Decision 23-06-029 June 29, 2023

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

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| Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations. | Rulemaking 21-10-002 |

# DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2024 - 2026, FLEXIBLE CAPACITY OBLIGATIONS FOR 2024, AND PROGRAM REFINEMENTS

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# DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2024 - 2026, FLEXIBLE CAPACITY OBLIGATIONS FOR 2024, AND PROGRAM REFINEMENTS

## Summary

This decision adopts Local Capacity Requirements for 2024 - 2026, Flexible Capacity Requirements for 2024, and refinements to the Resource Adequacy program scoped as Phase 3 of the Implementation Track, including modifying the planning reserve margin for 2024 and 2025 and modifying the demand response counting requirements.

This proceeding is closed.

## 1. Background

On October 7, 2021, the California Public Utilities Commission (Commission or CPUC) issued the Order Instituting Rulemaking (OIR) to oversee the Resource Adequacy (RA) program, consider program reforms and refinements, and establish forward RA procurement obligations applicable to Commission-jurisdictional load-serving entities (LSEs). Additional information on the procedural history of this proceeding is provided in the OIR.

A Scoping Memo and Ruling for this proceeding was issued on December 2, 2021. 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 (the Implementation Track and the Reform Track). Under the Implementation Track, the Scoping Memo divided the track into Phases 1, 2, and 3. Issues scoped as Phase 1 of the Implementation Track were addressed in Decision (D.) 22-03-034. Issues scoped as Phase 2 of the Implementation Track and issues scoped as the Reform Track were addressed in D.22-06-050.

On September 2, 2022, an Amended Scoping Memo and Ruling was issued that designated issues for Phase 3 of the Implementation Track and Phase 2 of the Reform Track. Issues scoped as Phase 2 of the Reform Track were addressed in D.23-04-010. This decision resolves issues scoped as Phase 3 of the Implementation Track.

Proposals on Phase 3 of the Implementation Track were filed on January 20, 2023 by: Alliance for Retail Energy Markets (AReM), California Community Choice Association (CalCCA), Central Coast Community Energy (CCCE), Middle River Power LLP (MRP), Pacific Gas and Electric Company (PG&E), Vistra Corp. (Vistra), and Western Power Trading Forum (WPTF). The Commission's Energy Division's Phase 3 proposals were filed by an Administrative Law Judge's (ALJ) ruling on January 20, 2023. A workshop on Phase 3 proposals was held on February 8, 2023.

On February 2, 2023, the California Energy Commission's (CEC) Qualifying Capacity of Supply-Side Demand Response (DR) Working Group Report (CEC Report) was issued via an ALJ ruling. On February 15, 2023, an ALJ ruling was issued that set forth questions regarding the CEC Report to address in comments and a schedule for comments. On February 24, 2023, an ALJ ruling notified that the CEC had provided the incorrect, draft version of the CEC Report and attached the corrected, final version of the CEC Report.

Opening comments on Phase 3 proposals were submitted on February 24, 2023 by: AReM; Bonneville Power Administration (BPA); CalCCA; California Efficiency + Demand Management Council, CPower, and OhmConnect, Inc. (collectively, Joint Demand Response (DR) Parties); California Energy Storage Alliance (CESA); California Independent System Operator (CAISO); CAISO's Department of Market Monitoring (DMM); California Large

Energy Consumers Association (CLECA); Calpine Corporation (Calpine); CCCE; GenOn Holdings, Inc. (GenOn); Green Power Institute (GPI); Independent Energy Producers Association (IEP); Marin Clean Energy (MCE); Microsoft Corporation (Microsoft); MRP; PG&E; Public Advocates' Office (Cal Advocates); San Diego Gas & Electric Company (SDG&E); Shell Energy North America (US). L.P. (Shell Energy); Silicon Valley Clean Energy Authority (SVCE); Southern California Edison (SCE); Union of Concerned Scientists, California Environmental Justice Alliance, and National Resources Defense Council (collectively, Joint Environmental Parties); Vistra; and WPTF.

Reply comments on Phase 3 proposals were filed on March 3, 2023 by: American Clean Power – California (ACP-CA), AReM, CAISO, California Wind Energy Association (CalWEA), Cal Advocates, CalCCA, CESA, CLECA, DMM, Enchanted Rock, LLC (Enchanted Rock), GenOn, GPI, IEP, Mainspring Energy, Inc. (Mainspring), Microsoft, MRP, OhmConnect, Inc. (OhmConnect), PG&E, SCE, SDG&E, and Shell Energy.

On March 1, 2023, opening comments on the CEC Report were filed by: CAISO; Cal Advocates; California Efficiency + Demand Management Council and CPower (jointly, CEDMC/CPower); CLECA; Demand Side Analytics (DSA); OhmConnect; PG&E; SDG&E; SCE; and WPTF. Reply Comments on the CEC Report were filed on March 8, 2023 by: CEDMC/CPower, CLECA, OhmConnect, PG&E, and SCE.

## 2. Submission Date

The matter for this decision was submitted on March 8, 2023.

## 3. Issues Before the Commission

The scope of Phase 3 of the Implementation Track, as adopted in the September 2, 2022 Amended Scoping Memo, are summarized below:

1. Consider 2024-2026 Local Capacity Requirements (LCR).
   a. 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 Phase 3, this will be for the 2024-2026 RA compliance years. The draft CAISO LCR study will be submitted to the Commission in April 2023 and the final LCR study will be submitted in May 2023. The Commission intends to issue a decision by the end of June 2023 so that jurisdictional LSEs and the central procurement entities have sufficient time to obtain the resources to meet local RA procurement requirements.
2. Consider 2024 Flexible Capacity Requirements (FCR).
   a. Similar to the LCR process, CAISO performs an annual FCR study, which is used to adopt flexible RA requirements for the following compliance year. The final FCR study will be submitted in May 2023. The Commission intends to issue a decision by the end of June 2023 so that jurisdictional LSEs have sufficient time to obtain the resources to meet their flexible RA procurement requirements for 2024.
3. Consider modifications to the Planning Reserve Margin (PRM) for the 2024 RA year and beyond, including Energy Division's recent loss of load expectation (LOLE) study in the Integrated Resource Planning (IRP) proceeding, or a future LOLE study for RA to be submitted into this proceeding no later than January 2023.
4. Consider modifications to the qualifying capacity (QC) methodology for demand response for the 2025 RA year, including the CEC Working Group report to be submitted into this proceeding by February 1, 2023.
5. Other time-sensitive issues identified by Energy Division or by parties.

# 4. Discussion

## 4.1. 2024 – 2026 Local Capacity Requirements

In D.06-06-064, the Commission established the local RA framework and adopted local procurement obligations for 2007. The Commission determined that a study of the LCR, performed by CAISO, would form the basis for the local RA program and that the local requirements should be based on a level of reliability described as "Option 2" in CAISO's LCR study report.[1] CAISO conducts an annual LCR study and the Commission resets local procurement obligations each year after review and approval of CAISO's recommendations. A series of subsequent decisions (most recently in D.22-06-050) established local procurement obligations for 2008 through 2025. 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 resources in each local area to meet its obligations.

Each year from 2007 to 2019, CAISO used the Option 2 reliability criteria as the basis for the annual LCR study. In 2020, CAISO changed its LCR study methodology by updating the LCR criteria to align with current mandatory reliability standards developed by the North American Electric Reliability

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

Corporation (NERC), the Western Electricity Coordinating Council (WECC), and CAISO.

CAISO's Draft 2024 Local Capacity Technical Report (Draft LCR Report) was submitted on April 6, 2023. Comments on the Draft LCR Report were filed on April 19, 2023 by: CalCCA and GPI. On April 20, 2023, Vistra served comments on the Draft LCR Report, with a motion to late-file its comments. Vistra's motion to late-file comments was granted on May 22, 2023.

CAISO's 2024 Final Local Capacity Technical Report (Final LCR Report) was submitted on May 1, 2023. Comments on the Final LCR Report were filed on May 8, 2023 by GPI. Reply comments on the Final LCR Report were filed on May 12, 2023 by CAISO.

CAISO's recommended 2024-2026 LCR values are summarized in the following table, with the recommended 2023-2025 LCR values provided for comparison.

| 2024 - 2026 Local Capacity Requirements | | | |
|---|---|---|---|
| **Local Area Name** | **2024** | **2025** | **2026** |
| Humboldt | 133 | 137 | 141 |
| North Coast/North Bay | 983 | 989* | 853 |
| Sierra | 1212* | 1263* | 1314* |
| Stockton | 750* | 750* | 750* |
| Greater Bay | 7329* | 7498* | 7667* |
| Greater Fresno | 2028* | 2203* | 2378* |
| Kern | 427* | 427* | 427* |
| Big Creek/Ventura | 1971 | 1110 | 1146 |
| LA Basin | 4413 | 4795 | 5177 |
| San Diego/Imperial Valley | 2834 | 3019 | 3205 |
| Total | 22080 | 22191 | 23058 |
| * CAISO note: Details about magnitude of deficiencies can be found in the applicable section [of the LCR Report]. Resource deficient areas and sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency. | | | |

| 2023 - 2025 Local Capacity Requirements | | | |
|---|---|---|---|
| **Local Area Name** | **2023** | **2024** | **2025** |
| Humboldt | 141 | 143 | 144 |
| North Coast/North Bay | 857 | 899* | 911* |
| Sierra | 1150* | 1199* | 1248* |
| Stockton | 579* | 579* | 579* |
| Greater Bay | 7312* | 7369* | 7426* |
| Greater Fresno | 1870* | 1947* | 2025* |
| Kern | 439* | 316* | 318* |
| Big Creek/Ventura | 2240 | 2258 | 2275 |
| LA Basin | 7529 | 5851 | 5944 |
| San Diego/Imperial Valley | 3332 | 3341 | 3351 |
| Total | 25449 | 23902 | 24221 |
| * 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 2024–2026 to be reasonable. Accordingly, CAISO's recommended 2024–2026 LCR values set forth in the table above are adopted.

### 4.2. 2024 Flexible Capacity Requirements

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

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

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

This year, CAISO notified the Commission that the final Flexible Capacity Needs Assessment for 2024 (Final FCR Report) would not be filed by May 12, 2023 due to delays outside of CAISO's control. On May 4, 2023, an ALJ's ruling was issued that shortened the time for comments on the Final FCR Report. The ruling stated that once CAISO filed the Final FCR Report into the proceeding, parties would have until the end of the second business day to file responsive comments.

The Final FCR Report was filed on May 17, 2023. Comments on the Final FCR Report were filed by MRP on May 19, 2023. MRP expresses concern regarding CAISO's scaling of the Integrated Energy Policy Report (IEPR) load forecast.

The Final FCR Report contains the following figures for 2024, with the 2023 FCR figures provided for comparison.

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

| **2024 Flexible Capacity Requirements** | | | | | |
|---|---|---|---|---|---|
| **NOTE: All numbers are in Megawatts** | **CAISO System Flexible Requirement** | **CPUC Flexible Requirement** | **CPUC** | | |
| | | | **Category 1 (minimum)** | **Category 2 (100% less Cat. 1 & 3)** | **Category 3 (maximum)** |
| January | 23583 | 22554 | 6065 | 15361 | 1128 |
| February | 23925 | 22909 | 6160 | 15604 | 1145 |
| March | 24446 | 23246 | 6251 | 15833 | 1162 |
| April | 23817 | 22643 | 6089 | 15422 | 1132 |
| May | 23485 | 22293 | 8303 | 12875 | 1115 |
| June | 23897 | 22776 | 8483 | 13154 | 1139 |
| July | 20651 | 19836 | 7388 | 11456 | 992 |
| August | 22018 | 21087 | 7854 | 12179 | 1054 |
| September | 23135 | 22226 | 8278 | 12837 | 1111 |
| October | 22655 | 21745 | 5847 | 14811 | 1087 |
| November | 23081 | 22145 | 5955 | 15083 | 1107 |
| December | 20900 | 20093 | 5403 | 13685 | 1005 |

| **2023 Flexible Capacity Requirements** | | | | | |
|---|---|---|---|---|---|
| **NOTE: All numbers are in Megawatts** | **CAISO System Flexible Requirement** | **CPUC Flexible Requirement** | **CPUC** | | |
| | | | **Category 1 (minimum)** | **Category 2 (100% less Cat. 1 & 3)** | **Category 3 (maximum)** |
| January | 21507 | 20487 | 6609 | 12854 | 1024 |
| February | 23815 | 22696 | 7321 | 14240 | 1135 |
| March | 24625 | 23313 | 7520 | 14627 | 1166 |
| April | 24250 | 22879 | 7380 | 14355 | 1144 |
| May | 22757 | 21433 | 9800 | 10561 | 1072 |
| June | 21403 | 20177 | 9226 | 9942 | 1009 |
| July | 19034 | 17971 | 8217 | 8855 | 899 |
| August | 20451 | 19318 | 8833 | 9519 | 966 |
| September | 22437 | 21345 | 9760 | 10518 | 1067 |
| October | 24443 | 23238 | 7496 | 14580 | 1162 |

| | | | | | |
|---|---|---|---|---|---|
| November | 24732 | 23448 | 7564 | 14712 | 1172 |
| December | 22321 | 21167 | 6828 | 13281 | 1058 |

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

Likewise, the Commission identifies RA "measurement hours" to establish QC values for select resources, particularly non-dispatchable and demand response resources. The current RA measurement hours were adopted in D.10-06-036 and revised in D.18-06-030 and D.22-06-050. Currently, the CAISO AAHs and RA measurement hours are 5:00-10:00 p.m. for March and April, and 4:00–9:00 p.m. for all other months. These hours have also been used to determine when use-limited resources are required to be available under the maximum cumulative capacity (MCC) bucket structure.

In CAISO's 2023 Final FCR Report, CAISO states that based on its analysis of the distribution of the top five percent of load hours within each month from 2024 to 2026, it is necessary to add May to the spring season adopted in D.22-06-050 for the months of March and April and that the spring AAH should remain 5:00–10:00 p.m.[3] CAISO recommends that the AAH for winter and summer months (January to February and June to December) should remain 4:00-9:00 p.m. for 2024.

[3] CAISO Final Flexible Capacity Needs Assessment for 2024, May 16, 2023, at 32-36.

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

In addition, the Commission finds CAISO's revised AAHs for May to be reasonable and adopts the same revised hours for the RA measurement hours. This modification ensures that the Commission's measurement hours remain aligned with the CAISO's AAH window. Accordingly, the RA measurement hours shall be 5:00-10:00 p.m. for March, April, and May, and 4:00–9:00 p.m. for all other months beginning in the 2024 RA compliance year.

The DR MCC bucket and MCC bucket categories 1, 2, and 3 are based on the existing measurement hours. As such, it is also necessary to adjust the hours for the DR MCC bucket and MCC buckets 1, 2, and 3 to reflect the new revised measurement hours. Accordingly, the DR MCC bucket and MCC buckets 1, 2, and 3 are modified to reflect the newly adopted measurement hours, as follows:

| Category | Availability | Maximum Cumulative Capacity for Bucket and Buckets Above |
|---|---|---|
| DR | Varies by contract or tariff provisions, but must be available at least 24 hours per month from May-September. For May, must be available Monday-Saturday for 4 consecutive hours between 5 PM-10 PM. For June-September, must be available Monday-Saturday for 4 consecutive hours between 4 PM-9 PM. | 8.3% |
| 1 | Monday–Saturday, at least 100 hours per month. For February, total availability is at least 96 hours. January - February, June-December, 4 consecutive hours between 4 PM - 9 PM. March-May, 4 consecutive hours between 5 PM – 10 PM. | 17.0% |
| 2 | Every Monday–Saturday. January-February, June-December, 8 consecutive hours that include 4 PM–9 PM. March-May, 8 consecutive hours that include 5 PM–10 PM. | 24.9% |
| 3 | Every Monday–Saturday. January-February, June - December, 16 consecutive hours that include 4 PM – 9 PM. March-May, 16 consecutive hours that include 5 PM–10 PM. | 34.8% |
| 4 | Every day of the month. Dispatchable resources must be available all 24 hours. | 100% (at least 56.1% available all 24 hours) |

### 4.3. Planning Reserve Margin

In D.22-06-050, the Commission stated that:[4]

> To balance the recognized and urgent need to increase the PRM for 2023 with the acknowledgement that additional LOLE modeling must be undertaken, the Commission finds it prudent to adopt a marginally increased PRM for 2023 and 2024 that falls within the 15 to 17 percent PRM range initially adopted in D.04-01-050. The Commission finds it appropriate to adopt a PRM of 16 percent for the 2023 RA year and a minimum 17 percent PRM for the 2024 RA year; accordingly, we adopt these requirements here.

[4] D.22-06-050 at 22.

The Commission noted, however, that "the PRM for the 2024 RA year may be further revised in a June 2023 decision, after a review of Energy Division's updates to the LOLE modeling by stakeholders and the Commission."[5]

#### 4.3.1. Summary of Proposals

Energy Division performed an LOLE study for 2024 that modeled the existing fleet of resources with updates for recent development and IRP filings, and made revisions to methodologies based on comments in 2022 on prior LOLE studies.[6] Energy Division performed LOLE studies using the current Strategic Energy & Risk Valuation Model (SERVM) dataset, which includes the 2021 IEPR demand forecast and the new 2022 baseline resource file as inputs. Energy Division no longer included any RESOLVE build out in the study and calibrated the model to identify LOLE events using the import constraint as the tuning variable instead of retiring thermal generation.

For the 2024 RA compliance year, Energy Division's LOLE study proposes a PRM of 18-20 percent for all months of the year, based on the modeled generation fleet and CEC load profiles.[7] In a separate Energy Division Staff proposal, Energy Division identifies four options for the 2024 PRM:[8]

(1) Maintain the status quo of 17 percent;
(2) Reduce the PRM to 16 percent (the 2023 PRM level);
(3) Increase the PRM to the PRM proposed in the LOLE study of 18-20 percent;
(4) Select a PRM between 16–20 percent.

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[5] *Id*. at 23.

[6] *See generally* Energy Division's Loss of Load Expectation and Slice of Day Tool Analysis for 2024 (Energy Division LOLE Study).

[7] Energy Division LOLE Study at 27.

[8] Energy Division Phase 3 Proposals at 7.

Energy Division estimates that based on an estimated September 2024 peak load forecast of 42,700 MW, the associated RA requirements would be as follows:[9]

| PRM (%) | RA Requirement in MW |
|---|---|
| 16 | 49,534 |
| 17 | 49,960 |
| 18 | 50,387 |
| 19 | 50,814 |
| 20 | 51,241 |

This equates to about a 430 MW increase in RA requirement for each percentage increase in PRM.

Energy Division states that any of the four options could be considered with an extension of the "effective PRM," which was first adopted in D.21-03-056 of Rulemaking (R.) 20-11-003, the OIR to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021. Energy Division states that the effective PRM allows for the investor-owned utilities (IOU) to buy additional megawatts (MW) beyond their RA obligations and charge the costs to all customers as contingency resources.

In addition, Energy Division's LOLE study outlined steps that would be undertaken to calibrate the results of the LOLE study to calculate the PRM for the 24-hour slice-of day (SOD) framework.[10] Energy Division outlines the following steps:

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[9] Energy Division Phase 3 Proposals at 6.

[10] Energy Division LOLE Study at 27.

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

(2) Calibrate portfolio to PRM requirements using SOD resource counting;

(3) Apply PRM to compliance requirement.

In its Phase 3 proposal, Energy Division highlights that when the PRM was being considered in 2021 and 2022, the CEC load forecast increased substantially, and that with the increased PRM, RA requirements for 2023 were 4-5 percent higher than in 2021.[11] In addition, Energy Division states that the modeled resource fleet for 2024 assumes 5,823 MW of nameplate capacity of resources that were in development as of November 2022. Given the large number of resources currently under development that were included in the 2024 LOLE modeling, as well as the significant delays developers have experienced in recent years, Energy Division is concerned that the study assumptions will not materialize, and resources will not be available to meet the estimated RA requirements.

For these reasons, Energy Division recommends maintaining the status quo at 17 percent PRM for 2024 and extending the effective PRM through 2025.[12] Energy Division states that the effective PRM could be set at a level equal to the difference between the modeled and adopted PRMs. For example, if the PRM is 17 percent and the modeled PRM is 20 percent, the effective PRM would be a range of MWs roughly equivalent to 3 percent of the Commission share of September load. Energy Division recommends that the effective PRM continue to apply to peak summer months of June - October, with IOUs able to use excess

[11] Energy Division Phase 3 Proposals at 5.

[12] *Id*. at 7.

resources from existing portfolios to meet minimum target levels in June and October.

Energy Division further proposes that if the effective PRM is extended through 2025, all resources now eligible to be in the contingency resource bucket can remain contingency resources. Resources eligible to count towards the effective PRM would remain unchanged from D.21-12-015. Procurement targets should be divided between the three IOUs similar to the targets adopted in D.21-12-015 (900-1350 MW for SCE and PG&E; 200-300 MW for SDG&E). Energy Division seeks comments on whether deficient LSEs should be assigned costs first before allocating costs to all customers through the Cost Allocation Mechanism (CAM), as it is possible that the effective PRM will first cover any LSE RA deficiencies before adding to above-PRM procurement.

#### 4.3.2. Comments on Proposals

Cal Advocates, CalWEA, GPI, and SCE support Energy Division's proposed PRM framework.[13] The parties generally state that this approach reasonably balances the LOLE results with the reality of available RA supply while ensuring reliability in 2024. SCE states that a tight RA market is precisely why it is reasonable to retain the current PRM framework and that increasing the PRM may create shortages, which will lead to excessive prices and excessive costs to customers.[14] SCE argues that retaining the effective PRM will keep costs down and provide reliability benefits because there are less stringent counting rules and fewer entities competing for the same resources. Cal Advocates

[13] Cal Advocates Opening Comments at 9, SCE Opening Comments at 2, CalWEA Reply Comments at 2, GPI Opening Comments at 1.

[14] SCE Reply Comments at 3.

recommends that Energy Division quantify procurement delays, if possible, to provide a clearer picture of RA supply in 2024.

Cal Advocates, CalWEA, CESA, GPI, IEP, SCE, and CalCCA (with modifications) support extending the effective PRM.[15] CESA states that it would allow Emergency Load Reduction Program (ELRP) resources to continue counting towards reliability through 2025 and the program has been authorized through 2025. CalCCA supports the effective PRM only if resources that count towards the effective PRM are incremental to the RA stack because allowing RA-eligible resources to count towards the effective PRM adds competing demand for RA supply. AReM states that if the effective PRM is adopted, IOUs should be required to demonstrate that the effective capacity resource was offered to other LSEs at market value and there was no interest.[16]

AReM, CAISO, Calpine, GenOn, Microsoft, MRP, WPTF, and Vistra oppose Energy Division's proposal and extending the effective PRM.[17] These parties generally are concerned that the effective PRM allows IOUs to procure non-RA resources that may be less reliable than RA resources because non-RA resources are not subject to CAISO's RA rules (such as the must-offer obligation and RAAIM), and that CAISO can only use the Capacity Procurement Mechanism (CPM) backstop authority to cure deficiencies for the binding PRM (not the effective PRM). These parties point out that Energy Division's proposal

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[15] CESA Opening Comments at 2, Cal Advocates Opening Comments at 9, SCE Opening Comments at 2, CalWEA Reply Comments at 2, GPI Opening Comments at 1, CalCCA Opening Comments at 30, IEP Opening Comments at 3.

[16] AReM Opening Comments at 6.

[17] AReM Opening Comments at 6, CAISO Opening Comments at 4, CAISO Reply Comments at 2, Calpine Opening Comments at 1, GenOn Opening Comments at 8, Microsoft Opening Comments at 4, MRP Opening Comments at 7, WPTF Opening Comments at 2, Vistra Opening Comments at 16.

would result in a PRM below the results of the LOLE study, which could significantly impact reliability. CAISO states that if the effective PRM is only applied to the summer months and the actual PRM is set below the 0.1 LOLE, reliability risk may surface in non-summer months.

SCE supports allocating effective PRM costs first to deficient LSEs before all LSEs and that deficient LSEs should pay for the costliest MWs that were procured for the effective PRM.[18] PG&E states that deficient LSEs should only be responsible for the increase in emergency procurement caused by the deficiency, not a greater share of the entire procurement.[19] PG&E states that if emergency procurement is used to make up for deficient LSEs, emergency procurement cannot increase reliability without increasing the level of IOUs' emergency procurement.

AReM and CalCCA oppose allocating effective PRM costs first to deficient LSEs.[20] AReM states that this would triple the LSEs' penalties, as they would be subject to Commission fines, CAISO backstop, and effective PRM costs, and that this is unfair considering an LSE's deficiency may have been partially caused by the effective PRM. CalCCA states that since the LSE could not procure resources used to meet the effective PRM to meet its RA requirement, it does not make sense to assign costs of the effective PRM to the deficient LSE.

CESA, Calpine, IEP, GenOn, MRP, Microsoft, and WPTF support a higher PRM with recommended ranges between 18-21 percent based on the LOLE study. Calpine and GenOn support an 18-20 percent PRM, WPTF supports at least an 18 percent PRM, and IEP and CESA recommend an 18 percent PRM with

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[18] SCE Opening Comments at 3.

[19] PG&E Opening Comments at 3.

[20] AReM Opening Comments at 8, CalCCA Reply Comments at 3.

retention of the effective PRM.[21] Microsoft recommends a 21 percent PRM based on the SERVM results indicating a 18-21 percent PRM will be needed for July-September. MRP recommends a 17.8 percent PRM based on the CEC-based September PRM plus 3.3 percent additional PRM to achieve 0.1 LOLE, or supports an 18-20 percent PRM.

