge of 0 MWh.

2. Compliance Day: an LSE maintains the resource's First Day end-of-day state-of-charge as an initial state-of-charge value to be considered for compliance with the charging sufficiency test.

DMM comments that RA ratings for storage resources should take actual availability of batteries into account, including state-of-charge limitations and operational resource constraints.[88] DMM asserts that this means storage capacity availability has two dimensions: (1) resource availability after outages and derates, and (2) state-of-charge availability.

The Commission observes that Energy Division's RA SOD Showing Template User's Guide provides that "[a]n initial state-of-charge of 100% is assumed for all resources at the beginning of hour ending 1 of the first day…."[89] CESA's proposal may have been based on an earlier version of the SOD template. Because a 100 percent initial state-of-charge is assumed in the current version of the SOD template, we find CESA's proposal to be moot and we decline to adopt it. For initial SOD implementation, the Commission finds that the state-of-charge assumptions in the SOD templates are sufficient. We will continue to monitor this aspect of the SOD program and make adjustments to the state-of-charge assumptions as warranted.

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[88] DMM Opening Comments at 5.

[89] *See* RA SOD Showing Template User's Guide at 19, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/slice-of-day-compliance-materials/rashowing_template_usersguide_rev27.docx.

4.7.3. Energy-Only Resources for Charging Sufficiency Requirement

SCE seeks clarification that energy-only (EO) resources can contribute to charging sufficiency for both co-located and hybrid storage resources.[90] In D.23-04-010, the Commission provided that "[a]n energy-only (EO) resource is eligible to count towards the storage charging sufficiency requirement if the EO resource is charging exclusively on-site storage, regardless of whether the paired storage is able to charge from the grid."[91] SCE states that while the record of the proceeding in R.21-10-002 and body of the decision support that EO resources may count towards the charging sufficiency requirement of co-located storage resources behind the same POI, Ordering Paragraph 7 provides that "the EO resource should exclusively charge on-site charge," implying that the Commission allows EO resources to provide charging sufficiency of paired storage resources in hybrid, but not co-located, configurations. SCE seeks a correction to Ordering Paragraph 7 to say that the Commission treats hybrid and co-located resources the same on this issue.

Ava, CESA, PG&E, and Sierra Club/CEJA support SCE's clarification that EO resources contribute to charging sufficiency for both co-located and hybrid resources.[92]

The Commission agrees with SCE's clarification that the Commission's intent in Ordering Paragraph 7 of D.23-04-010 was to allow both EO resources to provide charging sufficiency of paired storage resources in hybrid and co-located configurations. Accordingly, the following is adopted:

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[90] SCE Proposal at 8.

[91] D.23-04-010 at OP 7.

[92] Ava Opening Comments at 3, CESA Opening Comments at 3, PG&E Reply Comments at 10, Sierra Club/CEJA Reply Comments at 4.

> Paired storage resources will be characterized on the Master Resource Database (MRD) as either charging exclusively from paired resources or allowing grid charging. An energy-only (EO) resource is eligible to count towards the storage charging sufficiency requirement if the EO resource is charging exclusively paired storage, regardless of whether the paired storage is able to charge from the grid. The charging capacity of the renewable resource will be capped at the amount that can be used to charge the paired storage and the storage will be capped at the interconnection limit. Paired components will be shown as separate assets on the MRD and load-serving entities' showings, and the total of the components must not exceed the interconnection amount in any hour.

SCE also seeks clarification as to whether the off-taker of co-located storage resources must have off-take rights for the EO resources to allow counting towards charging sufficiency of the storage in SOD filings, but SCE acknowledges that this issue requires further development.[93] For early implementation, therefore, SCE proposes that starting in 2025, energy sufficiency from EO resources be prorated to all paired storage resources based on the NQC of the storage resources.

The Commission finds this to be reasonable as it allows the energy sufficiency benefit of the EO components to remain bundled with the storage components, while allowing for further discussion among stakeholders. It should also be noted that SOD compliance largely depends on supply plan verification from CAISO. EO resources are not able to submit supply plans to CAISO to confirm off-take agreements. Bundling the EO attribute with the paired resource will help ensure that the energy sufficiency value can be confirmed for compliance.

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[93] SCE Proposal at 8.

As such, beginning with the 2025 compliance year, and on an interim basis, energy sufficiency from EO resources will be prorated to all paired storage resources based on the NQC of the storage resources. For a more permanent solution, the issue of off-taking rights for EO resources should be considered in a later track of this proceeding.

4.7.4. Multi-Day Storage Facilities

Form Energy states that under the SOD framework, multi-day storage (MDS) systems should not be required to demonstrate that energy storage resources are fully recharged within the same 24-hour period.[94] Form Energy contends that this requirement is not reasonable as applied to MDS systems, like Form Energy's 100-hour battery, because they are able to discharge continuously well over a 24-hour period without recharging. Form Energy also states that a MDS system typically operates by charging and shifting excess renewable energy across many days and weeks to integrate renewable resources over longer periods. Form Energy asserts that its proposal is consistent with hydroelectric resources (such as pumped storage hydro) that are eligible to be shown as firm 24-hour resources at their monthly QC, regardless of duration limitations. Form Energy states that 100 hours is within the range of existing pumped storage hydro duration capabilities and that the "recharge" from stream flows is conceptually not different from partial recharge that would likely occur for a MDS dispatch. Form Energy thus proposes that MDS resources that can dispatch over multiple days should be treated as firm resources on an interim basis, until the Commission can further determine how MDS resources should be treated.

[94] Form Energy Proposal at 5.

CESA and Hydrostor support this proposal.[95] Hydrostor states that the RA program must distinguish between long-duration energy storage's (LDES) continuous discharge capabilities and shorter duration resources, to avoid over-reliance on single-technology storage.

Cal Advocates opposes the proposal, arguing that it not clear that the 100-hour battery would have sufficient state-of-charge in each month of the 24-hour showing to provide firm 24-hour capacity.[96] Cal Advocates notes that Form Energy states that its battery has an expected annual dispatch profile where the state-of-charge ranges between 0 to 10 percent in certain months, which would only provide between 0 to 10 hours of dispatch at its QC value, not 24 hours. Cal Advocates also states that exempting a 100-hour battery from the energy sufficiency test is problematic due to the battery's low round-trip efficiency of 50-55 percent. Cal Advocates states that in certain months of low state-of-charge, Form Energy's battery would require double the energy to charge than it would to discharge, and there is no guarantee of energy sufficiency.

As the Commission stated in D.23-04-010, "ensuring LDES resources are properly valued across the SOD framework is critical to the durability and success of the SOD framework."[97] In that decision, we concluded that a MDS counting methodology was not ready for adoption and "[a]dditional discussion on this issue should be undertaken after the initial implementation of the SOD framework."[98] The Commission finds that Form Energy's proposal lacks sufficient record support, and that Cal Advocates raises valid concerns that

[95] CESA Opening Comments at 3, Hydrostor Opening Comments at 3.

[96] Cal Advocates Opening Comments at 11.

[97] D.23-04-010 at 45.

[98] *Id*.

should be addressed. The Commission deems that additional development is still required to inform a MDS counting methodology and encourages parties to coordinate to develop an implementable solution in Track 3 of this proceeding, for application in the 2026 RA compliance year.

