Decision **PROPOSED DECISION OF ALJ CHIV (Mailed 6/1/2026)**

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 25-10-003

DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2027-2029, FLEXIBLE CAPACITY OBLIGATIONS FOR 2027, AND PROGRAM REFINEMENTS

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DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2027-2029, FLEXIBLE CAPACITY OBLIGATIONS FOR 2027, AND PROGRAM REFINEMENTS

Summary

This decision adopts Local Capacity Requirements for 2027-2029, Flexible Capacity Requirements for 2027, and program refinements to the Resource Adequacy (RA) program scoped for Track 1.

The refinements include adopting an Unforced Capacity framework for implementation in the 2028 RA year, clarifying requirements for bidding and revenue allocation for Residual Unit Commitment and Imbalance Reserve products in the California Independent System Operator market, clarifying the definition of "load migration" to account for changes to community choice aggregators' implementation plans, and modifying the RA penalty structure to account for deficiencies in charging sufficiency.

The refinements also include various modifications to the qualifying capacity (QC) counting methodologies, including modifications to QC counting rules for storage resources to account for nonlinearity, modifications to the charging sufficiency rules to allow excess energy produced by a co-located energy only resource to count towards charging sufficiency requirements up to the Point of Interconnection limit, charging sufficiency requirements for long-duration energy storage resources, and modifications to QC counting for demand response resources on an interim basis to address misalignment issues.

This proceeding remains open.

1. Background

On October 15, 2025, the California Public Utilities Commission (Commission or CPUC) issued the Order Instituting Rulemaking (OIR) to oversee the Resource Adequacy (RA) program, consider program reforms and refinements, and establish forward RA procurement obligations applicable to Commission-jurisdictional load-serving entities (LSEs). Additional information on the procedural history of this proceeding is provided in the OIR.

A prehearing conference was held on November 17, 2025. A Scoping Memo and Ruling (Scoping Memo) for this proceeding was issued on December 12, 2025. The Scoping Memo identified the issues to be addressed in this proceeding, set forth a schedule and process for addressing those issues, and established two tracks for this proceeding (Tracks 1 and 2).

Track 1 proposals were filed on January 23, 2026 by: American Clean Power-California (ACP-CA); AES Corporation (AES); Alliance for Retail Energy Markets (AReM); California Independent System Operator (CAISO); California Community Choice Association (CalCCA); Calpine Corporation (Calpine); California Environmental Justice Alliance/Sierra Club (jointly, CEJA/Sierra Club); California Energy Storage Alliance (CESA); CESA, Form Energy, Hydrostor, Inc. (Hydrostor) and Fourth Power (collectively, Joint Long-Duration Energy Storage (LDES) Parties); CESA, Solar Energy Industries Association (SEIA), Large-scale Solar Association (LSA), California Wind Energy Association (CalWEA) (collectively, Joint Energy Only (EO) Parties); MN8 Energy LLC (MN8); Pacific Gas and Electric Company (PG&E); Public Advocates Office at the California Public Utilities Commission (Cal Advocates); Southern California Edison

Company (SCE); Sonoma Clean Power Authority (SCPA); and Vistra Corporation (Vistra). Energy Division's Track 1 proposal was attached to an Administrative Law Judge's (ALJ) ruling on January 27, 2026.

A workshop on Track 1 proposals was held on February 10 and 11, 2026. On February 23, 2026, Energy Division issued its Report on Transactability within the Slice of Day (SOD) Resource Adequacy Framework (Transactability Report). The Track 1 schedule was modified by ruling on February 17, 2026. A revised version of the Transactability Report was issued on February 24, 2026, which was attached to an ALJ's ruling on the same day, which further modified the schedule. Proposals on "Transactability Issues" (transactability proposals) were filed on March 3, 2026 by CalCCA and Western Power Trading Forum (WPTF). A workshop on transactability proposals was held on March 9, 2026.

Opening comments on Track 1 proposals were filed on March 6, 2026 by: ACP-CA, Ava Community Energy and Peninsula Clean Energy (jointly, Ava/PCE), AES, AReM, CAISO, Cal Advocates, CalCCA, Calpine, CEJA/Sierra Club, Central Coast Community Energy (3CE), CESA, CAISO's Department of Market Monitoring (DMM), Electricite de France power solutions North America (EDFps), GreenGenStorage, LLC (GreenGen), Hydrostor, Independent Energy Producers Association (IEP), Joint EO Parties, Joint LDES Parties, Leapfrog Power, Inc. (Leap), LSA/SEIA, Middle River Power LLC (MRP), NextEra Energy Resources, LLC (NextEra), PG&E, Redwood Coast Energy Authority (RCEA), REV Renewables, LLC (REV), San Diego Gas & Electric Company (SDG&E), SCE, SCPA/PCE, Vistra, and WPTF.

Opening comments on transactability proposals were filed on March 16, 2026 by: Ava, CalCCA, CEJA/Sierra Club, MRP, and Vistra.

Reply comments on Track 1 proposals were filed on March 20, 2026 by: ACP-CA, AReM, Ava, CAISO, Cal Advocates, CalCCA, Calpine, CEJA/Sierra Club, CESA, GreenGen, Hydrostor, IEP, Joint EO Parties, Joint LDES Parties, Long Duration Energy Storage Council (LDES Council), MRP, NextEra, PG&E, SCE, and SDG&E.

Reply comments on transactability proposals were filed on March 30, 2026 by: CalCCA, CEJA/Sierra Club, MRP, PG&E, SCE, and SDG&E.

On April 3, 2026, the Track 1 schedule for Local Capacity Requirement (LCR) issues was modified by ruling. On April 14, 2026, CalCCA filed a Motion for Leave to File a Sur-Reply to the Reply Comments of PG&E, SDG&E, and SCE. On April 17, 2026, an ALJ ruling granted all parties leave to file a sur-reply to the reply comments of PG&E, SDG&E, and SCE. On April 17, 2026, CalCCA filed sur-reply comments.

CAISO's Draft 2027 Local Capacity Technical Report (Draft LCR Report) was submitted on April 3, 2026. On April 20, 2026, CEJA/Sierra Club filed comments on the Draft LCR Report. CAISO's 2027 Final Local Capacity Technical Report (Final LCR Report) was submitted on May 1, 2026. No comments were filed on the Final LCR Report.

On May 4, 2026, the Track 1 schedule for Flexible Capacity Requirement (FCR) issues was modified by ALJ ruling. CAISO's Final FCR Report was submitted on May 13, 2026. No comments were filed on the Final FCR Report.

2. Submission Date

The matter for this decision was submitted on May 13, 2026, upon the submission of CAISO's Final FCR Report.

3. Issues Before the Commission

The scope of issues in Track 1, as adopted in the December 12, 2025, Assigned Commissioner's Scoping Memo, is summarized as follows:

1. Adoption of 2027-2029 LCRs. 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 2027-2029 RA compliance years.
2. Adoption of 2027 FCRs. 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. Accreditation for Long-Duration Energy Storage. Consider accreditation methodologies for long-duration energy storage (LDES). In Decision (D.) 25-06-048, the Commission authorized Energy Division to hold a workshop on LDES issues and outlined several issues to consider in future proposals.
4. Unforced Capacity (UCAP) Evaluations and Framework. In D.25-06-048, the Commission authorized Energy Division, in coordination with CAISO, to further develop a final UCAP methodology framework that addressed multiple issues.
5. Accreditation for Solar and Wind Resources. In D.24-12-003, the Commission authorized Energy Division to conduct an analysis comparing exceedance profiles for wind and solar resources against Strategic Energy & Risk Valuation Model (SERVM) weather profiles. This analysis

was presented at a November 2025 workshop, and parties may put forth proposals based on this analysis.

6. Transactability Issues within the SOD Framework. In D.25-06-048, the Commission authorized Energy Division to conduct an evaluation after a full year of SOD implementation to assess the needs, benefits, and feasibility of an hourly load obligation trading mechanism. Energy Division was authorized to prepare a report on whether transactability issues exist by the 1st Quarter of 2026.
7. Residual Unit Commitment for RA Resources. In D.24-06-048, the Commission determined that there was insufficient record to consider SCE's proposal to remove the zero dollar bid requirement for Residual Unit Commitment for CAISO's Extended Day-Ahead Market. The Commission deferred consideration of the zero dollar bid requirement for Reliability Capacity Up/Reliability Capacity Down products of Residual Unit Commitment and Imbalance Reserve products to this rulemaking.
8. Energy Only (EO) Resources. In D.25-06-048, the Commission considered CalCCA's proposal to count co-located EO resources as RA resources but determined that the proposal was not adequately developed, would require modifications to the CAISO tariff, and conflicted with the annual deliverability assessment process. Parties are encouraged to submit proposals on how to address identified implementation barriers and reliability concerns.
9. Other time-sensitive issues identified by Energy Division or by parties in proposals.

4. Discussion

4.1. 2027-2029 Local Capacity Requirements

In D.06-06-064, the Commission established the local RA framework and adopted local procurement obligations for 2007. The Commission determined that a study of the LCR, performed by the CAISO, would form the basis for the local RA program and that the local requirements should be based on a level of reliability described as "Option 2" in the CAISO's LCR study report.[1] The CAISO conducts an annual LCR study and the Commission resets local procurement obligations each year after review and approval of the CAISO's recommendations. A series of subsequent decisions (most recently in D.25-06-048) established local procurement obligations for 2008 through 2028. 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 central procurement entity (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 in each local area to meet its obligations.

In comments to CAISO's Draft LCR Report, CEJA/Sierra Club urge prioritization of local procurement issues by having the Commission work with CAISO to integrate the best available local procurement data into a tracker.[2] CEJA/Sierra Club state that the Commission should evaluate whether local procurement needs are being addressed, as storage can replace gas generation in some areas, while other regions face charging limitation constraints that shape procurement strategies. CEJA/Sierra Club note that while the Commission

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1 D.06-06-064 at 17.

2 CEJA/Sierra Club Comments on CAISO 2027 Draft LCR Report at 4.

largely accepts CAISO's LCR studies in the RA proceeding, the Commission should take a more proactive role in the LCR studies by coordinating with the Integrated Resource Planning (IRP) proceeding, incentivizing local procurement, and creating a transparent data tracker.

The Commission notes that CAISO's 2027 LCR report highlights that energy storage faces some limitations in certain local areas due to charging constraints, which can reduce the ability to replace gas generation. The study reports that some sub-areas, such as the Western LA Basin, will reach charging limits by 2027 while the Eastern LA Basin reached its limit in 2025.[3] In these locations, storage must meet specific technical requirements to be effective; otherwise, it can create an "uplift" in capacity needs and potentially introduce reliability risks. These findings reinforce that local procurement planning must account for sub-area conditions and the operational limitations of storage.

The Commission previously required CPEs to base procurement on sub-local area needs (rather than aggregate requirements) and to consider storage charging constraints. In D.20-06-002, CPEs were instructed to use solicitations to meet local RA requirements using CAISO's studies that identify needs across local capacity areas (LCA) and specific sub-areas.[4] In D.22-03-034, CPEs were required to use specific selection criteria, emphasizing the need to consider facility location and best-fit resources for local reliability.[5] CEJA/Sierra Club's data tracking proposal is addressed below under Section 4.10.

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[3] CAISO 2027 Final LCR Report at 118, 121.

[4] D.20-06-002 at 62.

[5] D.22-03-034 at Ordering Paragraph (OP) 8.

CAISO's recommended 2027-2029 LCR values are summarized in the following table, with the adopted 2026-2028 LCR values provided for comparison.

2027-2029 Local Capacity Requirements			
Local Area Name	**2027**	**2028**	**2029**
Humboldt	149	156	163
North Coast/North Bay	592	700	808
Sierra	1892*	1913*	1924*
Stockton	732*	779*	847*
Greater Bay	8315*	8315*	8315*
Greater Fresno	2090*	2333*	2575*
Kern	315*	342*	368*
Big Creek/Ventura	704	721	737
LA Basin	6823	7272	7721
San Diego/Imperial Valley	2006	2014	2022
Total	23618	24545	25480
* CAISO note: Details about magnitude of deficiencies can be found in the applicable section [of the LCR Report]. Resource deficient areas and subarea implies that to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.			

2026-2028 Local Capacity Requirements			
Local Area Name	**2026**	**2027**	**2028**
Humboldt	136	150	167
North Coast/North Bay	848	732	558
Sierra	1354*	1493*	1633*
Stockton	756*	760*	774*
Greater Bay	7558*	7558*	7558*

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

The Commission finds the recommended LCR values for 2027-2029 to be reasonable. Accordingly, CAISO's recommended 2027-2029 LCR values set forth in the table above are adopted.

4.2. 2027 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."[6]

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

The Final FCR Report contains the following figures for 2027, with the 2026 FCR figures provided for comparison.

2027 Flexible Capacity Requirements					
NOTE: All numbers are in MW	CAISO System Flexible Requirement	CPUC Flexible Requirement	CPUC		
			Category 1 (minimum)	Category 2 (100% less Cat. 1 & 3)	Category 3 (maximum)
January	29660	28274	7560	19300	1414
February	25830	24698	6604	16859	1235
March	30378	29063	7771	19839	1453
April	29363	27842	7445	19005	1392
May	29665	28018	11654	14963	1401
June	27621	26219	10906	14002	1311
July	28362	26876	11179	14353	1344
August	28078	26825	11158	14326	1341
September	28632	27252	11335	14554	1363
October	29911	28261	7557	19291	1413
November	30058	28448	7607	19419	1422
December	25060	23824	6370	16263	1191

2026 Flexible Capacity Requirements					
NOTE: All numbers are in MW	CAISO System Flexible Requirement	CPUC Flexible Requirement	CPUC		
			Category 1 (minimum)	Category 2 (100% less Cat. 1 & 3)	Category 3 (maximum)
January	24697	23629	6280	16167	1181
February	24979	23901	6352	16354	1195
March	23403	22505	5981	15399	1125
April	27348	26207	6965	17932	1310

2026 Flexible Capacity Requirements					
			CPUC		
NOTE: All numbers are in MW	**CAISO System Flexible Requirement**	**CPUC Flexible Requirement**	**Category 1 (minimum)**	**Category 2 (100% less Cat. 1 & 3)**	**Category 3 (maximum)**
May	26326	25083	10024	13805	1254
June	27559	26329	10522	14491	1316
July	25038	24086	9626	13256	1204
August	26112	24927	9962	13719	1246
September	27388	26256	10493	14450	1313
October	25471	24571	6530	16812	1229
November	25065	24034	6388	16445	1202
December	23386	22531	5988	15416	1127

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

4.3. Accreditation for Solar, Wind, and Non-Dispatchable Resources

Below we summarize the following proposals: ACP-CA's revisions to its previous proposal to modify the qualifying capacity (QC) exceedance methodology for solar and wind resources; MN8's proposed changes to the peak-hour QC value that the Commission provides to CAISO for use in determining deliverability; and Energy Division's proposed modifications to the QC rules for non-dispatchable resources.

4.3.1. Summary of Proposals

MN8 states that the current QC rules do not accurately reflect solar resources' reliability contribution across seasons because the new QC factors are anchored to solar production at peak load hours rather than hours of highest reliability risk.[7] However, MN8 states that the Commission's loss of load expectation (LOLE) study, as compared to the 2025 draft net qualifying capacity (NQC) report, shows that peak load is not the same as peak reliability risk. MN8 asserts that this miscalibration has downstream impacts for co-located resources behind a shared Point of Interconnection (POI) that were sized under the previous QC factors and then represented in the CAISO NQC report as if constrained by the POI due to the increase in solar QC. MN8 contends that this drives a reduction in solar resource's deliverability and depresses NQC across all months because deliverability is applied annually. MN8 states that this incorrectly characterizes solar deliverability and artificially discounts NQC even in months where no binding POI constraints exist.

MN8 recommends that monthly tech factors (QC values at peak) should be set as the risk-weighted average production for each resource class "where production is weighted by hourly LOLE coefficients produced in the reliability analysis."[8] MN8 states that this would value resources based on expected performance during hours of peak reliability risk. The proposal requires CAISO to modify the monthly RA requirement to be the total amount of capacity needed in peak net load hour plus a reserve margin, rather than the peak hour.

ACP-CA recommends deferring consideration of its previously submitted proposal to replace exceedance with a full probabilistic method based on Energy Division's Energy Resource Modeling datasets, which Energy Division staff

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7 MN8 Track 1 Proposal at 2.

8 *Id*. at 5.

presented at the November 2025 workshop.[9] Although ACP-CA remains interested in a probabilistic methodology, it would like further resolution of methodological and data issues. Instead, ACP-CA advocates for eliminating the exceedance methodology and directly applying the worst-day average as an interim methodology. ACP-CA states that the worst-day profiles are currently calculated as a step on the path to the current exceedance approach and can be applied from existing processes. ACP-CA asserts that worst-day profiles are easily implementable as they have been calculated and are conservative values based on the average of the actual worst days.

Energy Division proposes that if a non-dispatchable resource is forced to go on outage due to rare situations of transmission testing or transmission failure, this should not affect the QC calculations.[10] Energy Division asserts that in that scenario, the resource owner should provide evidence that a transmission event was caused by the transmission operator. Then the hours affected would be replaced by proxy data defined by historical production during the affected months. Energy Division states that the proxy data in this scenario would use the production data immediately before and after the transmission-based outage. If a resource's transmission-based outage is part of a pattern of outages requiring a transmission upgrade, however, those outages would continue to be included in the QC calculation. Energy Division states that this proposal provides flexibility to properly value resources in unique cases and recommends adopting for the 2027 RA year.

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[9] ACP-CA Track 1 Proposal at 16.

[10] Energy Division Track 1 Proposal at 25.

4.3.2. Comments on Proposals

LSA/SEIA support MN8's proposal, stating that CAISO's method of derating solar from Full Capacity Deliverability Status (FCDS) to Partial Capacity Deliverability Status (PCDS) status could conflict with power purchase agreements that require FCDS solar.[11] Although the issue does not impact the SOD program, LSA/SEIA state that it involves how metrics from the program are calculated and communicated for CAISO's use. LSA/SEIA state that MN8's proposal or other alternatives could resolve this issue and recommend the Commission and CAISO coordinate on addressing this issue.

CESA suggests further discussion of MN8's proposal, arguing that the current NQC counting practice may result in deliverability status downgrades and cause contractual issues for developers/investors.[12] CESA states that because solar exceedance calculations under SOD have been much higher than effective load carrying capacity (ELCC) calculations, hybrid resource developers may be penalized due to a deliverability status downgrade despite no change in deliverability. MN8 states that the next best solution would be to send CAISO the net peak hour exceedance value for NQC purposes. MN8 argues that this approach is a better proxy for monthly ELCC than the status quo and is better aligned with the hours that drive reliability risk.[13]

MRP opposes ACP-CA's proposal to eliminate exceedance, noting that removing exceedance would remove the analytical framework the Commission

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11 LSA/SEIA Opening Comments on Track 1 Proposals at 4.

12 CESA Opening Comments on Track 1 Proposals at 17.

13 MN8 Opening Comments on Track 1 Proposals at 5.

relied on to associate exceedance with ELCC in D.22-06-050.[14] MRP opposes reverting solar/wind accreditation to a worst-day average that is no longer tied to an ELCC-based valuation. MRP states that this would also be inconsistent with Public Utilities (Pub. Util.) Code Section 399.26, which requires the Commission to use ELCC values for accrediting wind and solar resources to meet RA requirements. MRP states that exceedance should be retained until a fully developed probabilistic, ELCC-based alternative is adopted.

NextEra and PG&E support Energy Division's non-dispatchable QC proposal.[15] NextEra states that this is a commonsense approach to address circumstances outside of an operator's control that should not impact QC values.

4.3.3. Discussion

The Commission agrees with MRP that the current exceedance methodology was thoroughly developed through multiple Commission decisions as one basis for associating exceedance with ELCC. We also agree that eliminating the exceedance step and replacing it with a simple historical average could implicate Pub. Util. Code Section 399.26. The Commission declines to eliminate the exceedance methodology and will consider proposals for a probabilistic ELCC methodology once developed.

MN8's proposal to set monthly tech factors as the risk-weighted average production has merit but the proposal is not sufficiently developed. For example, MN8 recommends weighting production by using hourly LOLE coefficients produced in the reliability analysis but there are not enough

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14 MRP Opening Comments on Track 1 Proposals at 28.

15 NextEra Opening Comments on Track 1 Proposals at 19, PG&E Opening Comments on Track 1 Proposals at 2.

LOLE/Loss of Load Hour (LOLH) hours throughout the year to weight production hours. As a result, it is not clear how the proposed weighting methodology would be implemented. MN8 also proposes to use the net peak value as the tech factor for QC translation. The Commission notes that the proposal would still require CAISO to change its tariff to validate RA requirements off the net peak rather than the peak load. Therefore, absent a change to the CAISO tariff, we decline to adopt MN8's net peak alternative as this could result in unnecessary CAISO backstop procurement. The Commission encourages Energy Division and/or stakeholders to further develop a QC translation methodology to resolve the issue of over-counting solar resources in the summer and under-counting in the winter for consideration in Track 2.

Regarding Energy Division's proposal, the Commission agrees that in the rare occurrence when a non-dispatchable resource is forced to go on outage due to transmission testing or failure, the resource's RA QC value should not be impacted. Thus, Energy Division's proposal to remove outages due to transmission testing or failure from the QC calculations is reasonable. Accordingly, Energy Division's proposal is adopted as follows:

If a non-dispatchable resource is forced to go on outage due to transmission testing or transmission failure and the resource owner provides evidence that the transmission event was caused by the transmission operator, the hours affected will be replaced by proxy data defined by historical production during the months affected. This is effective beginning for the 2027 RA compliance year.

4.4. Accreditation for Energy Storage Resources

Energy Division and several parties submit proposals to modify accreditation rules for storage resources, including charging sufficiency rules for LDES resources.

4.4.1. Energy Storage Resources, Generally

In D.14-06-050, the Commission adopted QC rules for storage resources, as follows:

> Dispatchable storage shall receive a QC in the same manner as other dispatchable resources, including testing and verification in CAISO operations. Because all RA resources must be able to operate for four or more consecutive hours, the storage operator must submit to the CAISO an output level (in MW) at which the resource is capable of discharging for four or more uninterrupted hours; that is defined to be its PmaxRA, the maximum output that can be considered for RA calculations.[16]

In D.23-04-010, the Commission described the QC methodology for energy storage resources as follows: the assigned value will be "based on Pmax, restricted to daily resource capabilities (*e.g.*, maximum daily run hours, maximum continuous energy, and storage efficiency)."[17]

4.4.1.1. Summary of Proposals

Energy Division asserts that the current QC calculation may not accurately account for storage foldback or nonlinearity in charging/discharging capabilities as the resource approaches its state-of-charge (SOC) limits. Foldback (or

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16 D.14-06-050 at Appendix B.

17 D.23-04-010 at Appendix A.

nonlinearity)[18] occurs for certain storage technologies, such as lithium-ion batteries, when the maximum and minimum power that an asset can achieve (Pmax and Pmin) declines rapidly near a resource's SOC limits. In other words, certain battery technologies have a nonlinear capacity charge or discharge rate when approaching full discharge or full charge, whereby the rate decreases. This relates to the issue discussed in Section 4.6 below under the UCAP framework. The definition of PmaxRA, adopted in D.14-06-050, requires an asset to be able to discharge at a consistent output level, which means that a battery's QC range should not include where the battery is experiencing nonlinearity in its discharge rate.

To address this, Energy Division states that clarifications and adjustments to the storage QC rules and the Master Resource Database (MRD) are needed to minimize confusion, streamline calculations, and more accurately reflect storage attributes. Energy Division proposes adding a new field to the CAISO Master File to reflect the maximum continuous energy a resource is able to provide over a four-hour period without experiencing foldback and/or a PmaxRA value, as described in D.14-06-050. Energy Division states that this is necessary due to the foldback issues and particularly because the Maximum Continuous Energy and Minimum Continuous Energy fields in the Master File may include ranges impacted by foldback. Energy Division proposes the following clarifications to the storage QC methodology:

(1) The storage QC calculation will be clarified as MAX_CONT_ENERGY_LIMIT less

[18] We note that parties and Energy Division use the terms foldback and nonlinearity interchangeably. The terms are also used interchangeably in this decision.

MIN_CONT_ENERGY_LIMIT, divided by four and constrained by the point of interconnection, rather than based solely on MAX_CONT_ENERGY_LIMIT divided by 4; and

(2) Storage QC will be clarified as "the output level at which a resource can discharge for four or more continuous hours without being affected by nonlinearity (or foldback)." Once Energy Division has access to a value of continuous energy unaffected by foldback, that value (divided by four, and constrained at the POI) will replace the calculation above.[19]

Additionally, Energy Division recommends two modifications to the MRD to improve accuracy of the MRD's default values and to increase efficiency so that LSEs do not have to contact Energy Division to correct values.

(1) Add an "Hour Continuous Duration" field to the MRD that reflects how many hours a resource can discharge at Pmax. Currently, the field that comes closest to providing this is the Max Daily Hours field but this field can be greater than four if a resource discharges multiple cycles. The default value of the new field would be the Maximum Continuous Energy divided by Pmax; and

(2) Change the default method of calculating the "Maximum Continuous Energy" field in the MRD to the difference between MAX_CONT_ENERGY_LIMIT and MIN_CONT_ENERGY_LIMIT from the CAISO Master File.

On the second modification, Energy Division states that currently, the Maximum Continuous Energy field in the MRD is calculated by multiplying the Pmax/Net Dependable Capacity (NDC) field by four, and this is not accurate

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[19] Energy Division Track 1 Proposal at 17.

when a storage resource is greater than or less than four hours in duration, such as when a battery's QC is less than Pmax. Energy Division states that parties may request adjustments to default values, as is currently done, and the two MRD modifications will not impact the QC calculation described in the two clarifications to the storage QC process.

Vistra contends that the current storage QC methodology overvalues dispatchable resources, storage, and storage components within a co-located resource.[20] Vistra recommends calculating the storage QC based on the SOC that was contracted to discharge at a sustained output level, referred to as "Commercial Available Energy per Cycle." The duration of a cycle could range between four and 24 hours. Because "Available Energy" in CAISO markets is the difference between CAISO's Maximum Continuous Energy Limit and Minimum Continuous Energy Limit, Vistra posits that scheduling coordinators can narrow Available Energy by submitting a lower or upper SOC limit bid to the CAISO market, which can narrow the amount of storage available to the market while the registered SOC outside of the biddable range can be accessed through exceptional dispatches. Vistra is concerned that scheduling coordinators may use lower and upper SOC parameters to represent firm available energy limits, allowing resources to receive inflated QC values.

Vistra recommends using a Commercial Available Energy approach for QC calculations of PmaxRA that may be lower than "Available Energy per Cycle" for CAISO dispatch purposes in order to accurately capture the SOC range available. Vistra proposes new parameters in the MRD to allow the

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20 Vistra Track 1 Proposal at 6.

PmaxRA calculation to be based on Commercial Available Energy contracted to support maximum output level over the contracted duration, as summarized below.

(1) Available Energy per Cycle = Maximum Continuous Energy Limit minus Minimum Continuous Energy Limit

(2) Maximum Continuous Energy Limit for RA-eligibility per Cycle = (0.9 * Maximum Continuous Energy Limit)

   a. Maximum energy level for RA below which operating levels can be sustained for 4-24 hours

(3) Minimum Continuous Energy Limit for RA-eligibility per Cycle = Max(0.1 * Maximum Continuous Energy Limit, Minimum Energy Limit)

   a. Minimum energy level for RA above which operating levels can be sustained for 4-24 hours

(4) Commercial Available Energy Per Cycle = Maximum Continuous Energy Limit for RA minus Minimum Continuous Energy Limit for RA

   a. The portion of Available Energy per cycle that can support operating levels sustained for 4-24 hours

(5) Maximum Commercial Daily Energy = Daily Storage Cycles * Commercial Available Energy per Cycle

   a. Maximum energy under contract that can be supported based on contracted energy per cycle & contracted cycles

(6) Minimum Run Hours per Cycle = four hours

   a. Minimum continuous discharge hours capable of sustaining output within a single cycle as contracted (4-24 hours)

4.4.1.2. Comments on Proposals

CESA and REV support Energy Division's proposal, while CAISO and CalCCA support Energy Division's proposal with modifications.[21] Vistra directionally supports Energy Division's foldback proposal but prefers its own proposal.[22]

CESA states that Energy Division's clarifications are an appropriate interim step until unit-specific foldback information can be assessed or QC calculations can recognize varying durations. CESA states that since foldback at the upper limit does not impact a resource while discharging, it should be clarified that designating a Maximum Continuous Energy Limit unaffected by foldback is only the maximum continuous energy unaffected by discharge foldback.

CAISO agrees with Energy Division's proposed first clarification because using inputs from the Master File improves the QC methodology by recognizing that the CAISO market cannot access SOC between the Minimum Continuous Energy Limit and 0 MWh. For the second clarification, however, CAISO suggests two modifications. One is that the QC calculation should consider impacts of foldback in the discharge direction only because the QC methodology focuses on how storage discharges, not how it charges. A second modification is that the QC calculation should use the higher of the following values: (1) SOC level at the lower end of a storage resource's dispatchable range; and (2) its

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21 CESA Opening Comments on Track 1 Proposals at 14, REV Opening Comments on Track 1 Proposals at 7, CAISO Opening Comments on Track 1 Proposals at 19, CalCCA Opening Comments on Track 1 Proposals at 14.

22 Vistra Opening Comments on Track 1 Proposals at 4.

discharge nonlinearity breakpoint. CAISO states that this would account for when storage can only be discharged to a SOC level higher than the resource's discharge nonlinearity breakpoint.

Because Energy Division's proposal discounts RA counting for all hours the resource can be shown, CalCCA states that this does not reflect foldback and overly constrains the resource's RA value in the hour of greatest need. CalCCA suggests modifying the calculation to allow a resource to count for full capacity for three of the four hours and a derated amount in the other hour, arguing that this would more accurately reflect foldback impacts and result in a higher RA counting the hour of greatest need.

Cal Advocates opposes Energy Division's foldback proposal because Energy Division and CAISO do not describe the means to gather the necessary data to account for foldback, and this may create unknown costs and burdens.[23] There are also no estimated impacts to the RA fleet, as Energy Division's and CAISO's adjustments to the storage accreditation could replace storage NQC values and require LSEs to procure additional capacity to meet SOD requirements. Cal Advocates recommends the Commission estimate impacts to the aggregate NQC of the RA storage fleet, that CAISO and the Commission coordinate to ensure the storage QC methodology is based on correct data, and that CAISO conduct a study to estimate ratepayer costs of its proposed modifications to Energy Division's methodology.

Hydrostor recommends that QC be based on Maximum Continuous Energy divided by eight, limited by Pmax, for resources that come online during

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23 Cal Advocates Opening Comments on Track 1 Proposals at 24.

or after 2031.[24] Hydrostor asserts that this aligns with the needs identified in the IRP process that shows the system needs virtually no four-hour duration storage after 2031 and only needs eight-hour duration or longer storage resources.

CESA supports Vistra's proposal for more accurate evaluation of short- and long-term storage but recommends ensuring that the default use of the 0.1 and 0.9 factors in the calculation of Commercial Available Energy do not infringe on existing policy for continuous discharge dispatch capability.[25] CESA recommends further discussion on the accurate definition of fields. REV suggests further discussion of Vistra's QC proposal.[26]

4.4.1.3. Discussion

Energy Division asserts that the current QC calculation may not accurately account for battery energy storage foldback as the maximum and minimum power (Pmax, Pmin) a resource can achieve may decline rapidly near its SOC limits. The Commission concurs with parties that the QC calculation for storage resources should be clarified and modified to address foldback, which would more accurately reflect storage capabilities and reduce uncertainty in the QC methodology. We find that Energy Division's proposed clarifications and adjustments to the storage QC methodology, in addition to CAISO's suggested modifications to the definition and future calculation, appropriately address the foldback issue.

[24] Hydrostor Opening Comments on Track 1 Proposals at 10.

[25] CESA Opening Comments on Track 1 Proposals at 15.

[26] REV Opening Comments on Track 1 Proposals at 7.

Accordingly, the following clarifications and modifications to the storage QC methodology are adopted as follows, and will be effective beginning with the 2027 RA compliance year:

(1) The storage QC calculation is MAX_CONT_ENERGY_LIMIT less MIN_CONT_ENERGY_LIMIT, divided by four and constrained by the point of interconnection; and

(2) The storage QC value is clarified as the output level at which a resource can discharge for four or more continuous hours without being affected by nonlinearity (or foldback). Once Energy Division has access to a value of continuous energy unaffected by foldback, that value will be incorporated into the calculation in (1) above.

Vistra's proposal to add an additional field, "Commercial Available Energy per Cycle," to the MRD to account for foldback is effectively intended to achieve the same outcome as Energy Division's proposal. However, Vistra's proposal would include a default value to account for foldback that could be used until Energy Division has access to a value of continuous energy unaffected by foldback. While we see merit in Vistra's proposal, it would be duplicative of Energy Division's proposal. Additionally, we agree with CESA and Cal Advocates that more discussion is needed as to the appropriate default value so that it does not overly impact the aggregate NQC of the RA storage fleet.

The Commission agrees that modifications to the MRD are necessary to improve accuracy of the default values and administrative efficiency. Energy Division's proposed addition of an "Hour Continuous Duration" field and proposed modification to the default method of calculating the "Maximum Continuous Energy" field are reasonable. In addition, some of Vistra's proposed additions to the MRD have merit. Vistra's proposal to rename "Maximum Continuous Energy" as "Available Energy per Cycle" would reduce confusion because the Maximum Continuous Energy field is not equivalent to MAX_CONT_ENERGY_LIMIT on the Master File. Vistra's proposed addition of a "Minimum Run Hours per Cycle" field is similar to Energy Division's proposed MRD field "Hour Continuous Duration." However, the Commission prefers Energy Division's proposal to divide the Maximum Continuous Energy field by Pmax, as it would increase the accuracy of the value, would result in less administrative burden associated with managing the MRD, and would recognize that although the accreditation framework is based on four hours, there are some batteries that discharge at Pmax for less than four hours in duration. In the SOD Compliance Tool, batteries may discharge at Pmax for their duration, as it is a function of Pmax and its Maximum Continuous Energy.