CAISO states that the PRM should be higher than 17 percent to meet a 0.1 LOLE target.[22] However, CAISO states that it cannot conclude that an 18-20 percent PRM will meet a 0.1 reliability target because Energy Division's recommendation was between the PRM needs from the CEC and SERVM demand forecasts in summer months. AReM supports a 15.3 percent PRM, stating that the PRM should be calculated based on the CEC forecast and that for summer months, the PRM range based on the CEC forecast is 14.5-21.4 percent.[23] IEP disagrees and states that PRMs in the LOLE study are not monthly PRMs but are annual installed capacity needed to reach 0.1 LOLE divided by each month's peak load.[24]

Some parties argue that additional vetting of the LOLE study's inputs and assumptions is necessary. MRP and SCE generally state that the LOLE study is incompatible with the monthly RA program because it uses an annual rather than monthly portfolio such that the PRM results for most months are meaningless.[25] SCE recommends that future PRM studies match SOD resource

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[21] CESA Opening Comments at 4, Calpine Opening Comments at 1, IEP Opening Comments at 2, GenOn Opening Comments at 4, MRP Opening Comments at 6, Microsoft Opening Comments at 3, WPTF Opening Comments at 2.

[22] CAISO Opening Comments at 4, CAISO Reply Comments at 2.

[23] AReM Opening Comments at 3.

[24] IEP Reply Comments at 1.

[25] MRP Opening Comments at 4, SCE Opening Comments at 4.

counting and showing rules. Vistra states that Energy Division does not allow for the PRM to be updated on a recurring basis and appears to establish a probabilistic PRM for 2024 but a static PRM for 2025.[26] CAISO, MRP, and AReM state that additional testing is needed to ensure the PRM meets a 0.01 LOLE target, and more transparency is needed in the study process.[27]

CESA and MRP state that it is unclear whether there is a recommended PRM for the SOD framework.[28] MRP states that more discussion is needed to determine whether the SOD PRM range is compatible with the SOD framework. AReM states that further calibration of the portfolio may be needed on an hourly basis as loss of load events are concentrated in evening hours and applying the SOD PRM to every hour may overstate need outside of evening hours.[29]

#### 4.3.3. Discussion

In considering the appropriate PRM for 2024 and beyond, Energy Division highlights the following challenges:[30]

- Because the CEC's load forecast (used to set RA requirements) increased significantly in 2021, the increased load forecast and increased PRM levels resulted in summer 2023 RA requirements that were 4-5 percent higher than the 2021 RA requirements. For summer 2024, a 17 percent PRM would result in requirements that are nearly 8 percent higher than 2021 requirements.

- Energy Division's LOLE study modeled a 2024 resource fleet that relies heavily on in-development capacity

[26] Vistra Opening Comments at 16.

[27] AReM Reply Comments at 10, MRP Opening Comments at 4, CAISO Opening Comments at 5.

[28] CESA Opening Comments at 5, MRP Opening Comments at 9.

[29] AReM Opening Comments at 5.

[30] Energy Division Phase 3 Proposals at 4.

> (5,823 MW of in-development resources). In recent years, development projects have experienced significant delays.

The Commission observes that while the majority of parties recognize the identified challenges, parties diverge as to the appropriate PRM to addressing the challenges. On the one hand, numerous parties support a binding PRM that meets a 0.1 LOLE reliability target based on the LOLE study and oppose extending the effective PRM, for the purpose of ensuring grid reliability. By contrast, other parties favor maintaining the status quo PRM and extending the effective PRM in order to balance the results of the LOLE study with the reality of available RA supply, for the purpose of ensuring grid reliability while avoiding RA shortages that may lead to excessive prices and costs to customers.

In recent years, development projects have faced significant delays due to a host of issues, including supply chain delays, labor shortages, interconnection queue limitations, and rising costs. The Commission is very concerned that a large portion of the over 5,800 MW of RA resources under development and modeled into the LOLE study will experience delays and be unavailable for the 2024 RA year. Adopting a higher PRM before there is certainty on installed RA resources will likely result in RA shortages that will unnecessarily inflate RA costs. A lack of sufficient RA resources with a higher PRM may result not only in LSE deficiencies, but in increased prices for all RA capacity as demand exceeds supply, and such an outcome will be detrimental to ratepayers.

The Commission agrees with parties that support extending the effective PRM through 2025. Extending the effective PRM is beneficial in that it provides non-binding targets for IOUs to procure contingency resources, including resources that are not subject to strict RA counting rules and resources that fewer entities are competing for, such as imports procured after the RA showing date and firm energy from co-generation facilities. This allows procurement of resources that provide reliability benefits without unnecessarily inflating RA prices and costs to ratepayers, and without reducing the pool of available RA resources.

The Commission also agrees with parties that support retaining the status quo PRM of 17 percent as prudent for the 2024 and 2025 RA years given the realities of available RA supply and persistent delays in development projects. As mandated by Public Utilities (Pub. Util.) Code Section 380, the Commission's RA program must balance multiple objectives, including minimizing costs to ratepayers while ensuring grid reliability.[31] The Commission finds that increasing the PRM without greater certainty about installed RA resources for 2024 and 2025 is not appropriate at this time. There are 9,061 MW of new resources under contract for 2024.[32]Given the amount of new contracted resources and the ~470 MW increase in RA requirements associated with a 1 percent increase in the PRM, we find that the previously adopted 17 percent PRM for 2024 is reasonable.

The Commission finds it reasonable to maintain the effective PRM adopted in D.21-12-015 at the 2023 level for the 2024 and 2025 RA years. For 2023, the targeted procurement range of 2,000-3,000 MW, when added to a 16 percent PRM, results in an effective PRM of approximately 5-7.5 percent. Energy Division Staff estimates that the 2024 CPUC load forecast will be 42,700 MW. To maintain a similar target range with a 17 percent PRM, the effective PRM would

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[31] All statutory references shall be to the Public Utilities Code, unless otherwise specified.

[32] Joint Agency Reliability Planning Assessment – SB 846 Quarterly Report and AB 205 Report, CEC-21-ESR-01, at 44, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/joint-agency-reliability-planning-assessment_20230209t155250.pdf.

translate to 4-6.5 percent, or a range of 1,700-3,200 MW. Accordingly, for the 2024 and 2025 RA years, the Commission adopts a PRM requirement of 17 percent and adopts an effective PRM procurement target of 1,700-3,200 MW. The procurement targets will be divided between the three IOUs similar to the targets adopted in D.21-12-015, resulting in effective PRM targets of 170-320 MW for SDG&E, and 765-1,440 MW each for PG&E and SCE.

The requirements adopted in D.21-12-015 pertaining to the effective PRM are applicable to the effective PRM adopted in this decision. Specifically, the effective PRM will only apply for peak summer months (June–October) with IOUs permitted to use excess resources from existing portfolios to meet minimum target levels in June and October. Resources eligible to count towards the effective PRM will remain unchanged from D.21-12-015 and all resources that are currently eligible to be contingency resources will remain eligible to be contingency resources in 2024 and 2025. IOUs are reminded that their excess RA-eligible resources may be used towards the effective PRM targets, provided that the IOU has made reasonable attempts to sell the excess capacity to other LSEs, as provided in D.21-12-015.[33]

The Commission declines to assign costs for effective PRM procurement to deficient LSEs first. All costs associated with the effective PRM procurement will be assigned to all customers through the CAM, as adopted in D.21-12-015.

The Commission authorizes Energy Division to update and publish the LOLE study annually by February of each year with a baseline resource list published by November of the prior year. The Commission will continue to

[33] D.21-12-015 at Ordering Paragraph (OP) 72.

monitor market conditions and impacts of the adopted PRM framework and will reevaluate the PRM requirements for the 2026 RA year in 2024.

Regarding the SOD framework, we stated in the Amended Scoping Memo:[34]

> The Implementation Track will consider modifications to the PRM for 2024 and beyond, which may include the recent 2024 LOLE study in IRP or a future LOLE study for RA to be submitted into this proceeding no later than January 2023. The Reform Track will consider how to convert/calibrate the results of a LOLE study to the slice-of-day RA framework.

As such, the PRM framework adopted here will apply to the 2024 test year for the SOD framework. As determined in D.22.06-050, and reiterated in D.23-04-010, the Commission will apply a single PRM to all hours of the year for initial implementation of the SOD framework.[35] We stated that we may consider whether multiple PRMs are appropriate for the SOD framework in a future phase of this proceeding.

Further, in D.23-04-010, the Commission determined that:

> Energy Division is authorized to integrate the Natural Resources Defense Council (NRDC) and Southern California Edison's (SCE) calibration tools to convert the results of the loss of load study to the 24-hour slice-of-day framework, to the extent possible. After Energy Division modifies the calibration tool, Energy Division is directed to publish the draft calibration tool on the Commission's website and solicit informal party comments.[36]

As such, the calibration tool will be modified by Energy Division, as directed in D.23-04-010, and Energy Division will use the results of the LOLE

[34] Amended Scoping Memo at 3, 5.

[35] D.23-04-010 at 59.

[36] D.23-04-010 at OP 13.

study for the calibration. Energy Division will publish the results of the draft calibration tool on the Commission's website by September 2023, which will be followed by a workshop and an opportunity for informal party comment on the results of the calibration tool.

Several parties provide comments and critiques regarding the LOLE study's inputs and assumptions based on questions posed by Energy Division. The Commission notes that Energy Division considers these comments for future year studies and that parties are encouraged to participate in the process for applying inputs and assumptions, including participating in the Modeling Advisory Group.

Lastly, we note that AReM proposes multi-year forward obligations for system RA,[37] which a number of parties commented on. The Commission views this proposal as one of a number of ways of implementing a programmatic approach to reliability and clean power procurement that parties commented on in the IRP proceeding in December 2022 and January 2023. The Commission declines to consider a programmatic approach here and expects to engage with stakeholders in the IRP, RA, and Renewables Portfolio Standard (RPS) proceedings on this topic in the future.

### 4.4. Ambient Derating of Thermal Resources

Energy Division recommends a new method for derating thermal power plants based on forecasted ambient temperatures.[38] Energy Division states that the SERVM model - used to forecast energy prices and grid reliability - uses input capacities for thermal power plants that are "insensitive to environmental

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[37] AReM Phase 3 Proposals at 4.

[38] Energy Division Proposal for Derating Thermal Power Plants based on Ambient Temperature (Energy Division Derate Proposal) at 2.

factors – available capacities are assumed constant, unvaryingly equal to each plant's rated capacity and independent of ambient temperature."[39] Energy Division states that with a warming climate, the range of ambient temperatures under which generators operate are expected to increase, which may result in inconsistencies between actual operating conditions of power plants and modeled outcomes, potentially underestimating reliability risks.

Energy Division proposes a piecewise-linear relationship between ambient temperature and power capacity for a given power plant.[40] The model accounts for each power plant's tributary power sources and will be based on a correction factor which, when applied to a plant's rated power capacity, provides the approximate capacity available at an ambient temperature. The model applies to two unit types (Combustion Turbine and Combined Cycle resources) and uses historic weather data currently used in other SERVM inputs, with synthetic weather cases in future modeling.

#### 4.4.1. Comments on Proposal

CalCCA, Cal Advocates, Microsoft, MRP, PG&E, and SDG&E point out that Energy Division's proposal does not extend to resource counting rules, which could create a mismatch between resource counting in the LOLE study and resource counting for compliance purposes.[41] These parties state that if ambient derates are applied to net qualifying capacities (NQC) for modeling and PRM analysis, derate adjustments should also apply to NQCs for compliance. PG&E and Calpine note that some plants already account for ambient derates in

[39] *Id*.

[40] *Id*. at 22.

[41] CalCCA Opening Comments at 32, Cal Advocates Opening Comments at 13, Microsoft Opening Comments at 9, MRP Reply Comments at 6, PG&E Opening Comments at 17, SDG&E Opening Comments at 6.

their QC values, such as Calpine's combined cycle facilities, and Calpine states that this could lead to duplicative derating of some units.[42]

Calpine, PG&E, and SCE are concerned about Energy Division's use of CAISO's outage data.[43] Calpine notes that CAISO's data is incomplete because resources submit larger, overlapping outages that include ambient derates but are not recorded as such. SCE states that CAISO's data is reported ahead of the operational hour so that data is forecast rather than actual. PG&E states that CAISO's data used in calibrating the derate model includes outages for reasons other than ambient temperatures, and it is unclear whether the data was cleaned enough to isolate ambient derates.

IEP, MRP, WPTF, and Calpine oppose Energy Division's methodology as not robust enough for resource counting.[44] WPTF and Calpine state that the analysis ignores distinctions between different units and should be refined with more granular differentiation. Calpine and IEP express concern that the model excludes data for certain units, such as filtering out poorly fit resources, without a strong rationale. MRP states that the linear derate factors do not account for inlet cooling, as inlet cooling can counteract the effects of increased temperatures, so production capability does not decrease linearly with temperature.

GPI supports Energy Division's approach but is concerned that turbine manufacturer performance curves were not in the proposal.[45]

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[42] PG&E Opening Comments at 17, Calpine Opening Comments at 6.

[43] SCE Opening Comments at 20, Calpine Opening Comments at 6, PG&E Opening Comments at 17.

[44] Calpine Opening Comments at 5, WPTF Opening Comments at 13, MRP Opening Comments at 16, IEP Opening Comments at 5.

[45] GPI Opening Comments at 4.

SDG&E, Cal Advocates, and IEP generally support incorporating ambient derates into thermal resources' QC values and modeling.[46] CalCCA and IEP support development of an Unforced Capacity Evaluation (UCAP) methodology which would account for various forced outage types, including ambient derates.[47]

#### 4.4.2. Discussion

The Commission finds there is insufficient record support for Energy Division's proposed methodology at this time. We agree with parties that support incorporating outages, including ambient derates, into a thermal resource's QC value and deem such work as critical to enhancing reliability. As stated in D.23-04-010, we agree with "explor[ing] a comprehensive application of UCAP to account for other types of forced outages, not just ambient derates."[48] Further, we recognized the limitations with CAISO's outage data and "encourage[d] CAISO to work through these data limitations to further develop a full UCAP mechanism for consideration in this proceeding."[49] In addition, the Commission encourages Energy Division to collaborate with CAISO on alternatives to using outage management system data to develop a UCAP mechanism.

### 4.5. LSE Expansion

Energy Division states that in recent years, there has been a significant increase in LSE deficiencies, with seven LSEs receiving month-ahead RA

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[46] Cal Advocates Opening Comments at 6, SDG&E Opening Comments at 4, IEP Opening Comments at 6.

[47] CalCCA Opening Comments at 32, IEP Opening Comments at 6.

[48] D.23-04-010 at 41.

[49] *Id*.

deficiencies in 2021 and five LSEs receiving month-ahead RA deficiencies in 2022.[50] Energy Division notes that despite the fact that some LSEs have not procured sufficient capacity to meet their RA requirements, some LSEs have sought to expand their customer territories. Energy Division is concerned that expansion by LSEs that have not met their RA requirements jeopardizes reliability but also results in leaning on LSEs that have met their full RA obligations. Further, Energy Division adds that if an effective PRM is adopted, persistent under-procurement of RA undermines the purpose of the effective PRM, which is intended to provide additional resources to respond to unexpected events. The effective PRM is not intended to backfill for LSEs that do not meet their existing RA obligations.

For these reasons, Energy Division proposes that "any CCA or ESP with a deficiency of greater than 2.5 percent of its system RA requirement on a month ahead RA filing during the previous two calendar years should not be able to expand and take on any new customer load for the following year."[51] Energy Division states that, for example, a CCA that had deficiencies in 2021 or 2022 would not be eligible to submit an Implementation Plan to expand to serve new service areas in 2023 for service in 2024.

#### 4.5.1. Comments on Proposal

SDG&E, PG&E, and SCE support Energy Division's proposal.[52] PG&E contends that the proposal is consistent with D.21-06-033, which recommends

[50] Energy Division Phase 3 Proposals at 34.

[51] *Id.*

[52] SDG&E Opening Comments at 8, PG&E Opening Comments at 9, SCE Opening Comments at 18.

against direct access expansion in part due to reliability impacts.[53] PG&E argues that allowing CCAs with a record of deficiencies to expand may result in planning uncertainty and adverse reliability impacts. PG&E asserts that the Commission has ample authority under Section 380 to set rules that would prevent any attempt by a deficient LSE to expand its service area.[54] SCE likewise argues that Section 380 gives the Commission broad discretion to ensure compliance by all LSEs.[55] SCE states that LSEs' failure to procure sufficient RA increases risks that the Provider of Last Resort (POLR) may have to take over procurement.

AReM, CalCCA, CCCE, SVCE, GPI and Shell oppose the proposal for a variety of reasons.[56] First, parties contend that the Commission does not have jurisdiction to make decisions about CCA and ESP formation. CalCCA and CCCE cite Assembly Bill (AB) 117 to illustrate that state governmental subdivisions and their residents, not the Commission, have authority to make decisions about CCA formation. CalCCA also asserts that Section 380 allows the Commission to enforce requirements over CCAs but does not extend authority over CCA formation or expansion. AReM states that Section 394(f) does not give the Commission authority over the contracting practices of ESPs.

CalCCA further contends that while Section 366.2(c)(8) allows the Commission to designate the effective date for a CCA's program, this may only be set after considering the impact of "any annual procurement plan of the

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[53] PG&E Opening Comments at 9 (citing D.21-06-033 at 4).

[54] PG&E Reply Comments at 5.

[55] SCE Reply Comments at 6.

[56] GPI Opening Comments at 2, CalCCA Opening Comments at 19, AReM Opening Comments at 10, CCCE Opening Comments at 1, SVCE Opening Comments at 1, Shell Opening Comments at 2.

electrical corporation that has been approved by the commission."[57] CalCCA states that an LSE's non-compliance with RA requirements has nothing to do with another LSE's procurement plan. PG&E disagrees and asserts that CalCCA disregards that expansion of service by a deficient CCA results in reduced RA procurement by the LSE that is losing those customers.[58] Thus, PG&E argues that Section 366.2(c)(8) allows the Commission to designate an effective date for a CCA implementation plan for a date after the CCA is in compliance with its RA requirements.

PG&E and SCE cite to D.05-12-041 for the proposition that the Commission's responsibility regarding CCA implementation plans includes "assur[ing] that the CCA's plans and program elements are consistent with … Commission rules designed to protect customers."[59] SCE points out that D.05-12-041 directed that the Commission "retain[s] a responsibility to assure that a CCA's policies, practices, and operations do not compromise the operations of the utility or services to utility customers."[60] SCE further states that the Commission approved SCE's Rule 23, which authorizes the Commission to terminate a CCA's service for cause if it fails to meet its LSE obligations.

Similarly, SCE argues that for ESPs, D.04-07-037 provided that: "[o]ur imposition of resource adequacy requirements on ESPs is a logical implementation of our jurisdiction to determine an ESP's operational capability

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[57] CalCCA Opening Comments at 22.

[58] PG&E Reply Comments at 5.

[59] *Id*. at 7 (citing D.05-12-041 at 4), SCE Reply Comments at 4 (citing D.05-12-041 at 11).

[60] SCE Reply Comments at 4 (citing D.05-12-041 at 11).

because adequacy of resources directly affects an ESP's capability to operate."[61] SCE argues that the Commission has authority to terminate an ESP's service for cause.

Second, CalCCA, AReM, Shell, and SVCE assert that Energy Division's proposal would result in discriminatory application of Section 380 because it would only apply to CCAs and ESPs and not IOUs that currently act as Providers of Last Resort.[62] Third, CalCCA and Shell state that the proposal is ambiguous.[63] CalCCA states that the use of the terms "any new load" and "new customers" are vague and overly broad, and Shell states it is unclear what is meant by prohibiting "expand[ing] and tak[ing] on any new customer load."[64] Shell adds that the proposal makes no distinction between compliance shortfalls due to lack of available system capacity, as opposed to individual LSE procurement failures. Shell also argues that the 2.5 percent threshold in Energy Division's proposal is not explained.

Lastly, SVCE argues that customers are entitled to aggregate load with members of the local community.[65] Thus, SVCE states that barring a CCA from serving new load would violate customers' rights to receive service from a CCA, eliminate the potential of new development in a CCA's service area, and conflict with a CCA's obligation to offer services to all residential customers within its jurisdiction.

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[61] *Id*.

[62] CalCCA Opening Comments at 23, AReM Opening Comments at 9, SVCE Opening Comments at 3, Shell Opening Comments at 4.

[63] CalCCA Opening Comments at 26, Shell Opening Comments at 5.

[64] Shell Opening Comments at 6.

[65] SVCE Opening Comments at 2.

PG&E presents alternative options to address the concerns raised in Energy Division's proposal.[66] PG&E proposes a new fine for any LSE that expands its service territory but was deficient during the two prior years, at a sufficiently high level to prevent the LSE from expanding. PG&E also proposes reassigning any LSE that was deficient in the past two years and is pursuing expansion to the highest penalty tier (or new higher tier), making it too expensive for the LSE to expand.

#### 4.5.2. Discussion

As has been documented in the RA proceeding, the acceleration of climate change with extreme, unpredictable weather events across the West has resulted in severe heat events, droughts, and wildfires. In the summers of 2021 and 2022, severe heat events resulted in significant stress on the grid that required California to rely on every available resource to prevent electric outages. Against this backdrop, the Commission is very concerned that an increasing number of LSEs have failed to meet their RA obligations in recent years. In D.21-06-029, the Commission modified the RA penalty structure to further discourage RA non-compliance by using a point accrual system that increased RA penalties where an LSE is repeatedly deficient in its RA obligations. Despite these efforts, the Commission has observed LSEs are continuing to fail to meet RA obligations, with seven LSEs receiving month-ahead system RA deficiencies in 2021 and five LSEs receiving month-ahead system RA deficiencies in 2022.[67] A portion of these LSEs have repeatedly failed to meet their RA obligations. Even more concerning, some LSEs submitted implementation plans to expand their

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[66] PG&E Reply Comments at 7.

[67] Energy Division Phase 3 Proposals at 34.

customer load by increasing their service territory, even as they have been unable to secure sufficient capacity to meet their RA obligations and serve their existing customers.

Section 380(a) provides that the "commission…shall establish resource adequacy requirements for all load serving entities." While the primary purpose of Section 380 is to "ensure the reliability of electric service in California"[68] by facilitating the development of new generation and retaining existing generating capacity that is economic and needed, the statute also seeks to equitably allocate costs among customers.[69] The duty to prevent cost shifting is echoed in Section 366.2(a)(4), which provides:

> The implementation of a community choice aggregation program shall not result in shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation.

Section 366.2(a)(5) further makes clear that:

> A community choice aggregator shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator's customers except where other generation procurement arrangements are expressly authorized by statute.

CalCCA and other parties argue that AB 117 did not confer authority on the Commission to determine whether a city, county, or joint powers authority forms a CCA or expands its scope. CalCCA further argues that "RA non-compliance by an LSE has nothing to do with a utility's procurement plan."[70] These arguments ignore that if one LSE fails to contract for resources to serve its

[68] Section 380(b).

[69] Section 380(b)(3).

[70] CalCCA Opening Comments at 22.

own load, the customers of other LSEs that did accomplish such forward contracting are effectively subsidizing the deficient LSE's energy procurement, and such deficiencies may impact grid reliability.

AB 117, permitting the formation of CCAs, was adopted in 2002. In Decision 05-12-041, we implemented processes to permit CCAs to form and purchase power for their local residents and businesses. There, we acknowledged that the Commission "has the authority to exercise limited jurisdiction over non-utilities in furtherance of [our] regulation of public utilities, including resource adequacy."[71] We held that "[t]he utilities will not procure power on behalf of CCA customers as part of their resource adequacy planning."[72] This provision was codified in 2011, when the legislature added subdivisions (b)(4) and (5) to Section 366.2, clarifying that CCAs must prepare to fully supply electricity to their customers, and may not shift costs for energy to the customers of other LSEs by failing to contract in advance for such capacity. We further held that "[w]here continued CCA service…may substantially compromise utility operations or service to bundled customers," the Commission may authorize the utility to terminate a CCA's service.[73]

Energy Division's proposal is not a modification of D.05-12-041 but a new requirement under the umbrella of reliability and Resource Adequacy for CCAs planning to implement an expansion in their service territory or ESPs increasing their number of customers. The Commission agrees that allowing LSEs that cannot meet their existing RA obligations to expand their territory or to take on new customer load is detrimental to grid reliability. We also find that LSEs that

[71] D.05-12-041 at Conclusion of Law (COL) 2.

[72] *Id*. at COL 19.

[73] *Id*. at COL 55.

are deficient in their RA obligations result in leaning on other LSEs' procurement activities, and impairing grid reliability by failing to secure resources to support their existing customer base. The Commission has authority to approve Energy Division's proposal to ensure that LSEs procure sufficient capacity to meet their customer loads, maintain electrical grid reliability, and prevent deficient LSEs from increasing risk of grid emergencies arising from lack of resources bidding into CAISO's wholesale markets. As provided in Resolution E-4907, establishing the registration process for CCAs, we acknowledge our authority to approve the effective date for a CCA to implement a planned expansion[74] and here, we ensure that such planning accounts for a CCA's history of recent RA deficiencies demonstrating the CCA's inability to procure resources to serve its existing customers.

Some parties observe that in D.05-12-041, the Commission stated that AB 117 does not give the Commission "authority to approve or reject a CCA's implementation plan or to decertify a CCA."[75] Here, we do not consider rejecting a CCA's expansion plan or decertifying a CCA. Rather, Energy Division's proposal seeks to ensure LSEs do not plan to expand load until they demonstrate they are capable of procuring to meet their existing customer needs. The Commission finds this to be a reasonable, measured approach to enforcing the Public Utilities Code, including Section 380, to ensure grid reliability through Resource Adequacy compliance.