4.8. RA Import Requirements

4.8.1. Import Allocation Rights

In D.05-10-042, the Commission adopted a requirement that resource-specific and/or non-resource-specific import energy contracts must be paired with an import allocation right to count towards RA requirements.[99] PG&E states that under the SOD framework, a resource-specific import that has solar technology would have NQC values that differ across the 24-hour time period for RA compliance.[100] PG&E states that in D.23-04-010, however, the Commission stated that it would provide CAISO with "the greater of the peak hour value and a very small non-zero value (e.g., 0.01 MW) if the minimum value is zero" such that CAISO would use a single NQC value to evaluate compliance with the RA program.[101] PG&E seeks clarification on how many import allocation rights must be paired with resource-specific solar and wind resources that are also import energy contracts, and whether the amount is based on the value used by CAISO or another value used by the Commission. PG&E states that clarification is needed because the annual import allocation process is expected to begin in summer 2024.

Cal Advocates agrees that clarification is needed and states that CAISO and Energy Division have stated that imported variable energy resources would

[99] D.05-10-042 at 55.

[100] PG&E Proposal at 6.

[101] *Id.* (citing D.23-04-010 at OP 20).

need import allocation rights equivalent to the QC shown but did not clarify whether the rights must be shown equal to the RA value CAISO assigns or the RA value an LSE shows to the Commission for peak hour.[102]

The Commission agrees that clarification is needed. Accordingly, beginning with the 2025 RA compliance year, for resource-specific solar and wind import resources, an LSE must have import allocation rights equal to the RA value shown to the Commission at the peak hour of the month, unless the value at the peak hour is zero, in which case the LSE should have import allocation rights equal to the minimum value of 0.1.

4.8.2. Off-Peak Import Energy

In D.23-04-010, the Commission determined that for the SOD framework, a non-resource-specific import can count towards the RA requirements if certain requirements are met.[103] One requirement is that:

> The energy must self-schedule (or in the alternative, bid in at a level between negative $150/MWh and $0/MWh) into the California Independent System Operator day-ahead and real-time markets at least during the Availability Assessment Hours every Monday - Saturday excluding North American Electric Reliability Corporation holidays throughout the RA compliance month.

SCE proposes that LSEs should be allowed to count off-peak import energy that is not available during the Availability Assessment Hours (AAH) toward meeting RA requirements under the SOD framework, regardless of whether the import is paired with the on-peak import on a specific branch group, so long as the import adheres to the existing import requirements.[104] SCE argues

[102] Cal Advocates Opening Comments at 16.

[103] D.23-04-010 at OP 17.

[104] SCE Proposal at 7.

that it is critical for LSEs to procure and count off-peak imports along with on-peak imports to meet RA requirements but also to provide excess deliverable energy to provide energy sufficiency for storage.

AReM supports SCE's proposal as a helpful clarification to allow off-peak imports for off-peak slice compliance, and agrees that this would provide another tool for LSEs to meet battery charging sufficiency requirements and to meet non-coincident peak demands in off-peak hours.[105] Cal Advocates also supports SCE's proposal, stating that it would increase the RA-eligible supply, which would likely be at lower prices compared to other imports.[106] Cal Advocates states that a non-resource-specific off-peak import should still be subject to the other import rules, other than the AAH availability and bid requirement.

In comments on the proposed decision, SCE recommends adopting a validation process to verify the MOO to CAISO's energy markets for off-peak energy resources, similar to the process currently used to validate new resources and on-peak energy.[107] SCE also recommends that an interim rule should apply to Q3 2025 only until a full solution is developed. The Commission finds that SCE's proposal, with modifications raised in comments to the proposed decision, has merit. Accordingly, for Q3 2025, an LSE may count off-peak import energy that is not available during the AAH window towards meeting its RA requirements under the SOD framework, regardless of whether the import is paired with the on-peak import on a specific branch group, so long as the off-peak import energy adheres to the other existing import requirements. The LSE

[105] AReM Opening Comments at 17.

[106] Cal Advocates Opening Comments at 18.

[107] SCE Comments on Proposed Decision at 4.

must provide Energy Division with proof demonstrating: (1) the availability of import allocation rights, and (2) if there is an associated on-peak import on the branch group, to avoid over and under accounting of import allocation right availability.

4.8.3. Other Modifications to Imports Rules

BPA and CalCCA submit proposals regarding modifications to the import RA rules. BPA states that under the current rules, offers from out-of-state generators must be associated with a specific generator pseudo-tied into a California balancing area authority (BAA).[108] BPA states that this limits economic bids from out-of-state generators to single generators registered with CAISO and controlled for dispatch by a California BAA, which prevents marketers that operate coordinated systems for multiple hydro generators from making economic bids into California. BPA recommends allowing an exception for generation similarly situated to BPA's. That is, BPA proposes that a group of generators that have attested to unencumbered capacity and have firm transmission should be allowed to bid economically. BPA argues that this proposal would incentivize more participation from out-of-state hydro resources into California.

CAISO, CEERT, Microsoft, MRP, PG&E, SCE, and WPTF support BPA's proposal.[109] WPTF states that the proposal removes a significant impediment for import suppliers to participate in the California market and potentially increases the availability of imports to California LSEs, while still addressing concerns about speculative supply by requiring imports to be backed by physical capacity

[108] BPA Opening Comments at 2.

[109] CAISO Opening Comments at 7, CEERT Reply Comments at 5, MRP Opening Comments at 12, Microsoft Opening Comments at 11, PG&E Opening Comments at 10, SCE Opening Comments at 8, WPTF Opening Comments at 9.

and have firm transmission rights. CAISO states that BPA's proposal is implementable in the near-term and will help unlock additional reliable, firm RA supply. PG&E agrees that existing import rules prevent highly reliable resources from participating due to onerous requirements designed to address speculative import supply.

CalCCA re-submits its previous proposal from R.21-10-002 to allow non-resource-specific imports to be bid up to a maximum price based on estimated costs of a typical marginal resource within CAISO.[110] CalCCA cites data showing that year-ahead RA imports and bids have steadily declined since the current rules were adopted in 2020, and that LSEs that have expressed that suppliers are unwilling to transact under the current rules. CalCCA further cites analysis that Combustion Turbines (CT) bidding $0 during the AAHs have an operational cost greater than the maximum bid price of $0/MWh.

CalCCA proposes that a new maximum non-resource-specific RA import bid price should be set based on the typical marginal resource's (the CT's) estimated cost based on heat rate, natural gas prices and penalties, variable operations and maintenance, and greenhouse gas data. CalCCA proposes three tiers based on natural gas prices up to $10, $20, and $30 per MMBtu, with the Commission determining which tier is applicable each month.

AReM, CEERT, MRP, Microsoft, SCE, Shell Energy, and WPTF support CalCCA's proposal.[111] SCE states that the proposal addresses the Commission's past concern that some imports were bid at the cap, while still allowing imports to avoid bidding at negative prices. SCE states that the current bidding rules do

[110] CalCCA Proposal at 12.

[111] AReM Opening Comments at 19, CEERT Reply Comments at 5, Microsoft Opening Comments at 11, MRP Opening Comments at 12, SCE Opening Comments at 8, Shell Energy Opening Comments at 2, WPTF Opening Comments at 10.

not increase CAISO's access to generation capacity but rather, increase costs of the RA program. WPTF and MRP generally state that the proposal would incentivize out-of-state suppliers with operating costs higher than the current maximum bid price to sell import RA to California. AReM states that the proposal may broaden import access in a tight RA market by allowing generators to sell RA without requiring them to operate at a loss.

BPA states that from a supplier's perspective, it continues to see opportunities to offer resources to California entities but does not view its proposal as incompatible with CalCCA's proposal.[112]

4.8.3.1. Discussion

The Commission acknowledges the broad interest among parties to increase the availability of reliable RA imports to California. Currently, an aggregation of physically linked resources, such as those owned by BPA, would be subject to the rules for non-resource-specific imports set forth in D.20-06-028.[113] The Commission understands that BPA is proposing an exception to the non-resource-specific import bidding rules, if the non-resource-specific import meets the following criteria:

(1) The import is an aggregation of physically-linked resources.