Finally, Vistra's proposed fields for "Minimum Continuous Energy Limit for RA-eligibility per Cycle" and "Maximum Continuous Energy Limit for RA-eligibility per Cycle," are not necessary metrics for the RA program. Vistra's proposed "Maximum Commercial Daily Energy" is meant to be captured in the MRD under "Maximum Daily MWh." It is possible that Maximum Daily MWh is capturing energy that is not available for RA compliance, but the field is intended to show the maximum amount of energy that may be used for RA compliance, not the maximum amount of energy possible in a single day.

The Commission does not see the need to determine each of the naming conventions in the MRD. Rather, we authorize Energy Division to consider the clarity of the field names in the MRD and make adjustments as needed.

Accordingly, we adopt modifications to the MRD fields to add a column delineating duration and to change the default value of the "Maximum Continuous Energy" field to be the difference between MAX_CONT_ENERGY_LIMIT and MIN_CONT_ENERGY_LIMIT from the CAISO Master File. Energy Division is authorized to consider the clarity of the field names in the MRD and make adjustments as needed.

4.4.2. Energy Only Resources

RA eligibility is contingent upon a resource's deliverability status. This status is based on CAISO's Deliverability Assessment, which evaluates the transmission system's ability to accommodate the simultaneous delivery of resources to the aggregate system load during stressed conditions. Under CAISO's annual deliverability assessment process, resources are assigned FCDS or PCDS and consequently, their NQC for RA value is established.

Energy only resources, by contrast, are not eligible to count towards system, flexible or local RA requirements. However, in limited circumstances, energy only resources can count towards SOD charging sufficiency requirements, if the resource is paired with a deliverable storage resource at the same POI. This charging credit is capped at the amount required to charge the on-site storage and cannot be used to satisfy charging requirements for off-site storage resources.[27]

In D.25-06-048, the Commission considered CalCCA's proposal to count co-located EO resources as RA resources but determined that the proposal was not adequately developed, would require substantial modifications to the

[27] *See* D.24-06-004 at OP 9.

CAISO's tariff and systems, and conflicted with the annual deliverability assessment process. Parties were encouraged to submit proposals on how to address identified implementation barriers and reliability concerns.

4.4.2.1. Summary of Proposals

Multiple parties submit proposals on counting standalone EO resources towards charging sufficiency, counting EO portions of co-located resources towards charging sufficiency up to the POI limit, and counting EO resources towards RA requirements.

ACP-CA recommends allowing EO resources to count towards SOD charging sufficiency requirements, subject to the following conditions:[28]

(1) The EO resource is under contract with an LSE who will use it for energy sufficiency, with a must-bid obligation to CAISO, and potentially subject to affidavit requirements for the scheduling coordinator to submit bids; and

(2) The EO resource is paired in a supply plan with a storage resource in the same geographic area (i.e., Southern California or Northern California).

ACP-CA states that its proposal is consistent with the CAISO tariff in that it only allows EO resources to count for charging sufficiency. ACP-CA argues that a must-bid requirement ensures resource visibility and including EO resources in supply plans avoids double-counting in year-ahead and month-ahead processes, while ensuring availability and enforcement through review of contractual agreements. ACP-CA states that regional pairing would expand energy sufficiency contributions and allow contracting for FCDS storage and EO solar under separate contracts.

28 ACP-CA Track 1 Proposal at 3.

PG&E proposes to allow EO resources to count towards charging sufficiency on an interim basis through 2030, with a reevaluation the prior year.[29] PG&E proposes the following:

(1) Apply the existing QC exceedance methodology to EO resources as a proxy for deliverability during off-peak charging periods; and

(2) EO resources can only charge storage in same geographic region (i.e., North of Path/ South of Path 26).

Even without a must-offer obligation (MOO) for EO resources, PG&E claims that EO resources have sufficient incentives to be available in CAISO's market (such as Renewables Portfolio Standard (RPS) incentives) and to generate energy due to contractual terms that dictate bidding/scheduling. Such constraints provide guardrails, while capturing the energy provided by EO resources and reducing LSE procurement. Adopting this interim proposal would allow CAISO to conduct an EO-based deliverability study within three years to see if EO resources should count for charging sufficiency; alternatively, stakeholders could reevaluate this mechanism within three years.

Joint EO Parties recommend that EO resources be permitted to be used for charging sufficiency if the following conditions are met:[30]

(1) The storage is located in the same Transmission Planning Study Area as the EO resource;

(2) The EO resource must bid into the CAISO market, consistent with MOO for deliverable RA resources; and

[29] PG&E Track 1 Proposal at 1.

[30] Joint EO Parties Track 1 Proposal at 7.

(3) The LSE shows the EO resource and receives the energy benefit if it holds a contract with the EO resource.

CalCCA proposes to allow the EO portion of a co-located resource to count for RA or charging sufficiency for off-site storage, subject to the following conditions:[31]

(1) The EO resource is co-located with a deliverable resource; and

(2) The combined showing of the deliverable resource and EO component do not exceed the deliverability limits at the POI.

CalCCA recommends the Commission coordinate with CAISO to update CAISO's tariff to support this change by requiring a MOO for shown EO resources. CalCCA states that if multiple off-takers show a resource, they must coordinate contractually to ensure the showing is compliant and does not exceed the POI in any hour.

SCE proposes that excess energy produced by a co-located EO resource should be allowed to count towards an LSE's charging sufficiency need up to the POI limit.[32] SCE states that this approach will not reduce reliability because the POI for paired resources (the fully deliverable resource and the EO resource) have been studied for deliverability. SCE states that this proposal captures stranded value already validated by deliverability studies and reduces costs.

SCPA proposes to allow long-lead time EO resources under contact to count towards RA requirements, as this would encourage long-lead time resources outside areas with available capacity to enter CAISO's interconnection

[31] CalCCA Track 1 Proposal at 8.

[32] SCE Track 1 Proposal at 7.

process.[33] Alternatively, SCPA recommends allowing EO resources to count towards RA requirements in non-summer months. SCPA states that requiring all resources to be fully deliverable is unnecessarily limiting because it includes off-peak hours, and CAISO's deliverability status is based on summer peak months and has limited relevance in non-summer months.

4.4.2.2. Comments on Proposals

Multiple parties support allowing stand-alone EO resources to count for charging sufficiency, including 3CE, ACP-CA, CEJA/Sierra Club, Joint EO Parties, REV, and SCPA/PCE.[34] These parties generally state that allowing EO eligibility will offer incentives for contracting and development of EO resources, which are needed to meet greenhouse gas targets and for EO procurement in the IRP proceeding. 3CE, ACP-CA, AES, and SCPA/PCE argue that the treatment of EO resources in the RA proceeding conflicts with the IRP proceeding, which models EO resources as contributing to energy sufficiency.[35]

3CE, EDFps, REV, SCPA/PCE, and SDG&E state that CAISO's deliverability study focusing on peak hours does not represent the reality of storage charging periods during the middle of the day.[36] ACP-CA, GreenGen,

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[33] SCPA Track 1 Proposal at 5.

[34] 3CE Opening Comments on Track 1 Proposals at 3, ACP-CA Opening Comments on Track 1 Proposals at 2, CEJA/Sierra Club Reply Comments on Track 1 Proposals at 2, Joint EO Parties Opening Comments on Track 1 Proposals at 3, REV Opening Comments on Track 1 Proposals at 3, SCPA/PCE Opening Comments on Track 1 Proposals at 2.

[35] 3CE Opening Comments on Track 1 Proposals at 3, ACP-CA Opening Comments on Track 1 Proposals at 2, AES Opening Comments on Track 1 Proposals at 7, SCPA/PCE Opening Comments on Track 1 Proposals at 2.

[36] 3CE Opening Comments on Track 1 Proposals at 3, EDFps Opening Comments on Track 1 Proposals at 2, REV Opening Comments on Track 1 Proposals at 4, SCPA/PCE Opening

Joint EO Parties, NextEra, and SDG&E state that requiring charging sufficiency to come from FCDS resources risks increasing transmission upgrade costs, as LSEs will have to secure deliverable resources that do not have transmission reliability concerns to justify deliverability during peak stressed hours and that are built far from load centers.[37] AES, CEJA/Sierra Club, and GreenGen support a geographical limitation to ensure EO resources can charge near EO storage, such as CAISO's Transmission Planning Study Areas.[38]

Multiple parties oppose allowing EO resources to count for charging sufficiency and recommend deferring this issue for further process, including CAISO, Cal Advocates, MRP, SCE, Vistra, and WPTF.[39] These parties generally assert that there is insufficient data to determine that storage resources can charge from EO capacity and there is no way to ensure EO generation will be delivered to storage resources. CAISO states that because the RA process does not include a transmission system study that evaluates whether constraints limit generators' ability to charge storage during non-peak hours, allowing EO capacity to meet charging sufficiency requirements would rely on an untested assumption that EO capacity can provide charging energy to storage.

Comments on Track 1 Proposals at 4, SDG&E Opening Comments on Track 1 Proposals at 11.

37 ACP-CA Opening Comments on Track 1 Proposals at 3, GreenGen Opening Comments on Track 1 Proposals at 3, NextEra Opening Comments on Track 1 Proposals at 1, SDG&E Opening Comments on Track 1 Proposals at 11.

38 AES Opening Comments on Track 1 Proposals at 7, CEJA/Sierra Club Opening Comments on Track 1 Proposals at 11, GreenGen Opening Comments on Track 1 Proposals at 4.

39 CAISO Opening Comments on Track 1 Proposals at 2, Cal Advocates Opening Comments on Track 1 Proposals at 2, MRP Opening Comments on Track 1 Proposals at 18, SCE Opening Comments on Track 1 Proposals at 8, Vistra Opening Comments on Track 1 Proposals at 8, WPTF Opening Comments on Track 1 Proposals at 10.

These parties generally state that the Commission should defer consideration of EO charging sufficiency until it can consider the results of CAISO's forthcoming deliverability study.[40] As part of its 2026-2027 Transmission Planning Process (TPP), CAISO states that it will perform a study to provide information on whether the Commission can reasonably assume storage can charge from EO capacity. CAISO plans to provide two sets of results: (1) the extent to which transmission congestion constrains output from generation resources; and (2) the extent to which transmission congestion constrains storage resources' ability to charge. CAISO states that preliminary study results will be available in November 2026, and results will be incorporated into the Transmission Plan for approval by the CAISO Board of Governors in May 2027.

CAISO also states that the RA program has not established rules on which hours and locations EO capacity may be used to meet charging sufficiency requirements, and how to validate that EO capacity was contracted by LSEs. CAISO advises that the Commission develop these complementary rules before deciding to allow EO capacity to meet charging sufficiency requirements.

Vistra states that Pub. Util. Code Section 380(c) requires that generating capacity shall be "deliverable to locations and at times as may be necessary to maintain electrical service system reliability, local area reliability, and

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[40] *See* CAISO Opening Comments on Track 1 Proposals at 2, Cal Advocates Opening Comments on Track 1 Proposals at 2, MRP Reply Comments on Track 1 Proposals at 2, SCE Opening Comments on Track 1 Proposals at 8, WPTF Opening Comments on Track 1 Proposals at 10.

flexibility."[41] To meet this requirement, Vistra asserts that compliance must be limited to deliverable capacity and EO resources do not meet this definition. WPTF comments that allowing non-deliverable EO resources to backstop RA requirements or charge under geographical proxies could undermine reliability, distort locational signals, and lead to under-procurement of deliverable resources.[42] MRP states that because some resources have invested in network upgrades to obtain deliverability status, these proposals create a workaround for LSEs to procure cheaper EO resources and degrade the value of deliverability and investment incentives.[43]

Calpine, GreenGen, and NextEra support SCE's proposal to count co-located EO resources towards charging sufficiency up to the POI limit.[44] AES opposes SCE's proposal because limiting EO eligibility to resources co-located with an FCDS resource forecloses the majority of viable EO resources.[45]

Ava/PCE and 3CE support CalCCA's proposal.[46] GreenGen supports CalCCA's proposal with the modification that it be limited only to charging sufficiency, and NextEra supports the proposal with the modification that energy

41 Vistra Opening Comments on Track 1 Proposals at 7.

42 WPTF Opening Comments on Track 1 Proposals at 10.

43 MRP Opening Comments on Track 1 Proposals at 18.

44 Calpine Opening Comments on Track 1 Proposals at 7, GreenGen Opening Comments on Track 1 Proposals at 5, NextEra Opening Comments on Track 1 Proposals at 8.

45 AES Opening Comments on Track 1 Proposals at 7.

46 Ava/PCE Opening Comments on Track 1 Proposals at 3, 3CE Opening Comments on Track 1 Proposals at 7.

from EO resources first be used to charge co-located storage before delivery to the POI for system use.[47]

CAISO, Calpine, MRP, SCE, and Vistra oppose proposals allowing EO capacity to meet RA requirements, such as CalCCA's and SCPA's proposal.[48] CAISO states that CAISO's deliverability studies have demonstrated that EO capacity is undeliverable during stressed system conditions, such that they cannot reliably serve CAISO system load during these hours. CAISO also states that if EO capacity can potentially serve load in non-peak hours, it likely can only serve storage charging needs and not firm load reflected in RA requirements.

4.4.2.3. Discussion

The Commission declines to adopt proposals to count EO resources for RA capacity, as proposed by CalCCA and SCPA. Requiring an RA resource to be deliverable in order to meet an LSE's RA requirements has been a cornerstone of the RA program since its inception. EO resources have not been studied by CAISO for their ability to serve load during peak conditions, and allowing EO resources to count for RA requirements would introduce critical reliability risks. As such, we decline to adopt these proposals.

With respect to proposals to count standalone EO resources towards charging sufficiency, multiple parties highlight the deliverability risk and performance uncertainty of EO resources during off-peak hours and advocate for

47 GreenGen Reply Comments on Track 1 Proposals at 6, NextEra Opening Comments on Track 1 Proposals at 8.

48 Calpine Opening Comments on Track 1 Proposals at 7, CAISO Opening Comments on Track 1 Proposals at 8, MRP Opening Comments on Track 1 Proposals at 17, SCE Opening Comments on Track 1 Proposals at 8, Vistra Opening Comments on Track 1 Proposals at 7.

deferring this issue until CAISO can complete its TPP study. By contrast, many parties would like the EO counting rules for charging sufficiency to be relaxed, stating that the EO counting rules do not reflect the operational realities of standalone EO for charging storage in off-peak hours.

Weighing parties' proposals and comments, the Commission concurs that there is insufficient data to conclude that storage resources can charge from EO capacity at this time. The Commission agrees that it is prudent to defer consideration of this issue until the Commission can consider the results of CAISO's TPP study. CAISO states that the preliminary results of the TPP study will be issued in November 2026, with a final TPP to be approved by the Board of Governors in May 2027. The Commission encourages parties to participate in the CAISO's 2026-2027 TPP process. We will consider proposals to allow standalone EO resources to count towards charging sufficiency requirements in a future phase of this proceeding, following the release and evaluation of the forthcoming TPP study results. In addition, the Commission authorizes Energy Division to complete a study that applies the existing QC methodology to EO solar and wind resources, to be submitted into the proceeding.

SCE and CalCCA each propose to count EO that is co-located with a deliverable resource for charging sufficiency up to the POI limit. They reason that the POI of the co-located resource has been studied for deliverability and deliverable resources are presumed deliverable in all hours in the Commission's RA program. Therefore, allowing EO resources to count for off-site charging sufficiency in hours when storage is not shown does not violate the POI limit and more efficiently utilizes generation and transmission capacity. The Commission deems the proposed modification to be a reasonable expansion of the existing charging sufficiency methodology. Further, this modification would not require Energy Division to develop an additional compliance verification process. Accordingly, effective beginning for the 2027 RA compliance year, the charging sufficiency value from co-located EO resources will be calculated as follows:

Energy Available for Charging Sufficiency = [Total energy produced (subject to hourly POI limits)] minus [On-site paired storage energy sufficiency need]

4.4.3. Long-Duration Energy Storage Resources

In D.25-06-048, the Commission stated that "[b]efore adopting, or modifying, accreditation methodologies for LDES resources, several questions regarding charging sufficiency requirements and accreditation require further discussion."[49] The Commission outlined the following questions in D.25-06-048:[50]

1. Whether multi-day storage (MDS) and/or pumped storage hydropower (PSH) should have limitations on their ability to charge storage resources;
2. As MDS (24-hour+) and Extended Duration (ED)-LDES (12-24 hour) batteries are not able to fully charge in a 24-hour period, how can these batteries fit into the SOD framework;
3. As MDS and other ED-LDES resources may have different attributes, should these resources be treated differently from each other and how;
4. Whether a multi-day charging sufficiency test, as proposed by Cal Advocates, could work in the SOD framework,

[49] D.25-06-048 at 65.

[50] *Id*. at OP 9.

including how much extra time should be allowed for charging and to what types of multi-day resources this should apply;

5. How a seasonal PSH or MDS charging requirement could work, including how many months in advance should be permitted and how this would fit into the SOD framework;
6. For PSH accreditation in particular: (1) an analysis of reliability issues with the current methodology; (2) the different treatments of different designs of PSH (considering loop design, duration in number of hours, and round-trip efficiencies); and (3) whether PSH charging rules should be based on historical data.

The Commission encouraged parties to further develop LDES proposals following Energy Division's workshop on LDES issues.

4.4.3.1. Summary of Proposals

Joint LDES Parties and Cal Advocates submit proposals to address LDES charging sufficiency requirements.

Joint LDES Parties recommend a charging sufficiency approach that accounts for energy actually used to charge LDES resources.[51] Joint LDES Parties assert that for LDES resources that are operational and connected to the grid, resources are expected to store energy for SOD needs from three general categories: (1) residual energy expected to be carried within such systems at a general baseline level, called initial SOC; (2) energy expected to be added to an LDES resource in the days leading to a stressed system event, referred to as "Shifted Energy;" and (3) excess energy that may be available within the grid stress period, to the extent it exists, referred to as "SOD Excess Energy."

[51] Joint LDES Parties Track 1 Proposal at 6.

Joint LDES Parties state that by accounting for these categories, the Commission can determine how long LDES should be deemed available to meet load. Joint LDES Parties posit that an LSE should be allowed to show LDES as able to meet load to the extent they are expected to have enough total energy to be dispatched, up to their physical capacity during the SOD period. Joint LDES Parties state that for initial SOC, an assumption of 50% is a simple and conservative approach based on recent studies.

For Shifted Energy, the proposal establishes a charging window ranging from two to eight days preceding the worst-day, with the applicable number of charging days varying by resource based on storage duration. Under this proposal, the amount available to charge would be developed from the Integrated Energy Policy Report (IEPR) demand forecast up to eight days prior to the SOD worst-day forecast. Resources with durations under eight hours (non-LDES short-duration storage) would be treated consistently with the Commission's current implementation of the SOD framework. Joint LDES parties propose the table below:

Storage Duration (hours)	**Excess Energy Available (# of prior days)**
[≥8-<12)	2
[≥12-<16)	3
[≥16-<20)	4
[≥20-<24)	5
[≥24-<48)	6
[≥48-<72)	7
≥72+	8

Joint LDES Parties state that this proposal allows for rigorous energy accounting and avoids artificial energy scarcity by allowing initial SOC and Shifted Energy from the non-worst-day. The proposal would also reflect the operational realities of LDES resources, including that longer duration batteries will have longer charging timeframes, and will incentivize deployment of LDES resources.

Cal Advocates propose to implement a Multi-Day Energy Sufficiency Requirement (MDESR) that expands SOD single-day energy storage charging/discharging time horizons to multiple days for MDS.[52] The proposal has two components: (1) a multi-day charging period that accounts for MDS charging energy on an LSE's compliance plan; and (2) a requirement that MDS that is needed to provide more than 24 hours of continuous dispatch demonstrate sufficient energy to deliver over a multi-day period.

Cal Advocates proposes to define MDS as: a storage resource with a full discharge and charge cycle that is longer than 24 hours. To calculate charging sufficiency for MDS, Cal Advocates suggests spreading out energy required to charge the MDS over the forward charging period (FCP). FCP represents the number of days over which MDS is assumed to charge to reach an SOC that supports its capacity and slices shown on supply plans. Cal Advocates recommends a four-day FCP, which is the mid-point of CAISO's extreme weather notification process and corresponds to the point when CAISO initiates Restricted Maintenance Operations. Minimum consecutive day discharge (MCDD) would initially be set to one day because the Commission has not yet

52 Cal Advocates Track 1 Proposal at 4.

found a need for consecutive day dispatches provided by MDS in the IRP proceeding. However, if and when procurement for MDS is ordered for more than one day, the MCDD parameter should be set for more than one day.

Cal Advocates recommends that excess energy shown by an LSE on its monthly supply plan must be greater than or equal to the collective energy sufficiency requirement. The collective energy sufficiency requirement is the sum of: (1) the existing intra-day storage energy requirement; and (2) the MDESR. The intra-day energy requirement is the sum over all intra-day resources of the number of slices for each resource times the capacity per slice, divided by the product of the round-trip efficiency (RTE) and one charging day. This proposal would apply to all LDES and closed-loop PSH that cannot complete a full cycle in a single day and is shown on the SOD template but would not apply to open-loop PSH.

Vistra recommends that for LDES resources, the sufficiency assessment should have a storage charging sufficiency credit based on aggregated stored energy that the LSE would have going into Hour Ending (HE) 1.[53] The credit should be LSE-specific and based on the energy that could have been deployed to charge storage leading into the worst day being assessed under SOD. Vistra recommends calculating excess energy not needed for demand that could charge storage over a seven-day period with the initial condition for all storage assuming 0 MWh of SOC at the start of the assessment period. Vistra states that additional discussion is needed on the look-ahead period.

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53 Vistra Track 1 Proposal at 11.

4.4.3.2. Comments on Proposals

CEJA/Sierra Club, GreenGen, LDES Council, and NextEra support Joint LDES Parties' proposal,[54] while Ava/PCE support a simplified version of the proposal.[55] CEJA/Sierra Club support the proposal but recommend developing ELCC for LDES to properly value its grid contribution. GreenGen comments that the proposal is a reasonable starting point for grid-charging storage, including closed-loop PSH because it avoids applying a uniform construct to materially different storage resources. However, GreenGen states that it would be inaccurate to impose a charging sufficiency requirement on open-loop PSH as this would understate its reliability contribution by ignoring the access to natural water resources that open-loop PSH has.

CalCCA states that if Joint LDES Parties' proposal is adopted, a voluntary calculation methodology for "Shifted Energy" should be adopted, which would serve as the process for LSEs to submit their own profiles.[56] MRP states that open-loop PSH systems should not be exempt from the energy sufficiency requirement, but that the differences between open-loop and closed-loop PSH systems should be included in accounting, possibly by applying a higher RTE.[57] AReM argues that because natural water flow is not the primary source for

[54] CEJA/Sierra Club Opening Comments on Track 1 Proposals at 11, GreenGen Opening Comments on Track 1 Proposals at 2, LDES Council Opening Comments on Track 1 Proposals at 3, NextEra Opening Comments on Track 1 Proposals at 18.

[55] Ava/PCE Opening Comments on Track 1 Proposals at 10.

[56] CalCCA Opening Comments on Track 1 Proposals at 20.

[57] MRP Reply Comments on Track 1 Proposals at 10.

open-loop PSH, hydro generation and pumped storage should be separately modeled for all open-loop PSH resources.[58]

Cal Advocates, MRP, SCE, SDG&E, and Vistra oppose Joint LDES Parties' proposal.[59] SDG&E and Vistra oppose a 50% initial SOC assumption as arbitrary and unsubstantiated and instead support a 0% initial SOC assumption. These parties also argue that the proposal discriminates against shorter-duration energy storage by applying only to LDES resources. SCE states that the proposal would create data and administrative burdens for Commission staff and LSEs that are not necessary at the current level of LDES penetration, although SCE supports a 50% initial SOC.

Cal Advocates disputes the study Joint LDES Parties rely on to support their 50% initial SOC assumption, noting that the study shows only two days-long examples in August and December, neither of which justify the 50% initial SOC for all months. Cal Advocates contends that historical operational data could be used to estimate monthly SOCs, although this might stray from the SOD principles of accounting for all energy. Cal Advocates states that a single FCP for LDES and MDS should be established for all durations, as this would align with the reality of CAISO's operational response timeframe for extreme events. Cal Advocates opposes Joint LDES Parties' maximum eight-day FCP and Vistra's proposed seven-day FCP because this is outside of CAISO's seven-day

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[58] AReM Reply Comments on Track 1 Proposal at 6.

[59] Cal Advocates Opening Comments on Track 1 Proposals at 13, MRP Opening Comments on Track 1 Proposals at 20, SDG&E Opening Comments on Track 1 Proposals at 8, SCE Opening Comments on Track 1 Proposals at 16, Vistra Opening Comments on Track 1 Proposals at 6.

timeframe, and recommends a four-day window that provides greater price certainty to incentivize resources to hold and increase SOC. This also provides CAISO with greater certainty that there will be sufficient charging energy during the four-day window.

MRP states that the SOD framework was not intended to prescribe real-time operational behavior of storage but was meant to be a representational framework to evaluate whether an LSE procured sufficient capacity to meet reliability needs. MRP notes that for RA purposes, the critical requirement is whether the LSE has secured enough energy to support charging requirements. MRP states that charging sufficiency for LDES could be evaluated by requiring the LSE to show charging at least equal to the daily resource capability implied by the storage shown for RA plus efficiency losses. Alternatively, ELCC could be utilized to reflect charging capability in LDES capacity values.

SCE supports Cal Advocates' proposal, with modifications.[60] SCE states that an FCP of four days may underestimate the charging available to LDES in the days/weeks before stressed periods, as CAISO issues emergency alerts as early as seven days prior. SCE states that a 0% initial SOC assumption underestimates charging energy available to LDES from an operation perspective, and recommends an initial SOC of 50%. GreenGen supports Cal Advocates' proposal in recognizing the uniqueness of PSH.[61]

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[60] SCE Opening Comments on Track 1 Proposals at 16.

[61] GreenGen Opening Comments on Track 1 Proposals at 3.

Ava/PCE, CalCCA, Joint LDES Parties, and Vistra oppose Cal Advocates' proposal.[62] These parties generally state that the proposal is based on incorrect assumptions about using energy available to charge LDES from worst-day load profiles, which is overly conservative and will lead to over-procurement. Joint LDES Parties argue that the proposal forces a uniform multiplier of four across all LDES resources, fails to recognize a resource's ability to shift energy, and discriminates against LDES by imposing a multi-day standard that is not applied to other resources. Vistra claims that the proposal appears to discriminate against short-duration energy storage and LDES by only applying to MDS.

Vistra instead proposes an initial SOC at the start of the look-ahead to 0% and then after a look-ahead period to calculate when stored energy would be at the hour before the start of the worst day.[63] CalCCA recommends classifying LDES resources as any storage resource whose full charge and discharge cycle takes longer than 24 hours.[64]

AReM states that given the lack of consensus and analytical rigor, the Commission and CAISO should perform stochastic analysis of LDES and recommend how to value the technology.[65] AReM suggests waiting for this analysis rather than picking figures without basis.

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62 Ava/PCE Opening Comments on Track 1 Proposals at 6, CalCCA Opening Comments on Track 1 Proposals at 19, Joint LDES Parties Opening Comments on Track 1 Proposals at 2, Vistra Opening Comments on Track 1 Proposals at 6.

63 Vistra Opening Comments on Track 1 Proposals at 6.

64 CalCCA Opening Comments on Track 1 Proposals at 20.

65 AReM Reply Comments on Track 1 Proposals at 5.

4.4.3.3. Discussion

In D.22-06-050, the Commission stated that "ensuring LDES resources are properly valued across the slice-of-day framework is critical to the durability and success of the 24-hour framework."[66] The Commission subsequently considered valuation of LDES and MDS resources in several decisions, including D.22-06-050, D.23-04-010, D.24-06-010, and D.25-06-048, but ultimately determined that additional discussion and proposal development was needed. The Commission appreciates parties' efforts over multiple years to develop the record on this topic and address the Commission's concerns. The Commission, in particular, acknowledges the efforts undertaken by Cal Advocates to develop a multi-day charging sufficiency test proposal, as encouraged by the Commission in D.25-06-048.

Considering parties' proposals and comments, there is sufficient record to adopt a charging sufficiency methodology for LDES and MDS resources for use in the SOD framework, as further discussed below. The Commission finds that aspects of the proposals from Cal Advocates and Joint LDES Parties have merit.

As a preliminary matter, the Commission clarifies the definition for LDES and MDS resources for purposes of the RA program. In D.25-06-048, the Commission described the term Extended Duration (ED)-LDES as batteries with durations of 12-24 hours, and MDS resources as storage resources with a duration of 24+ hours that are not able to fully charge in a 24-hour period.[67] In that decision, the Commission rejected CESA's classification of IRP-LDES noting

[66] D.22-06-050 at 87.

[67] D.25-06-048 at OP 9.

that: "it is unclear what value would be added by including an 8-hour+ classification in the RA program, as 4- to 12-hour batteries are already accommodated in the Master Resource Database (MRD) and SOD compliance tool with regards to temporal charging constraints."[68]

Although the Commission previously rejected CESA's IRP-LDES classification, there is a growing need to distinguish between LDES and non-LDES resources for purposes of establishing equitable charging requirements. Thus, we find that defining LDES as any storage resource that can discharge continuously at a maximum capacity for at least eight hours is a simple, straightforward dividing line between LDES and non-LDES resources, and is needed to implement an FCP framework, as further discussed below. Additionally, this LDES definition aligns with the IRP program, which defines a LDES resources as any storage resource that can discharge continuously at a maximum capacity for at least eight hours.[69] Accordingly, an LDES resource is defined as any storage resource that can discharge continuously at a maximum capacity for at least eight hours. The accreditation rules adopted below will apply to all LDES resources, which includes MDS resources.

Proposals and comments on the appropriate energy sufficiency framework for LDES and MDS resources primarily focus on three key components: the length of the FCP, the assumed initial SOC coming into the FCP, and the basis on which to establish the excess energy required to support the energy sufficiency

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[68] *Id*. at 63.

[69] D.25-06-005 at OP 12-13.

charging requirements (*i.e.*, worst-day, days prior to the worst-day, and average differences between the worst-day and non-worst-day conditions).

As for how best to value the excess energy used for charging sufficiency, the Commission agrees that LDES resources should have a defined FCP attached to the excess energy used for charging sufficiency. We find that a resource-specific approach that adjusts the FCP based on the duration of the resource, as proposed by Joint LDES Parties, is reasonable because it applies a consistent methodology across all storage resource durations. This approach also offers a straightforward solution that avoids an arbitrary cutoff between different charging durations, while recognizing the unique operational characteristics and flexibility of LDES resources. The Commission finds that blending Joint LDES Parties' proposal and Cal Advocates' multiplier approach strikes a reasonable balance between recognizing operational flexibility and applying a clear energy sufficiency requirement. Energy used for charging short-duration energy storage will not be able to charge LDES; rather, all energy for short-duration energy storage and LDES charging will be counted concurrently so that there is no bias towards any battery duration. The following table represents a resource-specific approach to base the FCP on resource discharge duration for LDES charging sufficiency:

Storage Duration (hours)	**FCP Multiplier**
[≥8-<12)	2
[≥12-<16)	3
[≥16-<20)	4
[≥20-<24)	5

Storage Duration (hours)	**FCP Multiplier**
[≥24-<48)	6
[≥48-<72)	7
≥72+	8

We find that this blended approach incorporates LDES resources into the SOD framework, while appropriately reflecting that LDES resources can shift charging across multiple days and preserving a meaningful charging obligation. The duration of the storage resource will be calculated by dividing the Maximum Continuous Energy by the Pmax, as described in Section 4.3 above for energy storage accreditation.

With respect to an initial SOC assumption for LDES resources, the Commission agrees with parties that a 50% initial SOC assumption for LDES resources is not substantiated by the record and potentially discriminates against shorter-duration energy storage resources that do not have this assumption.[70] We also find that giving any assumed initial SOC for storage resources is overly generous, particularly when combined with an FCP multiplier, as this would effectively reduce LDES charging requirements to near zero. In this context, the FCP already serves as an appropriate proxy for the expected SOC that LDES resources will carry into the worst day.

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70 Parties that refer to an initial SOC are referring to what the SOD Compliance Tool calls "Storage Excess Capacity Test," not the "Storage Minimum State-of-Charge," which provides all storage resources 100% initial SOC for the purposes of counting co-located energy.

The methodology does not reject the reality that LDES may come into the worst day with charge; rather, the Commission finds that the initial SOC is baked into the FCP formula. For example, a 10 MW, 16-hour battery with a 4x FCP multiplier and 80% round-trip efficiency would require only 50 MWh of charging to provide the maximum 160 MWh recognized by the SOD Compliance Tool. This is equivalent to an effective initial SOC of 75%. Similarly, a 10 MW, 96-hour battery with a 8x FCP multiplier and 50% round-trip efficiency would require only 60 MWh of charging to provide the maximum 240 MWh recognized by the SOD Compliance Tool. This is equivalent to an effective initial SOC of 87%. For these reasons, we decline to adopt an initial SOC assumption.

With respect to the basis on which to establish the excess energy to support energy sufficiency charging for LDES, parties generally advocate for one of two categories: (1) the worst-day, or (2) days preceding the worst-day. The Joint LDES Parties recommend two options for applying the days preceding the worst-day: IEPR-specific days or a simplified slack period representing the average differences between the worst-day and non-worst-day conditions.

The Commission agrees with Cal Advocates that the LDES charging sufficiency requirements should be based on the existing SOD worst-day framework since a method has already been established for demonstrating RA capacity and this avoids introducing complexity with new data processes. We also concur that because LDES deployment is still limited, a detailed accreditation framework is premature and would unnecessarily burden the Commission and LSEs.

In addition, the Commission is not persuaded to adopt an approach based on days leading up to the worst day. RA resources are required to be able to perform across multiple consecutive days (with the minimum RA requirement of four hours for three consecutive days),[71] and the days prior to the worst day may also reflect system conditions that are near comparable to those on the worst day. Although there can only be one "worst" day in a month, many days leading up to the worst day can be stressed-system days.[72] Many LDES resources will likely be called to discharge on these days, even if they are not quite as bad as the "worst" day. Therefore, the FCP should not be interpreted as the literal days leading up to the worst day, but rather as a proxy for the general flexibility LDES resources have in charging and discharging, including both the slack value, as well as the initial SOC. The Commission finds that a simplified slack value approach requires further development and that it has not been demonstrated that the slack value is not already contained in the FCP multiplier.