We also disagree with arguments that Energy Division's proposal would violate Section 380's requirement that the Commission enforce the RA

[74] *See* Resolution E-4907, Registration Process for Community Choice Aggregators, February 9, 2018.

[75] D.05-12-041 at 4.

requirements "in a nondiscriminatory manner." The Public Utilities Code creates a variety of distinctions between different classes of LSEs as, for example, the IOUs are currently serving as the Providers of Last Resort (POLR), while CCAs and ESPs are permitted to return their customers. It is not discriminatory for our rules to reflect statutory legal distinctions. As discussed above, a CCA that fails to meet its RA requirements is leaning on the procurement of other CCAs that have met their procurement requirements to support grid reliability. Thus, some CCA customers may benefit from this proposal by avoiding reliability problems caused by other LSEs' failures to procure resources.

For these reasons, we find Energy Division's proposal, with modifications discussed below, to be a reasonable approach and permissible under Pub. Util. Code Section 380. This requirement should apply to any LSE with the exception of the POLR, as the POLR is mandated by Section 387 to serve load if other LSEs fail to provide service or "otherwise meet its obligations."[76]

Some parties seek clarification regarding whether Energy Division's proposal would prevent CCAs from serving load in newly developed areas within the existing CCA territory or where customers move into the CCA territory. We clarify that the limit on expansion only applies to a CCA's plans to expand its service territory, and not to new developments within a CCA territory or customers moving into the CCA territory. Thus, new customers in a CCA's existing territory may be defaulted into the CCA's service but the CCA is not permitted to submit an implementation plan to expand to incorporate new territory. As applied to an ESP, existing customers may experience load expansion, relocation, and changes in their service accounts, including adding

[76] Section 387(a)(3).

new accounts from the ESP's existing customers. However, the limit on expansion means the ESP is not permitted to sign new customers into its service, including taking on new customers switching from another ESP or entering the direct access program from an IOU or CCA's service via the direct access lottery.

The Commission declines to adopt the proposed 2.5 percent threshold for RA deficiencies but determines that a 1 percent minimum threshold is reasonable, similar to that adopted in D.21-06-029 for the penalty point structure. Therefore, an LSE's system deficiency of 1 percent or greater will be applicable to the expansion requirement adopted here.

The Commission agrees (with some caveats) that if an LSE "cures" its year-ahead RA deficiency in the month-ahead timeframe, the year-ahead deficiency will not be applied to the expansion requirement. However, this only applies to a year-ahead deficiency accrued two years before the year in which the LSE files its binding load forecast. To illustrate, Year 0 (Y0) is the year that an LSE files its binding load forecast with additional load it will serve. An LSE must meet its year-ahead and month-ahead requirements in the two years before Y0 (that is, Year Minus 1 (Y-1) and Year Minus 2 (Y-2)). If an LSE receives a year-ahead deficiency in Y-2 and "cures" that deficiency in the month-ahead process in Y-1, the Y-2 deficiency will not apply to the expansion requirement. A year-ahead deficiency in Y-1, however, will necessarily apply to the expansion requirement because there is insufficient time for the LSE to cure the Y-1 deficiency in the Y0 month-ahead timeframe, as the LSE will have filed its binding load forecast commitments. The applicable system RA deficiencies are depicted in the table below.

Accordingly, a CCA that has had system RA deficiencies within the prior two calendar years must first be in RA compliance for two calendar years prior to submitting an implementation plan to expand. An ESP that has had system RA deficiencies within the prior two calendar years must first be in RA compliance for two calendar years prior to signing new direct access customers. These rules are applicable to LSEs that are not acting as the POLR. As to CCAs, this requirement will apply to initial or revised implementation plans submitted after the effective date of this decision. As to ESPs, this requirement will apply to direct access customers signed after the effective date of this decision.

In other words, an LSE's eligibility to sign new direct access customers or to submit an implementation plan to expand its service territory will be contingent on compliance with RA requirements for the prior two calendar years. RA deficiencies accrued after the effective date of this decision will be used to calculate the potential expansion pause period. The first year-ahead deficiencies to be applied will be the 2024 year-ahead RA filing due on October 31, 2023, and the first month-ahead deficiency to be applied will be the September 2023 month-ahead RA filing.

The following system RA deficiencies will apply to the LSE expansion requirement:

| **System RA Deficiencies That Apply to the LSE Expansion Requirement** | |
|---|---|
| Year Plus 1 (Y+1) | Year that an LSE elects to expand |
| Year 0 (Y0) | Year that an LSE files its April load forecast |
| Year Minus 1 (Y-1) | (1) Month-Ahead deficiencies apply<br>(2) Year-Ahead deficiency (for Y0) applies<br>*Note: CCA Implementation Plans for Y+1 are filed by Dec 31 of Y-1. |
| Year Minus 2 (Y-2) | (1) Month-Ahead deficiencies apply |

| | |
|---|---|
| | (2) Year-Ahead deficiency (for Y-1) applies, unless Year-Ahead deficiency is cured in the Month-Ahead timeframe in Y-1 |

Substantive month-ahead and year-ahead system RA deficiencies will apply to the expansion rule. The following violations will not count towards the expansion requirement:

(1) A month-ahead or year-ahead system RA deficiency that is less than 1 percent of the LSE's system RA requirements.
(2) "Specified violations," as adopted in Resolutions E-4017 and E-4195 and modified in D.11-06-022.

To implement the adopted requirement, Energy Division is authorized to review RA enforcement referrals or citations issued by CPED, including confidential versions, for the prior two calendar years to determine if an LSE is eligible to expand. Energy Division will review and confirm compliance with the requirement ahead of the LSE's RA load forecast submissions, confirm the earliest possible effective date for the CCA expansion by letter from the Executive Director, and inform the CEC of any adjustments to the load forecast necessary due to non-compliance. Energy Division is authorized to make this determination regardless of any pending citation appeal.

## 4.6. CPE Requirements

### 4.6.1. Transparency and Reporting

Energy Division and CalCCA each propose additional reporting requirements for the CPEs to submit in their compliance filings and Annual Compliance Reports (ACR). Energy Division recommends that the August compliance filing and the September ACR each should include:[77]

[77] Energy Division Phase 3 Proposals at 31.

(1) Monthly MW amounts of deferred procurement that were the result of unreasonable prices over the compliance period;

(2) Monthly MW amounts of procurement not offered to the CPE in deficient areas over the compliance period;

(3) Monthly MW amounts of procurement offered in and later withdrawn over the compliance period; and

(4) Any additional information on outreach conducted by the CPE to resources that did not participate and/or withdrew their bids and the outcomes of the outreach.

Energy Division also recommends that the CPEs provide the following:

| **Monthly Procurement Summary Covering All CPE Procurement** | | | | | |
|---|---|---|---|---|---|
| Total CPUC Local Allocation (excluding DR) | Total CPUC-allocated Local DR | Local CAM (non-DR) | Total Procured Resources | Total Self-Shown | Net Total |

Energy Division seeks to publish this information on the Commission's website and states that the additional data would help LSEs manage upfront system RA procurement and assess the potential for backstop procurement. This would assist LSEs in understanding the inventory of available resources in the market.

CalCCA recommends additional data reporting to provide a more comprehensive view of CPE procurement efforts and recommends the following be submitted in the ACRs:[78]

(1) If any offers or self-showings were not selected by the CPE, why were they not selected (price, inability to negotiate contract terms, other); and

(2) Total NQC of local RA not offered or self-shown.

[78] CalCCA Phase 3 Proposals at 11.

Parties that support Energy Division's proposal include Cal Advocates, CAISO, GPI, Joint Environmental Parties, Shell, Vistra, WPTF, and PG&E (with modifications).[79] Joint Environmental Parties also request that the CPEs report on why LSEs are electing not to self-show. PG&E supports the additional reporting and recommends that the confidentiality matrix adopted in D.22-03-034 be modified to indicate the confidentiality status of the new requirements. PG&E suggests modifying the monthly MW amounts, as proposed by Energy Division, to protect market-sensitive information from the CPE's solicitation process, as follows:

a. Total aggregate monthly MW amount of procurement not offered to the CPE in deficient areas;

b. Total sum of (i) aggregate monthly MW amounts of deferred procurement that were the result of unreasonable prices, (ii) aggregate monthly MW amounts not procured due to inability to reach an agreement with request for offers participant, and (iii) aggregate monthly MW amounts of procurement offered in and then later withdrawn over the compliance period, where the total sum of these 3 amounts exceeds 10 MWs; and

c. Any additional information on outreach conducted by the CPE to resources that did not participate and/or withdrew their bids and the outcome of that outreach.

SCE opposes Energy Division's proposal to include aggregated resources that did not participate in the solicitations, or to conduct outreach to determine the reasons for lack of participation.[80] SCE states that the CPE does not have

[79] Cal Advocates Opening Comments at 10, WPTF Opening Comments at 11, Shell Opening Comments at 11, Joint Environmental Parties Opening Comments at 2, MRP Opening Comments at 19, Vistra Opening Comments at 23, CAISO Opening Comments at 10, PG&E Opening Comments at 5.

[80] SCE Opening Comments at 13.

visibility into which resources did not participate, including which resources will be coming online.[81] SCE does not object to other reporting so long as market-sensitive information remains confidential, and supports including confidential information in the ACR if it is not disclosed to market participants. SCE states that providing aggregated resources that were not selected due to high prices does not provide LSEs with information to help manage procurement, and pricing is market-sensitive information.

CalCCA disagrees with SCE and states that the CPE can use the NQC list that provides which RA resources are online or under development to determine which resources were not offered or self-shown.[82] CalCCA states that providing information on why resources were not selected to market participants would help LSEs understand how the CPE framework is functioning, including sources of any CPE deficiencies. CalCCA argues that the information is not market-sensitive because the CPEs would report it at an aggregated level according to the reasons for non-selection, and not publicize price information.

Parties that support CalCCA's proposals include Cal Advocates, WPTF, Shell, Joint Environmental Parties, Vistra, and GPI.[83] SCE opposes CalCCA's proposal to require CPEs to explain why offers or self-showings were not accepted or why LSEs did not submit offers.[84] PG&E states that its modifications to Energy Division's proposal would similarly cover CalCCA's request for NQCs

[81] SCE Reply Comments at 2.

[82] CalCCA Reply Comments at 4.

[83] Cal Advocates Opening Comments at 10, WPTF Opening Comments at 11, Shell Opening Comments at 11, Joint Environmental Parties Opening Comments at 2, MRP Opening Comments at 19, Vistra Opening Comments at 23, GPI Reply Comments at 2.

[84] SCE Opening Comments at 13.

of local RA not offered or self-shown and why an offer or self-showing was not selected by the CPE.[85]

#### 4.6.1.2. Discussion

The Commission agrees with the numerous parties that support additional data reporting by the CPE both to help LSEs manage upfront system RA procurement and to understand the inventory of available resources in the market in order to assess the potential for CAISO backstop procurement. We find that additional transparency in the CPE process would help market participants understand how the CPE framework is functioning. That said, we also agree that the additional data reporting should be aggregated in a way that does not disclose confidential, market-sensitive information.

To that end, we find Energy Division's proposal, with PG&E's modifications, to be appropriate additional data reporting by the CPE for the ACRs. With respect to the aggregate amounts of resources that were not offered to the CPEs, the CPEs should base this information by comparing the NQC list with the resources that bid into the CPE solicitation.

We clarify that the additional reporting does not require the CPE to survey or conduct outreach to LSEs as to the reasons for their lack of participation in the CPE solicitation. The "additional information" category is intended for the CPE to disclose any additional information it may be aware of as to resources that did not participate and/or withdrew their bids. In D.22-03-034, the Commission directed that an LSE that declined to self-show or bid a resource into the CPE solicitation shall file a justification statement with its year-ahead RA filing

[85] PG&E Opening Comments at 7.

explaining the LSE's rationale.[86] In that decision, we declined to make LSEs' justification statements public but authorized Energy Division to include an assessment of the statements in their 2024 report.[87]

Accordingly, the CPEs shall report the following in both (a) the mid-August compliance filings and (b) the September ACRs:

| Monthly Procurement Summary Covering All CPE Procurement | | | | | |
|---|---|---|---|---|---|
| Total CPUC Local Allocation (excluding DR) | Total CPUC-allocated Local DR | Local CAM (non-DR) | Total Procured Resources | Total Self-Shown | Net Total |

a. Total aggregate monthly MW amount of procurement not offered to the CPE in deficient areas;

b. Total sum of (i) aggregate monthly MW amounts of deferred procurement that were the result of unreasonable prices, (ii) aggregate monthly MW amounts not procured due to inability to reach an agreement with request for offers participant, and (iii) aggregate monthly MW amounts of procurement offered in and then later withdrawn over the compliance period, where the total sum of these 3 amounts exceeds 10 MWs; and

c. Any additional information on outreach conducted by the CPE to resources that did not participate and/or withdrew their bids and the outcome of that outreach.

Appendix A of D.22-03-034 is modified for consistency with the new reporting requirements to add the following.

| | | | | |
|---|---|---|---|---|
| Competitive Solicitation Information | Individual/ Specific Bid/Offer data | Confidential | 3 years after conclusion | Disclosure of the bid/offer data received during CPE procurement could potentially have an adverse effect on the market, put the CPE at |

[86] D.22-03-034 at OP 6.

[87] *Id*. at 47.

| | | | | |
|---|---|---|---|---|
| | | | of solicitation | a competitive disadvantage with regard to other market participants, and impact participants' future bidding behavior for capacity that has not yet been procured. |
| Competitive Solicitation Information | Aggregate Bid/Offer Data Not Selected/Procured (where the total exceeds 10 MWs) | Public | N/A | N/A |

A modified version of the confidentiality matrix adopted in D.22-03-034 is attached as Appendix A to this decision.

#### 4.6.2. CPE Process Modifications

WPTF states that while D.22-03-034 directed Energy Division to review the CPE framework's effectiveness in a 2024 report, specific timing of the report's issuance was not established.[88] WPTF recommends that Energy Division's report be issued in January 2024, and a review process with party proposals and comments be established. WPTF further suggests that Energy Division's report address a series of questions, including whether the CPE framework has been cost-effective, has enhanced reliability, and has been efficient.

WPTF further recommends that LSEs that have self-shown resources to the CPE be allowed to sell the system and/or flexible attributes of those resources that are in excess of their individual local capacity obligation to other LSEs.[89] The purchasing LSE would assume the selling LSE's obligation to self-show the RA on annual and monthly RA plans to satisfy its system and/or flexible RA needs, as designated in D.22-02-034 at Ordering Paragraph (OP) 2. WPTF states that

[88] WPTF Phase 3 Proposals at 4.

[89] *Id*. at 6.

this would improve market liquidity and LSEs' ability to meet system and flexible RA obligations. WPTF posits that this would potentially increase the amount of shown RA, as it removes a disincentive to self-show for LSEs that have excess system and flexible RA for local resources they own. WPTF adds that the purchasing LSE can submit an affidavit that states that: (a) the purchasing LSE will be bound by the requirement to show the resource on its RA plans, or (b) require the purchasing LSE to execute an addendum to the affidavit that affirms the resource will be shown on their RA plans.

IEP, MRP, and Shell support the proposal to allow LSEs to sell system and/or flexible RA attributes associated with self-shown local capacity.[90] PG&E does not offer comments on the proposal but asserts that it does not support the unbundling of RA products.[91] CESA, MRP, and Joint Environmental Parties support a clear timeline for reviewing the CPE framework.[92]

#### 4.6.2.1. Discussion

The Commission agrees that direction on the timing of Energy Division's CPE report is warranted and finds it reasonable for Energy Division to submit the CPE report in Q1 of 2024. Following the issuance of the report, parties will have an opportunity to submit comments on the report.

Under the current framework, LSEs may decline to self-show a local resource to the CPE in order to retain the option to sell the capacity. We agree that allowing LSEs to sell the self-shown resource may increase the amount of self-shown resources by removing a potential disincentive for self-showing and

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[90] IEP Opening Comments at 11, MRP Opening Comments at 20, Shell Opening Comments at 9.

[91] PG&E Reply Comments at 15.

[92] CESA Opening Comments at 6, Joint Environmental Parties Opening Comments at 3, MRP Opening Comments at 19.

provide additional opportunities for LSEs to procure system and/or flexible RA. Therefore, we find WPTF's proposal to be reasonable so long as the purchasing LSE assumes the selling LSE's self-showing obligation. This would not allow unbundling of a resource since the LSE is selling both the local and system attribute, the local attribute must be shown to the CPE, and the local attribute stays with the CPE.

Accordingly, an LSE that has self-shown a local resource to the CPE is permitted to sell the capacity to other LSEs, as long as the purchasing LSE assumes the selling LSE's obligation to self-show the RA on annual and monthly RA plans to satisfy its system and/or flexible RA needs, as required by OP 2 or D.22-02-034.

The Commission also finds it appropriate to modify the self-showing attestation for an LSE that sells its self-shown resource to another LSE. As adopted in D.22-03-034, an LSE that elects to self-show a local resource to the CPE must execute an attestation that provides that:[93]

(a) The LSE has the capacity rights to the RA resource for the period it is self-showing;

(b) The LSE intends to self-show the RA resource on annual and monthly RA plans to satisfy its system and/or flexible RA needs; and

(c) If applicable, the resource that the LSE intends to self-show for compensation under the Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM) meets the eligibility requirements pursuant to D.20-12-006.

[93] D.23-03-034 at OP 2.

For any LSE that has self-shown a local resource to the CPE, and subsequently sells the capacity to another LSE, the selling LSE shall modify its attestation to provide that:

(a) The LSE has sold the capacity to another LSE, and the purchasing LSE will self-show the RA resource on annual and monthly RA plans to satisfy its system and/or flexible RA needs as required by OP 2 of D.22-02-034; and
(b) If applicable, the resource that the LSE intends to self-show for compensation under the LCR RCM meets the eligibility requirements pursuant to D.20-12-006.

The modified attestation shall be provided to the CPE within 30 days of the purchase. Additionally, the purchasing LSE shall provide an attestation that it intends to self-show the capacity to the CPE within 30 days of the purchase.

Lastly, several parties put forth proposals for larger modifications to the CPE framework, such as CalCCA's proposal to lock in CPE procurement two years in advance,[94] MRP's proposal to allow CPE-procured capacity to be sold to LSEs and converted to self-shown capacity,[95] and Vistra's proposal for a CPE soft price cap to guide what constitutes high pricing.[96] The Commission defers consideration of larger changes to the CPE framework until after Energy Division's evaluation of the effectiveness of the CPE framework in 2024, as discussed above and adopted in OP 21 of D.22-03-034.

## 4.7. RA Import Requirements

### 4.7.1. Modifications to Import Requirements

In D.20-06-028, the Commission required that a non-resource-specific import shall count towards RA requirements, provided that:

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[94] CalCCA Phase 3 Proposals at 8.

[95] MRP Phase 3 Proposals at 3.

[96] Vistra Phase 3 Proposals at 18.

(a) The contract is an energy contract with no economic curtailment provisions;

(b) The energy must self-schedule (or in the alternative, bid in at a level between negative $150/MWh and $0/MWh) into the CAISO day-ahead and real-time markets at least during the Availability Assessment Hours throughout the RA compliance month, consistent with the Maximum Cumulative Capacity (MCC) buckets.

(c) The energy must be delivered to the load-serving entity in accordance with the governing contract, consistent with the MCC buckets.[97]

Energy Division states that "a number of load serving entities are structuring these non-resource specific imports as RA capacity contracts, not energy contracts, with the resource being bid into the CAISO, rather than delivered to meet the energy needs of the load serving entity."[98] Energy Division states that because the LSE is not the scheduling coordinator (SC) for the resource, it is more difficult to assess penalties to the LSE for failure to meet the requirements of D.20-06-028.

Energy Division proposes that the LSE must be the scheduling coordinator for the non-resource-specific RA import to ensure that the LSE is responsible for the Commission's requirements. Energy Division also requests consideration of whether the self-schedule or bid at $0 to negative $150/MWh should be replaced with an energy must-flow requirement to ensure that energy contracts are not speculative and to ensure grid reliability.

CalCCA states that the current rules have dampened interest in selling RA imports to California LSEs and therefore, CalCCA proposes that that a maximum

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[97] D.20-06-028 at OP 2.

[98] Energy Division Phase 3 Proposals at 37.

import RA bid price should be based on the costs of the typical marginal resource in the market and the resource typically on margin during the AAH window is a Combustion Turbine.[99] Each element of costs, including heat rate, gas prices, variable operations and maintenance, and greenhouse gas (GHG) emissions, could be calculated to form tiers to determine resources' bids for each month. CalCCA recommends the following bid caps for gas prices up to: (1) $10/MMBTU = $143/MWh; (2) $20/MMBTU - $263/MWh; (3) $30/MMBTU or higher = $383/ MWh. CalCCA states that maximum bid prices would allow generators outside of California to economically bid resources and ensure bid prices are not so high as to be unlikely to be selected.

#### 4.7.1.1. Comments on Proposals

AReM, BPA, CAISO, CalCCA, DMM, SCE, Vistra, and WPTF oppose requiring the LSE to be the SC.[100] These parties generally state that many LSEs cannot act as their own SC (due to size and operation costs), that this would be disruptive to business practices, and that this may increase costs to LSEs. MRP supports requiring LSEs to be the SCs.[101]

Some parties suggest alternatives to address Energy Division's concerns. AReM recommends that LSEs identify who their SC is in their RA showings to allow Energy Division to verify the import RA transaction.[102] CalCCA agrees with this proposal but clarifies that it is the SC associated with the import RA,

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[99] CalCCA Phase 3 Proposals at 14, 22.

[100] AReM Opening Comments at 13, BPA Opening Comments at 3, CalCCA Opening Comments at 28, DMM Opening Comments at 5, Vistra Opening Comments at 26, SCE Opening Comments at 19, WPTF Opening Comments at 15, CAISO Reply Comments at 6.

[101] MRP Opening Comments at 15.

[102] AReM Opening Comments at 13.

not other scheduled resources.[103] DMM and PG&E suggest that a CAISO resource ID associated with out-of-state resources could include the LSE ID for each LSE's share of the RA associated with the resource when the resource is scheduled/bid into the CAISO market.[104] DMM adds that each LSE could have its own scheduling coordinator ID that the third-party SC could use for imports under contract to that LSE.

AReM, CalCCA, SCE, WPTF, CAISO, MRP, and BPA oppose replacing the self-schedule or bid requirement with a must-flow requirement.[105] Several parties state that this could reduce willingness to transact with California LSEs and would limit an already tight RA market. AReM argues that there is no evidence why the current requirements are insufficient, noting that CAISO reported 99.96 percent of all RA static import capacity bid with either self-schedule or economic bids at or below $0/MWh in September 2022. BPA states it is unclear how the proposal would increase reliability of import deliveries. DMM seeks clarity on what a must-flow requirement would entail and finds it unclear if contracts would have to increase incentives for a supplier to deliver energy when the import receives a market award.[106]

AReM, DMM, Shell, IEP, MRP, and Vistra support CalCCA's proposal.[107] DMM and MRP state that suppliers would still expect to receive a CAISO import

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[103] CalCCA Reply Comments at 7.

[104] DMM Opening Comments at 5, PG&E Opening Comments at 10.

[105] AReM Opening Comments at 14, BPA Opening Comments at 3, CalCCA Opening Comments at 28, SCE Opening Comments at 19, WPTF Opening Comments at 15, CAISO Reply Comments at 6, MRP Opening Comments at 15.

[106] DMM Opening Comments at 6.

[107] AReM Opening Comments at 14, DMM Opening Comments at 8, Shell Opening Comments at 10, Vistra Opening Comments at 26, IEP Opening Comments at 12, MRP Opening Comments at 15.

schedule except during times of relatively low market prices, and this would provide the same reliability benefits as the current bid/self-schedule requirement. DMM does not recommend a particular bid cap but finds value in a bid cap over $0/MWh, but low enough for suppliers to expect an import schedule. IEP states that the proposal would dissuade speculative RA because the bid caps are pegged to market conditions.

PG&E opposes CalCCA's proposal and states that it is unclear it will increase overall import volume, as increasing the amount that can be recovered through the energy market would reduce the amount that needs to be recovered through the RA program.[108] Thus, while this may reduce the price of RA imports, PG&E states that it will not necessarily increase supply.

#### 4.7.1.2. Discussion

The Commission finds insufficient record to replace the current RA import rules with a must-flow energy requirement or a maximum import RA bid price. We agree with AReM that there is no information as to why the current requirements are insufficient. Likewise, there is insufficient information to determine whether CalCCA's proposal would necessarily increase the volume of imports, rather than merely reducing the price of imports. Should information arise as to why the current RA import bidding requirements warrant modification, Energy Division Staff should present that information to the Commission and stakeholders for consideration.

The Commission recognizes that Energy Division is concerned that some non-resource specific RA imports are not satisfying the RA import requirements established in D.20-06-028. Energy Division cannot confirm in all instances

[108] PG&E Opening Comments at 11.

which LSE is associated with an RA import when the LSE is not the scheduling coordinator for that import, and therefore, which LSE may be subject to penalties in the event of non-compliance. We agree with parties that state that requiring an LSE to be their own SC to address this concern would be overly burdensome on LSEs. In considering comments on the proposed decision, the Commission declines to adopt a proposal at this time. The Commission authorizes Energy Division to work with CAISO to identify the appropriate resource ID registration process that will allow non-resource specific RA import IDs to be mapped to the contracted LSE, when the LSE is not the scheduling coordinator. Energy Division should also investigate the real-time market reliability and liquidity concerns raised by parties in comments on the proposed decision, and submit a proposal into the RA proceeding as warranted.