(2) The import is owned by the contracting party providing the import RA to the CAISO BAA, where import capacity:

   a. Is unencumbered, with an accompanying attestation; and

   b. Has firm transmission to the CAISO BAA.

[112] BPA Opening Comments at 2.

[113] As revised per D.23-04-010, OP 17(b).

We agree with parties that BPA's proposal, with some modifications, would remove a barrier for out-of-state suppliers that would incentivize suppliers to sell RA imports to California LSEs. We also find that requiring imports to have firm transmission rights and requiring an attestation that confirms the import is backed by physical capacity not committed to another entity will help address the Commission's past concerns about speculative RA imports.

As such, the Commission finds it reasonable to adopt the following exemption, on an interim basis. Non-resource-specific imports may be exempt from the non-resource-specific import bidding requirements, provided that the LSE submit with its RA filing an attestation from the import provider attesting that the following conditions apply to the non-resource-specific import:

(1) That the import provider owns the energy resources providing the contracted capacity.

(2) That the resources are an aggregation of physically linked resources.

(3) That the capacity from the resources is not otherwise encumbered or sold to another party.

(4) That the import provider has firm transmission to the CAISO BAA for the full amount under contract and that it is backed by operating reserves.

(5) That the energy will be economically bid into the CAISO day-ahead and real-time markets in alignment with CAISO must-offer obligation rules for resource-specific imports.

(6) That should the resource receive a dispatch from the CAISO market, the energy and transmission will be firm and given priority equal to the LSEs' native load (i.e., that the energy will not be curtailed, except when the LSE is

> curtailing its own native load) and will not be curtailed for economic or reliability reasons, except under the circumstances noted above.

If the non-resource-specific import meets these requirements, it will be exempt from the current non-resource-specific import bidding requirements. The attestation affirming the conditions required above must be included with the LSE's RA filing to Energy Division. This will be effective upon the issuance of this decision.

Energy Division is authorized to monitor the bidding behavior of these resources regularly to ascertain issues of speculative supply. This monitoring will help inform the Commission's determination on whether to continue this exemption.

Regarding CalCCA's proposal, the Commission finds that the proposal is administratively complex and burdensome to implement. The proposal requires a complex multi-stage calculation based on CalCCA's assumption that the marginal CT costs and heat rate within CAISO would set an appropriate price for import energy from outside CAISO, which is primarily composed of hydroelectric, wind, and solar imports. In addition, heat rates and costs put forward by CalCCA would require additional investigation, and there is no evidence that this calculation would result in the best outcome in the RA market or for ratepayers. For these reasons, we decline to adopt this proposal.

4.9. Unforced Capacity Evaluation

Energy Division, PG&E and SCE recommend the following proposals related to a UCAP mechanism. Energy Division recommends using a class average UCAP framework to discount the NQC of affected generators for

monthly SOD counting in the MRD.[114] Energy Division states that the derate would be a combination of Equivalent Demand Forced Outage Rate (EFORd) and ambient derate to effectively replicate the LOLE effects resulting from the forced outage distributions and heat derate profiles using the IRP and RA modeling. Monthly factors would be calculated for both thermal power plants and battery energy storage systems, and separated into three categories (high, mid and low). The resource categories would also be separated into classes based on location.

Energy Division states that a revised version of the ambient thermal derate model that was presented to stakeholders in 2023 would be applied to the LOLE modeling and would be combined with the EFORd data to create class-specific monthly derate factors. A generator's UCAP value would be posted to the MRD, would be applicable in the SOD tool and the RA compliance program, and would be part of the LOLE model to create RA obligations. Energy Division contends that the proposal would result in a consistent process for derating resources by passing appropriate availability incentives to resources through QC derates, as well as result in planning for reliability impacts of ambient temperatures and seasonal changes. Energy Division also recommends coordinating with CAISO on refinements to the Resource Adequacy Availability Incentive Mechanism (RAAIM) to ensure incentives and penalties are compatible with the proposed UCAP framework.

PG&E submits proposed principles that should be reflected in a viable UCAP methodology.[115] The principles are that a final methodology should: (1) be implemented simultaneously by CAISO to avoid complications that would

[114] Energy Division Proposal at 13.

[115] PG&E Proposal at 4.

stem from significantly different QC values between the Commission and CAISO; (2) be adopted in tandem with adjustments to the PRM to reflect the shift of resource outage uncertainty from the PRM to the QC value; (3) be adopted with changes to CAISO's RAAIM; (4) be at the resource-specific level to avoid QC distortions that are inevitable in an average-based approach; (5) use public data so resource owners can reasonably calculate a QC value; and (6) feature reasonable timing for implementation.

SCE recommends that UCAP-based QC adjustments should be based on historical outage performance for existing resources and expected outage performance for new resources.[116] SCE reasons that as forced outage performance of new resources becomes known, performance should be blended with the technology's expected performance until the historical period requirements for individual resource UCAP-based QC adjustments have been met. SCE recommends a three-year look-back performance period consistent with the periods for geothermal and biomass resources.

4.9.1. Comments on Proposals

CalCCA, Cal Advocates, and DMM support a UCAP framework but recommend developing resource-level UCAP values, as opposed to Energy Division's class average. These parties generally state that resource-specific values are necessary to incentivize units to be available to the CAISO market and to minimize forced outages, rather than a derate that affects a group of resources.[117] DMM states that forced outages should be separated into two categories: those within the control of the scheduling coordinator and asset

[116] SCE Proposal at 6.

[117] CalCCA Opening Comments at 19, Cal Advocates Opening Comments at 7, DMM Opening Comments at 2.

owner, and those outside of their control. CalCCA recommends developing public UCAP values using the Outage Management System (OMS), and DMM recommends using public outage data to allow for transparency and unit-level UCAP values. Cal Advocates recommends Energy Division coordinate with CAISO to harmonize outages reported via the Generator Availability Data System with CAISO's OMS.[118]

Microsoft, Calpine and SDG&E support several of PG&E's proposed principles, including the focus on resource-specific UCAP values and coordination between the Commission and CAISO.[119] Calpine adds that any UCAP methodology should allow suppliers to appeal assessed UCAP values and avoid locking units into historical performance when resources are modified.

CAISO, PG&E, SDG&E, Vistra and WPTF oppose adopting a UCAP methodology at this time as discussion is needed to address outstanding issues.[120] PG&E supports deferring a UCAP methodology as Energy Division's proposal would reduce RA capacity from thermal plants and potentially tighten market conditions further. PG&E also states that Energy Division's proposal does not explain how the PRM would be adjusted since the current PRM includes some forced outage risk. SDG&E states that adopting a UCAP methodology would result in different counting between CAISO and the Commission, causing confusion and further divergence between the two RA programs. Vistra advocates for a UCAP working group to develop a robust methodology.

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[118] Cal Advocates Opening Comments at 7.

[119] Microsoft Opening Comments at 13, Calpine Opening Comments at 2, SDG&E Opening Comments at 5.

[120] CAISO Opening Comments at 6, PG&E Opening Comments at 18, SDG&E Opening Comments at 5, Vistra Opening Comments at 6, WPTF Opening Comments at 7.

While CAISO appreciates Energy Division's commitment to coordinating with CAISO on UCAP, CAISO continues to vet components of a proposal in working groups and identifies areas for more discussion between CAISO and the Commission: (1) whether the CAISO or Commission should develop a UCAP mechanism and/or application of ambient derates; (2) to strengthen availability incentives, whether a UCAP mechanism and/or ambient derates should be applied on a resource-specific basis versus class average; and (3) if a resource-specific approach is favorable, what data sources are required.