For all of these reasons, we conclude that the FCP multiplier-based approach alone is a clear, enforceable framework for incorporating LDES resources into the SOD framework. Accordingly, effective for the 2027 RA compliance year, LSEs with LDES resources may count their capacity across the 24-hour SOD period up to the resources' capabilities using the adopted FCP multiplier framework to comply with storage charging sufficiency requirements. The Commission will continue to monitor operational data, as it becomes

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[71] *See* D.14-06-050, Appendix B at B-2.

[72] *See* California Governor Executive Order N-15-22.

available, and will consider refinements to the FCP multiplier framework in the future as warranted.

The Commission notes that future refinements to the treatment of LDES resources should account for the monthly usage limitations associated with these resources and should assess whether availability-based caps (similar to those applied to DR resources) are needed to preserve reliability value. This is particularly important to ensure that LDES with FCP multipliers are still available on days leading up to the worst day. As the Commission stated in D.22-06-050, the development of LDES counting rules should be coordinated with any modification or elimination of the Maximum Cumulative Capacity (MCC) bucket framework to ensure LDES resources are appropriately valued.[73]

With respect to PSH, the Commission previously stated in D.25-06-048 that "these resources can be either closed-loop or open-loop systems, which will affect the charging patterns of these resources and should be considered for future changes to the PSH counting rules."[74] In that decision, the Commission stated that it agrees "that open-loop PSH resources (the large majority of pumped storage hydro MW) have storage reservoirs that are fed by natural water inflow, in addition to pumped water."[75] The Commission finds it appropriate to treat closed-loop PSH resources like LDES resources because all energy discharged by closed-loop PSH must be attained by pumping water, as stated by parties. However, we note that currently there appear to be no

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[73] *See* D.22-06-050 at 87.

[74] D.25-06-048 at 64.

[75] *Id*.

closed-loop PSH resources in California. Accordingly, effective beginning for the 2027 RA compliance year, closed-loop PSH resources will be treated like LDES resources for purposes of charging sufficiency requirements.

With respect to open-loop PSH resources, by contrast, these resources should be treated differently from MDS resources because they have access to natural water flows. AReM points out that it is possible to model both storage and hydro components separately for open-loop PSH. A charging requirement should be determined for open-loop PSH based on duration and hydro input; however, at this time, there is insufficient record to adopt such a requirement. The Commission encourages parties to develop a method of accounting for the complexities of open-loop PSH that considers both its storage and hydro components and builds off the LDES charging sufficiency framework adopted in this decision.

4.5. Accreditation for Demand Response Resources

Energy Division states that when the SOD framework was adopted, the Commission established a single monthly QC value representing the contribution for most resources' hourly showings, except for demand response and solar and wind which utilize hourly profiles.[76] Prior to the SOD framework, third-party demand response providers (DRP) were awarded a single average value QC over the five-hour RA window based on their Load Impact Protocol (LIP) filings, and the single value QC was adopted as the single value NQC at CAISO.

[76] Energy Division Track 1 Proposal at 19.

In D.23-04-010, the Commission adopted three values to send to CAISO to ensure CAISO's visibility into the Commission's contracted fleet:[77]

(1) The maximum showing value;

(2) The peak showing value; and

(3) The greater of the peak showing value and a very small non-zero QC value if the peak showing value is zero.

Energy Division states that incongruencies arise because CAISO's systems do not yet support varying hourly profiles for developing CAISO's NQC list. However, California Energy Commission's (CEC) annual demand forecast and the Commission's RA framework have transitioned to 8,760 hourly profiles. Because demand response (DR) resources are required to be available for at least four consecutive hours within the five-hour window, for several months during the 2026 RA year, the CEC's peak hour falls outside of the latter four consecutive hours within the CAISO Availability Assessment Hour (AAH) window. Thus, all LIP filing entities with resources in the latter four hours will have a zero QC value in the CEC's peak hour.

4.5.1. Summary of Proposals

Energy Division and SCE submit proposals to address the misalignment between the IEPR California Energy Demand Peak Hour, the SOD QC valuation, and CAISO's NQC values.

Energy Division proposes an interim short-term solution while CAISO's systems are being updated.[78] Instead of the third value from D.23-03-010 (i.e., the greater of the peak showing value and a very small non-zero QC value if the

[77] D.23-04-010 at OP 20.

[78] Energy Division Track 1 Proposal at 10.

peak showing value is zero), Energy Division recommends submitting to CAISO the following value for only DR resources: the average of hourly MW values within the AAH window. Energy Division asserts that this value most accurately reflects the DR resources' load profile and would be used to determine NQC at CAISO. Energy Division recommends adopting the proposal in mid-2026 to implement the changes in the 2027 RA filing year.

As a long-term solution, Energy Division suggests that CAISO include the hourly NQC profiles in the CAISO Resource Adequacy Modeling and Program Design (RAMPD) or the Demand and Distributed Energy Market Integration (DDEMI) initiatives and working groups.[79] Energy Division asserts that this would align the operational reality of DR resources with true capabilities, as adopted in the Commission's hourly QC values. Energy Division encourages CAISO to integrate hourly NQC profiles to accommodate hourly NQC profiles before the 2028 RA year, when the CEC's Peak Hour projection occurs in the morning. For DRPs to implement this change, this will need to be adopted by end of August 2027.

SCE states that unless the RA measurement hours for DR resources are changed, DR providers and LSEs could lose RA NQC for the months where CEC peak demand is outside of the Commission's RA Measurement Hours or AAHs.[80] SCE therefore proposes designating an alternative peak hour within the AAH for determining DR QC when the CEC's monthly peak hour forecast falls outside of the AAH window. SCE states that this should be adopted in 2026 to

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[79] *Id.*

[80] SCE Track 1 Proposal at 12.

apply for the 2028 RA year due to a one-year lag in implementation of the DR RA requirements.

4.5.2. Comments on Proposals

PG&E supports Energy Division's proposal with one modification, stating that an average across the AAH window is a more reasonable assessment of DR resources' value during the AAH compared to selecting a single peak hour value.[81] PG&E states that it should be made clear that the average is across the impacts from the event hours only and does not include a non-event hour in the average (if any). This modification is needed because the minimum requirements are available for only four consecutive hours within the AAH.

Leap opposes Energy Division's solution and argues that it potentially undercuts the capacity value that DR can provide in the affected months.[82] Because many DR programs use devices like smart thermostats, Leap states that hourly NQC values are often higher in the peak hour than across the four-hour period, and thus, averaging NQC across four hours will yield a lower capacity value than will have been available in the peak hour. Leap states that CAISO will see a lower capacity value than DR is capable of providing in that peak hour. Leap instead proposes that the NQC of the first hour (or average of the first two hours) be used. Based on Energy Division's data, Leap asserts that in months where the peak hour occurs outside of a DR resources' four-hour LIP window, it always occurs in the first hour of that month's AAH. Leap claims that if a DR

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[81] PG&E Opening Comments on Track 1 Proposals at 18.

[82] Leap Opening Comments on Track 1 Proposals at 3.

resource's dispatch included the peak hour, that peak hour would also be the first hour the resource is dispatched.

Leap and PG&E support Energy Division's long-term solution to have CAISO adopt hourly NQC values.[83] Leap states that this would better align DRP's market participation with the SOD framework but that a complete solution would require the Commission to allocate NQC to DR resources in hours outside of the AAH as well.

AReM supports SCE's proposal as it would offer flexibility in showing DR at the hours it provides value.[84] AReM contends that this is the simplest approach until CAISO can accommodate the SOD framework. Leap opposes SCE's proposal and states that it would not allow DR to dispatch when it is most valuable, undermining the practice of targeting DR dispatch in periods of greatest need.[85]

4.5.3. Discussion

SCE's proposed modification to designate an alternative peak hour within the AAH window would require the Commission to make subjective, month-by-month determinations as to which hour is "representative" of system peak. Such a process would add both administrative complexity and uncertainty into the methodology. The Commission also observes that Leap's proposal to use the first-hour or average of two hours ignores the operational reality of resource "fatigue" and adds significant reliability risk. Further, establishing a

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83 Leap Opening Comments on Track 1 Proposals at 5, PG&E Opening Comments on Track 1 Proposals at 18.

84 AReM Opening Comments on Track 1 Proposals at 7.

85 Leap Opening Comments on Track 1 Proposals at 8.

MOO based on a first-hour maximum would create unsustainable performance requirements, potentially subjecting providers to unwarranted Resource Adequacy Availability Incentive Mechanism (RAAIM) penalties. Therefore, we decline to adopt SCE's and Leap's proposal.

The Commission deems Energy Division's proposal to use the average of hourly MW values within the AAH window to be a reasonable near-term solution to address the misalignment between the CEC's peak hour and DR participation windows. This methodology ensures that DR resources remain transactable and prevents the stranding of capacity due to the technical accounting incongruities identified in the 2026 and 2027 compliance years. Energy Division's averaging methodology provides an objective, formulaic standard that is immediately compatible with existing LIP data. We also agree with PG&E's modification that the average of hourly MW values is limited to the hours within the AAH window during which the resource is available, since the minimum requirements established in D.23-06-029 require availability for only four consecutive hours within the AAHs. The three values, including the average in subpart (3), will be sent to CAISO for each month, and the average methodology is not limited to months in which the CEC's monthly peak hour falls outside the AAH window. The terms "event hour" and "non-event hour" will not be used because resource availability is governed by the MCC availability requirements adopted in D.23-06-029.

Accordingly, for DR resources, the Commission will send the following three values for each month to CAISO to ensure CAISO's visibility into the Commission's contracted fleet, effective immediately:

(1) The maximum showing value;

(2) The peak showing value; and

(3) The average of hourly MW values for the hours within the AAH window during which the resource is available.

While the adopted solution addresses near-term concerns, the fundamental issue of the discrepancy between the Commission's hourly SOD framework and CAISO's single-value monthly NQC profiles remains. As CAISO's systems currently lack the granularity to recognize actual DR capabilities, the Commission urges CAISO to integrate a 24-hour SOD framework into its RAMPD or DDEMI initiatives. This alignment is the only durable solution that ensures DR is accurately compensated for its performance, eliminates workarounds, and optimizes grid benefits. Adopting 24-hour SOD profiles is also critical for future reliability as peak hours shift to the morning after 2027, falling outside the current AAH window.

4.6. Unforced Capacity

In D.24-12-003, the Commission stated that "Energy Division should coordinate with CAISO to develop a UCAP accreditation methodology for thermal power plants and battery electric storage systems for consideration in advance of the 2028 RA compliance year and to submit a revised UCAP proposal in Track 3 of this proceeding."[86] In D.25-06-048, we stated that:

> The Commission authorizes Energy Division, in coordination with the CAISO, to further develop a final UCAP framework to address the following areas: (1) establish a definition(s) for the types of "forced outage" that will be applicable to the UCAP calculation; (2) refine the ambient temperature derate

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

> methodology to address any Staff-identified issues; (3) develop UCAP for hybrid resources containing battery storage; (4) address how the incentives for UCAP should be transferred to the resource owner via the RA contract and identify whether any modifications are needed to the CAISO tariff; and (5) calculate the estimated impact of UCAP on resource counting and to the [planning reserve margin] PRM for procurement.

In D.25-06-048, the Commission stated that the 2028 RA compliance year would be the target for UCAP implementation. The Commission also authorized Energy Division to publish preliminary resource-specific and class-average UCAP values and estimated impacts to the PRM without a forced outage rate in advance of adopting a final UCAP framework.

4.6.1. Summary of Proposals

Energy Division and parties submit UCAP proposals, as summarized below.

4.6.1.1. Energy Division's Proposal

As authorized in D.25-06-048, Energy Division published preliminary resource-specific and class-average UCAP values, without an ambient temperature derate, on the Commission's website prior to a November 2025 workshop.[87] The preliminary values reflected the three full years of historic outage data available at the time. In January 2026, Energy Division posted revised UCAP values, utilizing the best three out of four full years of historical outage data and applying a proposed ambient temperature derate to thermal

[87] *See* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/r25-10-003/ucap_2022-2024.xlsx.

resources.[88] In addition, Energy Division published a workbook demonstrating the estimated impacts of the UCAP framework on the PRM.[89]

Energy Division submits a proposed UCAP framework intended to bring more consistency to resource accreditation by: (1) reflecting each resource's forced outage rate and, if applicable, a weather-normalized deration rate to the RA value due to ambient temperatures; (2) encouraging resources to maintain or improve reliability (as forced outages reduce a resource's UCAP value which affects the compensated amount of RA capacity); and (3) assigning forced outage risk to individual resources, enabling LSEs to target more reliable and effective capacity in their procurement strategies (compared to the current method of using the PRM to address capacity needed to replace resources on forced outage).[90]

Energy Division recommends the following principles to guide development of the UCAP framework and the selection of outage types for purposes of calculating the expected forced outage rate:

(1) Implementing UCAP into the RA program should incentivize LSEs to procure more effective, reliable resources.

(2) Unit outage types that indicate unplanned equipment failure that impacts the performance or availability of a

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88 *See* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/ucap_normderations_2022-2025_20260120.xlsx.

89 *See* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/ucap_adjusted-prm-calibration-workbook-20260123.xlsm.

90 Energy Division Track 1 Proposal at 31.

resource to provide future capacity should be included in the forced outage rate.

(3) Unit outage types should be consistent between RA resource accreditation and the inputs used for RA LOLE modeling (used in the development of PRMs) so the efforts are consistent. To support the reliability modeling, the forced outage rate will exclude derates for temperature because it will be calculated separately.

(4) To be consistent with the 1-in-2 load forecast, a typical weather year will be used to calculate a separate set of hourly weather-normalized derations due to ambient temperature.

(5) To the extent possible, the data will rely on publicly available data.

(6) Per Commission guidance in D.25-06-048, the preference is for UCAP to be applied on a unit-specific basis.

(7) The Commission supported using the best three out of the last four years of outage data. This will account for force majeure or highly unusual events that occurred in the past and may not be expected to occur in the future. Therefore, the exclusion of nature of work codes from the UCAP calculation should be very limited.[91]

Energy Division proposes to apply the UCAP framework to the following resource types: biogas, biomass, combined cycle gas turbine, combined heat and power, combustion turbine, geothermal, nuclear, reciprocating engine, and stand-alone and co-located battery storage. Among these resource types (except for nuclear), the UCAP evaluation will only apply to dispatchable resources. Energy Division's proposal did not include a calculation for hybrid units.

[91] *Id*.

Energy Division proposes that the forced outage rates be calculated to determine UCAP rates for both the SOD program and for inputs for reliability modeling to improve consistency between the two processes. To estimate a unit's expected forced outage rate when needed for future reliability, outage types that are likely to occur in the future would be included in the forced outage rate, and historical performance metrics would inform the UCAP calculation. Only outages during the RA Measurement Hours would contribute towards the forced outage rate.

Energy Division provides a list of Nature of Work (NOW) outage codes from CAISO's Outage Management System (OMS) that would be included when evaluating the Equivalent Forced Outage Rate during Demand (EFORd), as Appendix A to its Track 1 proposal. Energy Division notes that the NOW codes were selected based on its UCAP principles, that Energy Division staff would monitor the usage of outage types and NOW codes during UCAP implementation, and that Energy Division staff would update the selected codes, as needed, based on the principles. The forced outages and curtailments with NOW codes that would be excluded from the EFORd evaluation are: (1) Ambient Due to Temperature;[92] (2) New Generator Test Energy; and (3) Transmission Induced Outages. Forced curtailments reported as Ambient Due to Temperature would apply instead toward the weather-normalized deration rate due to ambient temperatures.

[92] The impacts of capacity reductions due to Ambient Due to Temperature are included in the model to normalize temperature adjustments to capacity.

Energy Division proposes a ten-step methodology detailed in its proposal.[93] Energy Division also recommends that if a battery cannot provide its QC value during the RA Measurement Hours due to nonlinear charging and discharging capacity, the UCAP value should reflect that for planning purposes. Energy Division proposes that outages due to foldback should be included in the unit's EFORd calculation for UCAP, as it reflects an operational condition. (Note that Energy Division's proposal included an inadvertent error that stated that the EFORd calculation would be based on PmaxRA, rather than Pmax.) Energy Division states that double-counting for foldback would not occur because the forced outage rate is a reduction to a unit's RA-eligible Pmax which reflects historical availability and is not a capacity counting issue for PmaxRA. Energy Division proposes to monitor this issue and make adjustments to the UCAP methodology to avoid double-counting unit derations in the event that CAISO's market conditions or reporting standards change.

Energy Division recommends using the RA Measurement Hours, which are based on CAISO's AAH and approved by the Commission to use in the RA program. Energy Division recommends using CAISO's OMS data as resource types for both RA accreditation and reliability modeling, as this data is publicly available and not subject to confidentiality concerns associated with the North American Energy Reliability Corporation's Generation Availability Data System (GADS) data.

Four complete calendar years of historic data would be used to evaluate UCAP values for each resource, with the best three out of four calendar years to

[93] Energy Division Track 1 Proposal at 33.

be assessed individually for each resource (to allow for automatic exclusion of unusual outage events). For new resources, or resources without four years of historic data, contemporaneous capacity-weighted class-averaged EFORd values would be used for each resource's pre-operational hours. As new resources' outage data become available in subsequent years, each resource's UCAP value will be determined using more individual resource outage data, and less class-averaged outage rates. During the first calendar year of a new resource's operation, its UCAP values will be determined based solely on its class-average outage rates.

Energy Division recommends special treatment for derations reported as "Ambient Due to Temperature" because the output capacity of thermal plants "are known to be sensitive to ambient temperatures due to the thermodynamic processes through which mechanical energy is derived from temperature and pressure differentials in the working fluid."[94] Energy Division states that using a model that accounts for ambient temperature by normalizing historic outages to a typical meteorological year will help mitigate effects of unusual weather events and provide a better predictor of derations in the future. The weather-normalization of derations due to ambient temperatures would be consistent with the 1-in-2 weather year assumption for the load forecast used in setting system RA obligations.

Energy Division cites D.25-06-048, in which the Commission stated it prefers resource-specific values but remains concerned about data quality

[94] *Id*. at 42.

issues.[95] To address this, Energy Division offers two options. Option 1 is to use unit-specific values in 2028 whereby units with at least one year of historical data would receive EFORd and UCAP values. For new units coming online in 2028, class-averaged EFORd values for the resource type would be used to calculate UCAP values. Units coming online within the four-year transition period (2025-2028) would be phased in, during which a unit's historic outage and curtailment data would be blended with the applicable class-average outage rates. Option 2 is to phase into unit-specific UCAP by 2032 and treat all units as "new" for 2028 and use class-averaged EFORd, although historic data would be used in evaluating class-averaged EFORd. The following years would progressively use historical data in the calculation until 2032 when all units with four years of history would utilize unit-specific data.

Energy Division proposes implementing UCAP values beginning with the 2028 RA compliance year, as stated in D.25-06-048. Energy Division would publish UCAP values using the annual process to update the MRD, which publishes a draft in July or August with a final version in September. For the first year, Energy Division would publish preliminary UCAP values in early 2027 for stakeholder review and comment to identify potential errors, with a longer review process before UCAP is included in the MRD update process. The PRM that is consistent with the EFORd utilized for UCAP would be applied to the Commission's schedule adopted in D.25-06-048; that is, a new PRM would be issued in 2027 for the 2028 compliance year. The underlying forced outage rates

95 D.25-06-048 at 50.

used to calculate UCAP would be incorporated in future Commission reliability modeling, beginning with the 2028 LOLE study.

4.6.1.2. Party Proposals

AES proposes that UCAP calculations only reflect forced outages due to equipment failures and exclude outages related to SOC management and other operation constraints.[96] AES recommends using unit-specific methodologies and that new assets use class-average values for the first year, then transition to resource-specific values based on actual operational data. AES recommends a Python-based approach over Excel due to barriers with transparent verification of the UCAP calculation. AES recommends that upon significant performance improvements, a resource should use class-average or reset the resource-specific calculations with technical documentation supporting the improvement to immediately reflect the investment. AES recommends a 60-day review period following issuance of preliminary UCAP values for the 2028 UCAP calculation.

Calpine states that its Geysers geothermal units operate as an integrated system, allocating thermal energy from a shared steam field across multiple units.[97] Calpine asserts that a unit-specific framework overlooks the operational flexibility and interdependence of multi-unit geothermal resources. Unit-specific values reflect historic performance on average but may fail to reflect how specific units perform in the event of a specific outage because steam can be redirected to other units. Calpine favors preserving the status quo NQCs for individual units at current non-UCAP levels, while capping aggregate facility-wide showings at

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[96] AES Track 1 Proposal at 3.

[97] Calpine Track 1 Proposal at 3.

the reliable capacity of the whole facility using the total of unit-specific UCAPs. Calpine states that this facility-wide sum (capped by UCAP) reflects maximum deliverable output that a unit may produce, accounting for constraints on capacity and limits on steam reallocation. Calpine recommends enforcing the seasonal cap through the RA compliance process, similar to how POI limits for co-located resources are enforced.

CESA recommends that principles should be followed to determine which outages are evaluated under UCAP and that an outage rate should: be comparable across resource classes, reflect a resource's tendency to experience equipment failures, and not reflect outages outside of management control.[98] CESA supports Energy Division's proposal for unit-specific EFORd, the best three out of four years of EFORd, and the use of verifiable CAISO OMS data. CESA expresses concern that the Commission may unwittingly cede jurisdiction of QC to CAISO if a clear rationale for outage selection is not established and a clear forced outage definition is not adopted. CESA notes that CAISO modified outage definitions in 2025 through its Business Practice Manual (BPM) updates, which may allow QC changes to occur outside of a Commission process. CESA recommends that regulatory definitions should not reference defined terms from the CAISO tariff or BPM. CESA proposes the following forced outage definition: an outage that requires immediate or delayed removal of a unit from service, derating, or other outage due to equipment failure or risk of imminent equipment failure.

98 CESA Track 1 Proposal at 3.

CESA proposes to evaluate storage outages only during times when the resource is "in demand" or would have been dispatched by CAISO if it were not on outage.[99] CESA recommends that forced outages be evaluated if they occur during intervals when a resource's Pnode price is greater than its bid cost. CESA recommends a data validation and review process before finalizing UCAP values, similar to the Commission's MRD process for flagging errors and documenting unusual events. Prior to the first binding year, a 60-day review should be permitted after publishing preliminary UCAP values.

Vistra proposes two QC metrics. The first is to maintain the current QC framework under which RA resources continue to have NQC established, deliverability assessed, and a MOO administered based on PmaxRA. The second metric is a new UCAP QC value ($PmaxRA_{UCAP}$) be developed to assess RA compliance.[100] Vistra proposes that the Commission produce a PRM based on PmaxRA to inform CAISO backstop assessments and a second PRM based on $PmaxRA_{UCAP}$ to evaluate the Commission's RA compliance. The UCAP Pmax value would be calculated by applying EFORd to minimum and maximum energy limits, subtracting the values. Vistra recommends a more limited set of NOW codes be included in the EFORd calculation.

Vistra further proposes that the UCAP framework for energy storage includes an EFORd for Available Energy in addition to an EFORd associated with the resources' maximum output level, arguing that physical outages affecting Continuous Energy Limits can be more restrictive than outages

[99] *Id*. at 11.

[100] Vistra Track 1 Proposal at 17.

affecting Pmax. Specifically, Vistra proposes an EFORd for the Maximum Continuous Energy Limit and the Minimum Continuous Energy Limit. For hybrid and co-located resources, Vistra proposes to apply the same UCAP QC methodology to the battery portion of the resource.

4.6.2. Comments on Proposals

CAISO, Cal Advocates, and SCE support Energy Division's UCAP proposal.[101] CAISO maintains that the proposal substantially aligns with CAISO's UCAP framework, as both proposals are resource-specific, calculate the UCAP derate based on a near-identical list of outage types, and use similar methods to determine UCAP demand hours. Energy Division's proposal aligns with CAISO's longer-term vision of reforming CAISO's availability incentive mechanism. SCE supports UCAP solely for the SOD program and not as a means to modify CAISO tariff constructs, which is outside the scope of the proceeding.

Several parties advocate for a clear definition of "forced outage" that is lacking in Energy Division's proposal, including AES, CESA, NextEra, REV, and SCE.[102] These parties generally state that a clear definition is needed for consistent application, equitable treatment for resource types, and to avoid contractual disputes. SCE states that without a clear definition, there may be uncertainty over whether contractual UCAP values reflect regulatory policy,

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[101] CAISO Opening Comments on Track 1 Proposals at 13, Cal Advocates Opening Comments on Track 1 Proposals at 21, SCE Opening Comments on Track 1 Proposals at 11.

[102] AES Opening Comments on Track 1 Proposals at 2, CESA Opening Comments on Track 1 Proposals at 3, NextEra Opening Comments on Track 1 Proposals at 12, REV Opening Comments on Track 1 Proposals at 6, SCE Opening Comments on Track 1 Proposals at 12.

which could increase transaction and ratepayer costs. SCE and NextEra agree with CESA's recommendation that the forced outage definition should be based on the Commission's policy objectives to preserve Commission jurisdiction and stabilize procurement/contracting expectations.

AES, IEP, MRP, Vistra, and WPTF oppose including outage categories that are outside of an operator's control from the forced outage definition.[103] These parties state that outages generators cannot prepare for or mitigate force majeure events (and other conditions beyond the operator's control), which could dilute performance incentives and penalize resources. NextEra supports the use of the best three out of four years of outage data to account for force majeure or highly unusual events that may not be expected in future years.[104] CEJA/Sierra Club support using all four years of outage data, rather than the best three out of four years.[105] Calpine opposes CEJA/Sierra Club's comments, stating that "exclud[ing] the worst year of performance data is intended to mitigate the impact of atypical events, such as major outages or significant maintenance, that can temporarily depress performance but are not necessarily representative of a unit's expected availability over time."[106] Calpine argues that this rationale applies to all resource types and provides more stable, predictable UCAP values.

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[103] AES Opening Comments on Track 1 Proposals at 3, IEP Opening Comments on Track 1 Proposals at 2, MRP Opening Comments on Track 1 Proposals at 4, Vistra Opening Comments on Track 1 Proposal at 12, WPTF Opening Comments on Track 1 Proposals at 4.

[104] NextEra Opening Comments on Track 1 Proposals at 16.

[105] CEJA/Sierra Club Opening Comments on Track 1 Proposals at 9.

[106] Calpine Reply Comments on Track 1 Proposals at 3.

CAISO comments that a "UCAP framework that captures a wide set of outage types reduces the incentives for RA resources to submit inappropriately classified forced outages to avoid impacts to the UCAP derate."[107] MRP states that in CAISO's filing to support RAAIM, certain NOW codes were excluded.[108] Cal Advocates recommends ambient derates for any resource that may be affected by ambient conditions, even if the operator has not yet reported that outage.[109]

Multiple parties, including AES, AReM, Ava/PCE, Calpine, CESA, CalCCA, NextEra, IEP, and REV oppose foldback being treated as a forced outage through EFORd, as this would result in double-counting.[110] These parties generally claim that foldback is already reflected in storage's QC value because RA accreditation is based on sustained deliverable output, and if a resource submits an outage when it enters foldback, inclusion of that outage in the EFORd and UCAP value reduces accredited capacity below the deliverability level, resulting in a double penalty. AES and CESA point out that since RA accreditation is based on a four-hour consistent discharge and the AAHs or RA Measurement Hours are a five-hour window, a storage resource delivering at

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107 CAISO Opening Comments on Track 1 Proposals at 14.

108 MRP Opening Comments on Track 1 Proposals at 5.

109 Cal Advocates Opening Comments on Track 1 Proposals at 21.

110 AES Opening Comments on Track 1 Proposals at 3, AReM Opening Comments on Track 1 Proposals at 6, Ava/PCE Opening Comments on Track 1 Proposals at 11, Calpine Opening Comments on Track 1 Proposals at 3, CESA Opening Comments on Track 1 Proposals at 8, CalCCA Opening Comments on Track 1 Proposals at 16, NextEra Opening Comments on Track 1 Proposals at 17, IEP Opening Comments on Track 1 Proposals at 3, REV Opening Comments on Track 1 Proposals at 6.

maximum RA capacity will enter the foldback range in the fifth hour.[111] In this scenario, the resource still has energy to contribute to the grid but under Energy Division's proposal, the resource operator would either submit an outage card (penalizing its UCAP value) or withhold energy to preserve accreditation.

AES, Ava/PCE, CAISO, IEP, MRP, SCE, and SDG&E state that a UCAP methodology for hybrid resources should be developed as this is not part of Energy Division's proposal.[112] AES states that while hybrid resources function as a single unit with one POI in CAISO's market, CAISO's OMS reporting does not reflect individual components. Therefore, if an outage impacts one component of a hybrid resource, OMS reporting does not indicate which component is affected which results in double-counting that may overstate the true unavailability of hybrid resources. CAISO states that this introduces a scenario where a hybrid resource and co-located resource that are identical, other than how CAISO models, would receive different QC values.

DMM and CAISO contend that adoption of a UCAP framework should not be delayed to address hybrid resource counting.[113] DMM states that due to differences in the NQC of component resources, the derate may result in small UCAP value differences; however, the UCAP framework can still be

[111] AES Opening Comments on Track 1 Proposals at 3, CESA Opening Comments on Track 1 Proposals at 10.

[112] AES Opening Comments on Track 1 Proposals at 4, Ava/PCE Opening Comments on Track 1 Proposals at 11, CAISO Opening Comments on Track 1 Proposals at 13, IEP Opening Comments on Track 1 Proposals at 3, MRP Opening Comments on Track 1 Proposals at 10, SCE Reply Comments on Track 1 Proposals at 7, SDG&E Opening Comments on Track 1 Proposals at 10.

[113] DMM Opening Comments on Track 1 Proposals at 4, CAISO Opening Comments on Track 1 Proposals at 13.

implemented and derates can be compared against a resource's Pmax and applied to the QC of the component parts. CAISO states that before 2028, a methodology for hybrid resources should be developed but implementation of a broader UCAP framework should not be delayed.

Likewise, several parties recommend delaying UCAP implementation until data quality and other major issues are resolved, including AES, Ava, CalCCA, NextEra, PG&E, and WPTF.[114] PG&E supports delaying implementation until 2030 to allow time to publish preliminary UCAP values and a PRM for 2028/2029 similar to the SOD framework's test year. AReM supports a delay in implementing the foldback proposals discussed above until CAISO implements the identification of foldback in the outage database. Ava supports a delay until a unit-specific framework for all resources can be implemented. SCE opposes delaying implementation due to data issues, stating that delaying UCAP would perpetuate recognized inefficiencies and the Commission should develop a parallel process to validate UCAP data.[115]

Many parties support using unit-specific values over class-average values, including Ava/PCE, CAISO, Calpine, CEJA/Sierra Club, DMM, Hydrostor, NextEra, PG&E, and SCE.[116] These parties generally state that unit-specific

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[114] AES Opening Comments on Track 1 Proposals at 6, Ava Reply Comments on Track 1 Proposals at 12, CalCCA Opening Comments on Track 1 Proposals at 18, NextEra Opening Comments on Track 1 Proposals at 12, PG&E Opening Comments on Track 1 Proposals at 4, WPTF Opening Comments on Track 1 Proposals at 2.

[115] SCE Opening Comments on Track 1 Proposals at 12.

[116] Ava/PCE Opening Comments on Track 1 Proposals at 11, CAISO Opening Comments on Track 1 Proposals at 17, Calpine Opening Comments on Track 1 Proposals at 3, CEJA/Sierra Club Opening Comments on Track 1 Proposals at 8, DMM Opening Comments on Track 1 Proposals at 2, Hydrostor Opening Comments on Track 1 Proposals at 9, NextEra Opening

values incentivize resources to be available when the grid needs them most, while class-average values dilute the calculation and do not incentivize resources to improve reliability. These parties assert that class-average values penalize resources that perform better than the class average and reward those that perform below the average. CAISO comments that a resource-specific UCAP framework aligns with RAAIM reform, while class-average would dilute the incentive for reliability during UCAP demand hours.

PG&E recommends that new resources should be counted at Pmax for the first year and after that, resource-specific values should be applied using historical data, as this would be simpler and give direct incentives to LSEs and resources owners.[117] NextEra recommends new resources use a resource operator's class average (instead of the resource type class average).[118]

Several parties support a data validation/review process to allow operators to correct errors in the preliminary UCAP values before finalizing values, including ACP-CA, AReM, Cal Advocates, Calpine, NextEra, and SCE.[119] Calpine, CESA, MRP, NextEra, REV, SCE, and WPTF support AES's proposal for a UCAP refresh mechanism for new or upgraded resources with substantial

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Comments on Track 1 Proposals at 12, PG&E Opening Comments on Track 1 Proposals at 6, SCE Opening Comments on Track 1 Proposals at 13.

117 PG&E Opening Comments on Track 1 Proposals at 10.

118 NextEra Opening Comments on Track 1 Proposals at 15, NextEra Reply Comments on Track 1 Proposals at 11.

119 ACP-CA Opening Comments on Track 1 Proposals at 8, AReM Opening Comments on Track 1 Proposals at 6, Cal Advocates Opening Comments on Track 1 Proposals at 22, Calpine Opening Comments on Track 1 Proposals at 2, NextEra Opening Comments on Track 1 Proposals at 16, SCE Opening Comments on Track 1 Proposals at 13.

performance improvements, after a demonstration of improved performance.[120] CESA states this is necessary because a resource with UCAP values that undertakes repairs to improve reliability is assessed on past years' performance, which may no longer be accurate.

Several parties point out that Energy Division's proposal does not address which QC and PRM values would be submitted to CAISO following UCAP implementation. CAISO states that the Commission should not send CAISO QC values that do not align with values used by the Commission for RA showings, as this would create confusion and the need to track two values.[121] PG&E opposes allowing installed capacity (ICAP) to continue to form the basis of the QC sent to CAISO and recommends embedding UCAP into the QC and PRM provided to CAISO.[122] PG&E states that while CAISO operations may depend on the current installed capacity QC values, CAISO's RA process should align with the resource accreditation created by the Commission.