#### 4.7.2. Available Transmission Capability

CAISO is currently developing rules for wheeling transactions (as part of its Transmission Service and Market Scheduling Priorities (TSMSP) stakeholder process) that would allow non-CAISO LSEs to reserve available transmission capability (ATC) across the CAISO system based on historical RA usage in the 13-month ahead timeframe and based on actual usage in the monthly and daily timeframe at each particular intertie location.[109] Energy Division states that the high priority wheels would be given priority equal to CAISO load, if CAISO is unable to serve its own load, and allow for wheeling across its transmission system. CAISO does not propose that CAISO LSEs could buy the ATC in the 13-month ahead timeframe or monthly timeframe; however, CAISO proposes to allow those with high priority wheeling rights to sell those rights to others.

[109] Energy Division Phase 3 Proposals at 38.

Energy Division notes that Commission rules only allow Commission-jurisdictional entities to pair RA imports with maximum import capability (MIC) allocations, and therefore, RA imports paired with ATC would not count towards RA obligations. Energy Division proposes that if a Commission-jurisdictional LSE procures ATC or acquires it through the resale process, the LSE should be allowed to pair the ATC with RA imports to meet RA requirements. Alternatively, Energy Division proposes to remove the MIC requirement for RA imports (which restricts the RA imports that entities can buy at each of the interties) since MIC does not currently convey deliverability.

SDG&E supports Energy Division's proposals and states that either proposal could address the concerns with CAISO's ATC proposal.[110] Shell states that Energy Division's first proposal, to allow ATC to be paired with RA imports to count towards RA requirements, is a good first step and should be further evaluated.[111]

CAISO and DMM oppose Energy Division's proposals.[112] CAISO states that MIC and deliverability concepts are subject to the CAISO tariff, and changes would require a stakeholder process. CAISO comments that its TSMSP proposal accounts for native load needs and includes additional margin in the calculations before releasing ATC to non-CAISO LSEs. CAISO adds that ATC is not a substitute for MIC and ATC does not represent simultaneous import capability deliverable to the CAISO load. CAISO states that its tariff requires LSEs to pair MIC with imports when shown as RA to ensure RA imports will be deliverable to the aggregate load along with internal generation. CAISO states that allowing

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[110] SDG&E Opening Comments at 7.

[111] Shell Opening Comments at 7.

[112] CAISO Opening Comments at 13, DMM Reply Comments at 2.

LSEs to use ATCs to show RA imports would conflate the MIC process for imports with the ATC process for external parties to support wheels across CAISO.[113] CAISO notes that it is open to reviewing its MIC design to ensure LSEs can transact for allocated intertie capacity to the maximum extent possible.

DMM agrees with CAISO that allowing ATC to meet RA import requirements could exacerbate the reliability risks of CAISO's TSMSP proposal.[114] DMM states that CAISO should consider internal transmission needs of native load as it implements its proposal and cautions against removing the MIC requirement for RA imports without more consideration as this could require other rules to ensure CAISO's balancing authority area is not counting on more import RA than possible.[115]

The Commission agrees with Energy Division's and parties' concerns about the uncertainty posed by the TSMSP proposal and that CAISO LSEs are disadvantaged in being unable to acquire available import capability to meet their RA needs. Thus, the Commission finds Energy Division's first proposal to be reasonable. That said, we recognize CAISO's concern that this could potentially result in a violation of the simultaneous import capability.

One way to address this is to limit the ability to acquire additional import capability through the ATC process to the two import locations most used by LSEs to pair with import RA: California-Oregon Border (COB)/Malin and Nevada-Oregon Border (NOB). By limiting the additional acquisition of ATC to these two interties, this would effectively ensure that there is no violation of the simultaneous import limit, nor any associated reliability risk. For this reason, we

[113] CAISO Reply Comments at 5.

[114] DMM Reply Comments at 2.

[115] DMM Opening Comments at 10.

find this modification to Energy Division's proposal to be reasonable, and adopt it here. We also direct Energy Division Staff to work with CAISO on concerns that CAISO's penalty parameters do not sufficiently prioritize RA imports and that MIC does not reserve internal transmission for RA imports.

Accordingly, if a Commission-jurisdictional LSE procures ATC or acquires ATC through the resale process at either COB/Malin or NOB, the LSE is permitted to pair the ATC with RA imports to meet its RA requirements.

## 4.8. Compliance and Penalty Procedures

Below we address several proposals on the RA compliance and penalty processes.

### 4.8.1. Penalty Point System

In D.21-06-029, the Commission adopted a point system and tiered penalty structure for system RA deficiencies, as follows:[116]

| Months | Points for Each Instance of System RA Deficiency |
|---|---|
| Non-Summer (November – April) | 1 |
| Summer (May – October) | 2 |

| Tier | Accrued Points | System RA Penalty Price |
|---|---|---|
| 1 | 0-5 | Applicable system RA penalty price |
| 2 | 6-10 | 2x the applicable system RA penalty price |
| 3 | 11+ | 3x the applicable system RA penalty price |

Energy Division clarifies that the penalty price corresponding to an LSE's tier will apply to all penalties accrued by the LSE, including year-ahead penalties.[117] Energy Division cites the example that if an LSE is in Tier 2, the LSE

[116] D.21-06-029 at OP 16.

[117] Energy Division Phase 3 Proposals at 26.

would be required to pay 2x the system penalty price for any year-ahead or month-ahead deficiency.

Energy Division also proposes that if the LSE enters a higher tier in a year that it had year-ahead deficiencies, the higher penalty should apply beginning with the monthly deficiency when the LSE enters the higher tier. Energy Division cites the example of an LSE with year-ahead deficiencies for May to September, and the same deficiencies for May to September in the month-ahead process. The LSE would pay the year-ahead penalty, and accrue two points for month-ahead May and two points for month-ahead June, totaling four points. The LSE would pay no additional penalties for month-ahead May and June, as it remains in Tier 1. However, the LSE would accrue two points for the month-ahead July deficiency, bringing the total to six points and raising the LSE's penalty price to Tier 2. For the month-ahead July penalty, Energy Division states that the LSE would pay the difference between the 2x system RA penalty for July and the year-ahead penalty price for July, and the Tier 2 penalty for any additional deficiencies. Energy Division further proposes that when an LSE accrues points that bring it to the next tier, the higher penalty should apply in the deficient month for which the points are accrued. Energy Division recommends that these changes apply to 2023 RA compliance.

SCE supports Energy Division's clarifications as reasonable and states that the proposal provides certainty to LSEs.[118] AReM, CalCCA, and CCCE oppose Energy Division's proposal.[119] AReM states that the proposal is punitive and that assessing points on year-ahead deficiencies lengthens the time LSEs hold

[118] SCE Opening Comments at 13.

[119] AReM Opening Comments at 8, CCCE Opening Comments at 3, CalCCA Opening Comments at 15.

penalty points, as the points do not expire until 24 months after the violation. CCCE states that the proposal retroactively applies a higher price for a new tier to year-ahead deficiencies. CalCCA states that points should no longer be applied to LSE deficiencies for LSEs that demonstrate they took reasonable efforts to comply.

In adopting the penalty point system in D.21-06-029, the Commission stated that "[p]oints shall only be accrued for month-ahead deficiencies, not year-ahead deficiencies."[120] While points are only accrued for month-ahead deficiencies, the Commission did not state or intend that points are only applied to month-ahead deficiency penalties. We agree, therefore, that clarification is necessary that any points accrued by an LSE shall be applied to the LSE's month-ahead and year-ahead RA penalties. We note that the application of points apply to going-forward deficiencies, not applied retroactively. As provided in D.21-06-029, points shall expire 24 months after the violation.

The Commission also agrees that if an LSE enters a higher tier during a year in which it incurs year-ahead deficiencies, the higher penalty will apply beginning with the monthly deficiency when the LSE enters the higher tier. For example, if an LSE has year-ahead deficiencies and accrues Tier 2 points in the month-ahead process for July, the LSE will pay the difference between the 2x system RA penalty for July and the year-ahead penalty price for July, and the Tier 2 penalty for any additional deficiencies. Likewise, we agree that the month in which an LSE accrues points that bring it into the next tier, the higher penalty shall apply to the deficient month for which the points were accrued. For example, if an LSE has month-ahead deficiencies for June and July, and the July

[120] D.21-06-029 at OP 16.

deficiency results in points that would bring the LSE into Tier 2, the Tier 2 multiplier would apply to the month-ahead July deficiency penalty.

Accordingly, penalty points accrued by an LSE shall be applied to an LSE's month-ahead and/or year-ahead RA penalties. If an LSE enters a higher tier during a year in which it incurs year-ahead deficiencies, the higher penalty will apply beginning with the monthly deficiency when the LSE enters the higher tier. The month in which an LSE accrues points that bring the LSE into the next tier, the higher penalty shall apply to the deficient month for which the points were accrued.

In the event that an LSE moves from a higher tier into a lower tier, due to the expiration of penalty points, we adopt a formula to address this scenario. All year-ahead RA deficiencies will be charged at the Tier 1 price, and in the month-ahead RA filing process, the LSE will pay the difference between its month-ahead tier penalty and the Tier 1 penalty that was already paid on its year-ahead RA deficiency, plus the LSE's current tier price on any incremental month-ahead RA deficiency. Accordingly, the following formula is adopted:

$$\text{Year-Ahead penalty} = \text{Deficiency}^{\text{Year-Ahead}} \times \text{Tier 1 Price}$$

$$\text{Month-Ahead penalty} = [(\text{Deficiency}^{\text{Year-Ahead}} \times \text{Tier Price}^{\text{Month-Ahead}}) - \text{Year-Ahead penalty}] + (\text{Deficiency}^{\text{Month-Ahead incremental}} \times \text{Tier Price}^{\text{Month-Ahead}})$$

These clarifications to the penalty point system shall be effective beginning for the July 2023 RA filing.

### 4.8.2. Publication of Deficiency Information

Currently, certain information about RA citations and penalties is made public by the Consumer Protection Enforcement Division (CPED) on the Commission's website. Energy Division states, however, that information regarding the type of citation, type of RA deficiency, month of deficiency, deficiency amount, amount of deficiency as a portion of the LSE's requirement, and any points accrued are not published.[121] Energy Division notes that the purpose of the RA penalty program and citations is to deter non-compliance but in recent years, there has been a large increase in non-compliant LSEs. Since 2009, Energy Division states that 143 RA citations have been issued and paid, and at least eight system RA citations have been issued in August or September 2022. Without information on the magnitude and type of RA deficiencies, Energy Division states that policymakers do not have sufficient information to understand and address RA program violations.

Energy Division recommends that for month-ahead deficiencies, the following should be made public: the type of citation, type of RA deficiency, month of deficiency, deficiency amount, amount of deficiency as a portion of the LSE's requirement, and any points accrued. For year-ahead deficiencies, the information would remain confidential until after the compliance month to avoid revealing market-sensitive information since the LSE still has a chance to cure the year-ahead deficiency before the month-ahead process. Energy Division also proposes that citations for other program violations, such as late load forecasts and late RA filings, should not be redacted.

Cal Advocates and Joint Environmental Parties support Energy Division's proposal.[122] Cal Advocates states that publicizing this information will increase public knowledge of LSEs' ability to meet RA requirements, provide insights into reliability risks caused by LSEs' deficiencies, help stakeholders better understand

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[121] Energy Division Phase 3 Proposals at 28.

[122] Cal Advocates Opening Comments at 14, Joint Environmental Parties Opening Comments at 6.

problematic processes and timelines, and deter future deficiencies. Joint Environmental Parties remark that the RA program is currently inaccessible to the public as information is often scattered or withheld as confidential, making it difficult for the public to understand the impact of the RA program on contracting.

AReM and CalCCA oppose Energy Division's proposal.[123] AReM and CalCCA state that publishing the amount of an RA deficiency and the percent of an LSE's requirements can be used to back-calculate an LSE's RA requirements and determine the amount of load an LSE serves. CalCCA argues that even if posted after the compliance month, the information discloses an LSE's position as it continues to procure for future RA months. CalCCA cites the example that if information is posted the month after a July deficiency, the LSE may still be trying to procure for August and September to close the gap on those deficiencies. CalCCA argues that an LSE's net short RA position is protected under the Public Records Act and D.06-06-066, which protects IOU net short positions.

#### 4.8.2.1. Discussion

The Commission concurs that more transparency into LSEs' compliance with the RA program is critical to providing insight into reliability risks related to LSEs' RA deficiencies and RA program violations. CalCCA likewise acknowledges the importance of additional transparency in the RA program, as it states that "[w]ithout additional transparency, understanding the causes of RA deficiencies will be unlikely and evaluating fixes to the problem haphazard."[124]

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[123] AReM Opening Comments at 9, CalCCA Opening Comments at 16.

[124] CalCCA Opening Comments at 8.

The Commission recognizes CalCCA's concern that disclosing an LSE's deficiency information following, for example, the July RA showing, may reveal the LSE's procurement status as the LSE continues to procure to close its deficiency gap for August and September. This could potentially put the LSE at a disadvantage with sellers as it continues to procure for the peak summer months. To address this concern, we find it reasonable that the proposed LSE deficiency information is published after the peak summer months (June-September), or no earlier than October 1 of the compliance year. The Commission also finds that disclosing the "amount of deficiency as a portion of the LSE's requirement" is not necessary information, in light of the other proposed disclosures. With these modifications, the Commission determines that Energy Division's proposal is a reasonable approach to increasing transparency regarding the RA program's compliance violations, and does not expose an LSE's net short position.[125] We adopt the proposal as modified here.

Accordingly, for any LSE's month-ahead and year-ahead deficiencies, the following information is not confidential and will be published on the Commission's website by CPED or Energy Division: the type of RA deficiency, month of deficiency, deficiency amount (MW), and any points accrued. The

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[125] While we determine that the adopted disclosure is not confidential, we note that the Public Records Act, and related Commission decisions, allow the Commission to prevent the release of market-sensitive information that would harm energy markets and customers. D.06-06-066, Appendix A, § VI.A at 13. *See also* D.20-07-050 at OP 5 (adopting Appendix B, § II.B at 2 of D.08-04-023).

As provided by D.06-06-066, the Commission must weigh the need for open decision-making and meaningful public participation, with the legitimate needs of parties that appear before the Commission to determine whether data receives confidential treatment in a particular instance. Further, "[t]he merits of a claim that data are confidential will always depend on the context, and we must have the flexibility to make decisions based on specific facts rather than developing across-the-board rules." D.06-06-066 at COL 18, 22.

information will be published no earlier than October 1 of the compliance year. For other non-deficiency RA program violations, such as late load forecasts and late RA filings, the information on the RA citation is deemed not confidential and may be published on the Commission's website by CPED or Energy Division.

#### 4.8.3. Untimely Local Waiver Advice Letters

Local RA waiver requests must be submitted via a Tier 2 Advice Letter, as provided in D.19-06-026. Pursuant to the 2023 Resource Adequacy Guide, local waiver Advice Letters are due at the same time as the year-ahead and month-ahead RA filings. Energy Division points out that several LSEs are repeatedly late in filing local waiver Advice Letters and there is no associated penalty with late filings.[126] Energy Division proposes that late local waiver Advice Letters should not be accepted and should be denied.

No parties commented on this proposal. The Commission agrees with Energy Division that late local waiver submissions should not be accepted past the stated deadline and should be automatically denied. Accordingly, a local RA waiver request that is filed past the submission deadline will be rejected.

#### 4.8.4. CAM/RMR Credit Allocations

CAM and Reliability Must Run (RMR) credits are allocated to LSEs on a quarterly basis pursuant to D.14-06-050 and allocations are due 45 days before the RA filing deadline. Energy Division states that RMR allocations are dependent on CAISO providing the total Commission-jurisdictional share of RMR credits, which are generally not provided until October.[127] Energy Division notes that for the 1st Quarter of 2023, CAM and RMR credits were due on October 3, 2022, 45 days before the January 2023 filings, which were due on

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[126] Energy Division Phase 3 Proposals at 27.

[127] Energy Division Phase 3 Proposals at 27.

November 17, 2022. However, CAISO did not provide the Commission's RMR share by that date. Therefore, Energy Division proposes that for the 1st Quarter of each year, Energy Division will provide CAM and RMR credits to LSEs no later than five business days after CAISO provides the RMR credits to Energy Division.

CAISO supports this proposal and echoes that it cannot provide Energy Division with RMR credits until October of each year.[128]

The Commission agrees that the proposed timing is reasonable and would give Energy Division time to allocate CAM and RMR credits based on the total Commission-jurisdictional share of RMR credits. Accordingly, for the 1st Quarter of every year, Energy Division will provide CAM and RMR credits to LSEs no later than five business days after CAISO provides the CPUC-jurisdictional RMR credits to Energy Division.

### 4.9. Annual Load Forecasts for RA Requirements

In the current RA program, LSEs submit binding load forecasts for the Commission to determine an LSE's year-ahead requirements and LSEs may update their monthly load forecasts to account for load migration that may occur throughout the year. Energy Division states that the monthly load forecast updates add administrative complexity to the RA program because the monthly updates modify the monthly RA requirements, require significant Commission Staff resources, and call into question the purpose of the binding load forecast.[129] Energy Division adds that allowing monthly updates also provides an opportunity for load migration to insert reliability risk.

[128] CAISO Opening Comments at 10.

[129] Energy Division Phase 3 Proposals at 35.

Energy Division seeks consideration for locking in year-ahead system and local forecasts for the RA program, obviating the need for monthly load forecast updates. Under this proposal, system and local RA requirements would vary by month but be locked in for the entire year, which would give LSEs and the Commission more certainty regarding which entity is responsible for the RA obligation.

MRP, PG&E and Vistra support this proposal.[130] PG&E asserts that the monthly process is burdensome and complex, and results in only minor changes to the RA requirements. PG&E points out that larger load migration changes are already accounted for and are not a serious concern during the monthly true-up process because CCAs are required to provide at least 12 months' notice before implementation or expansion into new territory. MRP opposes the current monthly framework of the RA program in favor of an annual framework.

AReM, CalCCA, and Shell oppose the proposal.[131] AReM objects to locking in annual load so long as customers have a choice to move between IOUs and CCAs. Shell comments that it is important to calculate monthly obligations based on the most current load forecasts; otherwise, LSEs that lose load incur obligations for load that is the responsibility of another LSE. CalCCA states that the proposal will lead to inaccuracies in requirement allocation as load moves among LSEs but requirements stay the same. SDG&E asserts that additional

[130] MRP Opening Comments at 26, PG&E Reply Comments at 9, Vistra Opening Comments at 23.

[131] AReM Opening Comments at 12, Shell Opening Comments at 7, CalCCA Opening Comments at 34.

analysis is needed to determine whether the year-ahead forecast can be reliable enough to estimate demand to meet the 1-in-2 standard.[132]

The Commission agrees that the monthly load forecast update process requires significant Commission Staff resources, while generally resulting in only small modifications to the RA requirements. As pointed out by PG&E, any larger changes in load migration will already be accounted for because CCAs are required to provide at least a one-year notice prior to implementation or expansion. With the existing monthly true-up process, month-to-month requirements do not change significantly as a result of the monthly load forecast updates. In considering comments on the proposed decision, the Commission finds it reasonable to allow one mid-year load migration update in mid-February to cover May-December load migration, similar to the local and flexible RA true-up process. Other than the one load migration update, the Commission finds it reasonable that an LSE's load forecasts should be locked in for January-April and May-December.

In adopting this requirement, the incremental local and flexible RA true-up will be retained; however, the forecast submittal used in the true-up will be due in February rather than mid-March. The quarterly CAM/RMR process will be modified to only provide LSEs refreshed CAM/RMR credits for June-December based on CAM resource information and the updated June-December forecasts. Revised load forecasts will be due mid-February with an LSE's April month-ahead RA filing. These forecasts will be reviewed for plausibility before being used to allocate local and flexible RA true-ups and CAM/RMR credits. The May-December revised forecast will be used in determining an LSE's month-

[132] SDG&E Opening Comments at 8.

ahead system obligations for May-December. Energy Division Staff is authorized to review the administrative impact of this requirement in 2024 and submit a proposal with modifications into the RA proceeding if warranted. Accordingly, an LSE is permitted one load migration update in mid-February to cover May to December load migration; otherwise, an LSE's load forecast is locked in for the January-April timeframe and May-December timeframe.

## 5. Demand Response Issues

### 5.1. Qualifying Capacity of Supply-Side DR Resources and CEC Working Group on Supply-Side DR

In the RA program, RA capacity from DR resources administered by the IOUs is allocated to LSEs as DR credits that are counted towards an LSE's RA requirements.[133] Currently, the QC value of DR resources for both IOUs and third-party Demand Response Providers (DRPs), with the exception of resources participating in the Demand Response Auction Mechanism (DRAM) pilot, is based on the Load Impact Protocols (LIPs), which are informed and adjusted by historic DR performance. In D.21-06-029, the Commission discussed CAISO's initiation of proposed revision request (PRR) 1280 to its Business Practice Manual. The Commission identified that the revision would reject any non-net neutral credits that lower an RA requirement without the resource being shown on the CAISO Supply Plan and determined its implementation would effectively mean that DR credits allocated to LSEs by the Commission would no longer be accepted by the CAISO.[134] CAISO initially proposed an Effective Load Carrying

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[133] *See generally* D.09-06-028.

[134] D.21-06-029 at 27. CAISO subsequently withdrew PRR 1280 on August 30, 2021. *See* http://www.caiso.com/Documents/ProposedRevisionRequest1280WithdrawalCall091321.html.

Capability (ELCC) methodology to determine the QC of variable-output DR, rather than the LIPs, as CAISO stated that LIPs do not consider use limitations and portfolio interactions, and thus overvalue DR resources' contributions to reliability.

In D.21-06-029, the Commission declined to adopt an ELCC methodology for DR counting and instead adopted a working group process led by the CEC to develop a DR QC counting methodology and develop recommendations for a comprehensive and consistent measurement and verification strategy, including a new counting methodology for DR addressing *ex post* and *ex ante* load impacts for implementation as early as practicable. The CEC was requested to submit recommendations for implementation for the 2023 RA year.

The CEC submitted a Qualifying Capacity of Supply-Side Demand Response Working Group Report (Initial CEC Report) on February 18, 2022, in which it noted that there was insufficient time to develop a permanent QC methodology for the 2023 RA year and that stakeholders asserted the Working Group should await the outcome of the Reform Track process before making a recommendation.[135]

In D.22-06-050, the Commission found insufficient record to adopt a DR QC counting proposal for the 2023 RA year.[136] The Commission determined that the CEC Working Group should continue to develop long-term recommendations, consistent with the adopted Reform Track framework, and those recommendations should focus on the 2025 RA year and beyond.[137] The

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[135] Initial CEC Report at 34.

[136] D.22-06-050 at 40.

[137] *Id*. at COL 8.

Commission specifically requested that the CEC Working Group develop recommendations that consider the following issues for the 2025 RA year:[138]

(1) Whether the proposals that are presented in the CEC's stakeholder process are reasonable and appropriate to determine the QC of DR resources;

(2) Whether the DR QC methodology reflects the contributions of DR resources to reliability;

(3) Whether the DR QC methodology is compatible with the new RA framework for the 2025 RA year and beyond;

(4) Whether the DR QC methodology is transparent and how it could be implemented in a time-efficient manner;

(5) Whether and to what extent alignment of DR M&V methods in the operational space for CAISO market settlement purposes with methods to determine DR QC in the planning space should be achieved, and if so, how;

(6) Whether, and if so what, enhancements to intra-cycle adjustments to DR QC during the RA compliance year, as adopted in D.20-06-031, are feasible and appropriate to account for variability in the DR resource in the month-ahead and operational space; and

(7) Whether, and if so how, any changes to DR adders should be reflected in DR QC methodology.

The CEC recommenced the Working Group pursuant to D.22-06-050 with a deadline of February 1, 2023 to submit final recommendations.

### 5.1.1. CEC Working Group Report

On January 25, 2023, the CEC adopted the report that resulted from the CEC Supply-Side DR QC Working Group - *The Qualifying Capacity of Supply-Side Demand Response Working Group Final Report* (CEC Report). The CEC Report provides the CEC's final findings and recommendations from the Working

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[138] *Id.* at OP 11.

Group. On February 2, 2023, an ALJ ruling was issued that attached the CEC Report. On February 15, 2023, an ALJ ruling provided questions and established a comment schedule on the CEC Report. On February 24, 2023, an ALJ ruling issued a corrected final version of the CEC Report.

The CEC Report makes 18 recommendations:[139] (1) apply a consistent QC framework and methodology across DR resources; (2) adopt an incentive-based approach; (3) adopt the capacity shortfall penalty incentive mechanism with forced outage adder; (4) adopt the *ex ante* capability profile and *ex post* regression approach; (5) require resources to show takeback; (6) require DR providers to submit capability profiles and slice-of-day table to summarize QC values; (7) reduce reporting requirements for QC determination; (8) plan to produce final QC numbers by June 1 preceding the RA compliance year; (9) adopt streamlined QC approval criteria; (10) the Commission should implement the proposed penalty mechanism and CAISO should exempt DR from the RAAIM; (11) phase in incentive-based approach over time; (12) require DR providers to use the same baseline for settlement and ex post evaluation unless an alternative is more accurate but unable to be used for settlement; (13) adopt bid normalization for load impacts in ex post capacity valuation; (14) reduce the threshold required for midyear QC update; (15) eliminate the components of the PRM adder associated with operating reserves and load forecast error; (16) convert the forced outage adder to a multiplier applied in the capacity shortfall penalty; (17) maintain the distribution loss factor adder in QC values; and (18) update transmission loss factors and include the adder as a credit.