ACP-CA, AES, CESA, Hydrostor, REV, and Terra-Gen oppose applying Energy Division's proposal to storage resources at this time.[121] These parties generally state that outstanding issues need to be discussed, including how to accurately apply outage data to the unique characteristics of storage and to consider unknown implications for storage in the SOD framework.

4.9.2. Discussion

As the Commission stated in D.23-06-029, we "support incorporating outages, including ambient derates, into a thermal resource's QC value and deem such work as critical to enhancing reliability."[122] The Commission observes that a broad range of parties agree that further discussion is needed to develop a UCAP methodology for thermal and storage resources. As such, we decline to adopt a UCAP methodology at this time. We note the UCAP framework is being further developed in Track 2, as a UCAP framework is intended to be used for 2026 RA LOLE modeling efforts and for developing forced and ambient outage derates for the 2026 compliance year at the

[121] AES Opening Comments at 1, ACP-CA Opening Comments at 15, CESA Opening Comments at 5, Hydrostor Opening Comments at 4, REV Opening Comments at 5, Terra-Gen Opening Comments at 7.

[122] D.23-06-029 at 29.

earliest. Parties are encouraged to discuss the UCAP framework in Track 2 workshops.

4.10. Demand Response Load Impact Protocols Working Group

In D.23-06-029, the Commission authorized Energy Division to pursue simplification of the current LIPs requirements using a stakeholder process.[123] Energy Division and multiple parties undertook a Working Group process to develop simplifications for the LIPs process and requirements. On January 19, 2024, the LIP Simplification Working Group submitted its LIP Working Group Report. No party commented on the LIP Working Group Report.

The Commission needs additional time to consider the LIP Working Group Report's recommendations and will address this issue in Track 2 of the proceeding. We encourage parties to review and comment on the LIP Working Group Report in Track 2 as well.

4.11. Other Proposals

4.11.1. Diablo Canyon Extension

In D.23-12-036, the Commission determined that the statutorily defined costs of extended operations for the Diablo Canyon Power Plant (DCPP) should be allocated among the three large electrical corporations, using a process that mirrors the CAM.[124] In D.23-12-036, the Commission also opted to utilize the existing CAM process to allocate RA benefits of DCPP to all LSEs in each IOU's service territory. This process requires the allocation of RA credits to non-IOU LSEs, and RA debits (negative values) to IOUs (an addition to the IOU's RA obligation) equal to the amount of CAM credits provided to non-IOU utility LSEs serving load in each transmission access charge area. In exchange for the RA

[123] D.23-06-029 at Conclusion of Law 17.

[124] D.23-12-036 at 74.

debit, the IOU can show the entire CAM resource on its RA plans. In the case of DCPP, credits will be allocated to all LSEs in each IOU's service area, including to non-PG&E IOUs for their bundled customer RA requirements, and the debit will only be provided to PG&E, as PG&E is the IOU managing the resource. The CAM also provides an IOU authority for cost recovery of replacement resources needed to manage scheduled outages when the IOU is acting as the scheduling coordinator for the CAM resource. In the event of an unplanned outage that results in PG&E's inability to meet its system RA obligations, D.23-12-036 states that this may be considered in the RA proceeding.

Energy Division states that consistent with D.23-12-036, it will allocate the RA benefits of the DCPP to all LSEs within each IOUs' service territory using the CAM.[125] In the event of an unplanned outage that results in PG&E's inability to meet its system RA obligations, Energy Division proposes that PG&E be allowed to file a system waiver similar to the system waiver for the Provider of Last Resort (POLR) adopted in D.20-06-031. Specifically, PG&E could file a Tier 2 Advice Letter outlining the reason for its deficiency in meeting its RA requirement due to the unplanned outage of the DCPP, and demonstrate it made every reasonable effort to procure replacement capacity to mitigate the unplanned outage.

AReM and SDG&E support Energy Division's proposal.[126] SDG&E encourages the Commission to provide the 2025 allocations as soon as possible as this will help LSEs understand preliminary 2025 positions and adjust procurement as needed. Vistra seeks clarification that the Commission did not

[125] Energy Division Proposal at 18.

[126] AReM Opening Comments at 20, SDG&E Opening Comments at 13.

intend that PG&E could show the entire DCPP on its RA showing, since a share of DCPP is being provided to all other LSEs as an RA credit.[127]

The Commission finds Energy Division's proposal for allocating credits from the Diablo Canyon Power Plant to all LSEs to be reasonable. We also find it reasonable that in the event of an unplanned outage at DCPP that results in PG&E's inability to meet its system RA obligations, a system waiver process will be adopted, similar to the waiver process for the POLR adopted in D.20-06-031.

Accordingly, consistent with D.23-12-036, Energy Division will allocate the RA benefits of the DCPP to all LSEs within each IOUs' service territory using the CAM. In the event of an unplanned outage that results in PG&E's inability to meet its system RA obligations, PG&E is eligible for a limited system waiver. The waiver request shall be submitted through a Tier 2 Advice Letter that provides: (1) the reason for PG&E's deficiency in meeting the RA requirement due to the unplanned outage of the DCPP, and (2) a demonstration that PG&E made every reasonable effort to procure replacement capacity to mitigate the unplanned outage. This is effective upon the issuance of this decision, commencing with the extended operating periods of DCPP Units 1 and 2.

Consistent with the current CAM mechanism, we also clarify that PG&E will get a RA debit equal to the amount of credits allocated to all other LSEs and in exchange, is permitted to show the entire DCPP on its RA showing.

4.11.2. Substitution Capacity Costs for CAM Resources

PG&E states that based on D.14-06-050, it currently manages CAM-eligible resources on behalf of all customers in its service territory and is responsible for providing substitution capacity to the CAISO when the resource is on an

[127] Vistra Opening Comments at 5.

outage.[128] PG&E states that in some cases, the calculation of these substitution capacity costs are based on a different benchmark price than the benchmark price that is used to provide substitution capacity from resources within PG&E's portfolio. This difference can result in cost-shifting between bundled customers and departed load customers.

To address this difference, PG&E recommends using the Power Charge Indifference Adjustment (PCIA) market price benchmark to determine substitution capacity costs when using resources from its PCIA-eligible portfolio, rather than the weighted average RA capacity price from the most recent Energy Division RA Report. PG&E states that this would eliminate the existing cost shift and ensure the appropriate set of customers are paying their proportional share of costs.

SDG&E and Cal Advocates support PG&E's proposal.[129] SDG&E states that the PCIA benchmark is a more current reflection of market prices and differentiates between system, local, and flexible RA products, and thus, is a more accurate benchmark that minimizes cost-shifting. Cal Advocates agrees that the PCIA benchmark is preferred as it better represents current RA market conditions and better reflects the alternative to procuring substitute RA from the market through a solicitation or broker market.

The Commission finds PG&E's proposal to use the PCIA market price benchmark to determine substitution capacity costs to be reasonable because it would minimize cost shifting between bundled customers and departing load. Accordingly, when an IOU uses resources from an IOU's PCIA-eligible portfolio, the IOU may use the PCIA market price benchmark to determine substitution

[128] PG&E Proposal at 2.

[129] SDG&E Opening Comments at 12, Cal Advocates Opening Comments at 19.

capacity costs for CAM resources. This is effective upon the issuance of the decision.

4.11.3. Deliverable Resources Shown to CAISO

CAISO proposes a rule that LSEs must show CAISO all deliverable resources on SOD RA plans (i.e., resources with full or partial deliverability status, not EO resources).[130] CAISO proposes that LSEs show these deliverable resources to CAISO regardless of what hour the resources are shown to the Commission in SOD showings. This rule would ensure deliverable resources shown to the Commission are shown to CAISO to correctly flag RA resources in CAISO's systems and processes, to ensure resources are subject to CAISO's RA rules, and so that CAISO accounts for these resources for RA compliance. CAISO notes that this rule would prevent CAISO from labeling these resources as eligible for other designations, such as the CPM.