SCE comments that Energy Division could publish non-UCAP adjusted PRM for CAISO backstop, similar to Vistra's proposal, to prevent over-procurement and cost exposure due to PRM misalignment.[123] MRP supports Vistra's proposal to provide two QC values.[124] CEJA/Sierra Club and

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[120] Calpine Opening Comments on Track 1 Proposals at 2, CESA Opening Comments on Track 1 Proposals at 12, MRP Opening Comments on Track 1 Proposals at 9, NextEra Opening Comments on Track 1 Proposals at 15, REV Opening Comments on Track 1 Proposals at 7, SCE Opening Comments on Track 1 Proposals at 13, WPTF Opening Comments on Track 1 Proposals at 7.

[121] CAISO Opening Comments on Track 1 Proposals at 17.

[122] PG&E Opening Comments on Track 1 Proposals at 8.

[123] SCE Opening Comments on Track 1 Proposals at 12.

[124] MRP Opening Comments on Track 1 Proposals at 12.

SCE support adjusting the PRM to account for reliance on UCAP.[125] SCE states that UCAP implementation should not create misalignment between the Commission's and CAISO's backstop assessments that could cause LSEs to procure more capacity than is necessary.

MRP and SDG&E assert that Energy Division's proposal does not explain if the UCAP framework will impact a resource's MOO at its UCAP value.[126] MRP argues that it would be illogical to set a resource's MOO at its UCAP value, as this would result in no bids into the CAISO market above the UCAP up to a resource's Pmax or ICAP. SDG&E recommends that the MOO be based on the UCAP QC, rather than NQC, as aligning the MOO with the same metric used for SOD would ensure a resource's obligation at CAISO corresponds to its Commission RA value. PG&E acknowledges that a MOO based upon UCAP may not be prudent but states that CAISO can modify its tariff.[127]

AReM and SDG&E oppose CESA's in-demand hours proposal for calculating EFORd for determining UCAP values.[128] SDG&E opposes assessing forced outages only when a resource's Pnode price exceeds its bid price, as that would require retrospective analysis of pricing and granularity level not practical for a predictable, transparent RA program and would complexity to the RA program. AReM states that the complexity of CESA's proposal is not justified.

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[125] CEJA/Sierra Club Opening Comments on Track 1 Proposals, SCE Reply Comments on Track 1 Proposals at 8.

[126] MRP Opening Comments on Track 1 Proposals at 12, SDG&E Opening Comments on Track 1 Proposals at 9.

[127] PG&E Reply Comments on Track 1 Proposals at 7.

[128] AReM Opening Comments on Track 1 Proposals at 5, SDG&E Opening Comments on Track 1 Proposals at 11.

WPTF supports the use of the RA Measurement Hours but only on the top ten net load days of the month.[129]

AReM contends that Vistra's proposal adds complexity to the RA framework and is contrary to aligning CAISO's and the Commission's RA programs.[130] CESA recommends more discussion on Vistra's proposal as storage's ability to provide full QC value may be constrained by equipment failures, such as energy impacted by an inverter or SOC safety limits.[131] Cal Advocates opposes Vistra's proposal as it transfers risk of UCAP revisions from the resource to the RA-purchasing LSE, which would harm ratepayers as LSEs may have to procure additional resources.[132]

AReM, IEP, MRP, and SCE support Calpine's proposal for its Geysers geothermal facility.[133] IEP and MRP suggest Calpine's proposal could be used for hybrid or co-located units. ACP-CA supports an elective process for new geothermal resources to submit a proposed accreditation that is aligned with the UCAP framework that does not rely on a class-average approach.[134]

Hydrostor expresses concern about the impact UCAP will have on executed long-term contracts and the potential for off-takers to delay contract

[129] WPTF Opening Comments on Track 1 Proposals at 6.

[130] AReM Opening Comments on Track 1 Proposals at 3.

[131] CESA Opening Comments on Track 1 Proposals at 14.

[132] Cal Advocates Opening Comments on Track 1 Proposals at 22.

[133] AReM Reply Comments on Track 1 Proposals at 2, IEP Opening Comments on Track 1 Proposals at 3, MRP Opening Comments on Track 1 Proposals at 11, SCE Opening Comments on Track 1 Proposals at 14.

[134] ACP-CA Opening Comments on Track 1 Proposals at 8.

negotiations while these changes are assessed.[135] Hydrostor recommends transitional measures to provide certainty to off-takers/developers entering procurement negotiations, such as grandfathering existing long-term (10+ year) contracts. CalCCA objects to Hydrostor's proposal, stating that grandfathering existing resources' capacity value greater than the UCAP value would result in a fleet that does not meet the 1-in-10 reliability standard and that parties should have known the Commission was evaluating a UCAP framework for RA for many years.[136] SCE opposes Hydrostor's request for technology- and facility-specific carveouts from the UCAP framework.[137]

DMM recommends considering the interactions of the UCAP framework with the flexible RA framework, including for instance, whether UCAP would be imposed on the effective flexible capacity (EFC) of a flexible RA resource, whether the UCAP derate would apply to the full set of flexible RA AAHs, how UCAP would apply to a storage resource with EFC in the charging range, and how a charging UCAP would be calculated.[138]

4.6.3. Discussion

The Commission appreciates the significant effort undertaken by Energy Division to further refine the UCAP framework proposal over the past few years, as well as parties' efforts to develop a thorough record on this issue. For the reasons discussed below, the Commission finds that Energy Division's UCAP framework should be adopted, with some modifications.

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135 Hydrostor Opening Comments on Track 1 Proposals at 8.

136 CalCCA Reply Comment on Track 1 Proposals at 17

137 SCE Reply Comments on Track 1 Proposals at 9.

138 DMM Opening Comments on Track 1 Proposals at 3.

Regarding the forced outage calculation, some parties argue that outage codes outside of an operator's control should be excluded. The Commission notes that a UCAP framework is not intended to only incent reliability but also to calculate a resource's expected future availability. If events that are outside an operator's control that reduce a resource's output are occurring frequently, those events should be incorporated into a resource's future expected reliability value. Moreover, existing measures are built into Energy Division's proposed UCAP framework to limit an outage's impact on the EFORd rate, including that the outage must occur during the five RA Measurement Hours and that the best three out of four years of outage data be used to mitigate highly unusual events. The Commission agrees that this approach will mitigate force majeure or highly unusual events that have occurred but may not be expected to occur in the future.

The Commission agrees with Energy Division and CAISO that the NOW codes that are excluded from the UCAP calculation should be very narrowly drawn, as allowing numerous exemptions to the EFORd calculation may leave the framework open to gaming or falsely reporting outages to avoid inclusion in the EFORd calculation. We find Energy Division's proposal to include all NOW outages codes in the forced outage calculation, with three exclusions, to be appropriate and to be consistent with Energy Division's UCAP principles. Eliminating the "New Generator Test Energy" and "Transmission Induced Outage" codes are reasonable, as the New Generator Test Energy code is for new unit testing and is not expected to occur in the future, and a Transmission Induced Outage is infrequent as the transmission system is generally reliable with maintenance outages coordinated for minimal impact. It is reasonable to exclude outages reported with the "Ambient Due to Temperature" code in the EFORd calculation because temperature impacts will be subject to weather-normalization and handled separately under Energy Division's proposal. The deration rates for temperature will be added to the EFORd impacts for the affected resource types to calculate the UCAP value.

Several parties advocate for a clear, technology-neutral definition of "forced outage" that is not tied to CAISO's BPM or tariff to provide certainty, consistent application, and avoid contractual disputes. CESA proposes to define forced outage as: an outage that requires immediate or delayed removal of a unit from service, derating, or other outage due to equipment failure or risk of imminent equipment failure. While the Commission finds that CESA's proposed definition has merit, it is tied only to equipment failure and does not include other conditions that cause a unit to be unavailable up to its full output level, such as fuel unavailability.

To address other conditions that may cause unit unavailability, we find a modified version of CESA's proposed definition to be appropriate, as follows: a forced outage is an unplanned event that requires immediate, delayed, or postponed removal of a unit from service, derating, or another outage state due to equipment failure (or risk of imminent equipment failure) or due to factors that prevent a unit from operating at its full Pmax level. Accordingly, the Commission adopts this modified version of CESA's proposed definition of forced outage.

With respect to concerns that the Commission may inadvertently cede jurisdiction to CAISO, we are persuaded by Energy Division's proposal to adopt the UCAP principles that would determine the NOW codes to be included/excluded in the EFORd calculation. The proposed UCAP principles are sufficiently specific to allow Energy Division to determine which NOW codes should be included or excluded in the event that CAISO modifies the NOW codes or the definitions. As such, it is appropriate to adopt Energy Division's UCAP principles and authorize Energy Division to adjust the NOW codes that will be excluded or included in the EFORd calculation based on the principles. To the extent that CAISO updates its NOW codes through the tariff or BPM processes, Energy Division will incorporate changes to NOW codes into the UCAP framework and the timing of this process will follow the annual QC process.

CESA's proposal to calculate resource-specific in-demand hours for unit-specific EFORd would require collecting a unit's nodal price and calculating a default energy bid. This proposal would introduce new calculations and analysis that add complexity, would require confidential data, and would result in more dependence on CAISO's processes. By contrast, a broad range of parties support Energy Division's proposal to use the RA Measurement Hours, which captures hours when capacity is most needed and is subject to annual review by the Commission. As such, we find that Energy Division's proposal to use the RA Measurement Hours to determine the in-demand hours is appropriate, and we adopt it here.

Multiple parties comment that accounting for foldback in the UCAP calculation would result in double-counting because the foldback is already accounted for in the resource's QC value and would be accounted for again in the UCAP calculation. As noted above, Energy Division's proposal included an inadvertent typographical error that stated that the EFORd calculation would be based on PmaxRA, rather than just Pmax. For clarity, Energy Division's proposed EFORd calculation will apply to a unit's eligible Pmax, not its PmaxRA. Therefore, a double-counting issue will not arise because the existing PmaxRA, which is also the unit's QC, will not be part of the UCAP calculation.

Multiple parties state that an outage associated with nonlinearity should not be included in the EFORd calculation because such outage should not be considered a forced outage due to limitation in CAISO's market model. If foldback has been limiting a resource's capacity during the RA Measurement Hours, that should be reflected in assessing a resource's future contribution to reliability in the planning process. There is no NOW code for nonlinearity as these output reductions are currently reported as "plant trouble" in CAISO's reporting system. Therefore, the impact of foldback is unclear, as well as whether foldback occurs during the RA Measurement Hours (which impacts the EFORd calculation). As such, the Commission cannot identify derations associated with nonlinearity to exclude from the UCAP evaluation, and excluding all outages classified as "plant trouble" would be overly broad and inaccurate.

For these reasons, Energy Division's proposal to reflect foldback in a resource's expected EFORd and UCAP value is reasonable to address the foldback issue, and is adopted here. AES and CESA raise a concern if the foldback range occurs in the fifth hour of the RA Measurement Hours, creating a situation where the resource operator must report an outage to offer remaining energy or withhold energy to protect its accreditation. The fifth hour concern has merit and should be further considered. To address this concern, as discussed above, foldback must be incorporated into CAISO's OMS system. We encourage CAISO to address foldback by developing additional NOW codes that will allow the Commission to monitor this issue.

The Commission acknowledges parties' concerns regarding the absence of a UCAP calculation methodology for hybrid resources in Energy Division's proposal and concurs that a methodology should be developed prior to UCAP implementation.[139] We also agree with SCE, CAISO, and DMM that adoption of the broader UCAP framework need not be delayed while a hybrid methodology is developed. The Commission outlines a process below for development of additional UCAP framework issues.

The Commission observes that a broad range of parties support using unit-specific values over class-average values. In D.25-06-048, the Commission stated it "has a preference for resource-specific values but remains concerned about the data quality issues."[140] The Commission agrees with parties that resource-specific values would create stronger incentives for resources to be

[139] A hybrid unit is a generation component and battery storage component with a single resource ID. Because of the combined ID, CAISO data does not indicate the component supplying capacity at any given time, and outages are reported at the resource ID level and not the resource level.

[140] D.25-06-048 at 50.

available to the grid when needed most. By contrast, class-average values may dilute these incentives because resource performance, both positive and negative, are socialized across the broader resource class, rather than being directly attributed to the individual resource responsible for that performance.

NextEra proposes that resource operators with good track records should be able to use their history for new units (instead of the resource class-average) and should be able to submit their fleet class-average EFORd for the first year as a new unit. This proposal, however, introduces complexity to identify the resource owner from CAISO's outage data to perform the calculation, introduces verification issues for a resource operator to provide its own EFORd, and establishes a process no longer based on transparent public data. In addition, we are not persuaded by PG&E's proposal to use Pmax capacity value for a new resource and then apply unit-specific values, as this could overstate a resource's reliability contribution. We decline to adopt NextEra's and PG&E's proposals. Rather, the Commission finds that Energy Division's proposal to use class-average EFORd data for a new unit and then incorporate historical EFORd data is broadly supported by parties, and minimizes over- and under-valuation of RA capacity.

For these reasons, Energy Division's Option 1 proposal for unit-specific values beginning in 2028 is appropriate for the UCAP valuation, and we adopt it here. Under this option, all units with at least four years of historical data will receive their own EFORd and corresponding UCAP values. For new units scheduled to come online in 2028, the class-averaged EFORd value applicable to their resource type will be used to calculate their individual UCAP values. Units coming online with less than four years of historical data will have a phase-in period, during which a unit's historic outage and curtailment data will be blended with the applicable class-averaged outage rates to calculate individual EFORd values in proportion to the time before versus after the unit's commercial operation date.

Multiple parties support a data validation and review process to allow operators to correct errors in the preliminary UCAP values before finalizing the UCAP values. Energy Division's proposal includes two data review processes for the first year of UCAP implementation and for subsequent years. In the first year, Energy Division states that in early 2027, preliminary UCAP values will be published for stakeholder review and comment to identify potential calculation errors. Energy Division will then publish a second set of preliminary UCAP values in July or August during the annual process to update the MRD, with final UCAP values distributed in September. In subsequent years, preliminary UCAP values will be published in July or August during the annual process to update the MRD, with final UCAP values distributed in September.

The Commission finds the proposed review process to be reasonable, as it gives parties two review periods leading to the first year of UCAP implementation to identify and correct errors, and one review period in subsequent years, and we adopt it here. Each resource operator is responsible for verifying that its outage data is submitted accurately into CAISO's systems and reported by the CAISO in the Curtailed and Non-Operational Generator

Prior Trade Data Reports[141] as the Commission is unable to maintain and correct these reports. With respect to AES's proposed UCAP refresh mechanism for new and upgraded resources, the proposal is not sufficiently developed. For example, there is no defined threshold for what constitutes a "significant improvement" sufficient for a refresh and until a unit operates for one year, there is no means to validate if the investment was successful.

Regarding the PRM value, the existing PRM includes a forced outage rate and therefore will be incompatible once UCAP is implemented. A PRM that removes the impact of outages must be consistent with the UCAP value (which already incorporates outages) because otherwise, double-counting would occur with the forced outage rate and lead to over-procurement of resources. Likewise, QC values based on installed capacity and UCAP are two fundamentally different ways to value a resource as each calculation has its own purpose and need (*e.g.*, ICAP is used for must-offer obligations and deliverability studies). Energy Division recommends providing UCAP and the existing QC to CAISO, as it does today, because interactions with CAISO's tariff assume QC is based on installed capacity.

Alternatively, a single set of metrics would result in the current QC being redefined as UCAP, along with the adjusted PRM. This would ensure that any risks associated with UCAP derates transfers to the resource and not to the LSE. The Commission concurs with parties that oppose two sets of metrics, as two metrics would likely add confusion and increase the complexity of ensuring

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141 https://www.caiso.com/market-operations/outages/curtailed-and-non-operational-generators.

compliance between the Commission's and CAISO's RA programs. For these reasons, the Commission endorses the use of one set of QC and PRM metrics to be used by the Commission and CAISO. However, there are outstanding implementation issues, such as the basis for the MOO, that require resolution prior to implementation.

AReM point out that in March 2026, CAISO proposed in its RAMPD initiative to change the basis of the MOO from the current qualifying capacity to Pmax.[142] MRP points out that using UCAP as the basis of the MOO would result in bids into the CAISO market up to UCAP and no bids at the resource's Pmax or installed capacity.[143] There is insufficient record to adopt a value for the MOO apart from QC, or to determine how such a change would be incorporated into CAISO's tariff. We encourage CAISO to submit a proposal in Track 2 of this proceeding as to what changes CAISO would make to its tariff to accommodate redefining the existing QC to UCAP. The Commission notes that the current CAISO tariff provides deference to the local regulatory authority (LRA) establishing the QC values upon which the MOO tariff provisions rely,[144] and the Commission supports maintaining this deference in any future tariff modifications. Once the appropriate CAISO tariff revisions are developed, the Commission can determine whether Pmax or another metric should serve as the appropriate basis for the MOO.

[142] AReM Reply Comments on Track 1 Proposals at 4.

[143] MRP Opening Comments on Track 1 Proposals at 12.

[144] On March 2, 2026, CAISO presented changes to the determination of the must-offer obligation in its RAMPD initiative.

Vistra's proposes a concept that forced outages can impact energy and not just capacity. Energy Division's UCAP proposal focuses on capacity and did not address energy-related outages, and CAISO's outage reports do not appear to include battery energy-related outages, as it publishes outages for only capacity. Since the SOD compliance framework utilizes an energy metric of Maximum Continuous Energy to determine storage compliance rather than the QC value, the issue of how energy outages can impact the expected Maximum Continuous Energy warrants additional discussion, including how this impacts the UCAP value. We encourage further development and discussion of whether forced outages should apply to battery energy for the next iteration of the UCAP framework, as outlined below.

While Calpine's proposal for its Geysers geothermal facility has merit, there are unresolved issues that require development. Calpine's recommendation to maintain the existing NQC (based upon installed capacity) for each unit would be inconsistent with the Commission's intent to maintain a single set of QC metrics based on UCAP. Further, Calpine's argument that it would not require modifications to CAISO's compliance process would only apply if the status quo definition of NQC is maintained. A further developed proposal may be submitted for consideration.

Some parties recommend delaying implementation of UCAP until major issues are resolved, while other parties support a 2028 implementation while continuing to develop outstanding issues. As stated in D.25-06-048, the Commission affirms that the UCAP framework should be implemented beginning with the 2028 RA compliance year. As the UCAP calculations are complete, the Commission maintains that the outstanding issues can be addressed prior to implementation. The outstanding implementation details include:

(1) Implementation of UCAP within the SOD template for energy storage resources;

(2) Determination of the appropriate basis for the MOO once UCAP replaces the current ICAP-based methodology as QC, including any necessary CAISO tariff or Business Practice Manual modifications;

(3) Development and application of EFORd rates for the energy component of storage resource values;

(4) Establishment of a UCAP methodology for hybrid storage resources;

(5) Treatment of foldback limitations during the fifth hour of the RA Measurement Hours;

(6) Evaluation of how UCAP values will interact with and affect the flexible RA framework; and

(7) Application of the four-hour discharge requirement for storage to be eligible for RA capacity.

The Commission encourages Energy Division and stakeholders to continue working on the outstanding implementation details and submit proposals in Track 2.

Accordingly, Energy Division's UCAP framework is adopted, with the modifications discussed above. The details of the UCAP framework are outlined in Appendix B attached to this decision, and are adopted here. The UCAP framework will be effective for the 2028 RA compliance year.

4.7. Residual Unit Commitment and Imbalance Reserve Products

In D.25-06-048, the Commission discussed CAISO's Day-Ahead Market Enhancements (DAME) and Extended Day-Ahead Market (EDAM) initiatives, which were market design changes to accommodate the expansion of the day-ahead market to non-CAISO balancing authority entities.[145] The changes included renaming capacity procured in the Residual Unit Commitment (RUC) process with several bi-directional products: Reliability Capacity (RC) Up and Down (RCU/RCD) products, and establishing Imbalance Reserve (IR) Up and Down (IRU/IRD) products. The changes removed from CAISO's tariff the requirement for RA resources to submit a zero-dollar bid into the RUC and removed language that RA resources are not eligible to receive RUC revenues. The Federal Energy Regulatory Commission (FERC) approved CAISO's proposed market design changes and CAISO launched EDAM on May 1, 2026.

In D.05-10-042, the Commission adopted a requirement that an RA resource must submit a zero-dollar bid into the RUC and that an RA resource is not eligible for any RUC availability payment or revenue.[146] In D.25-06-48, the Commission considered a proposal submitted by SCE to eliminate the Commission's zero-dollar bid requirement and eliminate the prohibition against RA resources receiving RUC revenue, in anticipation of CAISO's upcoming tariff change. At that time, SCE stated that without this modification,

[145] D.25-06-048 at 100.

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

CPUC-jurisdictional LSEs' RA resources would provide RUC products for free into the EDAM by bidding zero dollars for RUC.[147]

In D.25-06-048, the Commission identified concerns with eliminating the long-standing requirements from D.05-10-042. The Commission stated that:

> [E]liminating the prohibition from D.05-10-042 that "an RA resource will not be eligible for any RUC availability payment or revenue" raises a concern about excess payment for capacity from both the RA contract and from the CAISO charges ultimately passed onto load for the RCU/RCD and Imbalance Reserve products. As stated in D.05-10-042, the Commission's intent is to avoid "simply provid[ing] needless revenue streams, or the ability to double-recover costs, to generators."[148]

The Commission stated that it "is concerned that RA contracts that do not provide that the RUC (or successor) revenues will be credited back to the LSE will result in a potential double payment for capacity benefits already included in the RA contract price."[149] The Commission stated that "[b]ecause the zero dollar bid requirement was adopted in conjunction with the prohibition on RA resources receiving RUC revenue in D.05-10-042, the Commission defers consideration of the zero dollar bid requirement for RCU/RCD and Imbalance Reserve products, and the appropriate allocation method for revenues collected, and whether those revenues should be credited back to the LSE that has

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[147] SCE Track 3 Proposal, R.23-10-011, submitted January 17, 2025, at 9.

[148] D.25-06-048 at 101.

[149] *Id*. at 102.

procured the RA capacity value of the resource."[150] The Commission stated that these issues would be considered in this track of the RA proceeding.

4.7.1. Summary of Proposals

Energy Division, CAISO, SCE, and AReM submit proposals to address this issue.

Energy Division proposes that when EDAM becomes operational, RA resources should not be required to submit a zero-dollar bid for RA capacity into RUC, or RC and IR products, provided that any capacity-related revenues are passed through to the buyer of the RA capacity.[151] Energy Division also proposes that jurisdictional LSEs with existing RA contracts should make a good faith effort to ensure that appropriate RC and IR revenues are credited back to the LSE that procured the RA capacity value of the resource, including using the DAME Transitional Measures to credit revenues to the contract bidder. For future contracts, Energy Division recommends that the contracting LSE specify in the RA contract that all CAISO capacity-related revenues for RCU, RCD, IRU, and IRD products, and capacity products not already specified, are allocated to the contracting LSE.

Energy Division also proposes that to avoid double payment by IOU customers subject to Commission jurisdiction, IOUs should put RC and IR product costs and revenues in a memorandum account. To the extent there are net costs, these should be reviewed in the Energy Resource Recovery Account (ERRA) proceeding. Energy Division states that for purposes of the proposal,

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[150] *Id.*

[151] Energy Division Track 1 Proposal at 29.

capacity-related revenues are compensation to make a resource's capacity available in the fifteen-minute and five-minute markets, including revenue associated with RC products. Under the Commission's RA product definition, buyers of RA-eligible capacity should receive revenues associated with capacity products, even if unforeseen market design changes modify the manner that capacity is offered into the energy markets.

SCE recommends a Commission finding that the IR and RC products are distinct because they address different reliability needs.[152] SCE states that RUC (RCU/RCD) procures physical capacity after the integrated forward market (IFM) to cover differences between CAISO's day-ahead forecast of load and generation committed through the IFM. By contrast, IRU/IRD are products procured in the IFM and co-optimized with energy and ancillary services to meet imbalances and ramping needs that may arise between the day-ahead and real-time markets. SCE states that RC products are those physically committed to be available while IR is a financial product that is sold in advance by physically capable resources for flexible dispatch capability. SCE states that in many cases, the award of IR will be in lieu of energy revenue, which the generator retains in its RA contracts.

For RC products, SCE recommends maintaining a zero-dollar bid requirement and eliminating the prohibition on resources receiving RC revenue so long as the revenue goes to the ultimate RA buyer showing the resource on its supply plan. SCE reasons that the zero-dollar bid requirement in the RUC process was imposed to be consistent with affordability principles, and the

[152] SCE Track 1 Proposal at 4.

requirement should be maintained for RC products to address differences between the Commission's and CAISO's rules. For IR products, SCE states that price bids should not be restricted because it partially displaces revenues that a generator is entitled to under the current framework. One category that should be exempt from a zero-dollar bid requirement is resources that physically cannot comply (or would be cost prohibitive to comply) with CAISO's MOO, as these resources are generally small and in remote areas.

SCE recommends not requiring LSEs to modify existing RA contracts, stating that existing contracts should be exempt from new Commission regulations. SCE recommends that parties settle RC/IR revenues between resource suppliers and RA buyers in accordance with CAISO's DAME Transitional Measure. This means parties showing RA will opt-in to the DAME Transitional Measure, and CAISO will allocate: RC revenues to the buyer, any lost opportunity cost revenue for IR to the generator's scheduling coordinator, and IR revenue above lost opportunity cost to the RA buyer. SCE states that this will ensure the generator is paid for the lost opportunity to supply energy, while the buyer receives revenue for the overlapping capacity payment on the MOO. SCE states that the Commission should encourage CAISO to make its DAME Transitional Measure permanent.

CAISO and AReM recommend that the Commission not adopt any bidding or revenue eligibility restrictions on RCU/RCD/IR products.[153] CAISO states that if bids for RCU/RCD products do not reflect the true costs of the product, this may distort unit commitment because the market may designate

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153 CAISO Track 1 Proposal at 3, AReM Track 1 Proposal at 2.

some resources to be available for dispatch when more reliable, cost-effective resources should be designated. CAISO states that revenue requirements may result in inflated wholesale market costs by removing an incentive for RA resources to bid the underlying costs of the RCU/RCD products and if market revenues are irrelevant to RA bidding, there is no incentive for RA resources to bid accurate costs. CAISO recommends contracting parties negotiate the treatment of RCU/RCD/IR revenues in bilateral contracts.

AReM supports allowing net revenues associated with EDAM product awards to be credited to the procuring LSE that showed the RA on the supply plan to avoid double recovery but does not support new contractual or accounting burdens to track secondary contractual arrangements.

4.7.2. Comments on Proposals

Multiple parties oppose Energy Division's proposal to maintain the zero bid requirement for RC/IR products unless contracts specify that capacity revenues flow to the RA buyer, including AES, CAISO, Calpine, IEP, MRP, PG&E, REV, SDG&E, Vistra, and WPTF.[154] These parties generally state that maintaining the zero-dollar bid requirement would distort the EDAM market if many CPUC-jurisdictional resources are bidding zero. These parties state that this could disadvantage CPUC-jurisdictional LSEs whose resources are more

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[154] AES Opening Comments on Track 1 Proposals at 6, CAISO Opening Comments on Track 1 Proposals at 8, Calpine Opening Comments on Track 1 Proposals at 6, IEP Reply Comments on Track 1 Proposals at 2, MRP Opening Comments on Track 1 Proposals at 13, PG&E Opening Comments on Track 1 Proposals at 11, REV Opening Comments on Track 1 Proposals at 8, SDG&E Opening Comments on Track 1 Proposals at 5, Vistra Opening Comments on Track 1 Proposals at 14, WPTF Opening Comments on Track 1 Proposals at 9.

likely to clear first, which would undermine the diversity benefit of optimizing all EDAM balancing areas.

CAISO contends that if CPUC-jurisdictional RA resources are required to bid zero dollars, they will be the first resources called upon for flexibility and reliability, while resources with no zero-dollar bid requirement may be able to provide flexibility/reliability services at a lower true cost. CAISO argues that over time, the lack of appropriate prices signals may discourage resources across EDAM from developing cost-effective services. CAISO states that zero-dollar bids may put upward pressure on RA prices as RA resources will still incur the costs associated with providing those services and suppliers may choose to increase RA contract prices to recover those costs.

Numerous parties oppose dictating the terms of existing and future RA contracts, including AES, AReM, CAISO, CalCCA, Calpine, IEP, MRP, PG&E, REV, SCE, Vistra, and WPTF.[155] These parties generally argue that LSEs should be allowed to negotiate the allocation of revenues in contracts and that buyers/sellers are in the best position to evaluate the revenues of the RA resources to pick a least-cost solution. These parties also claim that if sellers cannot retain CAISO revenues, this could result in higher RA capacity prices if generators account for lost revenue or inability to recover costs. Some parties

[155] AES Opening Comments on Track 1 Proposals at 6, AReM Opening Comments on Track 1 Proposals at 9, CAISO Opening Comments on Track 1 Proposals at 8, CalCCA Opening Comments on Track 1 Proposals at 8, Calpine Opening Comments on Track 1 Proposals at 6, IEP Reply Comments on Track 1 Proposals at 2, MRP Opening Comments on Track 1 Proposals at 13, PG&E Opening Comments on Track 1 Proposals at 13, REV Opening Comments on Track 1 Proposals at 8, SCE Opening Comments on Track 1 Proposals at 5, Vistra Opening Comments on Track 1 Proposals at 14, WPTF Opening Comments on Track 1 Proposals at 9.

likewise oppose Energy Division's proposal to require that parties renegotiate existing contracts in good faith because it puts LSEs in a weaker negotiating position and could result in higher RA contract costs as the counterparty may seek additional terms.[156]

CAISO notes that although existing RA contracts may not have internalized expected IR revenues, if the parties agree that the prices did not anticipate revenues, the parties may avail themselves of the DAME Transitional Measure for a period of three years. CAISO asserts that the risk of double payment is mitigated because it is in the LSE's interest to ensure RA suppliers are not double-compensated for the same service. CAISO states that DAME products provide RA suppliers and LSEs transparency as to the cost of the flexibility needed to serve net load uncertainty, which can inform negotiations. Any double payment risk that may exist only applies to the time that existing contracts are priced to reflect the embedded costs incurred by RA suppliers to provide the DAME products.

CalCCA comments that Energy Division's proposal would require monitoring of thousands of contracts to ensure the rules have been met, and a process to evaluate whether settlements followed the contractual language. Calpine is concerned about the ability of CAISO or suppliers to effectuate the settlement of revenues from new products to RA buyers accurately, especially for large resources that are often sold to many buyers.

[156] *See* AReM Opening Comments on Track 1 Proposals at 9, SDG&E Opening Comments on Track 1 Proposals at 4, SCE Opening Comments on Track 1 Proposals at 6, Vistra Opening Comments on Track 1 Proposals at 14.

By contrast, Cal Advocates and DMM support maintaining a zero-dollar bid requirement.[157] DMM states that it "does not foresee any detrimental impacts to the CAISO markets from RA resources bidding consistently with the provisions in their contract."[158] DMM states that if resources have a MOO and do not incur additional costs for providing IR, bidding zero for day-ahead products that create real-time MOO appears consistent with their incremental costs of providing these products.

Cal Advocates expresses concern about the uncertain impact that EDAM products may have on RA pricing and the potential for market manipulation. Cal Advocates notes that in initial testing for the RC/IR market, "CAISO found that the market-clearing price can be quite high (that is, a significant fraction of the cost of energy, regardless of whether the resource's generation is actually dispatched)."[159] Cal Advocates' preliminary estimate based on recent market simulation calculated direct IR costs to be about $500 million per year for the CAISO balancing authority area. Cal Advocates states that the combination of large volumes and high prices increases the possibility that these products will be costly to ratepayers.

In reply comments, CAISO disagrees with Cal Advocates on its direct cost estimates, stating that Cal Advocates ignores other cost decreases that could offset the net cost impact of IRs, and is overly simplistic because it extrapolates

[157] Cal Advocates Opening Comments on Track 1 Proposals at 7, DMM Opening Comments on Track 1 Proposals at 8.

[158] DMM Opening Comments on Track 1 Proposals at 8.

[159] Cal Advocates Opening Comments on Track 1 Proposals at 5.

direct costs for a year based on prices and quantities from one observed day.[160] CAISO notes that the direct cost estimate is based on simulated test data that is preliminary and does not reflect real world operations.

Cal Advocates contends the double payment issue may result in an unjust windfall profit for generators that retain both the IR/RC revenues and the rate paid for existing contracts. Cal Advocates also notes that not all RA-eligible resources are eligible for IR/RC, and the incomplete overlap further complicates the impacts of IR/RC revenues to RA contracts. Cal Advocates recommends the Commission direct LSEs and RA operators to negotiate splitting IR/RC revenues, rather than assume revenues will be passed to the RA buyer. If bids are used to determine revenues, Cal Advocates states that a resource's scheduling coordinator may have an incentive to modify bids to increase IR payments, distorting market dispatch because the scheduling coordinator now has two goals: to maximize profits from energy awards and maximize profits from its share of IR awards.

SCE supports Energy Division's proposal to lift the zero-dollar bid requirement and allocate RC/IR revenue to the RA buyer (with modifications), as this is harmonious with the DAME Transitional Measures and ensures RA buyers do not bear duplicative costs.[161] SCE agrees that RA buyers should not pay twice for the same capacity attributes but recommends simply reiterating that IR revenue above opportunity cost is associated with the resource's RA capacity attributes. SCE disagrees with requiring future contracts to specify the

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160 CAISO Reply Comments on Track 1 Proposals at 6.

161 SCE Opening Comments on Track 1 Proposals at 4.

revenue allocation policy or bid zero dollars, as this could increase RA prices if generators account for lost revenue or inability to cover costs.

Cal Advocates supports specifying that RC is a successor to RUC and that IR is a capacity product, stating that the clarification is necessary because CAISO has been unclear.[162] CAISO states that IR is not a capacity product, contrary to Energy Division's proposal, but a reserve product.[163] CAISO states that its integrated forward market already clears reserve products, such as spinning reserves, without disrupting the RA program. Vistra comments that only RCU can be considered a successor product to RUC, and Vistra and WPTF seek acknowledgement that IRU and IRD are distinct products unrelated to RA.[164]

In reply comments, SCE disagrees with CAISO that IR is not a capacity product, stating that when selling IR products, the units sell capacity and not energy; therefore, from an RA perspective, IR is a capacity product, not an energy product.[165] SCE disagrees with CAISO's "speculation that RA [capacity] prices will likely decrease if revenue is retained by the supplier but that RA [capacity] prices will likely increase if revenue is transferred to the RA buyer."[166] SCE states that "the ultimate costs of RA are unsupported, given that no IR price, volume, or volatility data is available. Moreover, IR revenue, if any, will not be uniform among all RA resources."[167] SCE thus maintains that there is no basis to

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162 Cal Advocates Opening Comments on Track 1 Proposals at 10.