[139] CEC Report at 47-50.

During the CEC Working Group process, stakeholder proposals were provided by CLECA, DSA in coordination with SDG&E, OhmConnect, CEDMC and CEC Staff. The CEC Report ultimately recommends adopting the CEC Staff proposal as part of its recommendations. The five Working Group proposals are summarized below.

#### 5.1.2. CLECA Proposal

CLECA proposes adapting the status quo LIP-based methodology to the SOD framework.[140] CLECA notes that the LIPs already produce hourly expected load reductions that are averaged under the current process, and that under the SOD framework, they simply do not need to be averaged. CLECA proposes that DR providers should be required to account for any significant spillover effects that increase or decrease load before or after the event. The CEC notes that CLECA's emphasis in its proposal is more on flexibility in when DR providers can provide capacity and requirements for counting capacity across hours rather than on the specific method used to calculate the values.[141]

#### 5.1.3. DSA Proposal

The DSA proposal is an application of the LIPs to the new SOD framework.[142] DSA's proposed modifications include updating planning temperatures to the "worst day" as defined in the RA program, allowing DR resources the flexibility to provide capacity value based on need, and accounting for spillover in nonevent hours. Much of the DSA proposal focuses on standardization of reporting requirements and outputs, including a SOD table to show the hourly load impacts for the worst day in each month and a

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[140] CEC Report at 8.

[141] *Id.*

[142] *Id.* at 11.

time-temperature matrix for weather-sensitive resources. DSA also proposes that a central planning authority produce a "reliability risk heatmap" for each compliance year that will help DR providers align resources and programs with system need. DSA also includes two *ex post* performance metrics in this proposal: (1) the bid alignment metric measures the extent to which resources bid as expected based on the associated SOD table or time-temperature matrix or both; and (2) the performance alignment metric measures the extent to which resources perform as expected when dispatched.

#### 5.1.4. OhmConnect Proposal

OhmConnect proposes using the same underlying methods used in the current LIP-based status quo, and focuses its proposal on removing, or otherwise streamlining, the LIP reporting requirements not directly applicable to QC.[143] Reporting changes proposed by OhmConnect include streamlining evaluation plan requirements, eliminating *ex post* and *ex ante* impact estimates not relevant to QC valuation, eliminating all non-event-based DR protocols, and streamlining evaluation reports.

#### 5.1.5. CEDMC Proposal

CEDMC proposes an *ex post* incentive structure that levies a penalty on underperformance to ensure delivered capacity.[144] This proposal is aimed at reducing the burden and risk for DR providers and Energy Division Staff because DR providers bear compliance costs of participation and uncertainty of awarded QC, and Energy Division Staff are responsible for auditing submissions and approving final awarded QC. The central aspect of the CEDMC proposal is

[143] *Id.* at 12.

[144] *Id.* at 13.

a penalty adapted from PG&E's Capacity Bidding Program that would be applied to the resource's performance during the best hour of each month.

### 5.1.6. CEC Staff Proposal

CEC Staff recommends the Commission move away from the LIPs approach and adopt an incentive-based QC approach. CEC Staff states that replacing the upfront forecasting approach with an incentive-based framework can prompt DR providers to commit to achievable capacity contributions and to meet those commitments while streamlining the process for both DR providers and Commission Staff.[145] CEC Staff proposes that the QC value would be based on the *ex ante* hourly capability profile created by the DR provider and that a capacity shortfall penalty with a forced outage multiplier would be applied to the *ex post* demonstrated capacity if it falls short of the committed capacity.[146] The demonstrated capacity would be based on CEC Staff's proposed bid-normalized load impact metric, which normalizes load impacts to the amount bid for events when delivered energy may be lower than *ex ante* because of partial dispatches rather than due to underperformance. Both QC and demonstrated capacity values would account for weather sensitivity by using linear regression to find the intersection of the hourly capability profile and the bid-normalized load impacts with the planning temperature.

### 5.1.7. Comments on Proposals and CEC Working Group Report

Parties take different positions on the various supply-side DR QC proposals, with no proposal receiving consensus support. Some parties express dissatisfaction with the Working Group process overall and the report's

[145] *Id.* at 1.

[146] *Id.* at 14.

representation of various party perspectives,[147] while others counter that the process was fair and accurately represents positions.[148]

While CAISO, CEDMC/CPower, and OhmConnect support further consideration of the CEC's proposal,[149] many parties (including CAISO, CEDMC/CPower, and OhmConnect) identify that the proposed penalty mechanism requires further refinement to clarify how it would be implemented[150] and that the proposal should be vetted using historical data.[151] Cal Advocates, CLECA, DSA, PG&E, SCE, and SDG&E oppose adopting the CEC's proposal. CLECA believes much greater evidence is needed to ensure it is workable and does not see benefit in continued work on the proposal.[152] DSA is concerned that because the proposal is a significant departure from the historically used approach, the proposal should be tested against other incentive-based methodologies.[153] DSA also believes the enforcement mechanism needs additional clarity.[154] SCE thinks a proof-of-concept exercise is needed on the

[147] CLECA Opening Comments on CEC Report at 2, SDG&E Opening Comments on CEC Report at 3, DSA Opening Comments on CEC Report at 6.

[148] CEDMC/CPower Reply Comments on CEC Report at 2-3, OhmConnect Reply Comments at 2-3.

[149] CAISO Opening Comments on CEC Report at 4, CEDMC/CPower Opening Comments on CEC Report at 10, OhmConnect Opening Comments on CEC Report at 10.

[150] OhmConnect Opening Comments on CEC Report at 4, CEDMC/CPower Opening Comments on CEC Report at 1, DSA Opening Comments on CEC Report at 5, SCE Reply Comments on CEC Report at 2.

[151] CAISO Opening Comments on CEC Report at 6, CLECA Opening Comments on CEC Report at 9, DSA Opening Comments on CEC Report at 4, PG&E Opening Comments on CEC Report at A-5, SCE Opening Comments on CEC Report at 3, SDG&E Opening Comments on CEC Report at Attachment A.

[152] CLECA Opening Comments on CEC Report at 10.

[153] DSA Opening Comments on CEC Report at 4-5.

[154] *Id.*

CEC's *ex post* methodology before the Commission adopts it.[155] SDG&E believes the prescriptive approach of the proposal needs to be tested in the field before it is adopted.[156]

PG&E, SCE and SDG&E support DSA's proposal.[157] CLECA asserts its own proposal should be adopted but supports DSA's proposal as an alternative.[158] OhmConnect believes DSA's proposal is too complex and supports CLECA's proposal with simplified LIPs if LIPs are retained as the basis for QC.[159] SDG&E sees merit in some of CLECA's proposal but opposes retaining the PRM adder and removing availability requirements between 4 p.m. and 9 p.m.[160] CEDMC/CPower oppose both DSA's and CLECA's proposals as they believe none of the LIP-based proposals address issues DRPs face under the LIPs.[161]

CEDMC/CPower offer that if the Commission retains LIPs in some form, it should adopt OhmConnect's simplified LIPs proposal.[162] Cal Advocates believes most changes OhmConnect proposes making to the LIPs are unnecessary and the current LIP guidelines are sufficient.[163] SDG&E supports

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[155] SCE Opening Comments on CEC Report at 8.

[156] SDG&E Opening Comments on CEC Report at Attachment A.

[157] PG&E Opening Comments on CEC Report at 2, SCE Opening Comments on CEC Report at 2, SDG&E Opening Comments on CEC Report at Attachment A.

[158] CLECA Opening Comments on CEC Report at 2.

[159] OhmConnect Opening Comments on CEC Report at 9.

[160] SDG&E Opening Comments on CEC Report at Attachment A.

[161] CEDMC/CPower Opening Comments on CEC Report at 2-3.

[162] *Id*. at 3.

[163] Cal Advocates Opening Comments on CEC Report at 7.

only some of the proposed changes to the LIPs.[164] CLECA believes OhmConnect's proposal requires further refinement.[165]

OhmConnect, Cal Advocates, and SDG&E oppose CEDMC's proposal. OhmConnect believes CEDMC's proposal would be vulnerable to the same criticisms as DRAM.[166] Cal Advocates asserts it would create a disconnect between claimed QC value and actual resource performance.[167] SDG&E finds various shortcomings with the proposal, including reliance on settlement baselines, not addressing weather sensitivity of DR, and penalty design that needs further vetting.[168]

Parties also made comments on the CEC Working Group Report recommendations that were not related to any proposed QC methodology. The issue of adders is discussed in a later section of this decision that discusses Energy Division's proposal on TLF and PRM adders.

#### 5.1.8. Discussion

The Commission appreciates the ongoing efforts by CEC Staff and parties in leading, and participating in, the supply-side DR QC Working Group over the last two years. Significant work has gone into this process and meaningful progress has been made. While we have seen advancement in the thinking on what the structure of a future supply-side DR QC approach could be, party comments demonstrate a plurality of views that no single proposal is sufficiently developed or tested to warrant adoption at this time. While we acknowledge the

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[164] SDG&E Opening Comments on CEC Report at Attachment A.

[165] CLECA Opening Comments on CEC Report at 10.

[166] OhmConnect Opening Comments on CEC Report at 9-10.

[167] Cal Advocates Opening Comments on CEC Report at 4.

[168] SDG&E Opening Comments on CEC Report at Attachment A.

existing LIPs process is imperfect, we find that maintaining the current method is preferable to transitioning too quickly to an untested method, which could have unanticipated outcomes.

Although we decline to adopt any new approach at this time, we agree with parties that see promise in the CEC's proposal, if provided with additional time for refinement and testing. We therefore maintain the LIPs as the supply-side DR QC methodology at this time and authorize Energy Division to lead a Working Group, with support from CEC Staff, and submit a joint proposal in the RA proceeding for an incentive-based supply-side DR QC methodology in December 2024. The Energy Division-led Working Group should focus its efforts on refining certain elements of the CEC's methodology that were identified by parties in comments. Those elements include, but are not limited to, the formula for the bid-normalized load impact metric, the design of the capacity shortfall penalty, and the enforcement mechanism for the capacity shortfall penalty.

The schedule for the Working Group and the joint report is adopted as follows:

| **Milestone** | **Timeframe** |
|---|---|
| Initiate Working Group to refine specific elements of the CEC proposal, as directed by Commission Decision. | July 2023 |
| LIP process begins for 2025 RA compliance year. In *ex post* analysis on 2023 performance, the CEC methodology is run side-by-side by LIPs on a "what if" basis with no penalties applied. | December 2023 |
| Final LIP reports for 2025 RA compliance year filed. Energy Division and CEC draft joint report summarizing *ex post* results for 2023. | April 2024 |
| Energy Division and CEC continue refining incentive-based proposal, incorporating learnings from "what if" exercise. | April - December 2024 |

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|---|---|
| Energy Division and CEC submit refined incentive-based proposal to the RA proceeding. | December 2024 |
| LIP process begins for 2026 RA compliance year. | December 2024 |

While this Working Group process is ongoing, we also authorize Energy Division to pursue simplification of the current LIP requirements using a stakeholder process to develop a proposal for Commission consideration. We authorize Energy Division Staff to establish a schedule for the process and the proposals.

### 5.2. Proxy Demand Response (PDR) Bid Cap

Energy Division has concerns that the bidding practices of many PDRs lead to suboptimal outcomes for ratepayers.[169] Energy Division is specifically concerned that many PDRs bid strategically to reduce their likelihood of being selected in the CAISO market, even on days when grid emergencies are anticipated based on the demand forecast. Compounding this issue is the fact that wholesale prices in the CAISO market, particularly in the day-ahead market, are not always reliable indicators of a grid emergency. Energy Division describes that in both the 2020 and 2022 heatwaves, CAISO declared an Energy Emergency Alert (EEA) Watch for hours that cleared at less than $1,000/MWh in the day-ahead market and/or the real-time market. Energy Division notes that CAISO inserts bids for Reliability Demand Response Resources (RDRR) at $950/MWh and will accept them if there are insufficient resources at a lower price.

As a result, there may be times when RDRR is dispatched, while "economic" PDRs that bid at the market cap would not be dispatched by CAISO,

[169] Energy Division Phase 3 Proposals at 9-10.

particularly long-start PDRs that can only bid into the day-ahead market. Energy Division identifies that this scenario effectively creates an irrational dispatch order wherein RDRR gets triggered while other "economic" DR resources, which are receiving ratepayer-funded RA compensation, become stranded assets during a grid emergency.

To remedy this issue with irrational dispatch, Energy Division proposes establishing a bid cap for RA-eligible PDRs bidding into the CAISO market that is below the price trigger for RDRR. Specifically, Energy Division proposes that the value of the PDR-specific bid price cap be no higher than $500/MWh for both the day-ahead and real-time markets. Energy Division believes this cap is appropriate because DMM found that prices rarely exceeded $500/MWh (<1 percent of intervals) from July 2021 to August 2022, and the day-ahead market price exceeded $500/MWh in about 3 percent of intervals in September 2022,[170] which is on par with the minimum monthly availability requirement currently in place for RA-eligible DR of 24 hours per month.

To assess compliance, Energy Division proposes to review the applicable tariffs or LSE contracts to determine that they include a bid cap provision. If tariffs or contracts require resources to bid below the PDR bid cap, LSEs will be considered provisionally compliant in meeting their RA requirements. Once the data becomes available "*ex post*," Energy Division would review the bid data set to assess whether any PDRs were in violation of the cap. If Energy Division identifies a PDR in violation of the cap, the resource would be treated as if it were not made available to the CAISO on a Supply Plan. As with other RA resources, a deficiency notice would be issued, depending on if the LSE

[170] Q3 2022 Report on Market Issues and Performance, CAISO Department of Market Monitoring, December 14, 2022, at 9.

otherwise had enough capacity to meet its RA requirement without violating PDR(s).

#### 5.2.1. Comments on Proposal

PG&E supports Energy Division's proposal and believes a bid cap would support greater dispatch of PDRs, but requests the Commission not issue deficiency notices to the IOUs for non-compliance by third-party DRPs because the IOUs have no control over how DRPs bid DRAM resources or other third-party DR contract resources into the market.[171] SCE also opposes penalizing the IOUs for non-compliance by a third-party and proposes that if a penalty is imposed, the IOUs should be able to establish contract provisions that withhold a percentage of a third-party DRP's capacity payment or impose a deposit requirement that could be forfeited after review of the bid data rather than retroactively discrediting an LSE's supply plan.[172]

Joint DR Parties, CESA and Vistra oppose a bid cap amount of $500/MWh.[173] Joint DR Parties assert that more recent CAISO reports from Summer 2022 demonstrate a bid cap is not needed to ensure PDRs are being scheduled in the CAISO market and believe that the cap would put third-party DR at a competitive disadvantage with IOU DR programs, like PG&E's Capacity Bidding Program, which has a $650/MWh bid cap.[174] Joint DR Parties also argue that the bid cap does not account for spikes in natural gas prices, such as those

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[171] PG&E Opening Comments at 14.

[172] SCE Opening Comments at 11.

[173] Joint DR Parties Opening Comments at 4, CESA Opening Comments at 10, Vistra Opening Comments at 27.

[174] Joint DR Parties Opening Comments at 4-6.

that pushed the clearing price beyond $500/MWh in December 2022.[175] CESA asserts that a bid cap at $500/MWh would not account for DR resources that may be located in load pockets where locational marginal prices tend to be higher or that have a higher marginal cost of dispatching.[176] Vistra argues a $500/MWh bid cap would create a disincentive for participation and would artificially suppress energy prices and shift these costs to the RA market.[177]

DMM overall agrees that RDRR should not be dispatched before or ahead of PDRs.[178] It identifies that in practice, conditions for PDRs to exceed RDRR bids in the real-time market have been very limited and cautions against setting a bid cap that is too low, because (1) the marginal cost of these resources is unclear, and (2) it may result in dispatches during milder conditions that result in the resources not being available when market conditions are tighter.[179] DMM therefore proposes that a $949/MWh bid cap for PDRs be established to address the concern.[180] Although CESA and OhmConnect do not support a bid cap, if the Commission were to establish one, they would also support a $949/MWh bid cap.[181]

CLECA and Vistra agree that RDRR should not be dispatched ahead of or instead of PDRs and that offers should be at a price that results in a more rational

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[175] *Id.* at 6.

[176] CESA Opening Comments at 10.

[177] Vistra Opening Comments at 27.

[178] DMM Opening Comments at 3, CLECA Reply Comments at 6.

[179] DMM Opening Comments at 5.

[180] *Id.*

[181] CESA Opening Comments at 10, OhmConnect Reply Comments at 3.

dispatch order.[182] Vistra proposes that instead of Energy Division's proposed $500/MWh bid cap, the Commission implement a merit order proposal wherein RDRR offers, when released through the CAISO market operations action, are released into the supply stack at 110 percent of the CAISO's Soft Energy Bid Cap or Hard Energy Bid Cap, not to exceed $2,000/MWh, and that PDR offers be limited to no more than $100/MWh less than RDRR.[183] OhmConnect supports Vistra's proposal.[184]

#### 5.2.2. Discussion

We agree with Energy Division and PG&E that implementing a bid cap for PDRs would prevent the possibility of an irrational dispatch order where RDRR is dispatched before PDRs. We also agree that this would support greater dispatch of PDRs, which would increase their contributions to reliability. We do, however, recognize that other parties such as DMM are concerned that increasing the frequency of dispatch could decrease the availability of PDRs during the most stressed grid conditions when they are needed most, which could impact reliability. While many parties agree that RDRR should not be dispatched before PDRs, parties are mixed on what the appropriate level for the PDR bid cap should be.

We find it appropriate to adopt a PDR bid cap of $949/MWh. While both the proposed $500/MWh and $949/MWh would result in a more appropriate dispatch order, we find that a $949/MWh cap, which most closely tracks to the RDRR trigger, to be most strongly supported for delivering the intended dispatch order without potential unintended consequences. We clarify that this

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[182] CLECA Reply Comments at 6, Vistra Opening Comments at 27.

[183] Vistra Opening Comments at 28-29.

[184] OhmConnect Reply Comments at 4.

cap will apply to the total cost of all bid components, including start-up costs and minimum load costs. This definition is consistent with the circumstance contemplated by and purpose of the cap – to prevent the possibility of an irrational dispatch order and to increase the contribution of PDRs to reliability. We emphasize that the PDR bid cap is a cap and not a floor, and that supply-side DR resources are expected to competitively bid into the CAISO wholesale market, consistent with CAISO market rules and the Commission's DR principles adopted in D.16-09-056. We do, however, intend to revisit this requirement as needed and as more information is gathered on PDR bidding behavior and dispatch.

We therefore require that PDR bids may not exceed $949/MWh in either the day-ahead or real-time markets in order for those resources to be counted towards RA requirements. This requirement will help ensure that all available PDR resources are exhausted in the real-time market prior to enabling RDRR under EEA notice conditions. This requirement will take effect for the 2024 RA compliance year and will apply to all PDRs procured for RA and in all months, with the exception of DRAM resources contracted for the 2024 RA delivery year. If DRAM is extended beyond the 2024 delivery year, then the PDR bid cap will apply to DRAM resources in future years.

We reiterate that the PDR bid cap adopted here is imposed on LSEs strictly as an RA requirement, consistent with the Commission's authority and obligations under Public Utilities Code Section 380. Section 380(h) provides the Commission discretion to determine how to implement its RA program.[185] In particular, Section 380(h)(6) requires the Commission to determine and authorize

[185] "[W]hile [Section 380] sets out requirements for an RA program, subdivision (h) gives us discretion to determine the best way to implement those requirements." D.06-04-040 at 8-9.

the most efficient and equitable means to ensure "that investments are made and in new and existing demand response resources that are cost effective and help to achieve electrical grid reliability and the state's goals for reducing emissions of greenhouse gases." The proposed PDR bid cap is a limiter on RA eligibility and not on wholesale market participation generally. As noted in D.20-06-028, California's RA market is voluntary and nothing precludes suppliers from bidding, unconstrained, into the CAISO's day-ahead and real-time markets without any RA obligations.[186]

We also adopt Energy Division's proposal to verify compliance with the bid price cap by reviewing bid price requirements in DR tariffs/contracts "ex ante" and by reviewing bid data "ex post" to verify that the bid price cap was not exceeded. We authorize the Energy Division Director or their delegated Staff to issue correction or deficiency notices to LSEs if any PDRs shown on their Supply Plans are found non-compliant and the LSEs otherwise would not have had enough capacity to meet their RA requirements without the non-compliant PDRs.

We acknowledge SCE's concern that LSEs do not have control over how a third-party DRP bids its resources into the CAISO market. We recognize that LSEs may wish to revise their tariffs and contracts to require third-party DRPs to comply with the bid price cap or add contract provisions that allow LSEs to withhold payment until compliance with the bid price cap is verified or to pass through any RA penalties incurred due to uncured deficiencies and nothing in this decision would prohibit LSEs from doing so.

[186] D.20-06-028 at 36.

We also address the distinction Joint DR Parties made between Energy Division's proposed PDR bid cap and the existing $650/MWh bid cap for PG&E's Capacity Bidding Program (CBP), and we clarify that the PDR bid cap will apply to all PDRs procured for RA, including PDRs participating in CBP. In addition, in response to parties' comments that long-start PDRs cannot be bid into the real-time market, we clarify that the bid cap adopted here does not require such resources to bid into the real-time market for hours they are not already dispatched.

### 5.3. Expanding Prohibited Resources Policy

The Commission established the Prohibited Resources policy in D.16-09-056, which prohibited the use of distributed generation technologies using diesel, natural gas, gasoline, propane, or liquefied petroleum gas (Prohibited Resources) to achieve incremental load reduction in non-exempt DR programs during DR events. This prohibition applied to all DR providers, including third party DRPs. D.16-09-056 also required IOUs to require attestations for new non-residential customers and design an audit verification plan.[187]

Energy Division identifies that in recent years DR resources have been used by non-IOU LSEs to meet their RA obligations, in line with loading order.[188] Energy Division states that because the Commission's existing Prohibited Resources policy, established in D.16-09-056 and modified by D.18-06-012, was adopted for IOU-procured DR, there is a risk that customers who participate in DR procured by non-IOU LSEs could participate using prohibited resources to

[187] D.16-09-056 at OPs 3-5.

[188] Energy Division Phase 3 Proposals at 12.

serve load during a DR event. Energy Division asserts that such an outcome would undermine the Commission's goal for RA-eligible DR resources to be clean. Energy Division also identifies that the existing policy creates a competitive disadvantage for customers participating in IOU-managed DR programs.

Energy Division therefore proposes: (1) requiring all RA-eligible DR resources to abide by the Prohibited Resources policy as defined in D.16-09-056 and subsequent decisions and resolutions, (2) extending the Prohibited Resources Verification Plan to all RA-eligible DR resources, and (3) recovering associated costs through the existing mechanism or through another mechanism if adopted through the five-year DR programs and budget applications.

#### 5.3.1. Comments on Proposals

Joint Environmental Parties, SDG&E, and Cal Advocates support the proposal.[189] Joint Environmental Parties assert the Prohibited Resources policy should be applied to all RA-eligible DR resources, so that non-IOUs do not interpret the existing policy as a loophole.[190] Joint Environmental Parties also state that D.16-09-056 found that Pub. Util. Code Section 380.5 makes clear that efforts to incorporate DR into the RA program should also reduce GHG emissions.[191] SDG&E asserts that Commission adoption of this requirement will place IOU DR on equal footing with third-party DR and will further the Commission's goals of reducing GHG emissions.[192] Cal Advocates argues that

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[189] Joint Environmental Parties Opening Comments at 5, SDG&E Opening Comments at 5, Cal Advocates Opening Comments at 15.

[190] Joint Environmental Parties Opening Comments at 6.

[191] *Id*. (referencing D.16-09-056 at 92).

[192] SDG&E Opening Comments at 5.

the enforceable prohibition of fossil fueled generation from DR is required to enforce California's clean energy policies.[193]

SCE agrees that the Prohibited Resources policy should apply to all RA-eligible DR resources, but believes this issue would be more appropriately handled in the DR proceeding.[194] Enchanted Rock supports the proposal but requests that the requirements should be augmented to allow RPS-eligible fuels' participation in DR programs to allow microgrids to participate.[195] Mainspring requests the Commission take an approach that allows resources that are capable of fuel switching between non-renewable and renewable fuels to be allowed to participate in DR programs.[196]

#### 5.3.2. Discussion

We agree with Energy Division and parties that extending the Prohibited Resources policy to all RA-eligible DR resources is in line with the Commission's initiating objectives in adopting the original Prohibited Resources policy in D.16-09-056 and aligns with state policy that DR resources participating in RA programs should be clean. With regard to the proposals from Enchanted Rock and Mainspring to expand the renewable fuel eligibility definition, we find this question out of scope for this proceeding.

We therefore adopt Energy Division's proposal and require, beginning with the 2024 RA compliance year, that (1) all RA-eligible DR resources must abide by the Prohibited Resources policy as defined in D.16-09-056 and subsequent decisions and resolutions, (2) the Prohibited Resources Verification

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[193] Cal Advocates Opening Comments at 15.

[194] SCE Opening Comments at 12.

[195] Enchanted Rock Reply Comments at 4.

[196] Mainspring Reply Comments at 2.

Plan applies to all RA-eligible DR resources, and (3) associated costs of implementation shall be recovered through the existing mechanism or through another mechanism if adopted through the current or subsequent five-year DR programs and budget applications.