No party commented on this proposal.

The Commission finds the proposal to be reasonable in order to ensure that all SOD resources are flagged as such in CAISO's systems and processes, and so that these resources will be subject to CAISO's RA rules, such as the MOO requirement. Accordingly, LSEs must show all deliverable resources on SOD RA plans to CAISO, with the exception of Q3 2025 off-peak imports that are being shown only to the Commission to meet requirements under the SOD framework. This is effective for the 2025 RA compliance year.

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.

[130] CAISO Revised Proposal at 1.

Comments were filed by June 6, 2023 by: ACP-CA; AES; AReM and the Regents of the University of California (jointly, AReM/UC); BPA; CAISO; CalCCA; CEJA; Central Coast Community Energy (3CE); CESA; Council, Leapfrog Power, Inc., and OhmConnect, Inc. (collectively, Joint DR Parties); DMM; Form Energy; Hydrostor, Large-Scale Solar Association (LSA); Microsoft; MRP; Peninsula Clean Energy (PCE); PG&E; SCE; Shell Energy; Terra-Gen; and WPTF. Reply comments were filed on June 11, 2024 by: ACP-CA, AReM/UC, Cal Advocates, CAISO, CalCCA, CESA, Hydrostor, Joint DR Parties, MRP, PG&E, SCE, SDG&E, Shell Energy, SJCE, and WPTF.

All comments have been carefully considered. Portions of the proposed decision that have been revised in light of comments are mentioned in this section. 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.

Some parties reiterate arguments that implementation of the SOD framework should be delayed past 2025, or that additional flexibility should be adopted if moving forward with SOD implementation, including ACP-CA, AReM/UC, CalCCA, CESA, and Hydrostor.[131] MRP, PG&E, and Shell Energy support moving forward with SOD implementation for 2025.[132] SDG&E states

[131] ACP-CA Comments on Proposed Decision at 2, AReM/UC Comments on Proposed Decision at 2, CalCCA Comments on Proposed Decision at 11, CESA Comments on Proposed Decision at 9, Hydrostor Comments on Proposed Decision at 5.

[132] MRP Comments on Proposed Decision at 2, Shell Energy Comments on Proposed Decision at 2, PG&E Reply Comments on Proposed Decision at 2.

that if SOD implementation is not delayed, LSEs should be provided their 2025 allocations as soon as reasonably possible.[133]

The Commission maintains its rationale for moving forward with SOD implementation for the 2025 RA compliance year. As stated in the decision, "[t]he Commission will continue to monitor the readiness of the SOD showing tools throughout 2024 and monitor LSEs' compliance with the SOD requirements in 2025 and will consider adjustments to the program as needed." In addition to program adjustments, the Commission may consider extenuating circumstances in enforcing the RA requirements for the first year of the SOD program, which may include directing Energy Division to delay the issuance of deficiency notices to LSEs to allow time for additional procurement, as we have previously ordered.[134] The Commission appreciates that some LSEs have been actively engaging with Energy Division to identify and correct issues with the SOD showing tools. To ensure the SOD showing tools are ready for 2025 implementation, we encourage other LSEs to actively engage with Energy Division in this effort.

CAISO, Microsoft, and MRP support the decision to retain the 17 percent PRM for 2025, rather than reduce the PRM.[135] CAISO and Microsoft comment that retaining the PRM can help offset uncertainty with the decreased load forecast and changing peak loads. MRP comments that a 17 percent PRM has not been shown to achieve the target LOLE and that Energy Division should be ordered to perform monthly stress testing. CAISO states that the Commission

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

[134] *See* D.22-03-034 at OP 14.

[135] CAISO Comments on Proposed Decision at 2, Microsoft Comments on Proposed Decision at 3, MRP Comments on Proposed Decision at 4.

should clarify that the effective PRM adopted in D.23-06-029 will continue to apply for 2025.

ACP-CA, CalCCA, CEJA, and SCE oppose a 17 percent PRM for 2025.[136] CalCCA states that a 17 percent PRM fails to account for differences in the existing RA framework and SOD framework, and the Commission should instead work with the CEC and stakeholders to assess the accuracy of the IEPR forecast. CEJA argues that the PRM should be reduced, that a decreased demand forecast is not a justification for an increased PRM, and that a 17 percent PRM will lead to overinvestment in reliability resources. ACP-CA states that 17 percent is not supported by the record and may not meet the 0.1 LOLE standard. SCE recommends its previous proposal to create a proxy portfolio to establish a SOD PRM, or if the 17 percent is maintained, then remove the effective PRM.

The Commission maintains its rationale for adopting a 17 percent SOD PRM for 2025 as a more prudent approach to help offset uncertainty with the decreased load forecast. As stated in the decision, the Commission will consider a revised LOLE study and PRM for the 2026 and 2027 compliance years in Track 2 of this proceeding and look forward to parties' participation in that phase. The Commission clarifies that the decision does not modify the effective PRM adopted in D.23-06-029, which will remain in place for 2025.

Several parties, including AReM/UC, CalCCA, Microsoft, PCE, Shell Energy, and 3CE, comment that the decision should address and adopt CalCCA's hourly load obligation trading proposal prior to SOD

[136] ACP-CA Comments on Proposed Decision at 3, CalCCA Comments on Proposed Decision at 13, CEJA Comments on Proposed Decision at 3, SCE Comments on Proposed Decision at 5.

implementation.[137] These parties comment that Energy Division's Report on SOD Implementation and Year Ahead Showings, issued February 5, 2024, indicates that more LSEs were non-compliant under the SOD framework than the current RA framework and that hourly trading would have increased compliance in the test year.

MRP, PG&E, and SDG&E comment that hourly transactability should not be adopted at this time, pointing to past Commission decisions in which the Commission declined to consider hourly transactability until after implementation of the SOD framework.[138] MRP states that while test year deficiencies could indicate a need to revise SOD tools or rules, the deficiencies could also indicate that LSEs have not sufficiently revised procurement practices for SOD implementation. MRP and PG&E state that the Commission should wait until clear evidence emerges that hourly transactability is needed.

The Commission notes that proponents of the hourly load transactability proposal fail to mention the Commission's recent decisions addressing such proposals over the past two years. In D.22-06-050, the Commission considered load obligation trading proposals and outlined numerous issues that would need to be addressed before considering such proposals, including "impacts on outage substitution, cost allocation, backstop procurement, and implementation…."[139] We stated that "we decline to consider hourly resource or load obligation trading for inclusion in the 24-hour framework at this time. However, if transactability

[137] 3CE Comments on Proposed Decision at 5, AReM/UC Comments on Proposed Decision at 7, CalCCA Comments on Proposed Decision at 3, Microsoft Comments on Proposed Decision at 7, PCE Comments on Proposed Decision at 1, Shell Energy Comments on Proposed Decision at 4.

[138] MRP Reply Comments on Proposed Decision at 3, PG&E Reply Comments on Proposed Decision at 1, SDG&E Reply Comments on Proposed Decision at 1.

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

and inefficiency concerns arise once the new 24-hour framework is implemented, the Commission may consider proposals to include hourly obligation trading."[140]

Then, in D.23-04-010, the Commission again considered proposals to assess hourly transactability during the test year and affirmed our rationale from D.22-06-050, declining to consider a test year evaluation of inter-LSE hourly transactability. In D.23-04-010, we reiterated, that "should these concerns arise once the SOD framework is implemented – after the test year- the Commission may consider such proposals."[141]

As we stated in both D.22-06-050 and D.23-04-010, once the SOD program is implemented, the Commission will consider hourly transactability proposals only "if transactability and inefficiency concerns arise." While parties point to the results of LSEs' test year filings as evidence for the need for hourly transactability, we emphasize our statement from D.23-04-010 that "[a]s LSEs are not required to meet their hourly RA requirements and compliance penalties are not imposed for the test year, deficiencies during the test year are plausible."[142] Once the SOD framework is implemented, and LSEs' RA showings are binding, the Commission can evaluate whether transactability concerns exist. As such, we decline to consider CalCCA's proposal in this decision.