163 CAISO Opening Comments on Track 1 Proposals at 11.

164 Vistra Opening Comments on Track 1 Proposals at 17, WPTF Opening Comments on Track 1 Proposals at 8.

165 SCE Reply Comments on Track 1 Proposals at 5.

166 *Id*.

167 *Id*.

conclude that total procurement costs to customers will be lower if RA resources retain IR revenue, particularly if customers double pay for capacity. SCE states that "total procurement costs to customers" should be the metric used for decision-making, not just the price of RA capacity.

PG&E, SDG&E, and SCE oppose the establishment of a memorandum account.[168] SCE and PG&E assert that requiring such revenues to be held in a memorandum account for three years is inconsistent with Assembly Bill 57 which requires timely cost recovery for the Bundled Procurement Plan process. SDG&E states that creating a new memorandum account for ERRA compliance would be unnecessary, duplicative and time-consuming.

4.7.3. Discussion

In D.05-10-042, the Commission provided that an RA resource "must submit a zero dollar ($0) bid for RA capacity bid into RUC and that an RA resource will not be eligible for any RUC availability payment or revenue."[169] The Commission's rationale for its decision was:

> It is not the intention of this Commission to simply provide needless revenue streams, or the ability to double-recover costs, to generators. It is the Commission's position that an RA resource that receives an RA payment should not also receive a RUC availability payment through the CAISO.[170]

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[168] PG&E Opening Comments on Track 1 Proposals at 14, SDG&E Opening Comments on Track 1 Proposals at 5, SCE Opening Comments on Track 1 Proposals at 7.

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

[170] *Id*.

D.05-10-042 also provided that "[a]ccordingly, LSE contracts with RA resources should reflect these policy determinations."[171] As such, the requirement from D.05-10-042 has been in place to date.

As a preliminary matter, there appears to be confusion over what type of products RC and IR products are, and how those products interact with the Commission's RA program. SCE proposes that the Commission should determine that IR and RC products are distinct because they fundamentally address different reliability needs. Cal Advocates comments that clarification is needed because the descriptions have not been clear and some of CAISO's filings at FERC have defined these products differently.

CAISO's proposal describes these products as follows:

(1) Reliability Capacity: "First, the RCU product will replace the existing product cleared in CAISO's current residual unit commitment (RUC) market that enables sufficient resources to be positioned in the day-ahead timeframe to reliably meet forecast demand. Second, the RCD product will provide reliability benefits by introducing downward flexibility into the market and helping address potential oversupply conditions in the real-time market."[172]

(2) Imbalance Reserve: "Third, IR will help address net load uncertainty issues and set aside capacity for resources to provide ramping capacity in the real-time market, further supporting reliability. IR will also make embedded net load uncertainty costs transparent, allowing the EDAM market to efficiently optimize these costs."[173]

171 *Id*.

172 CAISO Track 1 Proposal at 5.

173 *Id*.

In its proposal, CAISO states that the RCU product will replace the existing product cleared in CAISO's RUC market but does not mention the RCD product as an existing product. However, we note that CAISO's Business Practice Manual refers to RCU/RCD as enhancements to the RUC process.[174] Further, CAISO's current tariff defines components of RUC as including both RCU/RCD and a RUC Award is defined as "the quantity of RCU or RCD awarded to a resource by the RUC for a Settlement Period."[175] In comments on the proposed decision, CAISO recognizes that RC is the successor to RUC and that the Commission may view RC as more closely analogous to prior constructs on which it based D.05-10-042.[176] Based on the foregoing, the Commission determines that RCU and RCD are components of the RUC process.

With respect to the IR process, CAISO refers to IR products as working in concert with the RC process. For instance, CAISO's amended tariff filing provides that:

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[174] *See* CAISO Business Requirements Section, Day-Ahead Market Enhancement, April 29, 2026, available at: https://www.caiso.com/documents/business-requirements-specification-day-ahead-market-enhancement.pdf, at 21:

> The objective of this initiative is to enhance the California ISO's (CAISO's) day-ahead market by: …Enhancing the residual unit commitment process to also ensure there is sufficient downward dispatch capability (RCU/RCD) in the event real-time load is less than scheduled in the integrated forward market.

Further, "[t]he CAISO proposes to preserve the sequential integrated forward market and residual unit commitment process (IFM, RUC)." *Id*.

[175] CAISO Tariff Section 4 at Appendix A, available at: https://www.caiso.com/documents/all-pending-tariff-language-for-edam-dame.pdf. Section 4 also provides that: "RUC Capacity" = "RCU or RCD;" and "RUC Price" = "[t]he Locational RCU Price or Locational RCD Price." *Id*.

[176] CAISO Comments on Proposed Decision at 10.

> Imbalance reserves address circumstances where the actual real-time net load and associated ramping needs are different than the capacity the day-ahead market procured because net load is above or below the day-ahead forecast. RUC is necessary to procure incremental or decremental capacity to match the outcome of the day-ahead market to the forecast load. Reliability capacity is necessary regardless of any load or variable energy resource forecast uncertainty. RUC assumes the forecast is correct and procures to fill in the gaps. If the CAISO only procured imbalance reserves, there would be no assurance the day-ahead market would procure sufficient physical resources to meet expected demand in real-time. If the CAISO only procured reliability capacity, the CAISO would not have a market product to address net load imbalances and would continue to rely on manual adjustments in the RUC process.[177]

As CAISO's amended tariff provides, IR is needed to address whether actual real-time net load and ramping needs are different than the capacity the day-ahead market procured because net load is different from the day-ahead forecast. RUC is needed to procure incremental/decremental capacity to match the day-ahead market to the forecast load. Prior to EDAM, the net load uncertainties (i.e., the differences between the day-ahead and real-time needs due to load and variable resource uncertainties), as well as other uncertainties, were addressed through the "RUC net short" process.[178]

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[177] CAISO Day-Ahead Market Enhancements and Extended Day-Ahead Market Tariff Amendment, FERC Docket ER23-2686-000, August 22, 2023, at 56, available at: https://www.caiso.com/documents/aug22-2023-dame-edam-tariff-amendment-er23-2686.pdf.

[178] *See* FERC Order 166 FERC ¶ 61,138 at ¶¶12-13, FERC Docket ER19-538-000, February 21, 2019, available at: https://www.caiso.com/documents/feb21-2019-order-accepting-tariff-amendment-imbalance-conformance-enhancements-er19-538.pdf. *See also* CAISO tariff,

Further, CAISO's amended tariff states that both processes work in concert: if CAISO only procured IR, it would have no assurance that the day-ahead market would have sufficient physical resources to meet real-time demand; if CAISO only procured RC, it would not have a product to address net load imbalances and would need to rely on manual adjustments in RUC. In addition, CAISO indicates that if it fails to procure sufficient IR in the integrated forward market, under certain circumstances, it will procure additional RC to address the under-procurement of IR in the RUC process[179] and that the

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effective February 27, 2026, at 31.5.3.1.1 "RUC Net Short Conditions," available at: https://www.caiso.com/documents/conformed-tariff-as-of-feb-27-2026.pdf.

[179] *See* CAISO Business Practice Manual for Extended Day-Ahead Market, at Section 22.4.1, at 101-012, available at: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Extended%20Day-Ahead%20Market, stating:

> In addition to the circumstances listed above for an operational adder RUC Net Short, there may be a need to use a RUC adjustment to procure for any deficiency of Imbalance Reserve that did not clear in the IFM. Since Imbalance Reserve requirements are cleared on the price defined in a demand curve, IFM may economically procure less that the full requirement. Because this deficiency can be known only after the DAM IFM runs, the EDAM entity shall submit criteria to the market operator in advance of 7 days via a CIDI ticket for an ongoing automatic RUC load adjustment process. The inputs are the percentage of the full Imbalance Reserves that will be added to the RUC load adjustment based on peak load level bands less the Imbalance Reserves procured in the IFM. The full imbalance reserves used in the RUC adjustment process are based on the dynamic threshold set at the 97.5th percentile.

This section also states that:

> The IR deficiency and corresponding adder to the RUC load adjustment will be calculated for each hourly interval after IFM and before RUC. The table mapping peak load forecast to the IR procurement percentage is considered by the market operator to be a standing request for a RUC load adjustment in the case that the EDAM entity is IR deficient after the IFM run.

obligation to bid into the real-time market for IR and RC are the same.[180] For all of these reasons, although these products have been ascribed new names, the Commission finds that IR products and RC products may be used interchangeably, and that RC products are a component of the RUC process.

We also address whether IR products are capacity or energy products, for purposes of the RA program. Energy Division describes the IR product as a capacity product, while CAISO states that it is a reserve product, not a capacity product. SCE disagrees with CAISO, stating that when selling IR products, the units sell capacity (and not energy) and from an RA perspective, this means that IR is a capacity product.

CAISO's tariff acknowledges that RA capacity and flexible RA capacity can provide overlapping products, as provided in Section 11.2.6.2.1 Overlapping Capacity for IRU:[181]

> The quantity of overlapping IRU is the lower of the: (1) Imbalance Reserves Award for IRU; or (2) higher of the RA Capacity or Flexible RA Capacity shown on that resource's monthly Supply Plan minus the Energy Schedule minus the Ancillary Services Awards other than for Regulation Down. Provided, however, that the quantity of overlapping IRU cannot be less than zero.

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180 *See* CAISO Business Requirements Section, Day-Ahead Market Enhancement, April 29, 2026, at 22:

- An imbalance reserve award will obligate a supplier to provide economic energy bids in the real-time market.
- RCU/RCD [award] will obligate [a supplier] to provide economic energy bids in the real-time market.

181 There is a similar section for Overlapping Capacity for IRD.

The Commission observes that in both CAISO's proposal in this proceeding and filings at FERC, it refers to IR as a capacity product. In CAISO's proposal, it describes IR as a product to "set aside capacity for resources to provide ramping capacity in the real-time market."[182] Further, in the same section of CAISO's tariff amendment filings cited above, the filing refers to IR as a capacity product: "Imbalance reserves address circumstances where the actual real-time net load and associated ramping needs are different than the capacity the day-ahead market procured because net load is above or below the day-ahead forecast."[183] CAISO's DAME Transitional Measures also applies to "RA Capacity and Flexible RA Capacity provided from Resource Adequacy Resources…"[184]

Further, IR products overlap with the must-offer obligation contained in RA contracts and therefore, IR and RA capacity are duplicative, with the exception of the opportunity cost portion of the revenues. For example, flexible RA capacity contracts require economic bids into the real-time market and IR capacity contracts also require an economic bid into the real-time market. In addition, the day-ahead uncertainty now co-optimized in the integrated forward

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[182] CAISO Track 1 Proposal at 5.

[183] CAISO Day-Ahead Market Enhancements and Extended Day-Ahead Market Tariff Amendment, FERC Docket ER23-2686-000, August 22, 2023, at 56.

[184] *See id.*, at Section 11.2.6.1.:

> The CAISO applies DAME Transitional Measures to RA Capacity and Flexible RA Capacity provided from Resource Adequacy Resources if the CAISO receives notice, in the form and manner specified in the Business Practice Manual, from both the resource's Scheduling Coordinator and the LSE's Scheduling Coordinator that they mutually elect for the CAISO to apply DAME Transitional Measures to the RA Capacity and Flexible RA Capacity the resource provides on behalf of the LSE.

market was previously addressed with the RUC process, with zero-dollar bids and revenue returns to the RA buyer. For all of these reasons, the Commission finds that IR products are capacity products for purposes of the RA program.

Next, the Commission recognizes that many parties would like the zero-dollar bid requirement to be eliminated and the prohibition on receiving RUC revenues to be eliminated. Many parties note that maintaining the zero-dollar bid requirement could result in EDAM market distortion or disadvantaging LSEs whose resources clear first. By contrast, Cal Advocates points out that based on initial testing data of the EDAM market, the market-clearing price was quite high and that extrapolating those high prices across large volumes could result in significant costs to ratepayers. DMM notes that it does not foresee detrimental impacts to the CAISO market from RA resources bidding consistently with contract provisions, and that bidding zero for day-ahead products that create real-time MOO is consistent with the incremental contract costs of providing these products.

The EDAM initiative launched on May 1, 2026. The Commission is concerned that it does not know how these RC/IR products will impact RA prices or how non-CPUC-jurisdictional resources will bid into the EDAM market, and there is not yet data submitted to inform the record.

The Commission is not persuaded by parties that seek to abruptly remove the zero-dollar bid requirement and the revenue allocation prohibition for RA contracts for RC resources without any supporting data. Rather, the Commission is persuaded by Cal Advocates that the EDAM products' impact on RA pricing is uncertain and that if market-clearing prices are high, this could potentially result in significant costs to ratepayers depending on the volume of bids. The Commission is also persuaded by DMM's comments that DMM does not foresee any detrimental impacts to the CAISO markets if RA resources bid zero for day-ahead RC and IR products consistent with their contract provisions.

For RC products, the Commission concludes that the more prudent approach is to maintain the status quo requirements that have been in place in the RA program for over 20 years, and monitor the bidding behavior of the EDAM market and its impact on RC and IR pricing following the initial implementation, and any potential impacts on future RA pricing. The Commission will reconsider proposals to modify the RC bidding requirements and revenue allocation rules once the Commission can evaluate the pricing data for RC products and better understand the impact of removing the zero-dollar bid requirement and prohibition on revenue allocation. Accordingly, the Commission maintains and affirms the current rules established in D.05-10-042 for RC products. The Commission clarifies that the revenue allocation prohibition will not apply in the instance where the LSE is the resource owner and the resource is used by that LSE for RA compliance.

Accordingly, LSEs' RA contracts for RC products must reflect the policy determinations from D.05-10-042 to ensure zero-dollar bidding for capacity products, and to specify that the resource owner is not eligible for capacity-related revenue payments, except in the instance where the LSE is the resource owner and the resource is used by that LSE for RA compliance. Because CAISO has removed the previously-applicable tariff language that governed the return of RUC revenues, LSEs shall use the CAISO DAME Transitional

Measures, or other equally effective means, to effectuate this requirement. These rules apply to contracts executed after the effective date of this decision. For existing contracts, the RC rules from D.05-10-042 shall not disturb existing contracts; however, LSEs should undertake reasonable efforts to enforce existing contract provisions that account for the D.05-10-042 rules.

For IR products, the Commission maintains that these are capacity products for purposes of the Commission's RA program for the reasons discussed above. That said, we hear parties' concerns that applying a zero-dollar bidding requirement on IR products may lead to market distortions for RA prices and energy prices, and may impair storage resources' ability to bid opportunity costs in the IR market. To that end, the Commission declines to adopt a zero-dollar bid requirement for IR products.

With respect to the capacity-related revenue awarded for IR products, however, the Commission maintains its policy determination from D.05-10-042 that RA capacity should not be double-compensated: "It is not the intention of this Commission to simply provide needless revenue streams, or the ability to double-recover costs, to generators."[185] Based on the amended CAISO tariff, an RA resource owner bidding an IR product may be double-compensated for the same resource: (1) the owner is first paid for the RA resource when it sells its capacity to an LSE via its initial bilateral RA contract, and (2) the owner is paid again if the RA resource clears the IFM market for IR. This presents a windfall opportunity for generators for the same RA resource and conflicts with the Commission's policy against double-payment to generators for the same RA

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

resource. As these IR products are quite new, there is not sufficient record to establish what the market-clearing prices for these products will be and depending on the volume of IR bids, this could result in significantly increased costs to ratepayers.

As such, the Commission maintains its D.05-10-042 prohibition against double-compensation for IR products. In addition, under Pub. Util. Code Section 380, the Commission must achieve several objectives in its oversight of the RA program, including "[c]onsideration of mitigation measures, if the commissioner determines they are needed, to reduce costs to ratepayers" and to "minimize enforcement requirements and costs."[186] The Commission finds that prohibiting an RA resource owner from double-payment for the same capacity is necessary to minimize costs to ratepayers and to satisfy the objectives of Section 380.

We disagree with CalCCA that the Commission lacks jurisdiction over non-IOU LSEs to prohibit RA resource owners from double-recovery of an IR award. The Commission has broad authority under Pub. Util. Code Section 380 to establish RA requirements for all LSEs,[187] and prohibiting an RA resource owner from double-payment for the same capacity falls under the Commission's purview in overseeing the RA program and achieving the objectives in Section 380(b)(4) and (b)(5).

We recognize that IR revenue has two components, however, and we clarify that the revenue prohibition does not apply to the opportunity cost

[186] Pub. Util. Code Section 380(h)(4) and (5).

[187] *See* Pub. Util. Code Section 380(a) and (k).

portion of the IR revenue award. As with RA contracts for RC products, these IR rules shall apply to contracts executed after the effective date of this decision. For existing contracts, these IR rules shall not disturb existing contracts; however, LSEs should undertake reasonable efforts to enforce existing contract provisions that account for the D.05-10-042 rules.

As such, RA contracts for IR products must specify that the resource owner is not eligible for capacity-related revenue payments, except where the LSE is the resource owner and the resource is used by that LSE for RA compliance. This does not apply to the opportunity cost portion of the revenue payment. LSEs shall use the CAISO DAME Transitional Measures, or other equally effective means, to effectuate this requirement. These rules apply to contracts executed after the effective date of this decision. As with RC products, the Commission will consider proposals to modify the IR revenue allocation rules once the Commission can evaluate the pricing data for IR products and better understand the impact of removing the prohibition on revenue allocation.

Regarding the proposed memorandum account for RC and IR product costs and revenues, the Commission finds that a memorandum account is not necessary. Rather, the Commission finds it appropriate for IOUs to instead file certain information in their existing Quarterly Compliance Reports related to RC and IR products. This information provided will help the Commission monitor the EDAM market. In addition, the Commission directs the IOU to report this information at the quarterly Procurement Review Group meetings.

Accordingly, IOUs shall provide the following information in their Quarterly Compliance Reports, and provide the same information during quarterly Procurement Review Group (PRG) meetings, for a minimum period of three years, beginning with the third quarter report in 2026:

(1) Monthly Imbalance Reserve gross costs (in dollars), with IRU and IRD provided separately;

(2) Monthly Reliability Capacity gross costs (in dollars), with RCU and RCD provided separately and Tier 1 and Tier 2 allocations shown separately, where applicable;

(3) Monthly average Reliability Capacity and Imbalance Reserve prices (in $/MWH), with RCU, RCD, IRU, and IRD provided separately;

(4) Monthly Imbalance Reserve revenues (in dollars and $/MWH) in total and the portion of these revenues attributable to bundled service customers (with IRU and IRD provided separately), and where available, identify the capacity-related portion separately from the opportunity cost portion; and

(5) Monthly Reliability Capacity revenues (in dollars and $/MWH) in total and the portion of these revenues attributable to bundled service customers (with RCU and RCD provided separately).

(6) Monthly Imbalance Reserves and Reliability Capacity in dispute, in dollars, as provided to the scheduling coordinator for the LSE per CAISO tariff Section 11.2.6.4.

4.8. Hourly Load Obligation Trading

Proposals for hourly load obligation trading in the SOD framework have been considered in the RA proceeding and by the Commission multiple times over the past few years. The Commission first addressed hourly load trading proposals in D.22-06-050, in which the Commission stated that the proposal would add significant complexity to the SOD framework and instead, would be considered "if transactability and inefficiency concerns arise once the new

24-hour framework is implemented…"[188] In D.23-04-010, and again in D.24-06-004, we reiterated the Commission's rationale from D.22-06-050, stating that hourly load obligation trading proposals would be considered if and when transactability and inefficiency concerns arise after the implementation of the SOD framework.[189]

Most recently, the Commission addressed CalCCA's hourly load obligation trading proposal one year ago in D.25-06-048. There, the Commission reiterated that "load obligation trading would add both complexity to the new SOD framework and substantial administrative burden on Energy Division Staff to track transactions and verify compliance."[190] The Commission added that "the proposal fails to fully address critical issues, such as whether CalCCA's concerns could be addressed through existing trading mechanisms, what types of guardrails should be added to limit the use of hourly trading, and how the RA penalty regime will interact with the proposal."[191]

The Commission authorized Energy Division to "conduct an evaluation after a full year of SOD implementation to assess the need, benefits, and feasibility of an hourly load obligation trading mechanism" and prepare a report for the Commission in the 1st Quarter of 2026.[192] On February 23, 2026, Energy Division issued its *Report on Transactability within the Slice of Day Resource Adequacy Framework* (Transactability Report).

188 D.22-06-050 at 96.

189 D.23-04-010 at 71, D.24-06-004 at 73.

190 D.25-06-048 at 86.

191 *Id*.

192 *Id*.

4.8.1. Summary of Energy Division's Transactability Report

Energy Division's Transactability Report provided analyses of three components of the hourly load obligation trading mechanism: need, benefits and costs, and feasibility.[193] Key analysis and findings from the Transactability Report are summarized below.

4.8.1.1. Need Assessment

Under "need assessment," Energy Division evaluated whether the SOD framework has introduced new barriers to transactability that would indicate a need for an hourly load obligation trading mechanism.[194] Energy Division specifically examined: (1) whether hourly deficiencies observed in year-ahead filings reflect system capacity shortfalls or LSE portfolio misalignment; (2) whether LSEs with year-ahead deficiencies were able to cure deficiencies with existing market mechanisms; and (3) whether compliance outcomes materially differ from those observed under the prior RA framework.

Based on its analysis, Energy Division found that for September year-ahead filings, LSE deficiencies were seen across all hours and peaked in HE 18, although aggregate system surplus exceeded gross LSE deficiencies. The Transactability Report observed that for month-ahead compliance, LSEs successfully met their month-ahead obligations in every hour, including for those LSEs that had year-ahead deficiencies. Compared to prior years, Energy Division found that 2025 month-ahead outcomes under the SOD framework did not show increased deficiencies or system shortfalls.

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[193] Energy Division Transactability Report (Transactability Report) at 6.

[194] *Id*. at 10.

The Transactability Report stated that: "[w]hile SOD introduces greater granularity in how obligations and supply are evaluated, the observed portfolio scale, resource mix, and compliance results do not indicate that LSEs were unable to transact for appropriate products or were compelled to materially over-procure capacity to satisfy hourly requirements."[195]

4.8.1.2. Benefits and Costs Assessment

Under "benefits and costs," Energy Division evaluated the aggregate procurement efficiency and specifically, "whether hourly load obligation trading could reduce overall capacity procurement by facilitating improved alignment between contracted resources and LSE hourly load obligations."[196] The Transactability Report stated that "results suggest that improved portfolio alignment could yield measurable system-wide savings. Hourly load obligation trading may help facilitate incremental efficiency gains by allowing surplus capacity to be reallocated across LSEs."[197]

Energy Division's analysis showed that load obligation trading could, under certain assumptions, reduce aggregate procurement volumes in constrained hours that amounted to $2.9 million in avoided procurement costs for September 2025. By including unshown contracted storage, the cost estimate would add 111 MW of capacity, resulting in avoided procurement of approximately $4.1 million. Under a scenario in which the SOD program operated under a single, centralized system load profile that removed inter-LSE

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195 *Id*. at 24.

196 *Id*.

197 *Id*. at 30.

fragmentation, Energy Division estimated avoided procurement costs of approximately $7.6 million for September 2025. Regarding potential indirect benefits, the Transactability Report stated:

> While hourly load obligation trading could plausibly reduce marginal procurement volumes in constrained hours, the magnitude of any resulting market-wide price effect is uncertain. Indirect price moderation effects should be viewed as contingent on market tightness conditions and the scale of obligation trading, rather than as inherent or proportional outcomes.[198]

The Transactability Report noted that potential affordability benefits must be considered within the structural constraints of the RA program, particularly that there are 38 jurisdictional LSEs that independently procure for RA obligations rather than a centralized structure. The Transactability Report stated that:

> Hourly load obligation trading may improve coordination at the margin by enabling surplus in one portfolio to offset deficits in another. However, it would not alter the underlying decentralized nature of procurement decisions. Accordingly, while obligation trading could reduce certain portfolio alignment inefficiencies, realizing the full extent of these benefits would depend on a degree of centrally coordinated procurement planning that does not occur in today's market.[199]

The Transactability Report further cautioned that the assumption underlying the cost savings estimates — that is, that avoided procurement would flow to aggregated load — may not hold in practice. Energy Division noted that

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[198] *Id*. at 33.

[199] *Id*. at 34.

the majority of RA capacity transactions occur between LSEs, rather than from generators to load, and approximately 60% of transacted MWs were sold by LSEs in the 2025 compliance period. Thus, load obligation trading that reduces incremental procurement may simultaneously reduce the sales revenues of LSEs holding long positions, such that the net benefit to aggregate load is uncertain. The Transactability Report concluded that these structural considerations, including the decentralized procurement across 38 independent LSEs managing overlapping RPS and IRP obligations, mean that the full extent of modeled benefits flowing to aggregate load is unlikely to be realized in practice.

The Transactability Report stated that costs/benefits should also be considered through a reliability lens, and that reducing RA procurement by reallocating capacity surplus to other LSEs "would move the system closer to the bare minimum PRM threshold in constrained hours, reducing reliability margins and exposing LSEs to more energy market volatility."[200] The Transactability Report further stated:

> Moving portfolios closer to the minimum compliance threshold may increase exposure to forecast error and operational uncertainty, and such tradeoffs should be considered in the context of RA's primary role as a binding resource sufficiency framework, rather than as a tool for optimizing contracted capacity.[201]

4.8.1.3. Feasibility Assessment

Under the "feasibility assessment," Energy Division evaluated the feasibility of implementing hourly load obligation trading in the SOD program,

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[200] *Id*. at 35.

[201] *Id*.

with particular focus on administrative complexity, compliance review timelines, coordination with CAISO, and interaction with the penalty structure.[202] The Transactability Report pointed out that load obligation trading would disrupt the process by which Energy Division reviews compliance filings and issues deficiency notices by making obligations variable during the compliance review window. The Transactability Report described the issue as follows:

> Before staff could validate supply plans or assess procurement sufficiency, obligation trades would need to be reconciled across multiple LSE filings. Any unresolved mismatches would prevent staff from determining which LSE is responsible for meeting a given hourly obligation, forcing deficiency notices to become conditional and undermining their effectiveness. Given the number of LSEs, hours, and transactions involved, even a limited number of unresolved trades could delay or impede the MA compliance review.[203]

The Transactability Report stated that based on CalCCA's proposal submitted in the predecessor RA proceeding, Rulemaking (R.) 23-10-011, the proposed implementation would occur on the supply side, rather than load side. The Transactability Report observed that:

> This means that RA requirements which are informed by the LSE allocation tab and associated PRM would not change in the tool (essentially, the PRM becomes unbundled from the load trade). Because the PRM is applied as a percentage of each LSE's load obligation, modifying obligations through hourly trading would also implicitly modify the associated PRM requirement. Unbundling the PRM from fixed load allocations introduces additional complexity in ensuring that

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[202] *Id*. at 36.

[203] *Id*. at 38.

reserve margins remain consistently applied and transparently reflected in compliance determinations.[204]

The Transactability Report stated that several new review steps would need to be adopted for CalCCA's proposed mechanism, including:

- Initial cross validation of load obligation trades — to validate LSE load trades ahead of validation of supply plans, which would lock requirements for respective month-ahead obligations.
- Correct load trade mismatches — to send correction notices to LSEs to resolve load obligation trade mismatches within a shortened cure period.
- Final cross validation of load trading obligation — to validate resubmitted load trades.
- Incorporate final cross validation into allocations and lock revised allocations (based on validated load obligation trades) for use in month-ahead filing — to enable the locking of compliance obligations that LSEs will use to determine what they need to include in their filings to comply with their new RA obligations.[205]

With respect to CAISO's validation process, the Transactability Report noted there is already misalignment between the SOD validation process and CAISO's peak hour validation process, as CAISO looks at one hour while the Commission looks at 24 hours of load requirements and resource value. Without corresponding treatment at CAISO, load obligation trading would exacerbate this misalignment and increase the likelihood that an LSE appears deficient under CAISO's processes. The Transactability Report stated that "[t]his would

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[204] *Id*.

[205] *Id*. at 39.

create a misalignment between cost responsibility and the obligations established for CPUC compliance, weakening the link between RA requirements and reliability outcomes."[206]

Further, CAISO has authority to address deficiencies through its Capacity Procurement Mechanism (CPM) and such cost allocation is based on an LSE's obligation, not its CPUC-adjusted positions, which could expose LSEs that participate in obligation trading to backstop costs even if an LSE is complaint with Commission requirements. Regarding the penalty structure, the Transactability Report stated that disputes over load trades would require Energy Division to reconstruct obligation assignments under tight timelines.

4.8.1.4. Report Conclusion

The Transactability Report concluded that based on the first year of binding SOD compliance in 2025, "the filing record does not indicate a systemic inability for LSEs to meet hourly requirements using existing procurement and contracting mechanisms."[207] Ultimately, "Staff conclude that the potential benefits of such a mechanism do not justify the added complexity and risk of unintended consequences associated with its implementation. Accordingly, Staff recommend continuing to monitor market performance as the SOD framework continues to mature."[208]

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[206] *Id*. at 40.

[207] *Id*. at 44.

[208] *Id*.

4.8.2. Summary of Proposals

CalCCA recommends adopting the hourly load obligation trading mechanism it submitted in the prior RA rulemaking, R.23-10-011.[209] Under the proposal, LSEs would be able to trade load obligations at an hourly level, as compared to the current program that requires an LSE to contract an RA product for all hours it is available for the whole month. CalCCA states that this mismatch means that LSEs purchase more RA than they need to meet their obligations. A more detailed description of CalCCA's proposal can be found in D.25-06-048.[210]

CalCCA's updated proposal, submitted in this proceeding, recommends that the Commission invest in software and systems to automate the RA validation process to evaluate RA showings quickly, rather than using the compliance filing spreadsheet that has been used for the past 20 years, since the start of the RA program.[211] Alternatively, if software/automation systems cannot be procured, CalCCA proposes two interim guardrails to assess compliance. One guardrail is an initial trading limit of no more than 25% of an LSE's compliance obligation, or for smaller LSEs with RA requirements less than 200 MW, an allowance to trade up to 50 MW of their obligation. For an LSE that purchases a load obligation and sells it to another LSE, that sale would count towards the LSE's 25% limit. Another guardrail is to require hourly load

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[209] CalCCA Transactability Proposal at 8.

[210] D.25-06-048 at 81.

[211] CalCCA Transactability Proposal at 11.

transactions to be shown five business days prior to the RA showing to give Energy Division additional time to validate RA showings.

In comments, CalCCA states that if an IOU enters into a load obligation trade, that should be treated like a capacity sale for Power Charge Indifference Adjustment (PCIA) purposes.[212] CalCCA states that if an IOU sells RA capacity under the current framework, the IOU credits the revenue to the PCIA with no offsetting debit to bundled load. CalCCA posits that this accounting treatment for load obligation trades would ensure that all customers paying the PCIA benefit from IOU engaging in load obligation trading.

Regarding the Transactability Report, CalCCA argues that the report ignores the potential for capacity scarcity to return in the future and ignores the affordability issue the proposal is intended to address.[213] CalCCA claims that Energy Division used the wrong standard in the Transactability Report and the focus should not be on whether LSEs have the ability to comply with the RA requirements, but rather, the focus should be on the cost of compliance. CalCCA states that Energy Division's avoided procurement cost estimate of $3-7 million is understated because it is based on an analysis of the peak month and ignores indirect price suppression effects. CalCCA states that Energy Division should have considered an alternative storage allocation that optimized contracted storage to maximize the avoidable thermal generation.

CalCCA further argues that LSEs' ability to cure deficiencies for month-ahead compliance in the 2025 RA compliance year was due to the

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[212] CalCCA Opening Comments on Transactability Proposals at 36.

[213] *Id*. at 4.

additional capacity available in 2025 due to "a particularly good hydro year for California."[214] CalCCA states that the "[m]arket conditions in 2025 were more favorable that in 2024" and therefore the focus on 2025 "ignores the potential for capacity scarcity to return in the future."[215] CalCCA contends that LSEs procured significantly more RA capacity than needed to meet compliance obligations, although CalCCA acknowledges that all of this incremental procurement cannot be attributed to a lack of transactability.

WPTF submits two proposals to address transactability issues.[216] First, WPTF recommends that proposed hourly obligation trades be submitted via a standardized template during a window five-to-seven business days prior to the month-ahead deadline. Energy Division would validate trades and issue final adjusted obligations before LSEs submit month-ahead filings. This would eliminate variable obligations during the month-ahead review period and eliminate the need for correction notices and mid-review reconciliation. Second, WPTF recommends requiring LSEs to use standardized one-page contract templates with mandatory fields. This would reduce ambiguity and mismatch risks, as every trade would contain identical, machine-readable fields to enable a more automated process. WPTF generally agrees with the Transactability Report's assessment that transactability issues do not exist but suggests the Commission not prematurely close the door on hourly load trading.

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[214] *Id*. at 6.

[215] *Id*. at 8.

[216] WPTF Transactability Proposal at 2.

4.8.3. Comments on Proposals

Ava supports an hourly obligation trading mechanism and either CalCCA's or WPTF's proposed guardrails.[217] Ava agrees with CalCCA that the Transactability Report should have focused on the question of whether LSEs can comply at a lower cost, rather than whether LSEs can meet their RA requirements. Ava agrees with CalCCA's concerns about the Transactability Report, reiterating that the savings estimate is lower because only September 2025 was quantified, that indirect benefits were not included (such as reduction in marginal RA price with a change in RA demand), and that the 2025 market price benchmark (MPB) was used for the RA price, instead of 2024 prices. Ava argues that the large difference between CalCCA's and Energy Division's cost savings estimates should be viewed as support for continued analysis, and that a pathway should be preserved to adopt the proposal in the future.