### 5.4. Dispatch Requirements for Emergency DR Resources Qualifying for RA

Prior Commission decisions transitioned RDRR into a price-responsive product in order to make it more useful and to make it available for dispatch prior to CAISO procuring emergency supplies from neighboring balancing authorities or exceptionally dispatching resources.[197]

Energy Division expresses concern that the current RDRR dispatch approach results in RDRR being underutilized.[198] Energy Division explains that under CAISO's interpretation of NERC protocols, RDRR is prevented from being dispatched during or before an EEA 1 and if these resources are dispatched, CAISO automatically escalates to an EEA 2. In addition, market prices tend to increase substantially when the marginal clearing price is set by RDRR bids.

Energy Division asserts that this dispatch approach effectively means that RDRR is not providing RA because the resources are not used for mitigation or avoidance of emergencies, but only mid-emergency management. Moreover, while CAISO can declare an EEA Watch in the day-ahead or day-of timeframe when CAISO forecasts "one or more hours may be energy deficient,"[199] an EEA 2 must be declared in real-time when all available resources are in use and CAISO

[197] *See* CPUC Reliability-Based Demand Response Settlement, R.07-01-041, Phase 3 at 4-5 (adopted in D.10-06-034); D.18-11-029 at 23.

[198] Energy Division Phase 3 Proposals at 17.

[199] CAISO Operating Procedure 4420 at 7.

is no longer able to meet expected energy requirements.[200] As a result, Energy Division notes that these resources are infrequently dispatched. Therefore, rather than displacing procurement and preventing scarcity conditions, the current set of dispatch practices for RDRR contributes to the conditions it is meant to avoid – emergency procurement from neighboring balancing authorities and scarcity pricing.

Energy Division asserts that, in effect, ratepayers are paying twice, because RDRR receives RA capacity payments but does not appear to be meeting its intended objective of displacing procurement, addressing or mitigating scarcity pricing, or avoiding reliability event emergency conditions.

To address this, Energy Division proposes that RDRR (including the Base Interruptible Program (BIP)) may not count towards RA requirements unless it is available to be dispatched before an EEA 2. Specifically, Energy Division proposes that either: (1) RDRR not count towards RA requirements under the current paradigm in which these programs are only dispatched by CAISO at an EEA 2, or (2) RDRR count toward RA requirements, but only if the IOUs are able to dispatch RDRR at a day-of EEA Watch, or before or during an EEA 1. Energy Division further proposes that the IOUs be given discretion regarding when to dispatch RDRR to avoid the need for an EEA Watch, but be required to dispatch under all EEA conditions, including a day-of EEA Watch notice.

### 5.4.1. Comments on Proposal

CAISO generally supports Energy Division's proposal. CAISO agrees that in order to qualify as RA, RDRR should be available for dispatch at least upon a

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[200] *Id*. at 9. A third criterion for EEA 2 in Operating Procedure 4420 is that CAISO is still able to maintain minimum Contingency Reserve requirements. Failure to maintain minimum Contingency Reserve requirements triggers an escalation to EEA 3 and preparations for involuntary load drop.

declaration of an EEA Watch by CAISO, which would allow RDRR to be available for economic dispatch in real time.[201] CAISO recognizes this approach could result in more frequent dispatch of RDRR than in the past, but asserts that it would continue to respect DR resource use limitations.[202] CAISO also clarifies that in 2018 it made a tariff clarification that allowed it to dispatch RDRR *before* seeking emergency assistance from other balancing areas. Prior to this change, RDRR was only eligible for dispatch immediately prior to canvassing other balancing authorities.[203]

CLECA, SCE and Vistra oppose Energy Division's proposal. CLECA asserts that if RDRR were dispatched in advance of an EEA Watch that it would be a dramatic change from current dispatch rules. CLECA also asserts that the current approach is consistent with the 2010 settlement agreement that was approved in D.10-06-034, and cautions that calling RDRR too soon could lead to customer fatigue and reaching dispatch limits unnecessarily.[204]

SCE argues that the Energy Division's proposal could lead to attrition and thereby jeopardize reliability, as RDRR participants agreed to participate in the program with the understanding that it would be used as a last resort, and that the proposal would essentially make RDRR resources the same as all other resources with the likelihood of more frequent dispatch.[205] SCE also asserts that Energy Division's proposal would upend the 2010 settlement, which SCE argues established that RDRR would be used as a last resort only before canvassing

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[201] CAISO Opening Comments at 9.

[202] *Id.*

[203] *Id.* at 10.

[204] CLECA Opening Comments at 3-9.

[205] SCE Opening Comments at 6.

other balancing authorities.[206] SCE further states that if Energy Division intends for RDRR resources to be reverted to load modifying resources, SCE would support exploring that change but asserts it would be more appropriately considered in the DR proceeding.[207]

Vistra is concerned that calling on RDRR during an EEA Watch may be a premature use of "emergency" DR, as EEA Watch is more likely to be noticed when the concern does not materialize even without intervention.[208] Vistra states that its support for the proposal would be contingent upon only allowing CAISO to have the ability to call resources and if Vistra's proposal on bid limits is adopted, which would ensure RDRR wouldn't inappropriately suppress scarcity price signals.[209]

PG&E appreciates the rationale behind Energy Division's proposal, but observes that it may be operationally challenging or infeasible for certain RDRR participants to participate in earlier or longer duration dispatches, which could result in customer attrition or reduction in RDRR performance.[210]

MRP understands Energy Division's intention to have resources available before an emergency is declared, but has concerns that if RDRR were dispatched earlier, there could be risk that RDRR would be used as a market price manipulation product instead of a reliability product.[211]

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[206] *Id.*

[207] *Id.* at 7.

[208] Vistra Opening Comments at 30.

[209] *Id*.

[210] PG&E Opening Comments at 15.

[211] MRP Opening Comments at 24.

### 5.4.2. Discussion

Based on the information in Energy Division's proposal, the Commission is persuaded that RDRR as currently dispatched is being underutilized and is not delivering the same reliability value that we expect from RA-qualifying resources. The Commission's overriding objective for RDRR is that it should be available to mitigate or avoid an emergency grid reliability condition.

The Commission agrees that additional consideration of Energy Division's full proposal is necessary before adoption and therefore, we decline to adopt the proposal as written at this time. That said, we find that clarification of the role of RDRR in maintaining reliability under current rules and structures is warranted here.

In D.10-06-034 (RDRR Settlement Decision), the Commission adopted a settlement in which CAISO enabled RDRR bids to be available for dispatch before CAISO emergency measures are engaged.[212] In D.18-11-029, affirming the RDRR settlement, we clarified the appropriate dispatch order under CAISO's (now defunct) Alert, Warning, Emergency (AWE) system.[213]

Here, the Commission is faced with a similar question of when and how to appropriately dispatch RDRR. Due to the transition from the AWE system to NERC's EEA protocols, clarification is warranted as to what stage in the EEA sequence RDRR should be deployed. Based on the rationale articulated in D.10-06-034 and affirmed in D.18-11-029, we maintain that RDRR as a reliability

[212] D.10-06-034 at 14.

[213] D.18-11-029 at 40.

resource should be deployed before non-RA emergency resources in order to qualify for RA.[214]

Under CAISO's current operating procedures, RDRR is characterized as an emergency-triggered resource, and as such can only be enabled into the market during EEA 1. When RDRR is dispatched according to conditions in the real-time market, CAISO therefore must escalate its grid emergency status to EEA 2 pursuant to its interpretation of NERC protocols. This dispatch practice is inconsistent with the Commission's principle that RDRR should be available before non-RA emergency resources in order to qualify for RA. To provide consistency between the Commission's established principle for RDRR and CAISO's dispatch practices, the Commission clarifies that CAISO should be allowed to use RDRR, as an RA resource, for economic or exceptional dispatch upon the declaration of a day-of EEA Watch (or when a day-ahead EEA Watch persists in the day-of). We note that this is consistent with part of Energy Division's proposal to align the trigger to a day-of EEA Watch as a condition of RA-eligibility, which is supported by CAISO.

This clarification also addresses the concerns of some parties, such as CLECA, SCE, PG&E, and Vistra, that additional use of RDRR could result in customer fatigue and/or program attrition. We note that a day-of EEA Watch is only called when CAISO forecasts an energy deficiency of one or more hours later in the day, which is a condition we have determined should enable

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[214] *See* D.10-06-034 at 13; D.18-11-029 at 40. In D.10-06-034, the Commission provided that:

> A goal of this new [RDRR] product is to improve the cost-effectiveness of reliability-triggered DR by enabling it to work better in the CAISO's dispatch sequence. Specifically, a reliability-triggered DR product should enable the CAISO to use this resource before buying "exceptional dispatch" energy or capacity. (D.10-06-034 at 13)

RDRR.[215] We further note that if the RDRR trigger were later in the EEA sequence, RDRR would only be enabled to mitigate emergency conditions, not to help prevent them.

In summary, the Commission maintains that when RDRR is dispatched pursuant to conditions described in this decision, CAISO should not need to escalate its grid emergency status to EEA 2 (an emergency condition), thus ensuring that RDRR is available to avoid a reliability emergency.[216] Because the Commission is clarifying an existing policy, this clarification is effective immediately. The Commission recognizes that one or more of the IOUs' tariffs, such as SCE's BIP tariff, may define their program triggers in a way that is inconsistent with the Commission's clarification. If tariff adjustments are needed to operationalize the RDRR dispatch trigger, an IOU is required to submit those tariff adjustments as a Tier 1 Advice Letter within 10 days of the effective date of this decision.

### 5.5. Transmission Loss Factor and Planning Reserve Margin Adders for DR Resources

DR resources currently receive a Transmission Loss Factor (TLF) adder and a PRM adder. In 2010, the Commission determined that DR resources should be awarded a TLF adder, as these resources are supplied at the customer meter level and therefore eliminate the need to account for transmission line losses.[217] Under this method, QC values for DR resources are "grossed up" for

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[215] When all other RA resources are committed, system conditions show a potential shortfall, and RDRR is needed to help maintain reliability in advance of deploying emergency, non-RA resources.

[216] We also note that even though RDRR would be enabled into the market earlier than EEA 1, the circumstances under which the emergency-triggered RDRR would be dispatched do not change.

[217] D.10-06-036 at OP 6.

avoided line losses. The current TLFs are 3 percent for PG&E, 2.5 percent for SCE, and 2.5 percent for SDG&E. Additionally, each LSE's CEC-adjusted forecast includes a PRM adder, which only applies to system RA. In D.21-06-029, the Commission reduced the PRM adder for DR resources from 15 percent to 9 percent to remove elements corresponding with operating reserves and ancillary services, leaving a 9 percent adder for forced outages and load forecast error. In that same decision, the Commission requested the CEC-led working group make recommendations on this issue amongst others.[218]

Energy Division identifies that transmission-level losses and the PRM cannot be dispatched by CAISO.[219] Because they cannot be dispatched, they cannot be bid, and therefore are not incorporated into NQC values. As a result, in order for both adders to be counted, Energy Division must "gross up" RA filings to provide RA credits to CAISO to account for these adders. As the number of DR providers and LSEs purchasing DR has increased, the administrative complexity for Energy Division of "grossing up" and applying the adders has grown significantly, with the calculations often adding credits of only a fraction of a MW.

With regard specifically to the TLF adder, Energy Division identifies that no other distribution-connected resources receive a transmission adder, so there is an inconsistency between the treatment of DR and other resources at this time.

With regard specifically to the PRM adder, Energy Division asserts that while the current PRM adder accounts for forecast error and forced outages, DR does not lower either factor because if the CAISO does not procure to meet load,

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[218] D.21-06-029 at OP 11.

[219] Energy Division Phase 3 Proposals at 19.

there would be no DR load to curtail. Energy Division additionally notes that the CAISO has stated that there is no evidence that DR lowers the system forecast error or the system average forced outage rate.[220]

Energy Division's view is that the administrative burden of "grossing up" RA filings to account for these adders is not currently outweighed by the relatively small ratio of MW that are being processed, and that these related MW do not add to or further support reliability. Energy Division therefore proposes removing the TLF and PRM adders for DR resources.

#### 5.5.1. Comments on Proposal

CAISO, DMM, and SDG&E support the proposal. CAISO strongly supports the proposal and asserts that DR adders over-estimate the amount of available load reduction to CAISO on stressed system days, so CAISO believes that removing the adders will help mitigate potential capacity shortfalls during critical periods.[221] CAISO also reiterates that with regard to the PRM adder, there is no evidence that supply-side DR reduces load forecast error or forced outages of other resources.[222] DMM asserts that its recent studies have shown that the adders have resulted in RA values that overestimate the availability of DR capacity.[223] DMM specifically cites that during high load days in summer 2022 bid in DR capacity (including TLF and PRM adders) averaged only 67 percent of their credited RA value.[224] SDG&E believes it would be more

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[220] "Track 4 Proposals of the CAISO" in R.19-11-009, January 28, 2021, at 9.

[221] CAISO Opening Comments at 8.

[222] *Id.*

[223] DMM Opening Comments at 1.

[224] *Id.* at 1-2.

appropriate for DR to receive a QC or ELCC-like valuation, similar to other resources, rather than receive adders.[225]

Joint DR Parties, CESA, CLECA, and SCE oppose the proposal. Joint DR Parties, CESA and CLECA believe the Commission should defer to the CEC Working Group Report on the issue of adders, as this process included significant stakeholder engagement.[226] Joint DR Parties and CLECA assert that just because CAISO does not currently include a mechanism to gross up transmission losses, as it does for distribution losses, this does not negate the fact that DR avoids transmission losses.[227] Joint DR Parties are also concerned that removal of the adders would create an inconsistency between the way supply-side DR and load modifying DR are valued, with load modifying DR essentially being more highly valued even though both resources provide load reduction.[228] CESA disagrees with the rationale that the TLF should be removed based solely on the argument that it would reduce administrative burden on Staff.[229] SCE opposes the proposal to remove the TLF adder, arguing that DR supplied at the customer meter level avoids line losses because power does not need to be transmitted across the transmission and distribution system.[230]

The CEC Report addressed both adders per Commission request in D.21-06-029. The CEC Report recommends eliminating the operating reserves and load forecast error components of the PRM adder and converting the forced

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[225] SDG&E Opening Comments at 5.

[226] Joint DR Parties Opening Comments at 8, CLECA Opening Comments at 10, CESA Opening Comments at 11-12.

[227] Joint DR Parties Opening Comments at 7, CLECA Opening Comments at 9-10.

[228] Joint DR Parties Opening Comments at 7-8.

[229] CESA Opening Comments at 12.

[230] SCE Opening Comments at 12.

outage component to a 5.8 percent multiplier in the capacity shortfall penalty as part of its recommended QC methodology, but does not opine on whether the forced outage component should be maintained if its QC methodology is not adopted.[231] The CEC Report recommends conducting a TLF study to update the TLF values, but does not take a position on whether the current values should be maintained or eliminated.[232]

#### 5.5.2. Discussion

In D.23-04-010, the Commission stated that:

> In comments on the proposed decision, parties support revisiting the TLF adder issue in Phase 3 of the Implementation Track and we agree that additional consideration is necessary. In the interim, the Commission agrees that for the test year, the DLF and TLF adders should be retained to apply to DR.[233]

The Commission further stated in D.23-04-010 that "at this time there is insufficient record to address the PRM adder" for the 2024 SOD test year and that "[t]his issue will be considered in Phase 3 of the Implementation Track, alongside the CEC's DR Working Group Report recommendations."[234]

In D.23-04-010, the Commission stated that the crediting effort associated with the TLF adder "requires significant administrative overhead and complexity to account for a very small amount of incremental capacity value attributable to the TLF adder, often fractional MWs at the LSE level."[235] The Commission also agrees that there is a significant administrative burden on

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[231] CEC Report at 45-46.

[232] *Id.* at 46.

[233] D.23-04-010 at OP 12.

[234] *Id.* at 55.

[235] *Id.* at 54.

Energy Division Staff associated with applying the PRM adder to DR resources. The record does not demonstrate that this administrative burden for both the TLF and PRM adders is outweighed by the potential value of the relatively small amount of MW associated with the adders.

With respect to the PRM adder, the record suggests that removal of the adder is likely to enhance reliability, particularly during stressed conditions, by removing the risk that the PRM adder over-estimates the amount of capacity available to the CAISO on high system stress days. With respect to the TLF adder, we acknowledge that the Commission's Avoided Cost Calculator includes avoided transmission line losses for distributed energy resources and that the Commission is undertaking an effort in the Distributed Energy Resources Cost Effectiveness proceeding (R.22-11-013) to further study and refine the value of those avoided line losses. The Commission may revisit this issue, should a more streamlined process for incorporating TLF values into the CPUC and CAISO processes be identified in the future.

Based on this, we find it appropriate to discontinue the use of TLF and PRM adders for DR resources. Accordingly, the TLF and PRM adders will be removed for DR resources beginning with the 2024 RA compliance year and will also be removed for the 2024 SOD test year. We note that the DLF adder will be retained to apply to DR resources.

### 5.6. DR Availability Requirements

Current RA rules require all resources be available for a block of at least four consecutive hours on three consecutive days and must be able to run a minimum aggregate number of hours per month based on the number of hours that loads under CAISO control exceed 90 percent of peak demand in that month (which typically occurs during summer months).[236]

Energy Division identifies that current DR availability practice results in DR resources not being available when needed most. Energy Division cites to the DMM's report on resource performance in 2020 and 2021 that shows that a large portion of DR resource RA capacity was not available for dispatch during key peak net load hours and failed to perform when needed most under critical system conditions.[237] In addition, Energy Division identifies that regional demand reached historically high levels for a span of more than three consecutive days in 2022, (August 31–September 9), and under the existing rules, DR resources were not required to be available for the latter part of the extended high demand period.

To ensure DR resources are available when needed most, Energy Division proposes that DR resources: (1) must be available a minimum of three days per week with a minimum of four hours per day, for 24 hours per month, and (2) must additionally be available during all days during which a CAISO Flex Alert is called, up through the last day for which the CAISO has issued a Grid Warning, or the Governor's Office has issued an emergency notice. For example, in the event of a dispatch on day T, the resource must be available for a minimum of four hours on each of the following days:

> (3 Days [including day of dispatch, T]) + Flex Alert Days + Additional Days of Grid Warning or Governor-Issued Emergency Notice

[236] D.05-10-042 at OP 16.

[237] "2021 Annual Report on Market Issues Performance," CAISO and Western Energy Imbalance Market Department of Market Monitoring, July 27, 2022, at 26.

Energy Division asserts that this requirement would harmonize the availability requirements between DR resources and the needs of peak load.

#### 5.6.1. Comments on Proposal

DMM supports removing the ability for DR resources to take fatigue outages during tight system conditions, on days with any Flex Alerts, Grid Warning or Governor-Issued Emergency Notice designations and offers that DR resources can reflect their fatigue by bidding in at lower capacity.[238] DMM suggests that this may result in increased DR resource supply during peak conditions.[239] Vistra believes the proposal would provide consistency in treatment across RA-eligible resources, and asks for clarification on whether the requirements would apply to both PDR and RDRR.[240]

CLECA, Joint DR Parties, OhmConnect and SCE oppose Energy Division's proposal. CLECA argues that the new availability requirements would undermine existing BIP program limits, which have been carefully designed to reflect participants' constraints.[241] CLECA believes expansion of availability disregards participants' constraints and threatens viability of the RDRR program.[242] CLECA also notes that DMM's proposal to bid in a lower capacity would not work for RDRR providers, whose load is either on or off.[243] CLECA

[238] DMM Opening Comments at 3-4.

[239] *Id*.

[240] Vistra Opening Comments at 33.

[241] CLECA Opening Comments at 10.

[242] *Id*. at 13.

[243] CLECA Reply Comments at 7.

also believes the DR proceeding would be the more appropriate venue for considering such a proposal where it can be considered more holistically.[244]

Joint DR Parties and OhmConnect are concerned that the proposal lacks important implementation details that would create challenges for DRPs. For example, DRPs do not know that a Flex or Emergency Alert would be called before it happens and so it would be virtually impossible for a DRP to ensure that its capacity is offered in the day-ahead market ahead of an alert.[245] PG&E also expresses concern with this potential outcome.[246] The Joint DR Parties recommend that availability requirements be defined in such a way that DRPs know precisely when they are required to bid into the day-ahead market relatively well in advance of the close of bidding.[247]

SCE opposes the proposal, stating that RDRR resources are a resource of last resort because its participants are engaged in manufacturing food and medical products, supporting transit and port operations and are involved in other critical functions.[248] SCE also expresses concern that imposing these new requirements could have unintended and adverse policy ramifications including undermining the 2010 settlement agreement, the RDRR requirements and grid reliability.[249] It cites as an example the rate of customer attrition resulting from multiple emergency dispatches during the 2000-2002 Energy Crisis.[250]

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[244] CLECA Opening Comments at 11.

[245] Joint DR Parties Opening Comments at 9, OhmConnect Reply Comments at 4.

[246] PG&E Opening Comments at 15.

[247] Joint DR Parties Opening Comments at 10.

[248] SCE Opening Comments 6.

[249] *Id.* at 5-6.

[250] *Id.* at 8.

#### 5.6.2. Discussion

We agree with Energy Division that the Commission's DR availability requirements should help ensure that DR resources are available when the grid needs them most. While the existing DR availability requirements may have been sufficient to meet this criterion in the past, it is clear that adjustments are needed in order for DR to be available during the types of prolonged weather events we have experienced in recent years.

While we acknowledge parties' concerns that the additional requirements may create some challenges for certain DR participants, the instances in which the additional availability will be needed are limited and the need for the resources in those moments outweighs the potential for certain providers to be unable to perform.

We therefore adopt Energy Division's proposal to maintain the existing availability requirements and to add the requirement that DR resources must additionally be available during all days during which a CAISO Flex Alert is called, up through the last day for which the CAISO has issued a Grid Warning, or the Governor's Office has issued an emergency notice. This requirement is effective beginning with the 2024 RA compliance year. We clarify here that the term "Grid Warning" refers to the notifications issued under CAISO's EEA system and as implemented under the Procedure for System Emergencies and Operating Procedure for Emergency Notice.[251]

The Commission recognizes the operational constraints of certain industrial and manufacturing processes that may not be able to completely cease their operations. We therefore exempt RDRR resources from the requirement at

[251] CAISO Operating Procedures RC04010 and 4420, respectively.

this time. The Commission also acknowledges parties' concerns about submitting timely bids to meet this requirement. To that end, we specify that resources must be available during events for which alerts, notifications, and/or warnings are issued prior and up to the 10 a.m. day-ahead market deadline. For example, if a resource is dispatched and is performing between Monday, September 4 to Wednesday, September 6, and a Flex Alert is issued at 10 a.m. on Wednesday, September 6, the resource must be available for the additional days during which the Flex Alert is issued (*e.g.*, September 4-7).

We also acknowledge that many of the existing PDR resources (including long-start resources) may not be available or may be unable to submit timely bids if alerts, notifications, and/or warnings are issued after the 10 a.m. day-ahead market deadline. We will continue to monitor whether PDR resources are available when they are needed most and will consider enhancements, including adding requirements in response to day-ahead and/or real-time conditions, as appropriate in the future.

To implement this requirement, LSEs shall include contract language that DR resources: (1) must be available a minimum of three days per week with a minimum of four hours per day, and (2) must additionally be available during all days during which a CAISO Flex Alert is called, up through the last day for which the CAISO has issued a Grid Warning or EEA notification, or the Governor's Office has issued an emergency notice (the resource must be available for the duration of an Alert, Warning, or Notice that is issued prior and up to the 10 a.m. day-ahead market bid deadline).

### 5.7. Treatment of Late Requests of DR Monthly NQC

Energy Division identifies that DRPs frequently submit filings later than the deadline established in the RA guidelines for submitting monthly DR NQCs, which creates negative cascading effects for Energy Division Staff in its review and processing of these filings. To address this and minimize administrative burden, Energy Division proposes that DR NQC filings be made the first business day of the month two months prior to the requested month. As an example, under this approach, the submission deadline for the August 2023 RA showing would be June 1, 2023. Energy Division also proposes that failure to meet the deadline requirements would disqualify the month-ahead supply plan request.

This issue was not commented on by parties. The Commission finds that Energy Division's proposal is reasonable and will improve administrative efficiency of the RA program. We therefore adopt the requirement that, effective immediately, DR NQC filings must be made the first business day of the month two months prior to the requested month. Failure to meet the deadline requirements will disqualify the DRP's month-ahead supply plan request.

### 5.8. Treatment of DR Resources Failing to Perform During Testing

Current Commission rules require specific testing requirements for third-party DR resources procured by all non-IOU LSEs, including that:

- The DR resource must be dispatched for four consecutive hours in the RA window at least once every quarter, with dispatches fulfilled either through a CAISO market dispatch or an out-of-market test.
- The quarterly dispatch must be performed at the Resource ID level and concurrently within the same Sub-Load Aggregation Point (Sub-LAP).
- Dispatch performance results must be averaged over the four consecutive hours for each day.[252]

[252] D.20-06-031 at OPs 13, 14.

Energy Division observes that current test levels do not demonstrate that DR resources are performing reliably.[253] Energy Division's assessment is based on available 2022 test performance results, which were low in comparison to monthly supply plans, with actual performance ranging from 27 to 35 percent of what was shown in supply plans in Q2 of 2022 and from 23 to 58 percent of what was shown in supply plans in Q3 2022. In addition, Energy Division also identifies that DRPs are not submitting an updated filing when the resource portfolio falls below the threshold of 20 percent or 10 MW less than the assigned QC value, as required by D.20-06-031.

To address this underperformance, Energy Division proposes derating non-IOU DR resources procured from third-party DRPs that are unable to achieve their stated capacity in their test performance. Specifically, in order to account for the weather-dependent nature of DR, Energy Division proposes to apply derates that correspond to their respective performance during test events for a particular quarter. The average performance results for each quarter would inform the capacity awarded through the LIPs for the respective sub-LAP. For example, a 50 percent performance in Q1 2023 may lead to a corresponding derate of up to 50 percent in the Q1 2024 capacity awarded through the LIPs as filed in April 2023. In addition, Energy Division proposes that capacity could be further adjusted based on other relevant factors such as market dispatch performance results and reasonable enrollment forecasts. These adjustments would be assessed under the current LIP process.