AReM/UC, AES, CESA, Microsoft, Shell Energy, SCE, and SDG&E support the extended cure period for new resources with a COD after T-30 and before the start of the RA compliance month, but with modifications.[143] Some

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[140] *Id*.

[141] D.23-04-010 at 71.

[142] *Id*. at 72.

[143] AReM/UC Comments on Proposed Decision at 3, AES Comments on Proposed Decision at 3, CESA Comments on Proposed Decision at 4, Shell Energy Comments on Proposed Decision

parties comment that the rule should not be limited to specific months but apply to all months or months with a last-minute template change. Shell Energy states that the cure period should apply to June compliance as well, as MTR procurement requires additional capacity to come online by June 1. Cal Advocates supports Shell Energy's modification.[144]

SCE seeks clarification that if a deficiency is cured by the T-1 deadline, the Commission will not levy penalties, stating that the penalty structure provides that deficiencies cured within five business days may incur penalties based on the MW deficiency and the number of occurrences. PG&E comments that new resources would not be subject to CAISO's tariff, including the must-offer obligation, and recommends an after-the-fact review by Energy Division to ensure resource performance, rather than the contractual requirement which may not have consistent enforceability.[145]

The Commission agrees with Shell Energy and Cal Advocates that it is reasonable to apply the extended cure period to June, given that mid-term reliability procurement is required to come online by June 1. Accordingly, the decision is modified to include June compliance. With respect to SCE's comments, we clarify that in adopting the extended cure period for new resources, we did not intend to modify the current penalty structure whereby for deficiencies cured within five business days, LSEs can incur penalties ranging from $5,000 to $20,000 based on the MW deficiency and number of occurrences.

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at 6, Microsoft Comments on Proposed Decision at 6, SCE Comments on Proposed Decision at 8, SDG&E Reply Comments on Proposed Decision at 4.

[144] Cal Advocates Reply Comments on Proposed Decision at 2.

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

We decline to make further modifications to the new extended cure period rule at this time.

BPA supports the exemption for non-resource-specific imports as consistent with its proposal, and AReM/UC, CAISO, DMM, PG&E, Shell Energy, WPTF, and Microsoft support the exemption.[146] DMM comments that while CAISO market data is insufficient to ensure precise monitoring of the requirements, DMM can work with the Commission to identify conditions under which the requirements may be violated and may merit further investigation. WPTF seeks clarification of whether "physically linked" refers to resources linked by transmission to enable the resource to be operated as a single system to meet an import provider's obligations. WPTF, AReM/UC, and Shell Energy recommend that the exemption should apply not just to import "owners" but those that have the right to market or sell the product as well.

CAISO requests the Commission clarify that LSEs must economically bid the energy in alignment with CAISO must-offer obligation rules for resource-specific imports. PG&E states that the exemption should be corrected to require LSEs to submit an attestation, rather than an affidavit, as this is what BPA proposed and attestations are used for other import requirements in D.20-06-028.

We find CAISO's clarification that LSEs should economically bid the energy in alignment with CAISO MOO rules to be reasonable, in order to ensure that these imports have the same bidding obligations as resource-specific imports. The decision is modified to include this. The Commission also agrees

[146] BPA Comments on Proposed Decision at 2, AReM/UC Comments on Proposed Decision at 5, CAISO Comments on Proposed Decision at 6, DMM Comments on Proposed Decision at 1, Microsoft Comments on Proposed Decision at 5, PG&E Comments on Proposed Decision at 4, Shell Energy Comments on Proposed Decision at 7, WPTF Comments on Proposed Decision at 2.

with PG&E that it was an error to use the term "affidavit" rather than "attestation," and the decision is modified to replace "affidavit" with "attestation." We decline to include further modifications to the import exemption, as the other proposed modifications extend beyond the original intent in adopting the rule.

With respect to requiring LSEs to have import allocation rights equal to the RA capacity shown, CAISO comments that the decision should clarify that LSEs should have import allocation rights equal to their RA showing value for a specific resource.[147] CAISO also seeks clarification that consistent with CAISO's guidance from earlier this year, "[i]f the monthly coincident peak hour exceedance value is zero, then the QC value passed to the CAISO is 0.1 MW (greater of monthly coincident peak value and 0.1 MW)." CAISO states that if the LSE shows the full resource, in this example, the LSE should have import allocation rights equal to 0.1 MW. We agree with CAISO and clarify that in cases where the peak hour value is zero, the import allocation right should be equal to 0.1 MW, consistent with the NQC value. The decision is modified to reflect this.

SCE comments that the decision should count off-peak import energy that is not available during the AAH window towards RA requirements, as the Commission can validate the MOO by requiring LSEs to, for example, provide the contract and/or attestation for the product.[148] SCE recommends adopting an interim solution for Q3 2025 only and require LSEs to provide proof showing (1) the availability of import allocation rights and (2) if there is an associated on-peak import on the branch group, to avoid over and under counting of import allocation rights availability. CAISO supports the proposed decision declining to

[147] CAISO Comments on Proposed Decision at 7.

[148] SCE Comments on Proposed Decision at 3.

adopt SCE's proposal and states that it is unclear how an off-peak product would interact with existing RA rules.[149] CAISO affirms that under CAISO's RA rules, RA resources are subject to a MOO and if resources do not submit bids to CAISO, they may be subject to bid insertion. CAISO adds that for imports to count as RA capacity, imports must be paired with maximum import capability.

To respond to CAISO's concerns, SCE states that there is an existing process that the Commission uses for non-resource-specific on-peak import energy that can be used to verify off-peak import energy.[150] SCE states that the contracting LSE can attest to a MOO to CAISO, and for MIC pairing the SOD template can be updated to validate and confirm MIC availability and non-overlapping use. AReM/UC, SDG&E, Shell Energy, and PG&E support SCE's proposal and state that this could ease SOD implementation.[151]

In the proposed decision, we stated that SCE's original proposal to count off-peak import energy towards RA requirements had merit but raised concerns about the interactions with CAISO's RA rules. The Commission finds SCE's modification to its proposal to verify the MOO for off-peak import energy to be reasonable in addressing the Commission's previous concerns. SCE's proposal is also narrowly applied to Q3 2025. Therefore, we modify the decision to apply SCE's proposed rule for Q3 2025 only. However, this decision also adopts a requirement that LSEs must show all deliverable resources on SOD RA plans to CAISO. As such, we also add an exemption to that rule, stating that LSEs must show all deliverable resources on SOD RA plans to the CAISO, with the

[149] CAISO Comments on Proposed Decision at 8.

[150] SCE Reply Comments on Proposed Decision at 2.

[151] AReM/UC Reply Comments on Proposed Decision at 2, PG&E Reply Comments on Proposed Decision at 4, SDG&E Reply Comments on Proposed Decision at 3, Shell Energy Reply Comments on Proposed Decision at 3.

exception of off-peak imports that are being shown only to the Commission to meet requirements under the SOD framework. The decision is modified to reflect this.