CEJA/Sierra Club recommend continuing to assess transactability and the impact of the SOD framework on gas contracting.[218] CEJA/Sierra Club are concerned that the Transactability Report indicates that the SOD program is not furthering environmental goals and may be leading to increased gas contracting, as LSEs are not relying on available storage to meet RA requirements and deficient LSEs are turning to gas resources.

MRP, PG&E, SCE, SDG&E, and Vistra oppose the hourly load obligation trading proposal for multiple reasons.[219] These parties support the

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[217] Ava Opening Comments on Transactability Proposals at 7.

[218] CEJA/Sierra Club Opening Comments on Transactability Proposals at 1.

[219] MRP Opening Comments on Transactability Proposals at 3, PG&E Reply Comments on Transactability Proposals at 2, SCE Reply Comments on Transactability Proposals at 1,

Transactability Report's analysis and conclusion that there are no transactability issues or structural market barriers to the SOD framework, and thus, state that there is no evidence or basis to adopt an hourly load obligation trading mechanism. SDG&E and SCE state that structural reforms to the RA framework and complex administrative schemes, like hourly load obligation trading, should not be adopted unless there is a demonstrable concern. SDG&E, PG&E, and Vistra underscore that the Transactability Report's findings reveal that the SOD framework and the bilateral RA market are working as they should. These parties point out that the first year of SOD compliance resulted in zero citations for deficiencies, which is rare compared to deficiencies during the pre-SOD timeframe from 2017-2024.

Vistra and SDG&E assert that the Transactability Report considered the correct question of whether the SOD framework allows market participants to comply with RA requirements, and that Ava and CalCCA's preferred question (whether a trading mechanism would allow compliance at a lower cost) contradicts the Commission's direction to Energy Division in D.25-06-048. SDG&E further states that Ava/CalCCA's preferred question would decouple the transactability analysis from empirical evidence, allowing hourly trading supporters to argue it is needed whether or not the existing framework functions effectively.

PG&E disputes CalCCA's claim that 2025 is not a representative year, stating that 2025 is the first and only compliance year of the SOD program and

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SDG&E Reply Comments on Transactability Proposals at 3, Vistra Opening Comments on Transactability Proposals at 5.

should be a benchmark until additional data is gathered. SDG&E disagrees with Ava and CalCCA's comments that Energy Division's cost savings estimates are conservative and that benefits may increase, arguing that these assertions are speculative with no supporting data provided.

MRP, SDG&E, and Vistra maintain that the mechanism represents an alternative compliance method that allows LSEs to opt out of hourly RA requirements by paying an LSE to purchase an hourly obligation, without having to contract physical capacity.[220] SDG&E states that the mechanism formalizes "leaning" on other LSEs' procurement and improperly shifts costs to ratepayers that have already paid for compliance with RA requirements. Vistra contends that the proposal introduces a financial instrument where one LSE pays another to take on procurement obligations in exchange for avoiding RA penalties, which is inconsistent with the IRP proceeding's D.23-02-040, where the Commission stated that compliance obligation trading may not be through a financial arrangement where one LSE pays another to take its procurement requirement.[221] Vistra adds that the proposal is an attempt to relitigate the SOD framework by allowing LSEs to settle hourly short positions through trading, rather than procurement of physical capacity.

Vistra and PG&E contend that the mechanism gives certain LSEs a competitive advantage over others.[222] Vistra states that the proposal offers an

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[220] MRP Reply Comments on Transactability Proposals at 2, SDG&E Reply Comments on Transactability Proposals at 2, Vistra Opening Comments on Transactability Proposals at 12.

[221] Vistra Opening Comments on Transactability Proposals at 13 (citing D.23-02-040 at Conclusion of Law 14).

[222] Vistra Opening Comments on Transactability Proposals at 12, PG&E Opening Comments on Transactability Proposals at 22.

LSE-only product that discriminates against qualified RA sellers without load obligations, while PG&E states that IOUs are at a competitive disadvantage over community choice aggregators (CCA) and electric service providers (ESP) because IOUs have greater regulatory oversight to participate in load obligation trading, such as requirements to modify their Bundled Procurement Plan (BPP).

Parties raise numerous outstanding issues that should be addressed before considering an hourly load obligation trading proposal, including the following:

- PG&E states that the mechanism's impact on the PCIA calculation's treatment of RA capacity should be examined to avoid unintended consequences and ensure fair cost recovery.[223] Depending on an IOU's trading purchase, the categories of RA for PCIA purposes adopted in D.19-10-001 (retained, sold, unsold) may need modification. While CalCCA proposes to treat an IOU's trading purchase as "sold" by crediting revenues to the balancing account, PG&E states that RA purchases of less than one year do not qualify for PCIA and are recorded in ERRA to be paid by bundled customers. PG&E cautions that it may not be possible to tell which resource is enabling an IOU to make a trading purchase and thus, how the purchase should be credited.
- PG&E states that the mechanism's impact on IOU's BPP should be considered as it appears that in order for an IOU to participate in a hourly trade transaction, it would need approval of modifications to the BPP.[224] Due to the time needed for Commission approval, IOUs may be precluded from participating in the mechanism for some time, while CCAs and ESPs may participate.

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[223] PG&E Opening Comments on Transactability Proposals at 15.

[224] *Id*. at 22.

- PG&E states that the mechanism's impact on data used to calculate the PCIA RA MPB should be considered because the MPB is used to value "retained" RA from PCIA portfolios when used for RA compliance and the MPB is critical in IOUs' ratemaking to calculate the bundled service generation rate and PCIA rate.[225] PG&E states that in D.25-06-048, the MPB methodology was modified due to low transaction volumes that undermined the prior methodology. Because a potential benefit of the proposed mechanism is reduced volume of transacted RA and reduced number of transactions, the mechanism could resurface the issue that D.25-06-048 intended to eliminate.
- Vistra states that the proposal requires coordination to ensure CAISO can accurately determine an LSE's adjusted deficiency because if CAISO identifies a system shortfall that triggers backstop procurement, costs would be allocated to each LSE based on the proportion of deficiency.[226] CAISO's supply plan validation and CPM cost allocation may need amendments to reflect adjusted obligations.
- PG&E states that consideration is needed on the impacts of the mechanism on Cost Allocation Mechanism (CAM)-based allocations, Provider of Last Resort and Financial Security Requirements calculations, and the verification complexity with subsequent trading given the unlimited number of potential trades.[227]
- SCE states that the outcome of the IRP proceeding's Reliable and Clean Power Procurement Program (RCPPP) framework should be considered beforehand, in the event that the procurement landscape fundamentally changes.[228]

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225 *Id*. at 20.

226 Vistra Opening Comments on Transactability Proposals at 14.

227 PG&E Reply Comments on Transactability Proposals at 23.

228 SCE Reply Comments on Transactability Proposals at 4.

- MRP states that before the mechanism is considered, the PRM should be reassessed so that an efficient market is paired with appropriate RA requirements, Energy Division should confirm it has proper resources in place to handle compliance, and Energy Division should reevaluate the need for the mechanism by updating the Transactability Report.[229]

In sur-reply comments, CalCCA responds to a number of parties' concerns.[230] CalCCA states that hourly load transactions can be addressed in the PCIA proceeding just as other PCIA impacts from policy changes are addressed. CalCCA argues that the IOUs' criticism of its proposal is predicated on the idea that IOUs will participate in hourly load trading, and that these issues should be addressed if/when IOUs decide to participate. CalCCA adds that PG&E's concern of how to determine which resources are enabling an IOU to make an hourly load purchase are not unique to load obligation trading and should be raised in the PCIA proceeding. CalCCA responds that its proposal should not change CAM allocations, should be treated like other RA procurement for calculating FSR, and the 25% limit was intended to reduce trades to minimize administrative burden on Energy Division.[231]

4.8.4. Discussion

The Commission appreciates the considerable effort put forth by Energy Division in preparing the Transactability Report, as authorized in D.25-06-048. We also recognize the efforts undertaken by parties in workshops and written filings to develop a thorough record on this topic.

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229 MRP Opening Comments on Transactability Proposals at 4.

230 CalCCA Sur-Reply Comments on Transactability Proposals at 12.

231 *Id*. at 17.

As discussed above, most recently in D.25-06-048, the Commission stated that "[t]o evaluate whether transactability issues exist under the SOD framework, Energy Division should conduct an evaluation after a full year of SOD implementation to assess the need, benefits, and feasibility of an hourly load obligation trading mechanism."[232] Energy Division's February 2026 Transactability Report is the first Commission-directed report to evaluate whether the SOD framework has transactability and inefficiency concerns.

With regards to the analysis underlying the Transactability Report, CalCCA and Ava express various critiques with the Transactability Report's analysis, including whether Energy Division focused on the correct question in its analysis. The Commission finds that Energy Division evaluated the appropriate question, based on the Commission's direction in D.25-06-048. To evaluate whether transactability issues exist under the SOD framework, Energy Division assessed: whether LSEs were able to comply with their RA requirements under the SOD framework (need), whether hourly load obligation trading could reduce overall capacity procurement by improving alignment between LSEs' contracted resources and LSEs' hourly load obligations (benefits), and whether implementing an hourly load obligation trading would introduce complexity into the RA program and compliance process (feasibility). While CalCCA argues that the evaluation should have been whether an hourly load obligation trading mechanism could lower costs of LSEs' compliance with RA requirements, we note that Energy Division did assess this question as well under its "benefits/cost assessment."

[232] D.25-06-048 at 86.

The Commission concurs with parties that support the analysis and findings of the Transactability Report. We disagree with CalCCA that the 2025 RA compliance year should not be considered a representative year. Energy Division's analysis of the 2025 year-ahead compliance filings was appropriate because it is the only year of binding compliance data available under the SOD framework. We agree with PG&E that the 2025 compliance year should be considered a benchmark until further data is available. As such, the Commission credits the underlying analysis and findings of the Transactability Report.

In the previous four decisions where load obligation trading proposals were considered, the Commission made clear that it would not consider adopting an hourly load obligation trading mechanism until and if transactability and inefficiency concerns arise in the SOD framework.[233] The Transactability Report found that "[t]he RA filing and contract price data showed that LSEs were able to procure and trade sufficient capacity to meet hourly obligations, with no evidence of unresolved deficiencies and structural market barriers attributable to SOD."[234] Further, the Transactability Report concluded that "the filing record does not indicate a systemic inability for LSEs to meet hourly requirements using existing procurement and contracting mechanisms."[235] As such, we are persuaded by the Transactability Report's conclusion that the record does not demonstrate transactability or inefficiency concerns under the SOD framework at this time. Based on this finding, the

[233] *See* D.22-06-050 at 96, D.23-04-010 at 71, D.24-06-004 at 73, D.25-06-048 at 86.

[234] Energy Division Transactability Report at 6.

[235] *Id*. at 44.

Commission concludes that there is no demonstrated need for an hourly load obligation trading mechanism under the SOD framework at this time.

Although we find no evidence of transactability concerns under the SOD framework at this time, we note that the Transactability Report found that while an hourly load obligation trading mechanism may reduce portfolio alignment inefficiencies at the margins, the reality is that the RA program is a decentralized system in which 38 LSEs procure individually to meet their RA allocations based on independent preferences. For hourly load obligation trading to realize full cost savings through reduced aggregated procurement, such a mechanism would need to be coupled with a centralized procurement system.

The Commission is also persuaded by the Transactability Report's finding that implementation of an hourly load obligation trading mechanism would add significant complexity to the SOD program and a substantial burden on Commission staff and resources. The Transactability Report outlined multiple new review steps that would be required for Energy Division staff to review RA compliance under an already-compressed compliance timeframe, including validating both initial and final LSE load trades for year-ahead filings, sending correction notices, and incorporating final validations into allocations for month-ahead filings. CalCCA's proposal for the Commission to develop software and systems to automate the RA validation process is not a feasible, near-term solution to the administrative burdens raised in the Transactability Report, as the development and integration of new automated systems would require significant Commission staff resources and time. We agree with the Transactability Report's conclusion that "the potential benefits of such a mechanism do not justify the added complexity and risk of unintended consequences associated with its implementation."[236]

As for CalCCA's proposed 25% cap on an LSE's load obligation to limit transaction volume, this is not a sufficient guardrail to address the administrative burden concerns identified in the Transactability Report. The 25% limit constrains the total MW amount of any individual LSE's obligation that may be traded but does not limit the total number of discrete transactions, including potentially more complex secondary transactions that Energy Division would need to validate and reconcile under the existing compliance timeframe.

The Commission is further persuaded by the Transactability Report's finding that potential cost savings may ultimately not be delivered to aggregate load. Setting aside questions of magnitude, the fundamental premise underlying CalCCA's benefit analysis assumes that avoided procurement costs would materialize as ratepayer savings, and this assumption has not been established. We agree with the Transactability Report's finding that because the majority of RA transactions occur between LSEs (not from generators to LSEs), load obligation trading that reduces incremental procurement may also reduce sales revenues of LSEs holding long positions. In other words, any savings realized by one LSE may come at the direct expense of another LSE's sales revenues, such that the net benefit to aggregate load is uncertain, rather than additive. As such, the Commission is not persuaded, and the record does not establish, that the proposed trading mechanism would deliver the claimed ratepayer benefits.

[236] Energy Division Transactability Report at 44.

The Commission also agrees with concerns raised by parties that an hourly load obligation trading mechanism functions as an alternative compliance mechanism that allows LSEs to satisfy RA requirements through financial arrangements, rather than through the contracting of physical capacity. The mechanism's structure raises concerns about consistency with the fundamental design and intent of the RA program itself.

While the Commission finds no need for an hourly load obligation trading mechanism at this time, there are multiple outstanding issues with CalCCA's proposal that would require development before further consideration. These include: (1) the mechanism's unresolved impacts on the PCIA rate calculation methodology, including the classification of traded capacity, the allocation of load obligation trading revenues across IOU cost recovery mechanisms, and the potential effects on the RA MBP dataset; (2) anticipated competitive inequities between IOU and non-IOU LSEs arising from IOU BPP requirements, which may require IOUs to face lengthy Commission approval processes; (3) necessary coordination with CAISO regarding CPM cost allocation; (4) the interaction of any such mechanism with the RCPPP framework currently under development; and (5) a demonstration that any avoided procurement costs would deliver a net benefit to aggregate load (accounting for risk that savings to short LSEs may be offset by corresponding revenue losses to long LSEs). In addition to addressing the issues above, any future proposal would need to include a feasible implementation plan that addresses the concerns identified in Energy Division's Transactability Report, which may include a plan for Commission development of necessary software or process enhancements. For these reasons, the Commission declines to adopt an hourly load obligation trading proposal.

The Commission will continue to monitor the RA market and compliance filings as the SOD framework matures. Reconsideration of any hourly obligation trading proposal would need to demonstrate not only that the benefits of the proposed mechanism would clearly outweigh the associated costs and administrative complexity, but also that the proposed mechanism would address the outstanding issues outlined above.

4.9. Load Forecast Process

Energy Division, CalCCA, and PG&E submit proposals regarding changes to the load forecast process.

4.9.1. Pacific Gas and Electric Company's Load Migration Proposal

PG&E seeks clarification that "load migration" excludes events in which an LSE voluntarily changes the effective date confirmed in its approved implementation plan and does not submit a new implementation plan to the Commission.[237] PG&E states that in D.19-06-026, the Commission ordered that "load migration" is the only allowable reason for differences between the initial and final year-ahead load forecast submittals in April and August of each calendar year. The Commission clarified in that decision that load migration does not include changes to approved implementation plans.

PG&E notes that a CCA with an approved implementation plan could make changes between its initial and final year-ahead load forecast based on a

[237] PG&E Track 1 Proposal at 7.

voluntary change/delay in the effective date of service or expanded service, and such change may not require submitting a changed implementation plan. An LSE experiencing load departure from another LSE that voluntarily delays the effective date of service without submitting a changed implementation plan to the Commission could face uncertainty regarding its RA obligation, with less time to procure capacity, and risk non-compliance.

Ava/PCE support PG&E's proposal to the extent it means that if a CCA updates its implementation plan prior to submission of the initial year-ahead forecast, the forecast may be adjusted.[238] Once the year-ahead forecast is submitted, Ava/PCE support the forecast remaining fixed, except for recognized load migration adjustments.

CalCCA supports PG&E's proposal with the following modifications: (1) remove any requirement that a CCA's voluntary change must be confirmed by Energy Division through a letter certifying an amendment to the CCA's implementation plan, and instead require providing notice; (2) clarify that if the voluntary delay applies to a date where the initial service was in October-December, the CCA can communicate the change by the August load forecast update rather than the April update; and (3) allow for a mutually acceptable solution between the IOU and CCA that deviates from the timeline, with notification to the Commission of the solution.[239]

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[238] Ava/PCE Opening Comments on Track 1 Proposals at 19.

[239] CalCCA Opening Comments on Track 1 Proposals at 21.

4.9.1.1. Discussion

In D.19-06-026, the Commission adopted a binding load forecast process that "'locks in' RA requirements based on load forecast assumptions that an LSE can reasonably predict or control."[240] The process established that an LSE's initial year-ahead load forecast would serve at the Binding Notice of Intent for the following year. The decision determined that "[l]oad migration shall be the only allowable reason for differences between initial and final year ahead load forecasts."[241]

The Commission adopted the following definition of "load migration:"

> "Load migration," for purposes of the RA program, shall not include the following non-exhaustive events: changes to approved implementation plans, changes to customer class load profiles, changes to weather assumptions, changes resulting from the receipt of new or updated customer meter data, new service requests, losses due to disconnects or force majeure events, transfers of load out of the Transmission Access Charge area, or forecasting errors.[242]

As adopted in D.19-06-206, "changes to approved implementation plans" are already excluded from the definition of "load migration." However, PG&E is concerned that an LSE could voluntarily change the effective date of its implementation plan, which may not require approval from the Commission, after the initial load forecast is locked. The Commission finds PG&E's proposal to be a reasonable clarification to reduce uncertainty and to be consistent with the Commission's intent in D.19-06-026.

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240 D.19-06-026 at 27.

241 *Id*. at OP 10.

242 *Id*. at OP 12.

Accordingly, "changes to approved implementation plans" for purposes of the RA program shall include: "a voluntary change to the effective date of an approved implementation plan, even if the new implementation plan is not submitted for approval to the Commission." This is effective immediately.

4.9.2. California Community Choice Association's Data Center Load Proposal

CalCCA proposes that the Commission coordinate with the CEC to develop new processes for incorporating data center load into the RA forecast and allocations.[243] The process would include: (1) considering data center load separately from other forecasted load for RA purposes and using actual rather than forecasted load to determine RA requirements; and (2) allocating an RA obligation to an LSE serving a data center when certain milestones are met. CalCCA is concerned that when incorporating large and/or uncertain data center loads, load forecast accuracy can have significant affordability and reliability implications. Depending on how RA obligations are allocated, CalCCA states that specific LSEs may be particularly impacted by these significant procurement costs.

CalCCA recommends that data center load only be incorporated into the RA requirements if certain conditions are met. These conditions include: an executed interconnection agreement, a known energization data in the RA year, permitting milestones, and other indicators.

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[243] CalCCA Track 1 Proposal at 4.

3CE, CEJA/Sierra Club, and Ava/PCE support CalCCA's proposal.[244] Ava/PCE assert that this proposal could improve confidence in large load forecasting by tying RA requirement to meaningful milestones for these loads.

MRP, PG&E, SDG&E, and Vistra oppose CalCCA's proposal.[245] Vistra, MRP, and PG&E disagree with bifurcating the load forecast process between the Commission and CEC, generally stating that it would undermine confidence in the load forecasting process and create reliability risks by distorting the year-ahead and prompt-year procurement signals. MRP comments that the RA program relies on the IEPR forecast to inform decisions about whether existing capacity is needed and if data center load is removed from the forecast, LSEs may conclude there is a capacity surplus and decline to procure/retain existing capacity resources.

PG&E argues that the proposal is unnecessary, as it is not clear that demand forecasting for data center load is volatile enough in the prompt year to warrant a standalone allocation of RA procurement in the RA proceeding, distinct from the IEPR process. PG&E adds that the CEC's existing econometric model likely accounts for some level of uncertainty of new data center load. MRP states that the proposal could undermine local reliability as data centers are often geographically concentrated and if load is not reflected in the forecast used to set local RA requirements, that will impact local procurement signals. MRP

[244] 3CE Opening Comments on Track 1 Proposals at 6, CEJA/Sierra Club Opening Comments on Track 1 Proposals at 3, Ava/PCE Opening Comments on Track 1 Proposals at 15.

[245] MRP Opening Comments on Track 1 Proposals at 26, PG&E Opening Comments on Track 1 Proposals at 18, SDG&E Opening Comments on Track 1 Proposals at 6, Vistra Opening Comments on Track 1 Proposals at 18.

notes that the proposal fails to account for downstream impacts of removing data center load from the forecast, including import allocation rights, congestion revenue rights, and CAISO backstop procurement.

PG&E, SDG&E, and Vistra advocate for additional process to consider this topic. Vistra requests the CEC host cross-entity workshops within the 2026 IEPR where stakeholders can raise questions, and SDG&E suggests that further comments/workshops be undertaken to address this topic and other large load-related issues. PG&E states that if an LSE disagrees with the CEC's forecast methodology for RA procurement, the annual IEPR process is the most appropriate venue to address this.

In reply comments, CalCCA responds that the data center load would not be separated from the IEPR forecast, but would be on a "parallel path" for setting RA requirements.[246] CalCCA supports SDG&E's proposal for additional comments/workshops if additional issues need resolution and does not oppose a cross-entity workshop, but states that the effects of data center load are already materializing in RA forecasts and expected to grow in future years.

4.9.2.1. Discussion

The Commission recognizes that the issue of costs and uncertainty associated with new load from data centers is a topic that is being widely discussed in California. Senate Bill 57 requires the Commission to provide an assessment of the potential costs impacts of new, large data center loads to the Legislature by January 1, 2027. The Commission has initiated a rulemaking, R.26-04-009, to address this topic.

[246] CalCCA Reply Comments on Track 1 Proposals at 5.

The Commission concurs with PG&E that there is insufficient record at this time to demonstrate that data center load forecasting in the prompt year is so volatile as to necessitate CalCCA's proposed solution. In addition to the Commission's proceeding, R.26-04-009, the Commission is closely monitoring demand forecasting for data center load in the annual IEPR demand forecast process, in coordination with CEC. CEC's 2025 IEPR process is currently addressing the impact of increased data center demand through public collaboration and multi-year methodological updates that expand upon and refine prior years' approaches.

CEC seeks input into its forecast development and methodologies through various venues, including public workshops and public Demand Analysis Working Group (DAWG) meetings. CEC invited utilities to speak at the July 16, 2025, DAWG meeting to discuss data centers and other large loads. In addition, the 2025 IEPR forecast continues the dedicated data center modeling approach established in the 2024 IEPR, updating it with the latest utility data and further process refinements. CEC introduced three data center scenarios that are based on different assumptions around the likelihood of completion for energization applications and inquiries. These scenarios were presented for stakeholder discussion at the October 30, 2025, DAWG meeting and November 13, 2025, IEPR workshop. The CEC continues to engage with utilities and industry groups individually on this topic, and the IEPR process is the appropriate venue to consider changes to the load forecasting process.[247] The Commission will

[247] *See* April 16, 2026, 2025 IEPR Forecast — Single Forecast Set Agreement, available at: https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2025-integrated-energy-policy-report; 2025 IEPR Forecast-Updated Results, DAWG Meeting,

continue to monitor demand forecasting for data center load to determine whether modifications to the current load forecast process are warranted.

While the Commission defers consideration of this issue, we also note that CalCCA's proposal raises implementation questions and is not sufficiently developed at this time. For instance, it is unclear which regulatory entity would be responsible for verifying and monitoring compliance with the proposed milestones that data center customers would need to meet. There may also be reliability concerns if, for example, the data center was not included in the initial year-ahead forecast and subsequently comes online intra-year without having been accounted for in resource-planning, leaving insufficient time to procure capacity necessary to serve the new load.

4.9.3. Energy Division's Load Forecast/ Data Center Load Proposal

Energy Division submits a detailed summary of the existing RA load forecast adjustment process, as adopted in previous Commission decisions, to: (1) provide a comprehensive summary of the current load forecast process used for the SOD framework; and (2) formalize the implementation of the SOD load forecast process adopted in D.23-04-010, including clarifications on how various adjustments will be implemented.[248]

Energy Division describes the seven steps that CEC staff undertakes to develop adjusted LSE forecasts for the SOD program, because "[t]he shift to the SOD framework from monthly peak required methodology changes to the

January 5, 2026, available at: https://www.energy.ca.gov/event/meeting/2026-01/ca-energy-demand-forecast-2025-iepr-revised-result.

248 Energy Division Track 1 Proposal at 8.

previous RA peak demand forecast method, including changes to coincidence and LSE-specific adjustment, and the addition of an intermediate pro-rata step."[249] Energy Division summarizes the seven steps as: (1) Reference Forecasts; (2) LSE-Specific Adjustments, including load modifier adjustments, large load adjustments, monthly peak and peak day energy evaluation, and hour-specific adjustment; (3) Transmission and Unaccounted-for-Energy losses; (4) Coincidence Adjustment; (5) Load Credit Adjustment; (6) LSE-Type Pro Rata Adjustment; and (7) Final Pro Rata Adjustment.

As part of the LSE-specific adjustment step of the load forecast methodology mentioned above, Energy Division recommends an approach to how new or expanded large loads should be allocated to the appropriate LSEs. At or prior to the year-ahead forecast meet and confer process, IOUs should provide CCAs with information on customers expected to interconnect in the CCA's service area the following year, and IOUs should also provide this information in their year-ahead load forecasts to the CEC. At or prior to the year-ahead forecast meet and confer process, all LSEs should also provide information on new/expanding customers the LSE intends to serve in the following year. In each LSE's year-ahead forecast, new data centers or other large loads should be reported on Form 3, including significant expansion at current customer sites.

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249 *Id*.

AReM, CalCCA, and Vistra support Energy Division's meet and confer proposal.[250] CalCCA states that including large load adjustments in the meet and confer process will improve transparency and ensure all entities have timely access to data used to inform the load forecast. AReM states that all LSEs, including ESPs, should be required to notify the CEC and the Commission of new large loads ahead of the RA load forecast finalization process.

PG&E opposes Energy Division's proposal because it is unclear how much work would be required for IOUs to provide such information to CCAs and if the same information could be provided in another venue.[251] PG&E states that a large increase in data center load customers could hinder IOUs' ability to meet these requirements, and more exploration is needed before adoption.

4.9.3.1. Discussion

The Commission finds Energy Division's proposal on large load reporting to be an important step in providing LSEs information about adjustments to large loads. Providing this additional information to all LSEs will increase confidence in the accuracy of the load forecast and foster transparency. While we acknowledge PG&E's concern about the potential administrative burden on IOUs, we note that some of the proposed information is currently being provided by PG&E to relevant CCAs under the interim implementation of the Electric Rule 30 tariff for large transmission-level customers (50-230 kV) seeking retail service. As mandated by D.25-07-039, PG&E is required to provide

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250 AReM Opening Comments on Track 1 Proposals on Track 1 Proposals at 8, CalCCA Opening Comments on Track 1 Proposals at 7, Vistra Opening Comments on Track 1 Proposals at 18.

251 PG&E Reply Comments on Track 1 Proposals at 14.

transmission-level customer applications, as well as quarterly reports on executed service agreements, project and customer information updates, and interconnection timelines.[252] As such, until a longer-term solution is developed, Energy Division's proposal is reasonable to adopt on an interim basis beginning with the 2028 RA compliance year.

Accordingly, Energy Division's proposal is adopted as follows. At or prior to the year-ahead forecast meet and confer process, IOUs will provide CCAs with information on customers expected to interconnect in the CCA's service area the following year. IOUs will also provide this information in their year-ahead load forecasts submitted to the CEC. Data to be provided for each project will, at a minimum, include: project identifier, address and contact information, default LSE, capacity requested, expected energization date, expected ramping schedule, and application status. In advance of the meet and confer schedule, Energy Division, the IOUs, and the CEC will work together to finalize the details of these requirements. The details of the data sharing process will be finalized and published along with the annual CEC templates.

At or prior to the year-ahead forecast meet and confer process, all LSEs will provide information on new/expanding customers the LSE intends to serve in the following year. In each LSE's year-ahead forecast, new data center or other large loads will be reported on Form 3, including significant expansion at current customer sites. LSEs will follow the best estimates approach in

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[252] *See* PG&E Electric Rule No. 30 Retail Service Transmission Facilities Interim Implementation, available at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_30.pdf.

developing their forecast and document forecast assumptions and reasons for deviations from IOU-provided data. This is effective immediately.

Lastly, the Commission finds it reasonable to adopt Energy Division's summary of the load forecast process as applied under the SOD framework. This summary is beneficial in formalizing the implementation of the SOD load forecast process adopted in D.23-04-010. The seven-step process that the CEC follows to develop the adjusted LSE forecasts for the SOD program is detailed in Appendix A. Accordingly, Appendix A is adopted here.

4.10. Central Procurement Entity Framework

CEJA/Sierra Club, CalCCA, and PG&E submit proposals to modify the central procurement entity framework.

4.10.1. Local Capacity Requirement — Reduction Compensation Mechanism

PG&E recommends sunsetting the Local Capacity Requirement — Reduction Compensation Mechanism (LCR-RCM) framework.[253] PG&E reasons that the LCR-RCM has been an ineffective incentive that adds administrative burden and potentially adds customer costs through the extension of market power premiums to LSEs. PG&E points out that the Commission's *Report on the 2021-2023 CPE Framework* (CPE Report), issued on May 31, 2024, reported a lack of participation in the LCR-RCM option, finding that "[t]he lack of participation in the LCR RCM mechanism may indicate that either LSEs are not constructing clean resources in local areas where there are underlying needs, or that the CPE Framework is failing to recognize the associated value of selecting these

[253] PG&E Track 1 Proposal at 10.

resources for payment of a local premium."[254] The CPE Report also noted that "because LCR RCM premiums fluctuate significantly each year, it may not provide the right incentives to show and/or build in certain areas."[255]

PG&E adds that the mechanism is not yielding an observable policy or tangible benefit for new and preferred resources in local areas.[256] PG&E recommends sunsetting the LCR-RCM but continuing to allow existing commitments for LCR-RCM resources to be compensated until existing contracts with the applicable CPE contract expires.

SCE supports eliminating the LCR-RCM and asserts that doing so will streamline the CPE framework, reduce administrative burden, avoid unnecessary customer costs, and preserve transparency.[257] SCE states that the limited use of the mechanism suggests it is not driving incremental procurement of preferred resources in local areas.

Ava, CalCCA, CEJA/Sierra Club, and MRP oppose PG&E's proposal to remove the LCR-RCM.[258] These parties generally state that it is premature to remove the mechanism and that a lack of participation does not demonstrate that the LCR-RCM is ineffective. CalCCA comments that the lack of participation is based on current short-term RA market conditions and those conditions will evolve, while MRP states that limited participation is an expected outcome

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254 Energy Division CPE Report at 48.

255 *Id*.

256 PG&E Reply Comments on Track 1 Proposals at 10.

257 SCE Opening Comments on Track 1 Proposals at 18.

258 MRP Opening Comments on Track 1 Proposals at 23, CalCCA Opening Comments on Track 1 Proposals at 16, CEJA/Sierra Club Opening Comments on Track 1 Proposals at 6, Ava Reply Comments on Track 1 Proposals at 12.

because opportunities for new local procurement are inherently limited compared to system procurement. CalCCA states that removing the mechanism allows the CPEs to use an LSE's local procurement without payment, forcing one LSE to bear costs for all.

MRP and CEJA/Sierra Club argue that PG&E has not identified any data to support the exercise of market power through the LCR-RCM or that it has been ineffective. The parties opposing elimination of the LCR-RCM generally state that a viable alternative to the LCR-RCM should be considered before eliminating it. CEJA/Sierra Club suggest increasing the LCR-RCM incentives and fully evaluating this issue in coordination with the IRP proceeding. Ava adds that the LCR-RCM may provide important indirect benefits by improving negotiating dynamics and maintaining an alternative pathway to meet local needs.

4.10.1.1. Discussion

In D.20-12-006, the Commission adopted the LCR-RCM as part of the CPE framework as a financial credit mechanism to apply to new preferred resources and energy storage resources.[259] While we recognize that there has been limited participation of the mechanism over the past few years, we agree with parties that the limited participation does not mean that the LCR-RCM is ineffective. We also agree that prior market conditions may have contributed to this lack of participation, and that as the market continues to adapt to the new SOD framework, participation in the LCR-RCM may change. For these reasons, it is

[259] D.20-12-006 at OP 3.

premature to conclude that the LCR-RCM is ineffective and that it should be eliminated.

In addition, before considering the elimination of the LCR-RCM, it would be prudent for the Commission to first consider potential alternatives to replace the mechanism, or potential modifications to the current mechanism. The Commission will continue to monitor participation in the LCR-RCM and may consider modifications to the mechanism, as warranted.

4.10.2. Central Procurement Entity Data Issues

CalCCA and CEJA/Sierra Club submit proposals related to the use of the CPEs' data usage. CalCCA asserts that the two CPEs are using the aggregated results of Energy Division's LSE data request (referred to as the CPE data request file) differently, with SCE using the CPE data request file to determine whether CPE plus LSE procurement resulted in sufficient local resources under contract.[260] CalCCA states that it is unclear how the PG&E-CPE uses the CPE data request file, as the PG&E-CPE's Annual Compliance Report states that the results "informed" its procurement but not its compliance needs. CalCCA seeks clarification that both CPEs are consistently using the data request responses in procurement decisions, and recommends that the SCE-CPE's approach be used by both CPEs. CalCCA states that this would prevent over-procurement and lead to ratepayer savings.

CalCCA also recommends that the Commission publish the CPE data request file so that both CPEs and LSEs have the same information. CalCCA suggests that the file should reveal only the total RA MW under contract by local

[260] CalCCA Track 1 Proposal at 12.

area to protect market-sensitive information. CalCCA states that this would improve market transparency, inform LSEs' system RA procurement decisions, and help LSEs anticipate CAM credits from CPE procurement.