[253] Energy Division Phase 3 Proposals at 24.

### 5.8.1. Comments on Proposal

DMM and Vistra support Energy Division's proposal. DMM agrees that incorporating test results in capacity awards would be a useful tool for improving the reliability of DR resources by incentivizing resources to provide accurate capacity estimates and to perform better when dispatched.[254] DMM believes that the lack of penalties associated with performance may explain why supply plan DR resources only curtail around 50 percent of their scheduled load reduction on high load days.[255] DMM also asserts that DR resources that consistently fail to fully deliver their scheduled load curtailments should have their capacity awards lowered to better reflect the actual amount of RA the resource provides.[256] Vistra argues that making this change will ensure that DR does not undermine reliability by overcounting its contribution.[257]

Joint DR Parties and OhmConnect oppose Energy Division's proposal. They believe it is premature to adopt the proposal because it conflicts with the CEC's DR QC counting proposal, which contains a penalty mechanism. [258] They also state that the proposal discriminates against third-party DR, as it does not address the issue of under-delivery for IOU DR programs, and it is based on only a limited set of test data encompassing only Q2 and Q3 2022.[259]

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[254] DMM Opening Comments at 2.

[255] *Id.* at 2-3.

[256] *Id.* at 3.

[257] Vistra Opening Comments at 31.

[258] Joint DR Parties Opening Comments at 10-11, OhmConnect Reply Comments at 4-6.

[259] *Id.*

#### 5.8.2. Discussion

It is clear from the test results referenced in Energy Division's proposal that third-party DR is not performing reliably in comparison to monthly supply plans. Performance in the range from 25 to 50 percent of what is on the supply plans is not an acceptable level of performance. We agree with DMM that incorporating test results in capacity awards could incentivize resources to provide accurate capacity estimates and to perform better when dispatched so that they can become a more reliable RA resource.

With regard to the concerns raised by Joint DR Parties and OhmConnect, as discussed above, this decision does not adopt the CEC's recommendations from its DR QC Working Group Report, so currently there is no alternative mechanism for improving the reliability of third-party DR resources. The Commission also acknowledges these parties' concern regarding differential treatment of DR resources managed by IOUs versus those managed by third parties and that the proposed adjustments only apply to third parties. We do, however, also acknowledge DMM's comment that IOU DR resources appear to have met a majority of the scheduled load reductions.[260]

We find that Energy Division's proposal to enforce performance requirements by derating the QC of third-party DR resources based on their performance during test events relative to their QC values will incentivize better performance and lead to more accurate representation of the actual amount of RA that third-party DR resources provide. We therefore adopt Energy Division's proposal to consider test performance failures when making capacity awards to non-IOU DR resources procured by third-party DR providers under the LIPs.

[260] DMM Opening Comments at 2.

This requirement is effective beginning with the capacity awards granted through the LIP process for the 2024 RA compliance year. Derates will be applied so that they correspond to performance during test events for the most recently available quarterly test results at the time of the award for the relevant quarter. The average performance results of each quarter will inform the capacity awarded through the LIPs for the respective sub-load aggregation point.

## 6. Summary of Public Comments

Rule 1.18 allows any member of the public to submit written comment in any Commission proceeding using the "Public Comment" tab of the online Docket Card for that proceeding on the Commission's website. Rule 1.18(b) requires that relevant written comment submitted in a proceeding be summarized in the final decision issued in that proceeding.

## 7. Comments on Proposed Decision

The proposed decision of ALJs Chiv and O'Rourke in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on June 14, 2023 by: AReM and Regents of the University of California (UC) (jointly, AReM/UC), CAISO, CalCCA, CCCE, CESA, Clean Power Alliance of Southern California and Peninsula Clean Energy Authority (jointly, Joint CCAs), CLECA, CEDMC/CPower, East Bay Community Energy (EBCE), GPI, IEP, Leap Power, Inc. (Leap), MCE, Microsoft, MRP, OhmConnect, PG&E, SCE, Shell and Vistra. Reply comments were filed on June 19, 2023 by: AReM/UC, CAISO, Cal Advocates, CalCCA, CEERT, CLECA, CEDMC/CPower, DMM, IEP, Leap, MRP, PG&E, SCE, Shell, Valley Clean Energy Alliance (VCE), and WPTF.

All comments have been carefully considered. Significant aspects 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.

CAISO, Microsoft, and MRP comment that the PRM should not be adopted for 2025 at this time, stating generally that there is uncertainty regarding the results of the PRM calibration process for the SOD framework and insufficient record to ensure the PRM and effective PRM are reasonable for 2025.[261] IEP asserts that the Commission should allow the possibility of modifying the PRM in 2025 in light of market developments.[262] Cal Advocates responds that there will be uncertainty with implementing the SOD framework and that applying a 17 percent PRM for 2024 and 2025 provides a counter-balance of certainty for LSE's procurement planning, as changing the 2025 PRM in early 2024 gives LSEs little time to adjust procurement planning.[263] MRP requests Energy Division publish the results of the conversion tool to establish the PRM for the SOD framework, as it is unclear whether the traditional PRM from the LOLE study would ensure reliability under a SOD framework.

[261] CAISO Opening Comments on Proposed Decision at 1, Microsoft Opening Comments on Proposed Decision at 11, MRP Opening Comments on Proposed Decision at 8.

[262] IEP Opening Comments on Proposed Decision at 2.

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

For the reasons stated in the decision, the Commission finds it reasonable and prudent to adopt a PRM of 17 percent and the effective PRM for the 2024 and 2025 RA years, and declines to modify the decision. As stated in D.23-04-010 at Ordering Paragraph 14, after Energy Division modifies the SOD calibration tool, Energy Division will publish the draft calibration tool on the Commission's website and solicit informal party comments.

PG&E comments that D.21-12-015 required IOUs to file non-binding month-ahead RA filings, as part of the adoption of the effective PRM.[264] PG&E recommends removing this requirement, stating that the original intent of this was to provide insight into contracted RA resources so state agencies could develop a better understanding of supply conditions and that this need no longer exists. The Commission concludes that the non-binding month-ahead RA filings continue to provide important information to assess market supply conditions and declines to modify this requirement from D.21-12-015.

Numerous parties, including AReM/UC, CalCCA, CCCE, EBCE, MCE, Shell, and VCE, oppose the LSE expansion rule for various reasons.[265] CalCCA argues that the expansion rule exceeds the Commission's jurisdiction over CCA implementation plans generally and that basing the "earliest possible date" on an LSE's compliance history exceeds statutory authority to address cost shifts between groups. CCCE asserts that the expansion rule exceeds the Commission's authority under AB 117 and D.05-12-041. Shell comments that the

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

[265] AReM/UC Opening Comments on Proposed Decision at 2, CalCCA Opening Comments on Proposed Decision at 2, CCCE Opening Comments on Proposed Decision at 3, EBCE Opening Comments on Proposed Decision at 2, MCE Opening Comments on Proposed Decision at 2, Shell Opening Comments on Proposed Decision at 1, VCE Reply Comments on Proposed Decision at 1.

Commission has no statutory authority to curtail retain choice. AReM/UC argue that Section 366.2 is limited to CCAs and does not apply to ESPs.

CCCE and CalCCA contend that there is no evidence demonstrating a cost shift from deficient LSEs to compliant LSEs, and CalCCA states that there is no evidence that deficient LSEs rely on other LSEs' procurement or that allowing deficient LSEs to expand is detrimental to grid reliability. CalCCA and Shell argue that the expansion rule is discriminatory to non-IOUs because the rule does not apply to IOUs as their territories do not expand and IOUs are required to serve any new customer that requests service.

The Commission disagrees that Sections 366.2 or Section 365.1 constrain the Commission's ability to ensure CCAs seeking to expand service are capable of meeting their RA requirements. The Commission has statutory obligations to ensure energy reliability at just and reasonable rates and specific authority to ensure RA compliance. While the Public Utilities Code includes some specific sections regarding CCA certifications, our approach harmonizes the statutory scheme as a whole, including Sections 380, 365.1 and 366.2. Both CCA and ESP related statutes provide ways for the Commission to revoke the ability of such LSEs to operate if it shows the LSEs are unable to effectuate their primary functions of serving customer load consistent with their Commission-allocated RA obligations. Under the rule adopted today, the Commission does not claim an ability to revoke an LSE's authority to operate, but merely to ensure it may not expand if an LSE cannot satisfy its minimum RA procurement requirements as demonstrated by compliance failures. As discussed above, the Commission has clear statutory authority to ensure energy supply reliability and the inability (and in many instances, repeated inability) of some LSEs to meet minimum procurement requirements implies business choices that must take into account each LSE's duty to provide a reliable energy supply for its customers.

As discussed above, the expansion rule does not discriminate against CCAs and ESPs, rather it provides consequences for those CCAs and ESPs that fail to meet statutorily directed minimum reliability requirements expected of all LSEs and that lean on the procurement of other LSEs to provide energy for customers. Section 380, and the Commission's prior decisions interpreting it and related statutes, provide substantial evidence that failure to meet RA requirements threatens grid reliability. Accordingly, we decline to remove the LSE expansion requirement adopted in this decision.

AReM/UC and Shell argue that the expansion rule should only apply to future deficiencies as LSEs should not be sanctioned for past conduct that occurred before the rule was adopted.[266] We provide clarification that only prospective RA deficiencies accrued after the effective date of this decision will apply to the adopted expansion requirement. In other words, the first RA year-ahead deficiencies to be applied will be the 2024 year-ahead filing due on October 31, 2023, and the first month-ahead deficiency to be applied will be the September 2023 month-ahead filing. The decision has been modified with this clarification.

AReM/UC and Shell recommend that the expansion rule be limited to 24 months, not two calendar years, because CCAs typically enroll new service territories in January while ESP customer enrollment is staggered.[267] The

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[266] Shell Opening Comments on Proposed Decision at 12, AReM/UC Opening Comments on Proposed Decision at 2.

[267] AReM/UC Opening Comments on Proposed Decision at 9, Shell Opening Comments on Proposed Decision at 12.

Commission declines to modify the two-year retrospective analysis of RA compliance. RA requirements are based on an annual cycle and a binding load forecast must be submitted to meet year-ahead requirements for the year of an LSE's proposed expansion. Further, the Commission seeks to avoid potential willful gaming of compliance timelines.

AReM/UC and EBCE proposes that the rule only apply to deficiencies greater than 1 percent of an LSE's procurement requirement, similar to the threshold in the RA penalty point structure adopted in D.21-06-029, or using a 2.5 percent threshold, as proposed by Energy Division.[268] EBCE comments that the rule should only apply to substantive RA deficiencies and not to deficiencies that are cured by the LSE within five days after Energy Division's notification of the deficiency. In D.21-06-029, we adopted a rule that if an LSE's month-ahead deficiency "is less than 1% of the LSE's system RA requirements, no points will be accrued."[269] The Commission finds it reasonable that the 1 percent threshold adopted in D.21-06-029 should apply to the expansion requirement as well. We note that an LSE that incurs any system RA deficiency, even less than 1 percent of its system requirements, is still subject to the RA penalty process, as established in past Commission decisions. The decision has been modified with this change.

The Commission clarifies that deficiencies cured within five business days from the date of notification by Energy Division will not count towards the expansion rule. The Commission agrees that administrative deficiencies will not count towards the expansion rule. In D.11-06-022, modifying in part Resolution

[268] AReM/UC Opening Comments on Proposed Decision at 7, EBCE Opening Comments on Proposed Decision at 2.

[269] D.21-06-029 at OP 16.

E-4195, the Commission adopted "Specified Violations," as distinct from substantive RA deficiencies. "Specified Violations" include an LSE's failure to file historic load data and file load forecasts in the time and manner required, as well as deficiencies cured within five business days from the date of notification by Energy Division. These "specified violations" will not be applied to the expansion rule adopted here. The decision has been modified with these changes.

AReM/UC, Joint CCAs, and MCE comment that the expansion rule should only apply to month-ahead deficiencies, not year-ahead deficiencies.[270] AReM/UC and MCE argue that year-ahead deficiencies that are eventually cured do not jeopardize system reliability, while Joint CCAs state that month-ahead deficiencies are a more realistic measure of reliability. Joint CCAs and MCE add that applying month-ahead deficiencies would incentivize LSEs to cure year-ahead deficiencies in the month-ahead timeframe.

The Commission agrees (with some caveats) that if an LSE "cures" its year-ahead RA deficiency in the month-ahead timeframe, the year-ahead deficiency will not be applied to the adopted expansion rule. However, this only applies to a year-ahead deficiency accrued two years before the year in which the LSE files its binding load forecast. To illustrate, Year 0 (Y0) is the year that an LSE files its binding load forecast with additional load it will serve. An LSE must meet its year-ahead and month-ahead requirements in the two years before Y0 (that is, Year Minus 1 (Y-1) and Year Minus 2 (Y-2)). If an LSE receives a year-ahead deficiency in Y-2 and "cures" that deficiency in the month-ahead process in Y-1, the Commission finds it reasonable to remove the Y-2 deficiency from applying

[270] Joint CCA Opening Comments on Proposed Decision at 3, MCE Opening Comments on Proposed Decision at 2, AReM/UC Opening Comments on Proposed Decision at 7.

to the expansion rule. A year-ahead deficiency in Y-1, however, will necessarily apply to the expansion rule because there is insufficient time for the LSE to cure the Y-1 deficiency in the Y0 month-ahead timeframe, as the LSE will have filed its binding load forecast commitments. Accordingly, the decision is modified with these changes and the following table is adopted:

| System RA Deficiencies That Apply to the LSE Expansion Requirement | |
|---|---|
| Year Plus 1 (Y+1) | Year that an LSE elects to expand |
| Year 0 (Y0) | Year that an LSE files its April load forecast |
| Year Minus 1 (Y-1) | (1) Month-Ahead deficiencies apply<br>(2) Year-Ahead deficiency (for Y0) applies<br>*Note: CCA Implementation Plans for Y+1 are filed by Dec 31 of Y-1. |
| Year Minus 2 (Y-2) | (3) Month-Ahead deficiencies apply<br>(4) Year-Ahead deficiency (for Y-1) applies, unless Year-Ahead deficiency is cured in the Month-Ahead timeframe in Y-1 |

AReM/UC and Shell seek clarification about the definition of "new customers" or "new direct access customer."[271] AReM/UC recommend "new direct access customer" be defined as "one new to the DA program, *i.e.* entering the DA program from IOU or CCA service via the DA lottery without any existing DA service accounts." Shell recommends that "new Direct Access customers" should not include existing ESP customers that are adding a new service account or switching from one ESP provider to another. These parties state that this would be more consistent to treatment of CCAs that can expand

[271] AReM/UC Opening Comments on Proposed Decision at 8, Shell Opening Comments on Proposed Decision at 12.

their customer base in existing territories, and would resolve ambiguity regarding customer relocations, which should not be treated as a new customer.

The Commission clarifies that an ESP's existing customers may experience load expansion, relocation, and changes in their service accounts (including adding new accounts from the ESP's existing customers) during the expansion pause period. However, ESPs may not take on customers switching from another ESP or entering the DA program from IOU or CCA service via the DA lottery. The decision has been modified with this clarification.

AReM/UC comment that the decision refers to ESPs not being able to "enroll any new customers" and later than ESPs are restricted from "signing new direct access customers."[272] AReM/UC state that ESPs may have signed contracts before the rule was in place with customer enrollment dates that begin after the restriction. AReM/UC recommend that the rule should not apply to ESP enrollments for contracts signed before an ESP incurs a deficiency that triggers the restriction. As discussed above, the Commission has modified the decision to apply to prospective RA deficiencies following the effective date of this decision. We maintain that the rule will apply to the signing of direct access customers after the effective date of this decision.

Several parties oppose using an LSE ID for non-resource specific RA imports. CAISO asserts it is infeasible to implement because import resource IDs only include a Scheduling Coordinator ID and there is no association between resource IDs and LSE IDs in the Master file registration process.[273] CAISO adds that it generates import resource IDs for all import resources, not just those

[272] AReM/UC Opening Comments on Proposed Decision at 10.

[273] CAISO Opening Comments on Proposed Decision at 9.

contracted with LSEs for RA, and import RA IDs may represent capacity with several LSEs and potentially non-RA capacity. Instead, CAISO suggests that it and Energy Division work to identify what additional data could help Energy Division's compliance concerns. CCCE argues that requiring an LSE ID is at odds with how RA imports are executed in the market and if real-time substitutions must be duplicated over many resource IDs, this will likely reduce the supply of import RA.[274] WPTF agrees that using LSE IDs would increase administrative burdens and operational costs for import suppliers, reducing the import supply to California.[275]

In considering CAISO's comments, the Commission agrees it is not feasible for CAISO to incorporate LSE IDs for RA imports at this time, and we agree that the requirement should be removed from the decision. Rather, the Commission authorizes Energy Division to work with CAISO to identify the appropriate resource ID registration process that will allow non-resource specific RA import IDs to be mapped to the contracted LSE, when the LSE is not the scheduling coordinator. Energy Division should further investigate the real-time market reliability and liquidity concerns raised by parties, and submit a proposal into the RA proceeding as warranted. The decision is modified with these changes.

CalCCA and CCCE seek clarification as to when an LSE goes from Tier 2 in the year-ahead filing down to a Tier 1 in a month-ahead filing, which could occur where penalty points expire after two years.[276] CalCCA recommends all year-ahead deficiencies be penalized at the Tier 1 price and the balance collected in the

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[274] CCCE Opening Comments on Proposed Decision at 6.

[275] WPTF Reply Comments on Proposed Decision at 4.

[276] CalCCA Opening Comments on Proposed Decision at 15, CCCE Opening Comments on Proposed Decision at 7.

month-ahead process when the LSE moves down a tier. CCCE recommends a formula where year-ahead penalties are charged at the Tier 1 price; then, for the month-ahead penalty, an LSE pays the difference between the month-ahead penalty and Tier 1 penalty already paid on its year-ahead deficiency, plus the current tier price on any incremental month-ahead deficiency.

The Commission finds CCCE's recommended formula below to be reasonable and the decision is modified to include this formula.

$$\text{Year-Ahead penalty} = \text{Deficiency}^{\text{Year-Ahead}} \times \text{Tier 1 Price}$$

$$\text{Month-Ahead penalty} = [(\text{Deficiency}^{\text{Year-Ahead}} \times \text{Tier Price}^{\text{Month-Ahead}}) - \text{Year-Ahead penalty}] + (\text{Deficiency}^{\text{Month-Ahead incremental}} \times \text{Tier Price}^{\text{Month-Ahead}})$$

AReM/UC, CalCCA, and Shell oppose eliminating the monthly true-up and state that there are instances where a monthly true-up is needed to prevent large cost shifts.[277] AReM/UC state that while the load change amount may be a small fraction of overall system demand, to a small LSE this may have a large impact to their total demand. Shell and AReM/UC suggest allowing monthly true-ups if the migrating load is greater than 50 MW. While the Commission understands the issue of cost shifts may have larger impacts on smaller LSEs, we find that allowing monthly true-ups for 50 MW of migrating load or greater for all LSEs will continue to burden Commission Staff. We decline to adopt this threshold. However, recognizing parties' concerns with eliminating the load forecast update entirely, we find it reasonable to allow one load migration update in February to cover May to December load migration, similar to the local

[277] AReM/UC Opening Comments on Proposed Decision at 14, Shell Opening Comments on Proposed Decision at 13, CalCCA Opening Comments on Proposed Decision at 14.

and flexible RA true-up process today. The decision has been modified to reflect this.

SCE recommends removing the modified confidentiality matrix, stating that it is unnecessary and adds administrative and compliance challenges for utilities, especially when the modifications do not substantively change the existing matrix.[278] PG&E disagrees and argues that the modifications to the matrix are necessary to define the more narrow protections that apply to information being requested for transparency.[279] PG&E states that without the modifications to the matrix, the bid and offer data requested would be defined as confidential information. The Commission agrees with PG&E and declines to modify the decision.

CEDMC/CPower, CLECA, CESA, Leapfrog, and Shell oppose a PDR bid cap and request a $949/MWh PDR bid cap, if the Commission determines a bid cap is needed.[280] CLECA asserts that $949/MWh is warranted as each PDR has an opportunity cost that may be dynamic and may exceed the proposed $500/MWh cap. CLECA also specifically recommends the $949/MWh bid cap be applied year round.[281] CESA argues a $949/MWh bid cap will achieve the Commission's goal for PDR to be dispatched before RDRR.[282] CEDMC/CPower identify that a $949/MWh minimizes the potential that PDRs may reach their

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[278] SCE Opening Comments on Proposed Decision at 10.

[279] PG&E Reply Comments on Proposed Decision at 3.

[280] CEDMC/CPower Opening Comments on Proposed Decision at 8, CLECA Opening Comments on Proposed Decision at 16, CESA Opening Comments on Proposed Decision at 2, Leapfrog Opening Comments on Proposed Decision at 3-4, Shell Reply Comments on Proposed Decision at 3-4.

[281] CLECA Opening Comments on Proposed Decision at 13.

[282] CESA Opening Comments on Proposed Decision at 3.

dispatch limit before periods of most critical need. [283] Upon further consideration, we agree with parties that it is appropriate at this time to establish a PDR bid cap of $949/MWh, as this level will help ensure a more rational dispatch order and would minimize the potential of excluding resources that may have varying marginal costs from participating in the market when needed most. While it is appropriate to adopt a $949/MWh PDR bid cap at this time, we intend to revisit this requirement as needed and as more information is gathered on PDR bidding behavior and dispatch. We emphasize that the PDR bid cap is a cap and not a floor, and that supply-side DR resources are expected to competitively bid into the CAISO wholesale market, consistent with the Commission's DR principles adopted in D.16-09-056. The Commission has modified the decision with this change.

PG&E agrees with the exemption from the PDR bid cap for DRAM resources for 2024 and requests that consideration of whether to apply the PDR bid cap to DRAM resources after 2024 be deferred to the DR proceeding.[284] We decline to make this change, as the intention of this decision is for the bid cap to apply to all PDRs that are required to be dispatched into the real-time market.

CEDMC/CPower and SCE identify that long-start PDRs are not required to bid into the real-time market, and request the decision clarify that the bid cap proposal does not represent a requirement for long-start PDRs to bid or schedule into the real-time market for hours they are not already dispatched.[285] We agree

[283] CEDMC/CPower Opening Comments on Proposed Decision at 8.

[284] PG&E Opening Comments on Proposed Decision at 3.

[285] CEDMC/CPower Opening Comments on Proposed Decision at 7; SCE Opening Comments on Proposed Decision at 8.

that this clarification is warranted and the decision has been updated to reflect this.

CEDMC/CPower, CLECA and SCE oppose the Commission's clarification on the appropriate RDRR dispatch trigger. SCE specifically asserts that there is no support in the record of this proceeding or in D.10-06-034 or D.18-11-029 to support the Commission's principle that RDRR, as a reliability resource, should be deployed before non-RA resources.[286] SCE further argues that RDRR should not be read to harmonize with non-RA emergency resources that were created after the 2010 settlement and D.18-11-029.[287] CLECA agrees with SCE's assertion and argues D.10-06-034 contemplated more stringent conditions for triggering RDRR.[288] CEDMC/CPower similarly assert that the proposed decision inappropriately converts RDRR from an emergency resource to an economic resource.[289] SCE and CEDMC/CPower also view the triggering of RDRR dispatch at an EEA Watch as inconsistent with the existing trigger.[290]

We do not modify the RDRR dispatch section based on comments. We first address parties' assertions that the principle that RDRR, as a reliability resource, should be deployed before non-RA emergency resources, is not supported. These assertions are inaccurate. The 2010 settlement specifically contemplates RDRR being deployed in advance of non-RA emergency resources when it identifies that RDRR should be dispatched prior to CAISO canvassing

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[286] SCE Opening Comments on Proposed Decision at 2.

[287] *Id.* at 3.

[288] CLECA Opening Comments on Proposed Decision at 4.

[289] CEDMC/CPower Opening Comments on Proposed Decision at 9.

[290] SCE Opening Comments on Proposed Decision at 3, CEDMC/CPower Opening Comments on Proposed Decision at 10.

neighboring balancing authorities for available exceptional dispatch energy or capacity.[291] We next address the assertion that prior decisions would not allow RDRR dispatch to be harmonized with non-RA emergency resources that were created after D.10-06-034 and D.18-11-029. We disagree. The 2010 settlement describes the features of reliability-based DR programs to which the settlement would apply, indicating the Commission's intent that the settlement be harmonized with future resource offerings and not just specific offerings in existence at the time of the settlement.[292]

We also address the argument that the Commission's clarification converts RDRR from an emergency resource to an economic resource. This is similarly incorrect. As is discussed in this decision, the clarified RDRR dispatch trigger does not render RDRR a resource generally available for economic dispatch during normal system conditions, but rather maintains its availability during times of significant grid stress, which is consistent with the 2010 settlement.[293] With regard to concerns related to what stage RDRR is triggered, as discussed in this decision, the CAISO's transition to NERC protocols has necessitated a clarification of when RDRR should be appropriately dispatched, and the EEA Watch stage most appropriately aligns with the Commission's principle that RDRR be deployed before non-RA emergency resources. Finally, CAISO, a signatory to the settlement, states that it supports the Commission's clarification of the RDRR dispatch trigger, and its understanding that RDRR resources should be available for use to prevent emergency conditions rather than only after an

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[291] D.10-06-034, Appendix A at Section A(4)(l).