LSA and Terra-Gen state that by allowing EO resources to contribute to resource sufficiency requirements for co-located and hybrid configurations, a modification should be considered for projects in development that may have existing contracts regarding charging sufficiency.[152] LSA and Terra-Gen recommend exempting the proration rule for existing contracts that specify the allocation of rights to associated charging energy sufficiency. AReM/UC, CESA, and SJCE support LSA and Terra-Gen's modification.[153] SCE comments that LSA and Terra-Gen's proposal may warrant further consideration but should be considered after SOD implementation.[154]

The Commission finds that LSA's and Terra-Gen's proposal may have merit but there are outstanding issues that need to be addressed, including but not limited to, how the existing contracts would be factored into the SOD templates and how the Commission would verify the contractual obligations. As such, we decline to consider the proposal at this time and may consider this in Track 3 of this proceeding after initial implementation of the SOD framework.

SCE supports monthly exceedance levels but not for the 2025 RA year as it states that LSEs have already requested import allocation rights for wind and solar imports using a previously published exceedance profile.[155] SCE also comments that there are flaws in the methodology with regards to inconsistent

[152] LSA Comments on Proposed Decision at 2, Terra-Gen Comments on Proposed Decision at 3.

[153] AReM/UC Reply Comments on Proposed Decision at 2, CESA Reply Comments on Proposed Decision at 5, SJCE Reply Comments on Proposed Decision at 4.

[154] SCE Reply Comments on Proposed Decision at 3.

[155] SCE Comments on Proposed Decision at 10.

resource performance datasets between RA and IRP/Renewables Portfolio Standard that should be corrected before using monthly exceedance levels for compliance.

The Commission notes that SCE appears to misunderstand CAISO's MIC allocation process, as CAISO Tariff Section 40.4.6.2 provides that changes to QC methodologies are accounted for in the MIC allocation process. Further, while the datasets that SCE refers to are already used in the 2024 QC valuations and 2025 update, the transition to monthly exceedance levels is expected to add more available capacity to the grid. Modifications to the methodology regarding resource performance datasets may be considered in the future. We decline to modify the decision.

MRP comments that it interprets the Advice Letter requirement for the DCPP limited waiver process to apply to each month in which a forced outage would impact PG&E's ability to meet its monthly RA obligations and thus, PG&E would be required to submit a new Tier 2 Advice Letter for each compliance month.[156] The Commission clarifies that PG&E need only submit a Tier 2 Advice Letter for any compliance month in which it has a deficiency due to a DCPP forced outage.

Joint DR Parties, PG&E, SDG&E and SCE comment that the proposed decision should adopt the recommended LIP revisions from the LIP Working Group Report.[157] SCE states that it did not comment on the Report because its positions were captured in the survey and that if the recommendations are not adopted, a process should be established to provide comments on the Report.

[156] MRP Comments on Proposed Decision at 6.

[157] Joint DR Parties Comments on Proposed Decision at 2, SCE Comments on Proposed Decision at 9, PG&E Comments on Proposed Decision at 5, SDG&E Reply Comments on Proposed Decision at 5.

PG&E comments that the Report was based on consensus recommendations and the failure to submit comments on the Report should not be a reason to defer adoption. Joint DR Parties comment that the Working Group was highly collaborative and that the Report was so uncontroversial that parties likely did not see a need to submit comments.

The Commission appreciates parties commenting that consensus was reached in the Working Group process; however, the Report did not indicate that consensus was reached, and no party submitted comments on the Report prior to the submission of the record. The Report's survey results also did not reflect a consensus view, nor did it identify stakeholder positions. The Commission does not necessarily track each Working Group process and relies on a Working Group Report to summarize the culmination of the process. The Commission therefore could not adequately assess parties' views of the recommendations in time to consider them for this decision. The Commission will consider the Working Group Report's recommendations in Track 2 and parties should submit comments on the Report at the same time as comments on all Track 2 proposals, currently scheduled for July 29 and August 12, 2024.

6. Assignment of Proceeding

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

Findings of Fact

1. CAISO recommended that the existing capacity needed for all local areas is 22,782 MWs for 2025, 23,093 MWs for 2026, and 23,547 MWs for 2027.

2. CAISO recommended system-wide Flexible Capacity Requirements that range from 27,010 MWs in September to 20,533 MWs in March.

3. In D.22-06-050 (and reaffirmed in D.23-04-010), the Commission determined that a single PRM will apply to all hours of the year for initial

implementation of the SOD framework. In Track 1 of this proceeding, the Scoping Memo provided that the Commission will consider the translation of the adopted 17 percent PRM for the 2025 RA compliance year to the SOD framework.

4. The Commission is concerned that the reduced demand and shift in peak to July, as reflected in the CEC's 2023 IEPR demand forecast, may result in a restrictively lower PRM for procurement purposes. Applying a 17 percent SOD PRM for 2025 is a more prudent approach that would help offset uncertainty with the decreased load forecast.

5. Allowing new resources with a COD after T-30 and before the start of the RA compliance month to count towards that month's RA compliance increases the number of resources an LSE can count towards its RA obligations and increases the amount of resources with a must-offer obligation that are available to CAISO's markets to enhance grid reliability.

6. The grid charging restriction is being addressed as part of a state-of-charge test in the current SOD templates, which will ensure that paired batteries have enough energy to provide capacity from their paired resources.

7. Adjusting exceedance levels for wind and solar resources to a monthly level from the current seasonal level improves accuracy in exceedance levels and would not be burdensome on Commission Staff resources.

8. Allowing energy sufficiency from EO resources to be prorated to all paired storage resources based on the NQC of the storage resources allows the sufficiency benefit of the EO components to remain bundled with the storage, while allowing for further discussion among stakeholders.

9. For resource-specific solar and wind import resources, it is reasonable that an LSE has import allocation rights equal to the RA value shown to the Commission at the peak hour of the month.

10. BPA's proposal for an exemption to the non-resource-specific import requirements, with some modifications, removes a barrier for out-of-state suppliers and incentivizes suppliers to sell RA imports to California LSEs.

11. In D.23-12-036, the Commission provided that an unplanned outage at DCPP that results in PG&E's inability to meet its system RA obligations may be considered in the RA proceeding.

12. Allowing the IOUs to use the PCIA market price benchmark to determine substitution capacity costs minimizes cost shifting between bundled customers and departing load.

13. To ensure that all SOD resources are flagged as such in CAISO's systems and processes, and subject to CAISO's RA rules, deliverable resources on SOD RA plans need to be shown to CAISO, with the exception of Q3 2025 off-peak imports that are being shown only to the Commission to meet SOD requirements.

Conclusions of Law

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

2. CAISO's recommended systemwide FCR figures for 2025 are reasonable and should be adopted.

3. Considering the 2023 IEPR demand forecast, a 17 percent PRM is a more appropriate PRM to be applied to the SOD framework for the 2025 RA compliance year.

4. On an interim basis and limited to June-September month-ahead filings, it is reasonable to allow new resources with a COD after T-30 and before the start of the RA compliance month (T-1) to count towards that month's RA compliance.

5. As the state-of-charge test in the SOD template is addressing the paired resources' grid-restricted charging limitations, there is no longer a need to derate the QC values of grid-restricted charging resources.

6. Exceedance levels for wind and solar resources should be adjusted to monthly levels under the SOD framework, with updates occurring every three years to balance stability of exceedance values and inclusion of updated data.

7. SCE's clarification to D.23-04-010, Ordering Paragraph 7, is reasonable and was the Commission's intent in adopting this requirement.

8. It is reasonable to allow energy sufficiency from EO resources to be prorated to all paired storage resources based on the NQC of the storage resources.

9. For resource-specific solar and wind import resources, an LSE should have import allocation rights equal to the RA value shown to the Commission at the peak hour of the month.

10. SCE's proposal to allow off-peak import energy to count towards meeting RA requirements under the SOD framework is reasonable with some modifications and for Q3 2025 only.