CEJA/Sierra Club states that while there are thousands of MWs of new resources coming online, it is unclear where new clean energy and storage contracts are located, or what local capacity areas are best for targeting local procurement of clean resources.[261] CEJA/Sierra Club recommend creating a dashboard that includes planning and procurement data (separated by local capacity area) to understand potential areas to target for procurement and to inform communities where procurement can occur to reduce fossil fuel reliance. The dashboard should include the following information: the most updated aggregated local procurement data available, including online, contracted, and anticipated resources; the CPE data request file; the LCR requirements and resource projections developed in busbar mapping; and CAISO's 1-to-1 replacement to battery storage analysis.

4.10.2.1. Comments on Proposals

3CE and MRP support CalCCA's clarification on the CPE's usage of the CPE data request file.[262] MRP states that this would reduce over-procurement and unnecessary cost risks, as well as preserve LSE procurement autonomy by ensuring capacity under contract is recognized before the CPE enters the market.

PG&E opposes CalCCA's clarification, stating that while the PG&E-CPE's Annual Compliance Report stated that the data request process "informed" the

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[261] CEJA/Sierra Club Track 1 Proposal at 4.

[262] 3CE Opening Comments on Track 1 Proposals at 7, MRP Opening Comments on Track 1 Proposals at 30.

CPE's procurement, this does not mean the PG&E-CPE did not use the data to determine whether sufficient local resources were available to meet local requirements.[263] PG&E also argues that the Commission addressed this issue in D.24-12-003 and D.25-06-048 and concluded that there is no guarantee that local RA resources reported in the data aggregation will remain under contract or shown to CAISO, so reducing the CPE's requirement a 1-for-1 MW basis could result in an inaccurately low requirement.

AReM supports CalCCA's data publication proposal.[264] PG&E seeks clarification as to which information would be publicized, including the categories of information, time period, when/how the information should be publicized, whether the MW information should be in NQC, UCAP, etc., and whether the information would be aggregated by technology type.[265] In reply comments, CalCCA clarifies that it recommends providing the same information to LSEs that the Commission currently provides to the CPEs.[266]

No party commented on CEJA/Sierra Club's proposal.

4.10.2.2. Discussion

In D.24-12-003, the Commission authorized Energy Division to collect the following information from LSEs in the PG&E and SCE transmission access charge (TAC) areas about its local RA capacity under contract: (1) Resource ID; (2) Local Area; (3) Contract Start/End Date; (4) Resource Technology Type; and (5) Contracted Quantities of Capacity in Megawatt (MW) Capacity for the 3-Year

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[263] PG&E Opening Comments on Track 1 Proposals at 14.

[264] AReM Opening Comments on Track 1 Proposals at 8.

[265] PG&E Opening Comments on Track 1 Proposals at 16.

[266] CalCCA Reply Comments on Track 1 Proposals at 11.

Forward Period.[267] Energy Division was directed to aggregate and anonymize the information and provide the data file to the CPEs for use in the CPEs' annual solicitation and procurement process.

CalCCA proposes to publicize the information collected as part of the CPE data request to both the CPEs and LSEs. The Commission concurs that publicizing the aggregated, anonymized contract data provided in the CPE data request file would assist in improving transparency, reducing information asymmetry, informing LSEs' system RA procurement decisions, and helping LSEs anticipate their CAM credits from CPE procurement. The information would also assist LSEs in better understanding the CPEs' overall procurement need. As such, the Commission deems CalCCA's proposal to be reasonable. Accordingly, the Commission directs Energy Division to publish the CPE data request file, as provided in D.24-12-003, on the Commission's RA website.

In D.24-12-003, the Commission replaced the non-compensated self-show option of the CPE framework with a data request process whereby Energy Division would provide the CPEs with aggregated local procurement information from LSEs. The Commission provided the stated purpose of the data request:

> The information would be provided to the CPEs to better assess the state of the overall local portfolio before initiating the CPEs' annual solicitations and would include information on existing and new build resources under contract with LSEs. The CPEs would use this information to better assess the

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[267] D.24-12-003 at OP 4.

actual needs for short-term and long-term procurement for the three-year forward requirements and beyond.[268]

Since that decision, the Commission has revisited the question of specifically how the CPE should be using the CPE data request file when assessing the state of the overall local portfolio.[269]

CalCCA seeks clarification on how the CPEs should be using the CPE data request file. SCE's 2026 CPE Annual Compliance Report states that the SCE-CPE did not select local RA offers in certain local areas because the aggregated local data "indicates sufficient local resources in [these] local areas that are currently under contract. In short, the CPUC Data Request File demonstrates existing contracted capacity in excess of the Local Capacity needs identified in the CAISO technical studies for SCE-CPE's compliance obligations for years 2026-2028."[270] CalCCA states that it is unclear from PG&E-CPE's Annual Report specifically how it is using the data file to "inform" its procurement decisions.

The Commission understands the SCE-CPE to be using the CPE data request file to determine whether the total contracts procured in local areas (CPE + LSE contracts) result in sufficient local resources under contract. Based on that assessment, the SCE-CPE determines whether/what local resources need to be procured to meet the CPE's total local requirements. The Commission finds that additional clarification that expands on the SCE-CPE's approach to using the CPE data request file is reasonable. This clarified approach would allow the CPE

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268 *Id*. at 38.

269 D.25-06-048 at 96.

270 CalCCA Track 1 Proposal at 12 (citing SCE's 2026 CPE Annual Compliance Report, September 19, 2025, AL 5632-E, Attachment 1 at 4).

to "assess the state of the overall local portfolio before initiating the CPEs' annual solicitations," as directed in D.24-12-003, and minimize over-procurement of local resources and selection of redundant offers.

The Commission clarifies that consistent with D.24-12-003, the CPEs will use the aggregated local RA data to determine whether total contracted capacity (CPE + LSE contracts) results in sufficient local resources. Based on this procurement assessment, and by exercising the explicit procurement authority and discretion granted under D.20-06-002 and D.22-03-034, the CPEs will determine whether/what local resources need to be procured to meet the CPEs' total local requirements.[271] This procurement assessment will focus on ensuring that needs are met at both the LCA and sub-LCA levels, as defined by CAISO's annual LCR studies.[272] Further, the CPEs' procurement determinations must account for the storage charging limitations identified within the applicable annual CAISO LCR study. In response to CEJA/Sierra Club and CalCCA's requests for additional transparency, the CPEs shall demonstrate in their Annual Compliance Reports how their contracted capacity reflects these requirements, by sub-local area needs, including how the CPE considered the total contracted capacity results in making its procurement determinations. This is effective beginning with the 2027 CPE procurement cycle.

Regarding CEJA/Sierra Club's proposed procurement tracker, the development and maintenance of a quarterly dashboard that integrates procurement and planning data is very resource intensive. The Commission also

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[271] *See* D.20-06-002 at OP 11, D.22-03-034 at OP 10.

[272] D.22-03-034 at OP 8.

observes that the proposed data categories are already available through Energy Division's CPE CAM list and the CPE data request file. The CPE CAM list provides resource-specific contracts and durations, while the CPE data request file, as adopted in this decision, will be publicized in an aggregated, anonymized form. When paired with the CAISO's LCR study data — which recently included studies on storage charging limits — these resources will allow parties to track local procurements across specific technologies. As such, we decline to adopt this proposal.

4.11. Resource Adequacy Penalty Structure

Energy Division proposes a modification to the RA penalty structure that allows for enforcement of the charging sufficiency requirement.[273] Under the SOD framework, LSEs are subject to: (1) hourly capacity requirements (MW), evaluated against the hourly SOD requirement for each of the 24-hour slices; and (2) a charging sufficiency requirement (MWh) based on the total charging requirement of storage resources shown to meet hourly capacity requirements.

Energy Division states that the charging sufficiency requirement is currently evaluated by comparing: (1) the total charging energy required by shown storage resources to (2) the total amount of excess energy shown across all hours eligible to meet charging needs. A shortfall is identified as a single, daily MWh deficiency. Energy Division states that because the penalty structure is based on the largest capacity (MW) deficiency in a specific hour, the charging sufficiency deficiency (expressed in MWh) cannot be directly calculated and

[273] Energy Division Track 1 Proposal at 3.

enforced without a unit-consistent conversion. As such, an LSE may be deficient under the charging sufficiency test but not trigger a penalty.

To account for charging sufficiency deficiencies, Energy Division proposes to modify the RA penalty structure with the following steps:

- **Step 1:** As currently implemented, use the SOD Showing Template to calculate the charging sufficiency deficiency in MWh as the difference between (a) the total daily charging energy required by storage resources shown, including the roundtrip charging efficiency of the storage resource; and (b) the total amount of excess energy shown across all hours that is eligible to meet charging needs. If this results in a shortfall, the charging sufficiency deficiency is expressed in MWh.
- **Step 2**: Convert the MWh deficiency to a 24-hour flat-profile MW equivalent amount by allocating the energy shortfall evenly across all 24-hour slices:

$$24\ Hour\ Flat\ Profile\ Equivalent\ Charging\ Deficiency\ (MW) = \frac{Charging\ Sufficiency\ Deficiency\ (MWh)}{24}$$

  The conversion produces a MW deficiency value that, when applied evenly across all 24 hours, represents the energy equivalent to the calculated charging sufficiency shortfall.

- **Step 3:** The resulting 24-hour flat-profile MW equivalent would be applied as a proportional adder to each of the 24 hours. This means that: (a) for each hour, the LSE's hourly MW position would be adjusted by the 24-hour flat-profile equivalent charging MW deficiency amount; and (b) the hour with the largest MW deficiency would continue to serve as the basis for penalty assessment, consistent with the current penalty structure.

Energy Division cites the advantages of this proposal as minimal adjustments to the existing penalty structure and SOD compliance tools, consistent and proportional conversion from MWh to MW and allocation across hours, and administrative simplicity by spreading the deficiency across all hours. Energy Division notes that a potential downside is that by spreading the deficiency evenly across all hours, that may weaken the penalty signal compared to a more targeted or punitive approach.

4.11.1. Comments on Proposal

SCE supports Energy Division's proposal to correct the enforcement gap, with one modification.[274] Rather than applying the 24-hour MW equivalent across all hours and recalculating hourly positions, Energy Division should conclude the process after Step 2 (to convert the MWh deficiency to a 24-hour MW equivalent). Once the MWh deficiency is converted to the MW equivalent, it should be added to the current single hour deficit for penalty assessment. SCE argues that this approach avoids recalculating all 24-hour positions while maintaining unit consistency and incorporating charging sufficiency penalties.

MRP opposes Energy Division's proposal, stating that this would dilute charging sufficiency penalties by spreading charging shortfalls across hours that do not reflect how storage is actually relied on.[275] MRP argues that a charging sufficiency penalty should be anchored to the MWh deficiency calculated in the LSE showing, which limits the MW amount a storage resource may be shown for based on the available charging energy. The resulting shortfall should be evaluated as an RA deficiency in the hours in which the resource is relied on to meet RA obligations. AReM suggests a prohibition on submitting a SOD

[274] SCE Opening Comments on Track 1 Proposals at 10.

[275] MRP Opening Comments on Track 1 Proposals at 19.

template until a charging deficiency is resolved and if this results in an hourly deficiency, a penalty will be incurred.[276]

4.11.2. Discussion

SCE supports Energy Division's proposal but recommends applying the MW equivalent deficiency to the hour with the largest capacity shortfall. We find that SCE's modification would create confusion if an LSE's initial largest capacity shortfall hour changes if that LSE cures all or part of its capacity deficiency. We also observe that Energy Division's proposed Step 3 (to apply the MW equivalent as a proportional adder to each of the hours) does not appear burdensome to implement.

MRP's proposed alternative would require significant changes to the LSE Showing Template, as limiting RA capacity by available excess energy cannot be applied simply within the optimizer and would necessitate building an additional calculation step after the template calculated hourly capacity values and total charging needs (to reduce the shown storage by the available excess energy). MRP's proposal would also broaden the existing gap between the Commission's and CAISO's RA showings because limiting shown capacity under the SOD framework (but not under CAISO's RA showings) would create discrepancies across LSEs' SOD showings and supply plans at the individual LSE and system level. By directly discounting capacity based on a separate energy requirement, MRP's proposal would also conflate shown capacity and excess capacity for charging. We decline to adopt SCE's and MRP's alternate proposals.

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[276] AReM Opening Comments on Track 1 Proposals at 9.

The Commission finds that Energy Division's proposal offers an administratively simple solution that converts a MWh charging deficiency into a MW-equivalent amount only at the deficiency notice stage. By distributing the deficiency across all hours evenly with a proportional conversion (rather than applying to a single hour), the proposal does not dictate when charging must occur, which limits the impact on LSEs' compliance approaches. Implementing Energy Division's proposal would require only minor changes to the SOD compliance tools and deficiency notice process, and would keep the shown capacity and excess charging energy distinct within the LSE Showing Template. For these reasons, the Commission adopts Energy Division's proposal to address enforceability of the charging sufficiency requirement. The Commission encourages parties and Energy Division to submit proposals in Track 2 on how penalty points should be applied to this framework.

Accordingly, if an LSE incurs a charging sufficiency deficiency, the following steps will be taken, effective for the 2027 RA compliance year:

- **Step 1:** Use the LSE Showing Template to calculate the charging sufficiency deficiency in MWh as the difference between: (a) the total daily charging energy required by storage resources shown, including the roundtrip charging efficiency of the storage resource; and (b) the total amount of excess energy shown across all hours that is eligible to meet charging needs. If this results in a shortfall, the charging sufficiency deficiency is expressed in MWh.
- **Step 2**: Convert the MWh deficiency to a 24-hour flat-profile MW equivalent amount by allocating the energy shortfall evenly across all 24-hour slices:

$$24\ Hour\ Flat\ Profile\ Equivalent\ Charging\ Deficiency\ (MW) = \frac{Charging\ Sufficiency\ Deficiency\ (MWh)}{24}$$

The conversion produces a MW deficiency value that, when applied evenly across all 24 hours, represents the energy equivalent to the calculated charging sufficiency shortfall.

- **Step 3:** The resulting 24-hour flat-profile MW equivalent is applied as a proportional adder to each of the 24 hours. This means that: (a) for each hour, the LSE's hourly MW position would be adjusted by the 24-hour flat-profile equivalent charging MW deficiency amount; and (b) the hour with the largest MW deficiency would continue to serve as the basis for penalty assessment, consistent with the current penalty structure.

4.12. Resource Adequacy Imports

SCE recommends that the eligibility for off-peak imports to count for RA, as adopted in D.25-06-048, should be extended. In D.24-06-004, the Commission stated that for the third quarter (Q3) of 2025, LSEs could count off-peak import energy that is not available during the AAH window towards meeting the SOD requirements, so long as the import adheres to other existing import requirements, such as being paired with an Import Allocation Right (IAR).[277] In D.25-06-048, the Commission extended the rule to Q3 2026 but opted to reevaluate the issue before further extending the rule.

SCE states that without an extension, LSEs will lose a critical compliance option and affordability tool, which may increase procurement costs and limit LSEs' ability to manage portfolio uncertainty. SCE recommends allowing off-peak imports to count towards RA compliance in the Q3 months going forward.

[277] SCE Track 1 Proposal at 10.

Additionally, SCE states that even with the extension, LSEs may not be able to use the capacity because the current IAR and Maximum Import Capability (MIC) structure is geared to on-peak or around-the-clock RA imports, not just off-peak use. SCE therefore recommends allowing LSEs to bilaterally contract with another LSE to use their IARs that are not paired with an off-peak import, consistent with the Commission's off-peak RA import policy. SCE recommends this import rule apply year-round, not just in Q3 months. SCE recommends the Commission collaborate with CAISO to refine the details of how the existing IAR framework can support off-peak-only use consistent with physical intertie limits.

4.12.1. Discussion

In D.25-06-048, the Commission extended the Q3 off-peak import counting rule to Q3 2026 and stated that it would "reevaluate the counting rule and determine whether it is necessary and feasible to extend it beyond 2026."[278] In considering SCE's proposal, the Commission finds that extending eligibility of the off-peak import counting rule would provide LSEs more flexible options for managing their RA portfolio. As such, it is reasonable to extend the off-peak import counting rule beyond Q3 2026 to future Q3 months, as proposed by SCE. Accordingly, the off-peak import counting rule adopted in D.25-06-048 is extended to future Q3 months beyond 2026.

Regarding extending off-peak eligibility to non-Q3 months, the Commission notes that the original requirement from D.24-06-004 was intended to address affordability issues and tight market conditions, and we do not find

[278] D.25-06-048 at 89.

that these same issues have arisen in non-peak months. Therefore, we decline to extend off-peak eligibility of imports to non-Q3 months.

With respect to allowing LSEs to bilaterally contract for IAR in off-peak hours, we note that the current rules require imports to be paired with an IAR. SCE's proposal would be a departure from the current framework in that LSEs would be allowed to show off-peak imports without holding an IAR. Further, adopting this proposal would require the development of additional validation processes by Energy Division. The Commission declines to adopt this proposal.

4.13. Year-Ahead Compliance Filing

Energy Division seeks to clarify rules for showing under-construction resources in year-ahead compliance filings to meet flexible RA requirements.[279] Energy Division notes that Commission decisions have allowed LSEs to count under-construction resources towards their system and local RA obligations in their year-ahead filings, provided that the commercial operation date (COD) of the resource is 45 days before the first date of the compliance month. However, such rules have not been expressly applied to flexible year-ahead RA obligations.

Energy Division proposes that LSEs be allowed to show under-construction resources in the year-ahead filings to count towards flexible RA obligations, subject to verification that the resource is included on the year-ahead MRD and designated as a flex-eligible resource. Energy Division states that it uses the CAISO annual NQC list and EFC Report to compile the annual MRD, but the EFC Report does not include under-construction resources, which are included in the NQC list. Energy Division posits that this gap creates

[279] Energy Division Track 1 Proposal at 18.

challenges in verifying under-construction resources shown to meet year-ahead flexible RA obligations. During the year-ahead compliance review process, Energy Division proposes to verify that under-construction resources are flex-eligible based on the MRD and that any resource not included in the year-ahead MRD will not be eligible to count towards flexible RA compliance. Energy Division proposes that this requirement take effect for the 2027 RA year.

4.13.1. Discussion

We find that Energy Division's proposal is reasonable, in that it would foster equitable treatment for showing under-construction resources towards system, local, and flexible RA requirements for year-ahead compliance. Energy Division can use CAISO's NQC list and Public Queue Report to determine that an under-construction resource is flexible. Accordingly, we adopt Energy Division's proposal as follows:

During the year-ahead compliance process, Energy Division will verify that under-construction resources are flex-eligible based on the MRD. Any resource that is not included in the year-ahead MRD will not count towards flexible RA compliance. This is effective for the 2027 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 Pub. Util. Code Section 311 and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Opening comments were filed on June 22, 2026, by: ACP-CA, AReM, CAISO, Cal Advocates, CalCCA, Calpine, CalWEA, CEJA/Sierra Club, CESA, City of San Jose, EDFps, ENGIE North America, Inc. (ENGIE), Form Energy/Fourth Power, jointly (Form/Fourth), GreenGen, Hydrostor, IEP, LDES Council, LSA/SEIA, MRP, NextEra, PG&E, REV, SCE, SDG&E, Terra-Gen, Vistra, and WPTF. Reply comments were filed on June 29, 2026, by: ACP-CA, CAISO, Cal Advocates, CalCCA, CEJA/Sierra Club, CESA, EDFps, GreenGen, Hydrostor, NextEra, PG&E, SCE, SDG&E, Vistra, 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. However, additional changes have been made to the proposed decision in response to comments that may not be discussed here. We do not summarize every comment but focus on major arguments made in which the Commission did or did not make revisions in response to party input. We remind parties that under Rule 14.3(c), comments on a proposed decision must focus on factual, legal, or technical errors in the proposed decision; comments that fail to meet the requirements will be accorded no weight.

Numerous parties oppose the proposed decision's finding that IR is a capacity product, including CAISO, CalWEA, CESA, LSA/SEIA, REV, SDG&E, Terra-Gen, Vistra, and WPTF.[280] Other parties disagree with the finding that both IR and RC products are capacity products, including ACP-CA, Calpine, IEP, and MRP.[281] Parties generally argue that IR is a day-ahead product procured in the IFM and co-optimized with energy/ancillary services to address uncertainty

[280] CAISO Comments on Proposed Decision at 3, CalWEA Comments on Proposed Decision at 8, CESA Comments on Proposed Decision at 13, LSA/SEIA Comments on Proposed Decision at 5, REV Comments on Proposed Decision at 4, SDG&E Comments on Proposed Decision at 3, Terra-Gen Comments on Proposed Decision at 5, Vistra Comments on Proposed Decision at 13, WPTF Comments on Proposed Decision at 6.

[281] ACP-CA Comments on Proposed Decision at 9, Calpine Comments on Proposed Decision at 3, IEP Comments on Proposed Decision at 4, MRP Comments on Proposed Decision at 8.

in net load forecasts between the day-ahead and real-time markets. The parties point out that CAISO describes IR as a day-ahead reserve product rather than a capacity product, and that the Commission should rely on CAISO's product definitions. Some parties assert that RC and IR should not be deemed capacity products because they serve different functions than RA capacity.

Several parties oppose applying the zero-dollar bid requirement and revenue prohibition on IR products, including CESA, LSA/SEIA, PG&E, Terra-Gen, Vistra, and WPTF.[282] Multiple parties oppose applying the zero-dollar bid requirement and revenue prohibition on either IR and RC products, including ACP-CA, Calpine, CalCCA, CAISO, IEP, MRP, SDG&E, and REV.[283] Parties generally contend that a zero-dollar bid requirement for IR may distort RA prices and energy market prices, may undermine CAISO's market optimization by preventing RA resources from reflecting opportunity costs, and may bias dispatch towards CPUC-jurisdictional RA resources relative to other BAAs' resources. Some parties assert that bidding restrictions in the IR market may impair storage resources' ability to manage SOC, whereas economic bids would reflect opportunity costs and ensure storage is dispatched when most valuable to the system. Other parties point to CAISO's June 1, 2026 publication showing that average RUC prices were lower in May 2026 than in May 2025 and that IR prices

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[282] CESA Comments on Proposed Decision at 14, LSA/SEIA Comments on Proposed Decision at 6, PG&E Comments on Proposed Decision at 4, Terra-Gen Comments on Proposed Decision at 7, Vistra Comments on Proposed Decision at 12, WPTF Comments on Proposed Decision at 6.

[283] ACP-CA Comments on Proposed Decision at 10, Calpine Comments on Proposed Decision at 5, CalCCA Comments on Proposed Decision at 2, CAISO Comments on Proposed Decision at 2, IEP Comments on Proposed Decision at 4, MRP Comments at 8, SDG&E Comments on Proposed Decision at 8, REV Comments on Proposed Decision at 8.

within the CAISO's BAA for May 2026 have been in a modest range of approximately $15-20/MWh.

Calpine and CalCCA argue that the proposed decision intrudes on FERC jurisdiction as CAISO has amended its tariff to remove the zero-dollar bid requirement and revenue allocation prohibition, and the decision dictates how market participants bid for and receive compensation from FERC-jurisdictional products. CalCCA contends that the decision exceeds the Commission's jurisdiction over non-IOU LSEs by dictating specific terms on procurement agreements beyond what is necessary to ensure compliance with reliability and clean energy goals.

By contrast, CAISO, CalWEA, PG&E, REV, and SCE recognize that RC products are successors to RUC products.[284] CAISO acknowledges that RC is the successor to RUC and that the Commission may view RC as more closely analogous to prior constructs on which it based D.05-10-042. CAISO states that at a minimum, the decision should adopt a more tailored approach on IR and reject a zero-dollar bid requirement on IR, even if it is retained for RC. PG&E does not oppose the D.05-10-042 requirements for RC resources and recognizes valid arguments for a zero-dollar requirement for RC and prohibition against receiving RC revenue as consistent with affordability principles. WPTF recommends at a minimum, adopting a modified version of Energy Division's

[284] CAISO Comments on Proposed Decision at 10, CalWEA Comments on Proposed Decision at 8, PG&E Comments on Proposed Decision at 6, REV Comments on Proposed Decision at 5, SCE Comments on Proposed Decision at 5.

proposal where a zero-dollar bid requirement would not apply to IR if the contract provides for revenues to flow to the RA buyer.

Numerous parties oppose applying the D.05-10-042 restrictions to existing contracts, including ACP-CA, Calpine, CAISO, CalCCA, SCE, SDG&E, PG&E, Vistra, and WPTF.[285] Parties generally assert that this would lead to unnecessary litigation and transaction costs to renegotiate existing contracts, and substantially impair contracts by altering the economic allocation of products/revenues. SCE states that the decision should not assume that the policy determination in D.05-10-042 are reflected in existing contracts. PG&E does not express concern for applying RC restrictions to existing contracts, as these have been subject to the longstanding requirements for RUC, and RC is understood to be the successor to RUC.

Some parties agree that future contracts may reflect a zero-dollar bidding requirement and revenue allocation prohibition, including SCE, SDG&E, and PG&E.[286] SCE agrees that RA resources should not be paid twice for the same capacity, that the decision should clearly state how the policy applies to the new RC/IR framework, and that RA resale contracts should be exempt. SCE agrees that RC revenues are capacity-related and should flow to the buyer; however, PG&E and SCE note that the decision does not address that IR revenues have

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[285] ACP-CA Comments on Proposed Decision at 7, Calpine Comments on Proposed Decision at 6, CAISO Comments on Proposed Decision at 9, CalCCA Comments on Proposed Decision at 2, SCE Comments on Proposed Decision at 2, SDG&E Comments on Proposed Decision at 5, PG&E Comments on Proposed Decision at 6, Vistra Comments on Proposed Decision at 11, WPTF Comments on Proposed Decision at 9.

[286] SDG&E Comments on Proposed Decision at 5, SCE Comments on Proposed Decision at 2, PG&E Comments on Proposed Decision at 6.

two components: capacity-related associated with setting aside RA capability for potential real-time use, and lost opportunity costs associated with foregone market opportunities when a resource is reserved for IR rather than dispatched for energy/ancillary services. Vistra states that SCE misstates how IR revenues are published and that CAISO's publication structure does not create two IR revenue components.[287] PG&E states that IOUs should be permitted to retain RC/IR revenues for UOG resources used by IOUs for their own RA compliance.

The Commission acknowledges the numerous concerns raised by parties regarding the proposed decision's IR/RC requirements. While we recognize that CAISO describes IR as a reserve product, rather than a capacity product, the Commission maintains that for the purposes of the Commission's RA program, IR is deemed a capacity product. IR products overlap with the must-offer obligation contained in RA contracts and therefore, IR and RA capacity are duplicative, with the exception of the opportunity cost portion of the revenues. For example, flexible RA capacity contracts require economic bids into the real-time market and IR capacity contracts also require an economic bid into the real-time market. Further, the day-ahead uncertainty now co-optimized in the integrated forward market was previously addressed with the RUC process, with zero-dollar bids and revenue returns to the RA buyer. For these reasons, and the reasons provided in the decision, the Commission declines to modify the finding that IR is a capacity product.

For the reasons discussed in the decision, the Commission maintains its finding that RC is a capacity product and is a component of RUC. We note that

[287] Vistra Reply Comments on Proposed Decision at 2.

CAISO recognizes that RC is the successor to RUC and that the Commission may view RC as more closely analogous to prior constructs on which it based D.05-10-042. As RC is a successor to RUC, the Commission maintains the decision's finding that the zero-dollar bidding and revenue prohibition rules established in D.05-10-042 will apply to RC products. However, we agree with PG&E's comment and clarify that the revenue allocation prohibition should not apply in the instance where the LSE is the resource owner and the resource is used by that LSE for RA compliance. The decision has been modified to reflect this.

The Commission concurs with PG&E that the RC restrictions should apply to existing contracts, as existing contracts have been subject to the longstanding requirements for RUC in D.05-10-042. However, we hear parties' concerns that the D.05-10-042 rules could create disruptions for existing contracts that may require contractual disputes and renegotiations. As such, the Commission clarifies that the RC rules from D.05-10-042 shall not disturb existing contracts. LSEs should undertake reasonable efforts to enforce existing contract provisions that account for the D.05-10-042 rules. The decision is modified to state that the D.05-10-042 rules for RC products shall apply to contracts executed after the effective date of this decision.

For IR products, for the reasons discussed above, the Commission maintains that these are capacity products for purposes of the Commission's RA program. That said, we hear parties' concerns that applying a zero-dollar bidding requirement on IR products may lead to market distortions for RA prices and energy prices, and may impair storage resources' ability to bid opportunity costs in the IR market. To that end, the Commission agrees to remove the zero-dollar bid requirement as applied only to IR products. The decision has been modified to reflect this.

With respect to the capacity-related revenue awarded for IR products, however, the Commission maintains its policy determination from D.05-10-042 that RA capacity should not be double-compensated: "It is not the intention of this Commission to simply provide needless revenue streams, or the ability to double-recover costs, to generators." Based on the amended CAISO tariff, an RA resource owner bidding an IR product may be double-compensated for the same resource: (1) the owner is first paid for the RA resource when it sells its capacity to an LSE via its initial bilateral RA contract and (2) the owner is paid again if the RA resource clears the IFM market for IR. This presents a windfall opportunity for generators for the same RA resource and conflicts with the Commission's policy against double-payment to generators for the same RA resource. As these IR products are quite new, there is insufficient record to establish what the market-clearing prices for these products will be and depending on the volume of IR bids, this could result in significantly increased costs to ratepayers.

As such, the Commission maintains its D.05-10-042 prohibition against double-compensation for IR products. In addition, under Pub. Util. Code Section 380, the Commission must achieve several objectives in its oversight of the RA program, including "[c]onsideration of mitigation measures, if the commission determines they are needed, to reduce costs to ratepayers" and to "minimize enforcement requirements and costs."[288] The Commission finds that prohibiting

[288] Pub. Util. Code Section 380(b)(4) and (5).

an RA resource owner from double-payment for the same capacity is necessary to minimize costs to ratepayers and to satisfy the objectives of Section 380.

We disagree with CalCCA that the Commission lacks jurisdiction over non-IOU LSEs to prohibit RA resource owners from double-recovery of an IR award. The Commission has broad authority under Pub. Util. Code Section 380 to establish RA requirements for all LSEs,[289] and prohibiting an RA resource owner from double-payment for the same capacity falls under the Commission's purview in overseeing the RA program and achieving the objectives in Section 380(b)(4) and (b)(5).

We recognize that IR revenue has two components, however, and we clarify that the revenue prohibition does not apply to the opportunity cost portion of the IR revenue award. We disagree with Vistra that CAISO does not identify the two revenue components. CAISO tariff 11.2.6.3.1 outlines that CAISO's DAME Transitional Measures will allocate the opportunity cost component of the revenue and the balance of the revenue separately. Likewise, CAISO tariff 11.2.6.4 states that CAISO will provide "the Scheduling Coordinator for LSEs whose RA and Flexible RA obligations are met with that capacity information regarding the opportunity costs described in Section 11.2.6.3.1 and 11.2.6.3.3 and the Imbalance Reserves and Reliability Capacity revenue from that overlapping capacity." For these reasons, the decision has been modified to remove the zero-dollar bid requirement for IR products, and to clarify that RA contracts for IR products must specify that the resource owner is not eligible for IR capacity-related revenue payments, except in the instance where the LSE is

[289] *See* Pub. Util. Code Section 380(a) and (k).

the resource owner and the resource is used by that LSE for RA compliance. As with RA contracts for RC products, these IR rules shall not disturb existing contracts, and shall apply to contracts executed after the effective date of this decision. The decision has been modified to reflect this.

We also agree with Cal Advocates' modification to include gross costs for IOUs' data presented in the PRG and QCRs. Regarding SCE's request to eliminate QCR reporting, we do not adopt this modification but clarify that IOUs may submit the PRG material in the QCR to satisfy this requirement. Regarding SDG&E's recommendation to modify OP 16 to require reporting of aggregate data in the QCRs, the Commission modifies the decision regarding IR/RC gross costs as these would only be attributable to bundled load. The decision is modified to reflect this.

PG&E comments that OP 16 should be clarified so that disputes do not arise between the scheduling coordinator of the resource and owner;[290] however, we clarify that this reporting requirement should not implicate CAISO as it references CAISO tariff Section 11.2.6.4.

AReM and PG&E recommend that the battery storage QC calculation changes should not be effective immediately but should be implemented by the 2027 RA year.[291] AReM states that substantial procurement for the 2026 RA year has occurred and may be inadvertently penalized. PG&E states that there is insufficient time to adjust portfolios to assume foldback and immediate adoption would create compliance issues between CAISO's and CPUC's RA programs.

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290 PG&E Reply Comments on Proposed Decision at 4.

291 AReM Comments on Proposed Decision at 2, PG&E Comments on Proposed Decision at 11.

The Commission agrees that the storage QC calculation should be effective beginning for the 2027 RA year, and the decision has been modified to reflect this. The Commission notes that changes to the QC values are not expected in 2026 and that the earliest year changes may appear in the 2027 RA year. By the 2028 RA year, this methodology would be replaced by the UCAP framework. The decision has been modified.

AReM, CAISO, CESA, and Terra-Gen state that the decision does not address how the UCAP value interacts with the storage accreditation framework adopted in Section 4.4.1.3.[292] The Commission clarifies that the QC calculation discussed in Section 4.4.1 is not the same as the UCAP value for batteries. The current QC method will be used for batteries until UCAP is implemented in the 2028 RA year, at which point the QC calculation will be replaced by the UCAP methodology. The Commission acknowledges that the application of the storage four-hour discharge requirement for RA eligibility is an outstanding issue that should be considered in the next track of this proceeding. The decision has been modified to include this outstanding issue.

ACP-CA, EDFps, REV, and LSA/SEIA express concern that CAISO's 2026-2027 TPP Study Plan, issued on June 16, 2026, describe an off-peak deliverability assessment that is not different from the prior years' study plans and that no charging sufficiency study is mentioned.[293] EDFps states that CAISO should

[292] AReM Comments on Proposed Decision at 5, CAISO Comments on Proposed Decision at 14, CESA Comments on Proposed Decision at 7, Terra-Gen Comments on Proposed Decision at 2.

[293] ACP-CA Comments on Proposed Decision at 5, EDFps Comments on Proposed Decision at 3, REV Comments on Proposed Decision at 11, LSA/SEIA Comments on Proposed Decision at 2.

clarify its 2026-2027 study plans, and LSA/SEIA state that CAISO should establish parameters for additional analysis through amendment of its TPP study plan. PG&E states that Energy Division should complete a study that applies the existing QC methodology to all EO solar and wind resources, while CAISO's TPP study is pending and in the event that CAISO's study finds storage can charge from EO resources.[294]

In reply comments, CAISO affirms that its 2026-2027 TPP Reliability Assessment will include a Summer Off-Peak scenario for hour ending 11 with 95 to 96% solar production and maximized battery charging for PG&E, SCE, SDG&E, and Valley Electric Association territory.[295] CAISO states that the information provided by the study will be essential to determine whether EO resources can reliably provide energy for charging storage resources. The Commission appreciates CAISO's clarification. We find PG&E's recommendation to authorize Energy Division conduct an EO QC analysis to be reasonable, and the decision has been modified to reflect this.

ACP-CA, LSA/SEIA, and SCE seek clarification that where a co-located EO resource and a deliverable storage resource share a POI, the off-site Energy Available for Charging Sufficiency value is associated with the EO resource at the POI, not the storage resource.[296] ACP-CA states that D.24-06-004 ordered charging sufficiency from EO resources to be prorated to paired storage based on the NQC of the storage resource on an interim basis. LSA/SEIA state that it is

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[294] PG&E Comments on Proposed Decision at 9.

[295] CAISO Reply Comments on Proposed Decision at 3.

[296] ACP-CA Comments on Proposed Decision at 2, LSA/SEIA Comments on Proposed Decision at 3, SCE Comments on Proposed Decision at 7.

unclear how this rule will be allocated when a co-located project has multiple off-takers, noting that D.25-06-048 stated that the issue of off-taking rights for EO should be considered in a later track. The Commission clarifies that the charging sufficiency value from the co-located resource will remain bundled with the storage resource, and that the adopted rule does not modify the existing allocation method.

CAISO recommends that for co-located EO, the charging energy should be limited to the deliverable capacity of the co-located storage.[297] CAISO states that reliance on POI limits may be insufficient when the co-located storage has PCDS and recommends revising the formula. The Commission observes that a limited number of co-located storage resources are PCDS and does not see reliability concerns with the adopted formula. As such, we decline to modify the formula.

AReM seeks clarification that "multipliers" refers to the FCP, as specified by Cal Advocates' proposal.[298] Vistra comments that the decision should clarify whether MDS is used interchangeably with LDES or whether MDS is a subset of storage. The Commission clarifies that "multipliers" in the table refer to the FCP but for clarity, the term has been modified in the decision as "FCP Multipliers." We also reiterate that LDES and MDS have distinct definitions, as provided in the decision, and thus MDS is a subset of LDES resources.

AReM seeks clarification on whether LDES can provide excess charging capacity for short-duration batteries, citing to an example of an LDES resource shown for all 24 hour slices, including midday slices when an LSE shows excess

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297 CAISO Comments on Proposed Decision at 12.

298 AReM Comments on Proposed Decision at 3.

charging capacity.[299] The Commission clarifies that energy used for charging short-duration energy storage will not be able to charge LDES; rather, all energy for short-duration energy storage and LDES charging will be counted concurrently so that there is no bias towards any battery duration. The decision has been modified to clarify this.

Some parties disagree with the adopted LDES accreditation method, including LDES Council, CESA, Hydrostor, and Form/Fourth.[300] These parties generally object to not allowing LSEs to demonstrate energy available for prior-day charging periods, oppose using the worst day framework, and state that a 0% SOC assumption does not reflect the operational reality of LDES management. The parties also disagree with assertions that the days prior to the worst day may reflect extreme system conditions and that RA resources are required to perform across multiple days.

The Commission clarifies that the adopted methodology does not reject the reality that LDES may come into the worst day with charge; rather, the Commission finds that the initial SOC is baked into the FCP formula. For example, a 10 MW, 16-hour battery with a 4x FCP multiplier and 80% round-trip efficiency would require only 50 MWh of charging to provide the maximum 160 MWh recognized by the SOD Compliance Tool. This is equivalent to an effective initial SOC of 75%. Similarly, a 10 MW, 96-hour battery with a 8x FCP multiplier and 50% round-trip efficiency would require only 60 MWh of charging to

[299] *Id*. at 4.

[300] LDES Council on Proposed Decision at 5, Form/Fourth on Proposed Decision at 5, CESA on Proposed Decision at 10, Hydrostor Comments on Proposed Decision at 6.

provide the maximum 240 MWh recognized by the SOD Compliance Tool. This is equivalent to an effective initial SOC of 87%.

Further, the Commission clarifies that the days prior to the worst day may reflect system conditions that are near comparable to those on the worst day. Therefore, the FCP should not be interpreted as the literal days leading up to the worst day, but rather as a proxy for the general flexibility LDES resources have in charging and discharging, including both the slack value and the initial SOC. The Commission adds that it has not been demonstrated that the slack value is not already contained in the FCP multiplier. For the reasons and those stated in the decision, the Commission maintains the adopted LDES framework. The decision has been modified to clarify the Commission's reasoning.

CESA argues that the definition of "forced outage" for the UCAP framework is too broad and by including "factors preventing a unit from operating at its full capacity" could inadvertently capture scheduled outages for testing and maintenance that the decision recommends excluding from UCAP.[301] CESA recommends modifying the definition to be: an *unplanned event* that requires immediate, delayed, or postponed removal of a unit from service, derating, or another outage state due to equipment failure (or risk of imminent equipment failure) or other factors that prevent a unit from operating at its full Pmax level *and are not due to the unit's known design specifications.*

The Commission agrees that adding "unplanned event" to the definition would avoid inadvertently capturing scheduled outages for testing/maintenance. However, we do not agree with adding the second modification regarding a

[301] CESA Comments on Proposed Decision at 3.

unit's known design specifications as this appears to include a forced outage. The decision is modified to add "unplanned event" to the forced outage definition.

MRP recommends that the decision include direction to Energy Division on the process for stakeholder vetting of NOW adjustments.[302] The Commission clarifies that to the extent that CAISO updates its NOW codes through the tariff or BPM processes, Energy Division will incorporate changes to NOW codes into the UCAP framework based on the principles adopted in this decision. The timing of this process will follow the annual QC process. The decision is modified to reflect this.

MRP notes that the final LOLE study, which is to be filed in October 2026, will not utilize the forthcoming UCAP values to set the 2028-2029 PRMs because the UCAP values will not be finalized until September 2027. MRP recommends the decision address resolution of Track 2 issues to align UCAP values and the LOLE study. The LOLE and PRM study for the 2028 compliance year is expected to be published in October 2026 and evaluated as part of Track 2 of this proceeding. As a result, the UCAP values assumed in the study will necessarily reflect an earlier vintage than the UCAP values ultimately published for the 2028 compliance year. This timing difference is an inherent consequence of conducting the LOLE study and evaluating its results sufficiently in advance of the applicable compliance year. We note that this issue is not unique to UCAP values; it applies to all QC values used in the study.

[302] MRP Comments on Proposed Decision at 12.

MRP states that the decision does not explain the use of the AAHs in the UCAP calculation and whether the hours will be applied daily or weekday only, and if daily, the rationale for deviating from weekday assessments.[303] The Commission clarifies that the UCAP framework uses the RA Measurement Hours and not the CAISO's AAHs. The most recent RA Measurement Hours were adopted in D.25-06-048, which applies to all hours in the season.

MRP, Vistra, and WPTF recommend establishing a process for addressing the remaining UCAP issues in Track 2, including a workshop and comment process.[304] The Commission notes that a workshop on Track 2 issues and proposals, including the outstanding UCAP issues, will take place in Track 2 of this proceeding.

For demand response, SCE states that is unclear whether the average hourly MW value is for all months or only months when the CEC peak hour is outside the AAH.[305] SCE states that the MCC requirements in D.23-06-029 set forth the available requirements for DR RA resources so the terms "event hour" and "non-event hour" are confusing and should be changed to when resources are available or not available. The Commission clarifies that the average hourly MW value is for all months. We also agree that replacing event hour/non-event hour with when resources are available/not available will be less confusing. The decision has been modified to reflect this.

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303 MRP Comments on Proposed Decision at 14.

304 MRP Comments on Proposed Decision at 11, Vistra Comments on Proposed Decision at 10, WPTF Comments on Proposed Decision at 4.

305 SCE Comments on Proposed Decision at 10.

City of San Jose recommends that as part of the large load reporting process, the decision should specify what information is to be shared by IOUs, including project capacity, energization dates, ramp schedule, power factor, and site control.[306] PG&E recommends that for information provided by IOUs in the meet-and-confer process, IOUs' year-ahead load forecast submissions to the CEC and the information in the CEC's Form 3 should be consistent.[307] PG&E also recommends that the IOUs, Energy Division, and the CEC work together to finalize the details of such requirements, to avoid a situation where one party wants more data than what is actually needed to meet this requirement.

The Commission agrees with City of San Jose that more specificity is needed regarding the data to be provided during the meet and confer process. As such, the Commission modifies the decision to add that the following data will be provided, at a minimum, for each project: project identifier, address and contract information, default LSE, capacity requested, expected energization data, ramping schedule, and application status. The Commission also agrees with PG&E's recommendation that the CEC, Energy Division, and IOUs work together to finalize the details of these requirements; however, we disagree with PG&E regarding the consistency of reporting shared meet and confer data. We expect that the data shared with CCAs during the meet and confer process will be used to help LSEs develop their best estimate forecasts, which may differ from the data provided by the IOUs during the meet and confer process. The Commission clarifies that LSEs should follow the best estimates approach in

[306] City of San Jose Comments on Proposed Decision at 7.

[307] PG&E Comments on Proposed Decision at 12.

developing their forecast and document forecast assumptions and reasons for deviations from the IOU-provided data. The details of the data sharing process will be finalized and published along with the annual CEC templates. The decision is modified to reflect this. The Commission may consider modifications to this process in the future as needed.

SCE states that the decision should be clear that while the CPE should consider sub-local needs, sub-local needs are not a procurement requirement and not subject to the rules in D.20-06-002 and D.24-12-003.[308] The Commission clarifies that D.20-06-002 orders the CPE to be responsible for the entire amount of required local RA and describes local procurement as expressly including sub-local areas. Because LSEs in the PG&E and SCE TAC areas no longer demonstrate 100% local compliance, the CPEs are the only entities holding the local obligation so relabeling sub-local reliability as optional would leave a reliability gap with no responsible party and would shift avoidable CAISO backstop (CPM) costs onto ratepayers. As such, satisfying sub-local area reliability remains part of the CPE's procurement obligation under D.20-06-002 and D.24-12-003.

Vistra notes that the decision refers to Energy Division using CAISO's NQC list and Public Queue Report to determine that an under-construction resource is flexible, but that the NQC list does not determine whether a resource is flexible-eligible and CAISO's EFC list is the appropriate source. The Commission clarifies that the decision's reference to CAISO's NQC list and Public Queue Report is intended to provide an alternative means of confirming

[308] SCE Comments on Proposed Decision at 12.

the flex eligibility of under-construction resources that are not yet included on the EFC Report. Energy Division intends to use these sources to identify the resource technology of the under-construction resources to confirm flex eligibility for purposes of year-ahead RA filings. The EFC Report will continue to be used to determine new and existing resources' flex RA-eligibility and category, which CAISO determines once the resource has become operational.

AReM opposes the decision's adoption of the penalty structure in favor of AReM's structure and states that its proposal avoids certain issues, including that unneeded penalties may be corrected by resubmitting the template with a lower reliance on storage and ambiguity about whether penalty points should be applied. The Commission maintains the adopted penalty structure for the reasons stated in the decision but agrees with AReM's comment that there is ambiguity around how the point structure would apply to such deficiencies. The Commission encourages parties and Energy Division to submit proposals on how penalty points should be applied to this structure in Track 2 of this proceeding. The decision has been modified to reflect this.

CalCCA opposes the decision's rejection of the hourly load obligation trading proposal and reiterates its arguments.[309] SDG&E supports rejecting the proposed mechanism but states that the decision rests in part on findings that the mechanism is fundamentally incompatible with the RA program.[310] SDG&E argues that the decision should be modified to reject the proposal with prejudice and make explicit that reconsideration would require that the fundamental

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[309] CalCCA Comments on Proposed Decision at 7.

[310] SDG&E Comments on Proposed Decision at 11.

incompatibility be resolved. The Commission declines to reject CalCCA's proposal with prejudice; however, we provide clarifications as to the outstanding issues that must be addressed prior to reconsideration. The decision is modified to reflect this.

6. Assignment of Proceeding

John 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 23,618 MWs for 2027, 24,545 MWs for 2028, and 25,480 MWs for 2029. CAISO also recommended existing capacity needed for each local area.
2. CAISO recommended system-wide Flexible Capacity Requirements that range from 25,060 MWs in December to 30,378 MWs in March.
3. For purposes of non-dispatchable resource accreditation, in the rare occurrence when a non-dispatchable resource is forced to go on outage due to transmission testing or failure, the resource's RA QC value should not be impacted.
4. The QC calculation for storage resources should be clarified and modified to address foldback, which would more accurately reflect storage capabilities and reduce uncertainty in the QC methodology.
5. Modifications to the MRD are necessary to improve accuracy of the default energy storage values and for administrative efficiency.
6. The POI of the co-located resource has been studied for deliverability and deliverable resources are presumed deliverable in all hours in the Commission's RA program. Therefore, allowing co-located EO resources to count for off-site

charging sufficiency in hours when storage is not shown does not violate the POI limit.

7. Defining LDES as any storage resource that can discharge continuously at a maximum capacity for at least eight hours is a simple, straightforward dividing line between LDES and non-LDES resources, is needed to implement an FCP framework, and aligns with the IRP program.

8. Combining aspects of Joint LDES Parties' proposal and Cal Advocates' multiplier proposal strikes a reasonable balance between recognizing operational flexibility and applying a clear energy sufficiency requirement. The multiplier for charging energy should increase based on the duration of the battery.

9. It is appropriate to treat closed-loop PSH resources like LDES resources because all energy discharged by closed-loop PSH must be attained by pumping water.

10. Energy Division's proposed SOD QC valuation for DR resources ensures that DR resources remain transactable and prevents the stranding of capacity due to the technical accounting incongruities identified in the 2026 and 2027 compliance years. PG&E's proposed modification that the average of hourly MW values is limited to the hours within the AAH window during which the resource is available, is also reasonable, since the minimum requirements established in D.23-06-029 require availability for only four consecutive hours within the AAHs.

11. Energy Division's proposed SOD QC valuation for DR resources addresses near-term concerns. CAISO is urged to integrate a 24-hour SOD framework to

establish a viable, long-term solution between the Commission, CEC, and CAISO.

12. Energy Division's proposed UCAP approach using the best three out of four years of historic data will mitigate force majeure or highly unusual events that have occurred but may not be expected to occur in the future.

13. CESA's proposed definition of forced outage has merit but is tied only to equipment failure and does not include other conditions that cause a unit to be unavailable up to its full output level.

14. The proposed UCAP principles are sufficiently specific to allow Energy Division to determine which NOW codes should be included or excluded, in the event that CAISO modifies the NOW codes or the definitions.

15. A broad range of parties support Energy Division's proposal to use the RA Measurement Hours, which captures hours when capacity is most needed and is subject to annual review by the Commission.

16. Energy Division's proposal to reflect foldback in a resource's expected EFORd and UCAP value is a reasonable means to address the foldback issue.

17. Energy Division's Option 1 proposal to use class-average EFORd data for a new unit and then incorporate historical EFORd data is broadly supported by parties and minimizes over- and under-valuation of RA capacity.

18. A single set of QC and PRM metrics based on UCAP, as compared to two sets of metrics based on UCAP and ICAP, would be less complex and reduce confusion in ensuring compliance with the Commission's and CAISO's RA programs.

19. Adoption of the broader UCAP framework need not be delayed while outstanding implementation issues are further developed.

20. Energy Division's proposed review process for the UCAP values is reasonable, as it gives parties two review periods leading to the first year of UCAP implementation to identify and correct errors, and one review period in subsequent years.

21. Based on CAISO's Business Practice Manual and CAISO's current tariff, the Commission determines that RCU and RCD products are components of the RUC process.

22. Based on CAISO's Business Practice Manual and CAISO's current tariff, the Commission finds that IR products and RC products may be used interchangeably, and that the RC process is a component of the RUC process.

23. Based on CAISO's Business Practice Manual and CAISO's current tariff, the Commission finds that IR products are capacity products for purposes of the Commission's RA program. However, IR compensation may include both capacity-related and opportunity cost components.

24. A prudent approach is to maintain the status quo bidding and revenue requirements for capacity products adopted in D.05-10-042 for RC products and monitor the bidding behavior of the EDAM market and its impact on RC and IR pricing following the initial implementation, and any potential impacts on future RA pricing.

25. The Commission credits the underlying analysis and findings in Energy Division's Transactability Report.

26. The Commission is persuaded by the Transactability Report's conclusion that the record does not demonstrate transactability concerns under the SOD framework at this time.

27. The Commission is persuaded by the Transactability Report's finding that implementation of an hourly load obligation trading mechanism would add significant complexity to the SOD program and a substantial burden on Commission staff and resources.

28. There are multiple outstanding issues with CalCCA's proposed hourly load obligation trading mechanism that would require development before reconsideration.

29. PG&E's proposal to clarify "changes to approved implementation plans" is a reasonable clarification to reduce uncertainty and to be consistent with the Commission's intent in D.19-06-026.

30. Energy Division's proposal on large load reporting is an important step to provide additional information to all LSEs that will increase confidence in the accuracy of the load forecast and foster transparency.

31. Energy Division's summary of the load forecast process is beneficial in formalizing the implementation of the SOD load forecast process adopted in D.23-04-010.

32. Publicizing the aggregated, anonymized contract data provided in the CPE data request would assist in improving transparency, reducing information asymmetry, informing LSEs' system RA procurement decisions, and helping LSEs anticipate their CAM credits from CPE procurement. The information

would also assist LSEs in better understanding the CPE's overall procurement need.

33. Additional clarification that expands on the SCE-CPE's approach to using the CPE data request file is reasonable. This clarified approach allows the CPE to "assess the state of the overall local portfolio before initiating the CPEs' annual solicitations," as directed in D.24-12-003, and minimizes over-procurement of local resources and selection of redundant offers.

34. Energy Division's proposed modification to the RA penalty structure offers an administratively simple solution that converts a MWh charging deficiency into a MW-equivalent amount only at the deficiency notice stage. Implementation would require only minor changes to the SOD compliance tools and would keep the shown capacity and excess charging energy distinct within the LSE Showing Template.

35. SCE's proposal to extend eligibility of the off-peak import counting rule would provide LSEs more flexible options for managing their RA portfolio.

36. Energy Division's proposal to allow LSEs to show under-construction resources in year-ahead compliance filings towards flexible RA requirements would foster equitable treatment for showing under-construction resources towards system, local, and flexible RA requirements for year-ahead compliance.

Conclusions of Law

1. CAISO's recommended LCR study results for 2027-2029 are reasonable and should be adopted.

2. CAISO's recommended systemwide FCR figures for 2027 are reasonable and should be adopted.

3. Energy Division's proposal to remove outages due to transmission testing or failure from the QC calculation is reasonable and should be adopted.

4. Energy Division's proposed clarifications and adjustments to the storage QC methodology, in addition to CAISO's suggested modifications to the definition and clarification, are reasonable and should be adopted.

5. Modifications should be made to the MRD to reflect changes to energy storage default values. Energy Division should be authorized to adjust the MRD field names as needed.

6. A definition for LDES resources should be adopted.

7. To demonstrate charging sufficiency for LDES resources, the forward charging period multiplier is reasonable and should be adopted.

8. Closed-loop PSH resources should be treated like LDES resources for purposes of charging sufficiency requirements.

9. The proposed modification to allow excess energy produced by a co-located energy only resource is a reasonable expansion of the existing methodology for calculating a resource's charging sufficiency value and should be adopted.

10. Energy Division's proposal to use the average of hourly MW values within the AAH window for the hours during which the resource is available, with PG&E's modification to the proposal, is a reasonable near-term solution to address the misalignment between the CEC's peak hour and DR participation windows, and should be adopted.

11. A modified version of CESA's proposed definition of forced outage would address other conditions that may cause unit unavailability, and should be adopted.

12. Energy Division's UCAP principles should be adopted. Energy Division should be authorized to adjust the NOW codes that are excluded or included in the EFORd calculation based on the UCAP principles. Energy Division's UCAP proposal to include all NOW outages codes in the forced outage calculation, with three exclusions, should be adopted.

13. Energy Division's proposal to use the RA Measurement Hours to determine the in-demand hours is appropriate and should be adopted.

14. Energy Division's proposal to reflect foldback in a resource's expected EFORd and UCAP value should be adopted.

15. Energy Division's Option 1 proposal to use class-average EFORd data for a new unit and then incorporate historical EFORd data is reasonable and should be adopted.

16. Energy Division's proposed review process for the UCAP values should be adopted.

17. Energy Division's proposed UCAP framework and adjusted PRM, with modifications, and as outlined in Appendix B, should be adopted.

18. The Commission maintains and affirms the policy rules established in D.05-10-042 for offering RC capacity products into the CAISO market.

19. As IR products are deemed capacity products for purposes of the RA program, the revenue allocation prohibition established in D.05-10-042 applies to IR capacity-related revenue.

20. There is no demonstrated need for an hourly load obligation trading mechanism under the SOD framework at this time.

21. Reconsideration of any hourly obligation trading proposal will require not only that the benefits of the proposed mechanism would clearly outweigh the associated costs and administrative complexity, but also that that proposed mechanism addresses the identified outstanding issues.

22. PG&E's proposal to clarify "changes to approved implementation plans" should be adopted.

23. Until a longer-term solution is developed, Energy Division's proposal on large load reporting for IOUs is reasonable and should be adopted on an interim basis.

24. Is it reasonable to adopt Energy Division's summary of the load forecast process as applied under the SOD framework, detailed in Appendix A.

25. CalCCA's proposal to publish the CPE's data request file on the Commission's website is reasonable and should be adopted.

26. A clarification as to how the CPE should use the CPE data request file is warranted.

27. Energy Division's proposed modification to the RA penalty structure to address enforceability of the charging requirement is reasonable and should be adopted.

28. SCE's proposal to extend the off-peak import counting rule to future Q3 months is reasonable and should be adopted.

29. Energy Division's proposal to allow LSEs to show under-construction resources to count towards year-ahead flexible RA requirements is reasonable and should be adopted.

O R D E R

IT IS ORDERED that:

1. The Commission approves 23,618 megawatts as the existing capacity needed for the Local Capacity Requirement for 2027, and approves the existing capacity needed for each local area provided therein.

2. The Commission approves 24,545 megawatts as the existing capacity needed for the Local Capacity Requirement for 2028, and approves the existing capacity needed for each local area provided therein.

3. The Commission approves 25,480 megawatts as the existing capacity needed for the Local Capacity Requirement for 2029, and approves the existing capacity needed for each local area provided therein.

4. The California Independent System Operator's recommended Flexible Capacity Requirements for 2027 are adopted.

5. If a non-dispatchable resource is forced to go on outage due to transmission testing or transmission failure and the resource owner provides evidence that the transmission event was caused by the transmission operator, the hours affected will be replaced by proxy data defined by historical production during the months affected. This is effective beginning for the 2027 Resource Adequacy compliance year.

6. Effective beginning with the 2027 Resource Adequacy compliance year, the following clarifications and modifications to the storage qualifying capacity (QC) methodology are adopted as follows:

   (a) The storage QC calculation is MAX_CONT_ENERGY_LIMIT less MIN_CONT_ENERGY_LIMIT, divided by four and constrained by the point of interconnection; and

   (b) The storage QC value is clarified as the output level at which a resource can discharge for four or more continuous hours without being affected by nonlinearity (or foldback). Once Energy Division has access to a value of continuous energy unaffected by foldback, that value will be incorporated into the calculation in subpart (a) above.

7. The Master Resource Database (MRD) fields will be modified to add a column delineating duration and to change the default value of the "Maximum Continuous Energy" field to the difference between MAX_CONT_ENERGY_LIMIT and MIN_CONT_ENERGY_LIMIT from the California Independent System Operator Master File. Energy Division is authorized to consider the clarity of the MRD field names and adjust the field names as needed.

8. Effective beginning with the 2027 Resource Adequacy compliance year, the charging sufficiency value from co-located energy only resources will be calculated as follows:

Energy Available for Charging Sufficiency = [Total energy produced (subject to hourly Point of Interconnection limits)] minus [On-site paired storage energy sufficiency need]

9. A long-duration energy storage resource is defined as any storage resource that can discharge continuously at a maximum capacity for at least eight hours.

10. Effective beginning with the 2027 Resource Adequacy compliance year, load-serving entities with long-duration energy storage resources may count their capacity across the 24-hour Slice of Day period up to the resources' capabilities based on the below Forward Charge Period (FCP) multiplier framework, in order to comply with storage charging sufficiency requirements.

Storage Duration (hours)	FCP Multiplier
[≥8-<12)	2
[≥12-<16)	3
[≥16-<20)	4
[≥20-<24)	5
[≥24-<48)	6
[≥48-<72)	7
≥72+	8

11. Effective beginning with the 2027 Resource Adequacy compliance year, closed-loop pumped storage hydropower resources will be treated like long-duration energy storage resources for purposes of charging sufficiency requirements.

12. For demand response resources, the Commission will send the following three values for each month to the California Independent System Operator (CAISO) to ensure CAISO's visibility into the Commission's contracted fleet:

(a) The maximum showing value;

(b) The peak showing value; and

(c) The average of the hourly megawatt values for the hours within the Availability Assessment Hour window during which the resource is available.

13. Energy Division's Unforced Capacity (UCAP) framework is adopted, with the following modifications:

(a) Energy Division's Option 1 proposal for unit-specific values beginning in 2028 is adopted for the UCAP valuation.

(b) For purposes of the UCAP framework, forced outage will be defined as: an unplanned event that requires immediate, delayed, or postponed removal of a unit from service, derating, or another outage state due to equipment failure (or risk of imminent equipment failure) or due to factors that prevent a unit from operating at its full Pmax level.

(c) Energy Division's UCAP principles are adopted. Energy Division is authorized to adjust the Nature of Work codes that will be excluded or included in the Equivalent Forced Outage Rate during Demand calculation based on the adopted UCAP principles.

The UCAP framework, as detailed in Appendix B of this decision, is adopted. The UCAP framework will be effective for the 2028 Resource Adequacy compliance year.

14. The outstanding implementation details to be addressed as part of the Unforced Capacity (UCAP) framework include:

(a) Implementation of UCAP within the Slice of Day template for energy storage resources;

(b) Determination of the appropriate basis for the must-offer obligation once UCAP replaces the current ICAP-based methodology as qualifying capacity, including any necessary California Independent System Operator tariff or Business Practice Manual modifications;

(c) Development and application of Equivalent Forced Outage Rate during Demand rates for the energy component of storage resource values;

(d) Establishment of a UCAP methodology for hybrid storage resources;

(e) Treatment of foldback limitations during the fifth hour of the Resource Adequacy (RA) Measurement Hours;

(f) Evaluation of how UCAP values will interact with and affect the flexible RA framework; and

(g) Application of the four-hour discharge requirement for storage to be eligible for RA capacity.

15. Load-serving entities' (LSE) Resource Adequacy (RA) contracts must reflect the policy determinations from Decision 05-10-042 to ensure zero-dollar bidding for Reliability Capacity (RC) products, and to specify that the resource owner is not eligible for RC revenue payments, except in the instance in which the LSE is the resource owner and the resource is used by that LSE for RA compliance. LSEs shall use the California Independent System Operator Day-Ahead Market Enhancements Transitional Measures, or other equally effective means, to effectuate this requirement to return the revenues to the LSE that shows the RA resource. This requirement applies to contracts executed after the effective date of this decision.

16. Load-serving entities' (LSE) Resource Adequacy (RA) contracts for Imbalance Reserve (IR) products must specify that the resource owner is not eligible for IR capacity-related revenue payments, except in the instance in which the LSE is the resource owner and the resource is used by that LSE for RA

compliance. This provision does not apply to the opportunity-cost portion of the revenue payment. LSEs shall use the California Independent System Operator Day-Ahead Market Enhancements Transitional Measures, or other equally effective means, to effectuate this requirement to return capacity-related revenues to the LSE that shows the RA resource. This requirement applies to contracts executed after the effective date of this decision.

17. The Reliability Capacity and Imbalance Reserve rules adopted in Ordering Paragraphs 15 and 16 shall not disturb existing contracts. Load-serving entities should undertake reasonable efforts to enforce existing contract provisions that account for the Decision 05-10-042 rules.

18. Investor-owned utilities shall provide the following information in their Quarterly Compliance Reports and during quarterly Procurement Review Group meetings, for a minimum period of three years beginning with the third quarter report in 2026:

(a) Monthly Imbalance Reserve (IR) gross costs (in dollars), with Imbalance Reserve Up (IRU) and Imbalance Reserve Down (IRD) provided separately;

(b) Monthly Reliability Capacity (RC) gross costs (in dollars), with Reliability Capacity Up (RCU) and Reliability Capacity Down (RCD) provided separately and Tier 1 and Tier 2 allocations shown separately, where applicable;

(c) Monthly average Reliability Capacity and Imbalance Reserve prices (in $/MWH), with RCU, RCD, IRU, and IRD provided separately;

(d) Monthly Imbalance Reserve revenues (in dollars and $/MWH) in total and the portion of these revenues attributable to bundled service customers (with IRU and IRD provided separately), and, where available, identify the capacity-related portion separately from the opportunity cost portion;

(e) Monthly Reliability Capacity revenues (in dollars and $/MWH) in total and the portion of these revenues attributable to bundled service customers (with RCU and RCD provided separately); and

(f) Monthly Imbalance Reserves and Reliability Capacity in dispute, in dollars, as provided to the scheduling coordinator for the load-serving entity per the California Independent System Operator tariff Section 11.2.6.4.

19. For purposes of the Resource Adequacy program, "changes to approved implementation plans" will include: "a voluntary change to the effective date of an approved implementation plan, even if the new implementation plan is not submitted for approval to the Commission."

20. At or prior to the year-ahead forecast meet and confer process, investor-owned utilities (IOU) will provide community choice aggregators (CCA) with information on customers expected to interconnect in a CCA's service area the following year. IOUs will also provide this information with their year-ahead load forecasts submitted to the California Energy Commission (CEC). Data to be provided for each project will, at a minimum, include: project identifier, address and contact information, default load-serving entity (LSE), capacity requested, expected energization date, expected ramping schedule, and application status. At or prior to the year-ahead forecast meet and confer process, all LSEs will provide information on new/expanding customers the LSE intends to serve in the following year. In advance of the meet and confer process, Energy Division, IOUs, and the CEC will work together to finalize the details of these requirements. The details of the data sharing process will be

finalized and published along with the annual CEC templates. In each LSE's year-ahead forecast, new data center or other large loads will be reported on Form 3, including significant expansion at current customer sites. LSEs will follow the best estimates approach in developing this forecast and document forecast assumptions and reasons for deviations from IOU-provided data. This is adopted on an interim basis beginning for the 2028 RA year.

21. Energy Division's summary to formalize the implementation of the Slice of Day load forecast process, detailed in Appendix A, is adopted.

22. Energy Division is authorized to publish the central procurement entity data request file, as established in Decision 24-12-003, on the Commission's Resource Adequacy website.

23. Consistent with Decision (D.) 24-12-003, the central procurement entities (CPE) will use the aggregated local Resource Adequacy data to determine whether the total contracted capacity (CPE + load-serving entity contracts) result in sufficient local resources. Based on this procurement assessment, and by exercising the explicit procurement authority and discretion granted under D.20-06-002 and D.22-03-034, the CPEs will determine whether/what local resources need to be procured to meet the CPEs' total local requirements. This procurement assessment will focus on ensuring that needs are met at both the local capacity area (LCA) and sub-LCA levels, as defined by the California Independent System Operator's annual Local Capacity Requirement (LCR) study. The CPEs' procurement determinations must account for the storage charging limitations identified within the applicable annual CAISO LCR study. The CPEs shall demonstrate in their Annual Compliance Reports how their

contracted capacity reflects these requirements, by sub-local area needs, including how the CPE considered the total contracted capacity results in making its procurement determinations. This is effective beginning with the 2027 CPE procurement cycle.

24. If a load-serving entity (LSE) incurs a charging sufficiency deficiency, the following steps will be taken:

- **Step 1:** Use the LSE Showing Template to calculate the charging sufficiency deficiency in megawatt/hour (MWh) as the difference between (a) the total daily charging energy required by storage resources shown, including the roundtrip charging efficiency of the storage resource; and (b) the total amount of excess energy shown across all hours that is eligible to meet charging needs. If this results in a shortfall, the charging sufficiency deficiency is expressed in MWh.
- **Step 2**: Convert the MWh deficiency to a 24-hour flat-profile MW equivalent amount by allocating the energy shortfall evenly across all 24-hour slices:

$$24\ Hour\ Flat\ Profile\ Equivalent\ Charging\ Deficiency\ (MW) = \frac{Charging\ Sufficiency\ Deficiency\ (MWh)}{24}$$

  The conversion produces a MW deficiency value that, when applied evenly across all 24 hours, represents the energy equivalent to the calculated charging sufficiency shortfall.

- **Step 3:** The resulting 24-hour flat-profile MW equivalent is applied as a proportional adder to each of the 24 hours. This means that: (a) for each hour, the LSE's hourly MW position would be adjusted by the 24-hour flat-profile equivalent charging MW deficiency amount; and (b) the hour with the largest MW deficiency would continue to serve as the basis for penalty assessment, consistent with the current penalty structure.

This is effective for the 2027 Resource Adequacy compliance year.

25. The off-peak import counting rule, adopted in Decision 25-06-048, is extended to future 3rd Quarter months beyond 2026.

26. During the year-ahead compliance process, Energy Division will verify that under-construction resources are flex-eligible based on the Master Resource Database (MRD). Any resource that is not included in the year-ahead MRD will not count towards flexible Resource Adequacy compliance. This is effective beginning for the 2027 Resource Adequacy compliance year.

27. The rules adopted herein are effective immediately unless otherwise stated.

This order is effective today.

Dated ____________________, at Fort Bragg, California.

APPENDIX A

(END OF APPENDIX A)

APPENDIX B

(END OF APPENDIX B)