11. BPA's proposal for an exemption to the non-resource-specific import requirements is reasonable with some modifications and on an interim basis.

12. It is reasonable and consistent with D.23-12-036 for Energy Division to allocate credits from DCPP to all LSEs. It is reasonable that in the event of an unplanned outage at DCPP that results in PG&E's inability to meet its system RA

obligations, a limited system waiver process should be adopted, similar to the waiver process for the POLR.

13. It is reasonable to allow an IOU that uses resources from its PCIA-eligible portfolio to use the PCIA market price benchmark to determine substitution capacity costs for CAM resources.

14. It is reasonable that all deliverable resources on SOD RA plans be shown to CAISO with the exception of Q3 2025 off-peak imports that are being shown only to the Commission to meet requirements under the SOD framework.

O R D E R

IT IS ORDERED that:

1. The Commission approves 22,782 megawatts as the existing capacity needed for the Local Capacity Requirement for 2025.

2. The Commission approves 23,093 megawatts as the existing capacity needed for the Local Capacity Requirement for 2026.

3. The Commission approves 23,547 megawatts as the existing capacity needed for the Local Capacity Requirement for 2027.

4. The California Independent System Operator's recommended Flexible Capacity Requirements for 2025 are adopted.

5. Beginning with the 2025 Resource Adequacy year, a 17 percent planning reserve margin is adopted to apply to the Slice of Day framework.

6. For June-September month-ahead Resource Adequacy (RA) filings, new resources with a commercial operation date (COD) after T-30 and before the start of a load-serving entity's (LSE) RA compliance month (T-1) may count towards curing an LSE's identified RA deficiencies for that compliance month, provided that the LSE submits the following documentation to Energy Division:

   (a) The new resource contract verifying that the resource will be providing a must-offer obligation into the California

Independent System Operator's (CAISO) energy markets consistent with an RA product, and

(b) A COD notice that confirms the resource was online and deliverable before the start of the compliance month (T-1).

The megawatts associated with the identified resource must not accept any CAISO Capacity Procurement Mechanism designation for the associated compliance month.

To implement the adopted extended cure period, Energy Division will continue to issue deficiency notices prior to T-30. If an LSE meets the above requirements, after the RA compliance month, Energy Division will refer any remaining deficiency to the Consumer Protection and Enforcement Division. If the LSE's new resource cures the LSE's deficiencies, the LSE's deficiencies will be considered cured within five business days. This rule is effective upon the issuance of this decision and may be utilized by LSEs for compliance beginning with the July 2024 month-ahead showing.

7. Under the Slice of Day (SOD) framework, a hybrid and co-located resource's qualifying capacity (QC) counting methodology will be as follows: the renewable component's QC value will be calculated the same as other renewable resources' QC values, the storage component's QC value will be calculated the same as other storage resources' QC values, and the total QC value of the resource will be the sum of the two components limited by the Point-of-Interconnection limit and the SOD compliance tool's state-of-charge test. This is effective for the 2025 Resource Adequacy compliance year.

8. Under the Slice of Day (SOD) framework, the exceedance levels for wind and solar resources will be adjusted to monthly levels, with the next update to

occur in 2024 and subsequent updates every three years thereafter. This is effective for the 2025 Resource Adequacy compliance year.

9. Paired storage resources will be characterized on the Master Resource Database (MRD) as either charging exclusively from paired resources or allowing grid charging. An energy-only (EO) resource is eligible to count towards the storage charging sufficiency requirement if the EO resource is charging exclusively paired storage, regardless of whether the paired storage is able to charge from the grid. The charging capacity of the renewable resource will be capped at the amount that can be used to charge the paired storage and the storage will be capped at the interconnection limit. Paired components will be shown as separate assets on the MRD and load-serving entities' showings, and the total of the components must not exceed the interconnection amount in any hour. This is effective upon the issuance of the decision.

10. Beginning with the 2025 Resource Adequacy compliance year, and on an interim basis, energy sufficiency from energy-only resources will be prorated to all paired storage resources based on the net qualifying capacity of the storage resources.

11. Beginning with the 2025 Resource Adequacy (RA) compliance year, for resource-specific solar and wind import resources, a load-serving entity (LSE) must have import allocation rights equal to the RA value shown to the Commission at the peak hour of the month, unless the value at the peak hour is zero, in which case the LSE should have import allocation rights equal to the minimum value of 0.1.

12. For the 3rd Quarter of 2025, a load-serving entity (LSE) may count off-peak import energy that is not available during the Availability Assessment Hours towards meeting its Resource Adequacy requirements under the Slice of Day

framework, regardless of whether the import is paired with the on-peak import on a specific branch group, so long as the off-peak import adheres to the other existing import requirements. To validate that the off-peak energy resource provides a must-offer obligation to the California Independent System Operator's markets, the LSE must provide Energy Division with proof demonstrating: (1) the availability of import allocation rights, and (2) if there is an associated on-peak import on the branch group, to avoid over and under accounting of import allocation rights availability.

13. On an interim basis, non-resource-specific imports may be exempt from the non-resource-specific import bidding requirements, provided that the load-serving entity (LSE) submit with its Resource Adequacy (RA) filing an attestation from the import provider attesting that the following conditions apply to the non-resource-specific import:

(a) That the import provider owns the energy resources providing the contracted capacity.

(b) That the resources are an aggregation of physically linked resources.

(c) That the capacity from the resources is not otherwise encumbered or sold to another party.

(d) That the import provider has firm transmission to the California Independent System Operator (CAISO) balancing authority area for the full amount under contract and that it is backed by operating reserves.

(e) That the energy will be economically bid into the CAISO day-ahead and real-time markets in alignment with CAISO must-offer obligation rules for resource-specific imports.

(f) That should the resources receive a dispatch from the CAISO market, the energy and transmission will be firm and given priority equal to the LSEs' native load (i.e., that the energy will not be curtailed, except

> when the LSE is curtailing its own native load) and will not be curtailed for economic or reliability reasons, except under the circumstances noted above.

If the non-resource-specific import meets these requirements, it will be exempt from the current non-resource-specific import bidding requirements. The attestation affirming the conditions required above must be included with the LSE's RA filing to Energy Division. This is effective upon the issuance of the decision.

Energy Division is authorized to monitor the bidding behavior of these resources regularly to ascertain issues of speculative supply.

14. Energy Division will allocate the Resource Adequacy (RA) benefits of the Diablo Canyon Power Plant (DCPP) to all load-serving entities within each investor-owned utilities' service territory using the Cost Allocation Mechanism. In the event of an unplanned outage that results in Pacific Gas and Electric Company's (PG&E) inability to meet its system RA obligations, PG&E is eligible for a limited system waiver. The waiver request shall be submitted through a Tier 2 Advice Letter that provides: (1) the reason for PG&E's deficiency in meeting the RA requirement due to the unplanned outage of the DCPP, and (2) a demonstration that PG&E made every reasonable effort to procure replacement capacity to mitigate the unplanned outage. This is effective upon the issuance of this decision, commencing with the extended operating periods of DCPP Units 1 and 2.

15. If an investor-owned utility (IOU) uses resources from an IOU's Power Charge Indifference Adjustment (PCIA)-eligible portfolio, the IOU may use the PCIA market price benchmark to determine substitution capacity costs for Cost Allocation Mechanism resources. This is effective upon the issuance of the decision.

16. Load-serving entities must show all deliverable resources on Slice of Day (SOD) Resource Adequacy (RA) plans to the California Independent System Operator, with the exception of Q3 2025 off-peak imports that are being shown only to the Commission to meet requirements under the SOD framework. This is effective for the 2025 RA compliance year.

17. Rulemaking 23-10-011 remains open.

This order is effective today.

Dated June 20, 2024, at San Luis Obispo, 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.