[292] D.10-06-034 Appendix A, Settlement at 2.

[293] D.10-06-034 Appendix A, Settlement at Section A.(4)(e).

emergency exists.[294] CAISO further asserts that it will continue to respect RDRR use limits, and would use its discretion to allow for fatigue breaks and minimum dispatch periods to avoid RDRR use during transient price spikes.[295]

CLECA, PG&E and SCE request that if the RDRR dispatch trigger is adopted, that implementation either be delayed until 2024 and/or the Commission allow participants sufficient time to opt out or change their firm service level.[296] We do not modify the decision to incorporate these requests. As the Commission is clarifying an existing definition, the operationalization is effective immediately.

SCE also identifies that tariff changes may be necessary for the IOUs to operationalize the RDRR dispatch trigger if adopted.[297] The Commission recognizes that one or more of the IOUs' tariffs, such as SCE's BIP tariff, may define their program triggers in a way that is inconsistent with the Commission's clarification. If tariff adjustments are needed to operationalize the RDRR dispatch trigger, an IOU is required to submit those tariff adjustments as a Tier 1 Advice Letter within 10 days of the effective date of this decision.

CLECA asserts that no substantial additional record regarding the TLF and PRM adders has been developed since the adoption of D.23-04-010 on April 4, 2023, which retained the adders, and therefore it would be inappropriate to remove the adders in this decision.[298] The record for D.23-04-010 was

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[294] CAISO Reply Comments on Proposed Decision at 4.

[295] *Id.* at 4-5.

[296] CLECA Opening Comments on Proposed Decision at 5, PG&E Opening Comments on Proposed Decision at 6, SCE Opening Comments on Proposed Decision at 5.

[297] SCE Reply Comments on Proposed Decision at 4.

[298] CLECA Opening Comments on Proposed Decision at 10-11.

submitted in December 2022 as part of Phase 2 of the Reform Track.[299] Since that time, as part of Phase 3 of the Implementation Track, an Energy Division staff proposal, and numerous comments on the TLF and PRM adders have been submitted into the record of this proceeding, and it is upon that record that this decision makes its determination. Therefore, CLECA's concerns with the extent of the record upon which the Commission's determination was made are without merit.

With regard to the adjustments to the DR availability requirements, SCE and PG&E request that existing DR contracts be exempt from the requirement, as they believe renegotiation of those contracts would be necessary to enforce the requirement.[300] When the Commission adopts a policy that adjusts RA program rules, it may be necessary for contracts to be renegotiated in order to ensure compliance with the new rules. An exception is not warranted in this instance. We therefore decline to exempt existing contracts from the expanded availability requirements.

With regard to the treatment of DR resources failing to perform during testing, OhmConnect argues that it would be unfair to derate QC based on testing that was conducted before the adoption of this decision because participants did not have notice that the results of testing would be used for this purpose.[301] While this decision does connect test results to the LIP QC adjustment process, DRPs were already expected to provide accurate capacity estimates and to perform when dispatched, so any testing approach used by

[299] D.23-04-010 at 4.

[300] SCE Opening Comments on Proposed Decision at 6; PG&E Reply Comments on Proposed Decision at 2.

[301] OhmConnect Opening Comments on Proposed Decision at 5-6.

DRPs should already reflect a best attempt at estimating and performing reliably, and would be appropriate to use for the purposes of QC adjustment. We therefore decline to delay implementation of the requirement.

The Commission is not persuaded by the cases cited by OhmConnect.[302] While *Stillwater Mining Co. v. Federal Mine Safety & Health Review Comm'n* provides that regulatory settings generally should provide notice of what behavior is expected, the court in that case supported the regulatory agency's imposition of a penalty using a standard of the judgment of a reasonably prudent person with knowledge of the industry would have known what was expected with regard to the specific prohibition or standard. Here, in both the CPUC and the CAISO's DR related proceedings, decisions and tariffs have made clear that DR providers are required to make reasonably reliable commitments in the RA capacity and CAISO energy markets. Knowingly overstating the capabilities of one's resources is generally understood in the energy industry as a violation of market rules.[303] With respect to its due process claim, OhmConnect has not shown here a) that it has a due process right to a particular QC valuation of its resource that testing showed to be inaccurate, or b) that the modification of QC based on resource testing after a DRP fails to update its QC capacity is not reasonably foreseeable.

## 8. Assignment of Proceeding

Alice Reynolds is the assigned Commissioner and Debbie Chiv and Shannon O'Rourke are the assigned ALJs in this proceeding.

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[302] OhmConnect cites to *Stillwater Mining Co. v. Federal Mine Safety & Health Review Comm'n* (9th Cir. 1998) 142 F.3d 1179, among other cases.

[303] *See OhmConnect, Inc.*, Docket No. IN23-6-000, Order Approving Stipulation and Consent Agreement (May 22, 2023) 183 FERC ¶ 61,136.

## Findings of Fact

1. CAISO recommended that the existing capacity needed for all local areas is 22,080 MWs for 2024, 22,191 MWs for 2025, and 23,058 MWs for 2026.

2. CAISO recommended system-wide Flexible Capacity Requirements that range from 24,446 MWs in March to 20,018 MWs in July.

3. It is necessary to modify the RA measurement hours to align with CAISO's revised AAH window. It is appropriate to adjust the hours for the DR MCC bucket and MCC buckets 1, 2, and 3 based on revisions to the RA measurement hours.

4. Given the realities of available RA supply and persistent delays in development projects, it is prudent to retain the status quo 17 percent PRM for the 2024 and 2025 RA years. Increasing the PRM without greater certainty about installed RA resources for 2024 and 2025 is not appropriate at this time.

5. Extending the effective PRM through 2025 is beneficial in that it provides non-binding targets for IOUs to procure contingency resources and allows procurement of resources that provide reliability benefits without unnecessarily inflating RA prices and costs to ratepayers, and without reducing the pool of available RA resources.

6. Allowing LSEs that cannot meet their existing RA obligations to expand their territory or to otherwise take on new customer load is detrimental to grid reliability. LSEs that are deficient in their RA obligations result in reliance on other LSEs' procurement activities and cost-shifting.

7. Additional data reporting by the CPE will help LSEs manage upfront system RA procurement and understand the inventory of available resources to assess the potential for CAISO backstop procurement. Additional transparency

in the CPE process will also help market participants understand how the CPE framework is functioning.

8. Allowing LSEs to sell a self-shown local resource may increase the amount of self-shown resources by removing a potential disincentive for self-showing and provide additional opportunities for LSEs to procure system and/or flexible RA.

9. Limiting the additional acquisition of ATC at COB/Malin and NOB effectively ensures there is no violation of the simultaneous import limit, nor any associated reliability risk.

10. It is necessary to clarify that any penalty points accrued by an LSE will be applicable to the LSE's month-ahead and year-ahead RA penalties. It is also necessary to clarify that if an LSE enters a higher tier during a year in which it incurs year-ahead deficiencies, the higher penalty will apply beginning with the monthly deficiency when the LSE enters the higher tier.

11. More transparency into LSEs' compliance with the RA program is critical to providing insight into reliability risks related to LSEs' RA deficiencies and RA program violations.

12. It is appropriate to deny local waiver requests that are filed past the deadline.

13. Directing Energy Division to provide CAM and RMR credits to LSEs no later than five business days after CAISO provides the credits to Energy Division would provide sufficient time for Energy Division to allocate CAM and RMR credits based on the total CPUC-jurisdictional share.

14. The monthly load forecast update process requires significant Commission Staff resources, while generally resulting in only small modifications to the RA requirements. Any larger changes in load migration will be accounted for

because CCAs are required to provide at least a one-year notice prior to implementation or expansion.

15. The CEC's supply-side DR QC proposal would benefit from further refinement and testing.

16. The existing LIPs process is imperfect.

17. CAISO inserts bids for RDRR at $950/MWh and will accept them if there are insufficient resources at a lower price.

18. Implementing a bid price cap for PDRs would prevent the possibility of an irrational dispatch order where RDRR is dispatched before PDRs and increase PDRs' contributions to reliability.

19. Extending the Prohibited Resources policy to all RA-eligible DR resources is in line with the Commission's initiating objectives in adopting the original Prohibited Resources policy in D.16-09-056 and aligns with state policy that DR resources participating in RA programs should be clean.

20. There is significant administrative burden on Energy Division Staff associated with applying the TLF and PRM adders to DR resources and a relatively small amount of MW associated with the adders.

21. Removal of the PRM adder is likely to enhance reliability, particularly during stressed conditions, by removing the risk that the adder over-estimates the amount of capacity available to the CAISO on high system stress days.

22. Adjustments are needed to the existing DR availability requirements to ensure DR is available during the types of prolonged weather events experienced in recent years.

23. DRPs frequently submit filings later than the deadline established in the RA guidelines for submitting monthly DR NQCs, which creates administrative inefficiency in review and processing of filings.

24. Third party DR is not performing reliably in comparison to monthly supply plans.

**Conclusions of Law**

1. CAISO's recommended LCR study results for 2024-2026 are reasonable and should be adopted.

2. CAISO's recommended systemwide FCR figures for 2024 are reasonable and should be adopted.

3. Revised RA measurement hours for the spring month of May should be adopted.

4. Hours for the DR MCC bucket and MCC buckets 1, 2, and 3 should be adjusted based on the revised RA measurement hours.

5. A PRM of 17 percent is reasonable and prudent for the 2024 and 2025 RA years.

6. It is reasonable and prudent to maintain the effective PRM adopted in D.21-12-015 at the 2023 level for the 2024 and 2025 RA years.

7. A requirement that LSEs that have had a system RA deficiency within the prior two years cannot expand to take on new customer load is a reasonable approach and permissible under Pub. Util. Code Section 380.

8. Energy Division's proposal on additional data reporting for the CPE, with PG&E's modifications to the confidentiality matrix adopted in D.23-03-034, is appropriate.

9. It is reasonable to allow an LSE that has self-shown a local resource to the CPE to sell the capacity to other LSEs, as long as the purchasing LSE assumes the selling LSE's self-showing obligation.

10. An LSE that procures ATC, or acquires ATC through the resale process, at either COB/Malin or NOB should be permitted to pair the ATC with RA imports to meet its RA requirements.

11. Clarifications to the penalty point system applying to year-ahead RA deficiencies and as to what month a higher penalty will apply should be adopted.

12. Energy Division's proposal to increase transparency on LSEs' RA compliance violations, with modifications, should be adopted. The information should be disclosed by CPED or Energy Division no earlier than October 1 of the compliance year.

13. Late local waiver requests should be denied.

14. During the 1st quarter of each year, Energy Division should provide CAM and RMR credits to LSEs no later than five business days after CAISO provides the RMR credits to Energy Division.

15. It is reasonable that LSEs are allowed one load migration update in February to cover May-December load migration.

16. Energy Division should be authorized to lead a working group, with support from CEC Staff, to refine elements of the CEC's incentive-based supply-side DR QC proposal and submit a joint proposal in the RA proceeding no later than December 2024.

17. Energy Division should be authorized to pursue simplification of the current LIP requirements using a stakeholder process.

18. A PDR bid cap of $949/MWh should be adopted for both the day-ahead and real-time markets.

19. The following requirements should be adopted: (1) All RA-eligible DR resources should be required to abide by the Prohibited Resources policy as

defined in D.16-09-056 and subsequent decision and resolutions, (2) the Prohibited Resources Verification Plan should apply to all RA-eligible DR resources, and (3) associated costs of implementation shall be recovered through the existing mechanism or through another mechanism if adopted through Application 22-05-002 et al.

20. The TLF and PRM adders should be removed for DR resources beginning with the 2024 RA compliance year and be removed for the 2024 slice-of-day test year.

21. DR availability requirements should be expanded so that resources are available when most needed.

22. DR NQC filings should be made the first business day of the month two months prior to the requested month.

23. Third-party DR QC should be derated based on performance during test events relative to their QC values.

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

25. The proceeding should be closed.

**O R D E R**

**IT IS ORDERED** that:

1. The Commission approves 22,080 megawatts as the existing capacity needed for the Local Capacity Requirement for 2024.

2. The Commission approves 22,191 megawatts as the existing capacity needed for the Local Capacity Requirement for 2025.

3. The Commission approves 23,058 megawatts as the existing capacity needed for the Local Capacity Requirement for 2026.

4. The California Independent System Operator's recommended Flexible Capacity Requirements for 2024 are adopted.

5. The Resource Adequacy (RA) measurement hours are modified to 5:00-10:00 p.m. for March, April, and May, and 4:00–9:00 p.m. for all other months. The modified RA hours shall be effective beginning in the 2024 RA compliance year.

6. In adopting Ordering Paragraph 5, the demand response (DR) maximum cumulative capacity (MCC) bucket and MCC bucket categories 1, 2, and 3 are modified to reflect the new Resource Adequacy measurement hours. The revised MCC buckets are as follows:

| Category | Availability | Maximum Cumulative Capacity for Bucket and Buckets Above |
|---|---|---|
| DR | Varies by contract or tariff provisions, but must be available at least 24 hours per month from May-September. For May, must be available Monday-Saturday for 4 consecutive hours between 5 PM-10 PM. For June-September, must be available Monday-Saturday for 4 consecutive hours between 4 PM-9 PM. | 8.3% |
| 1 | Monday–Saturday, at least 100 hours per month. For February, total availability is at least 96 hours. January - February, June-December, 4 consecutive hours between 4 PM - 9 PM. March-May, 4 consecutive hours between 5 PM – 10 PM. | 17.0% |
| 2 | Every Monday–Saturday. January-February, June-December, 8 consecutive hours that include 4 PM–9 PM. March-May, 8 consecutive hours that include 5 PM–10 PM. | 24.9% |
| 3 | Every Monday–Saturday. January-February, June - December, 16 consecutive hours that include 4 PM – 9 PM. March-May, 16 consecutive hours that include 5 PM–10 PM. | 34.8% |
| 4 | Every day of the month. Dispatchable resources must be available all 24 hours. | 100% (at least 56.1% available all 24 hours) |

7. For the 2024 and 2025 Resource Adequacy compliance years, a 17 percent planning reserve margin (PRM) and an effective PRM procurement target of 1,700-3,200 megawatts (MW) is adopted. The procurement target will be divided between the three investor-owned utilities similar to the targets adopted in Decision 21-12-015: 170-320 MW for San Diego Gas & Electric Company, and 765-1,440 MW each for Pacific Gas and Electric Company and Southern California Edison Company.

8. The requirements adopted in Decision (D.) 21-12-015 pertaining to the effective planning reserve margin (PRM) are applicable to the effective PRM adopted in Ordering Paragraph 7. Specifically, resources eligible to count towards the effective PRM will remain unchanged from D.21-12-015 and all resources that are currently eligible to be contingency resources will remain eligible to be contingency resources in 2024 and 2025.

9. A community choice aggregator (CCA) that has had a system Resource Adequacy (RA) deficiency within the prior two calendar years must first be in RA compliance for two calendar years prior to submitting an implementation plan to expand. An electric service provider (ESP) that has had a system RA deficiency within the prior two calendar years must first be in RA compliance for two calendar years prior to signing new direct access customers. These rules are applicable to load-serving entities that are not acting as the Provider of Last Resort. As to CCAs, this requirement will apply to initial or revised implementation plans submitted after the effective date of this decision. As to ESPs, this requirement will apply to direct access customers signed after the effective date of this decision. RA deficiencies accrued after the effective date of this decision will apply to this requirement. The first year-ahead deficiencies to be applied will be the 2024 year-ahead RA filing due on October 31, 2023, and the

first month-ahead deficiency to be applied will be the September 2023 month-ahead RA filing.

10. Any year-ahead Resource Adequacy (RA) deficiency accrued in the calendar year two years prior to the year that a load-serving entity (LSE) files its binding load forecast will count towards the requirement adopted in Ordering Paragraph 9, unless the LSE cures the year-ahead RA deficiency in the month-ahead timeframe. The following RA deficiencies will apply to the requirement:

| **System RA Deficiencies That Apply to the LSE Expansion Requirement** | |
|---|---|
| Year Plus 1 (Y+1) | Year that an LSE elects to expand |
| Year 0 (Y0) | Year that an LSE files its April load forecast |
| Year Minus 1 (Y-1) | (1) Month-Ahead deficiencies apply<br>(2) Year-Ahead deficiency (for Y0) applies<br>*Note: CCA Implementation Plans for Y+1 are filed by Dec 31 of Y-1. |
| Year Minus 2 (Y-2) | (1) Month-Ahead deficiencies apply<br>(2) Year-Ahead deficiency (for Y-1) applies, unless Year-Ahead deficiency is cured in the Month-Ahead timeframe in Y-1 |

The following violations will not apply to the expansion requirement:

(1) A month-ahead or system-ahead system RA deficiency that is less than 1 percent of the LSE's system RA requirements.

(2) "Specified violations," as adopted in Resolutions E-4017 and E-4195 and modified in Decision 11-06-022.

11. To implement the requirements adopted in Ordering Paragraph 9, Energy Division is authorized to review Resource Adequacy (RA) enforcement referrals and/or citations issued by the Consumer Protection and Enforcement Division, including confidential versions, for the prior two years to determine if a load-

serving entity (LSE) is eligible to expand. Energy Division will review and confirm compliance with the adopted requirements ahead of the LSE's RA load forecast submissions, confirm the earliest possible effective date for the community choice aggregator (CCA) expansion by letter from the Executive Director, and inform the California Energy Commission of any adjustments to the load forecast necessary due to non-compliance. Energy Division is authorized to make this determination regardless of any pending citation appeal.

12. The central procurement entity (CPE) shall report the following in both: (a) the mid-August compliance filing and (b) the September Annual Compliance Report:

| **Monthly Procurement Summary Covering All CPE Procurement** | | | | | |
|---|---|---|---|---|---|
| Total California Public Utility Commission (CPUC) Local Allocation (excluding demand response (DR)) | Total CPUC-allocated Local DR | Local Cost Allocation Mechanism (CAM) (non-DR) | Total Procured Resources | Total Self-Shown | Net Total |

(a) Total aggregate monthly megawatt (MW) amount of procurement not offered to the CPE in deficient areas;

(b) Total sum of (i) aggregate monthly MW amounts of deferred procurement that were the result of unreasonable prices, (ii) aggregate monthly MW amounts not procured due to inability to reach an agreement with request for offers participant, and (iii) aggregate monthly MW amounts of procurement offered in and then later withdrawn over the compliance period, where the total sum of these 3 amounts exceeds 10 MWs; and

(c) Any additional information on outreach conducted by the CPE to resources that did not participate and/or withdrew their bids and the outcome of that outreach.

13. The confidentiality matrix adopted in Decision 22-03-034 is modified to add the following categories.

| | | | | |
|---|---|---|---|---|
| Competitive Solicitation Information | Individual/ Specific Bid/Offer data | Confidential | 3 years after conclusion of solicitation | Disclosure of the bid/offer data received during CPE procurement could potentially have an adverse effect on the market, put the CPE at a competitive disadvantage with regard to other market participants, and impact participants' future bidding behavior for capacity that has not yet been procured. |
| Competitive Solicitation Information | Aggregate Bid/Offer Data Not Selected/Procured (where the total exceeds 10 MWs) | Public | N/A | N/A |

A modified version of the confidentiality matrix adopted in Decision 22-03-034 is attached as Appendix A.

14. A load-serving entity (LSE) that has self-shown a local Resource Adequacy (RA) resource to the central procurement entity is permitted to sell the capacity to other LSEs, as long as the purchasing LSE assumes the selling LSE's obligation to self-show the RA on annual and monthly RA plans to satisfy its system

and/or flexible RA needs, as required by Ordering Paragraph 2 of Decision 22-02-034.

15. For any load-serving entity (LSE) that has self-shown a local resource to the central procurement entity (CPE), and subsequently sells the capacity to another LSE, the selling LSE shall modify its attestation to the CPE to provide that:

(1) The LSE has sold the capacity to another LSE, and the purchasing LSE will self-show the Resource Adequacy (RA) resource on annual and monthly RA plans to satisfy its system and/or flexible RA needs as required by Ordering Paragraph 2 of Decision (D.) 22-02-034; and

(2) If applicable, the resource that the LSE intends to self-show for compensation under the Local Capacity Requirement Reduction Compensation Mechanism meets the eligibility requirements pursuant to D.20-12-006.

The modified attestation shall be provided to the CPE within 30 days of the purchase. The purchasing LSE shall provide an attestation to the CPE that it intends to self-show the capacity within 30 days of the purchase.

16. If a load-serving entity (LSE) procures available transmission capability (ATC), or acquires ATC through the resale process, at either the California-Oregon Border/Malin or the Nevada-Oregon Border, the LSE is permitted to pair the ATC with Resource Adequacy (RA) imports to meet its RA requirements.

17. Penalty points accrued by a load-serving entity (LSE) will be applied to an LSE's month-ahead and/or year-ahead Resource Adequacy (RA) penalties. If an LSE enters a higher tier during a year in which it incurs year-ahead deficiencies, the higher penalty will apply beginning with the monthly deficiency when the

LSE enters the higher tier. The month in which an LSE accrues points that brings the LSE into the next tier, the higher penalty will apply to the deficient month for which the points were accrued. The requirements adopted here are effective beginning for the July 2023 RA filing.

18. All year-ahead Resource Adequacy (RA) deficiencies will be charged at the Tier 1 price, and in the month-ahead RA process, the load-serving entity (LSE) will pay the difference between its month-ahead tier penalty and the Tier 1 penalty that was already paid on its year-ahead RA deficiency, plus the LSE's current tier price on any incremental month-ahead RA deficiency. The following formula will be applied:

- Year-Ahead penalty = $\text{Deficiency}^{\text{Year-Ahead}}$ x Tier 1 Price
- Month-Ahead penalty = [($\text{Deficiency}^{\text{Year-Ahead}}$ x Tier $\text{Price}^{\text{Month-Ahead}}$) – Year-Ahead penalty] + (Deficiency $^{\text{Month-Ahead incremental}}$ x Tier $\text{Price}^{\text{Month-Ahead}}$)

19. For any load-serving entities' (LSE) month-ahead and year-ahead Resource Adequacy (RA) deficiencies, the following information is deemed not confidential and will be published on the Commission's website by the Consumer Protection and Enforcement Division (CPED) or Energy Division: the type of RA deficiency, month of deficiency, deficiency amount (MW), and any points accrued. The information will be published no earlier than October 1 of the compliance year. For other non-deficiency RA program violations, such as late load forecasts and late RA filings, the information on the RA citation is deemed not confidential and may be published on the Commission's website by CPED or Energy Division.

20. A local Resource Adequacy waiver request that is filed past the submission deadline will be rejected.

21. For the 1st quarter of each year, Energy Division will provide Cost Allocation Mechanism (CAM) and Reliability Must Run (RMR) credits to load-serving entities (LSE) no later than five business days after the California Independent System Operator (CAISO) provides the California Public Utilities Commission (CPUC)-jurisdictional RMR credits to Energy Division.

22. A load-serving entity (LSE) is permitted one load migration update in mid-February to cover May to December load migration. Other than the one load migration update, an LSE's load forecast is locked in for the January-April timeframe and the May-December timeframe of each Resource Adequacy compliance year.

23. Energy Division is authorized to lead a working group, with support from California Energy Commission (CEC) Staff, to refine elements of the CEC's incentive-based supply-side demand response qualifying capacity proposal and submit a joint proposal in the Resource Adequacy (RA) proceeding in December 2024. The schedule for the Working Group and the joint report is as follows:

| Milestone | Timeframe |
|---|---|
| Initiate Working Group to refine specific elements of the CEC proposal, as directed by Commission Decision. | July 2023 |
| LIP process begins for 2025 RA compliance year. In ex post analysis on 2023 performance, the CEC methodology is run side-by-side by LIPs on a "what if" basis with no penalties applied. | December 2023 |
| Final LIP reports for 2025 RA compliance year filed. Energy Division and CEC draft joint report summarizing ex post results for 2023. | April 2024 |
| Energy Division and CEC continue refining incentive-based proposal, incorporating learnings from "what if" exercise. | April - December 2024 |

| | |
|---|---|
| Energy Division and CEC submit refined incentive-based proposal to RA proceeding. | December 2024 |
| LIP process begins for 2026 RA compliance year. | December 2024 |

24. Beginning with the 2024 Resource Adequacy compliance year, in order for proxy demand response resources to count toward Resource Adequacy requirements, proxy demand response resource bids must not exceed $949 per megawatt hour in either the day-ahead or real-time market. The Energy Division Director or their delegate is authorized to issue correction or deficiency notices to load-serving entities if any non-compliant proxy demand response resources are shown on their Supply Plans and the load-serving entities do not have enough capacity to meet their Resource Adequacy requirements without the non-compliant proxy demand response resources. This requirement does not apply to demand response auction mechanism resources contracted for the 2024 delivery year.

25. To the extent tariff adjustments are needed to operationalize the reliability demand response resource dispatch trigger, Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall submit those tariff adjustments as a Tier 1 Advice Letter within 10 days of the effective date of this decision.

26. Beginning with the 2024 Resource Adequacy compliance year, the Prohibited Resources policy, as defined in Decision 16-09-056 and subsequent decisions and resolutions, applies to all Resource Adequacy-eligible demand response resources.

27. Beginning with the 2024 Resource Adequacy compliance year, the Prohibited Resources Verification Plan applies to all Resource Adequacy-eligible demand response resources.

28. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company are authorized to recover costs associated with implementing the Prohibited Resources requirements adopted in Ordering Paragraphs 26 and 27 through the cost recovery mechanisms authorized under the existing Prohibited Resources policy or through another mechanism if adopted through Application 22-05-002 et al. or a subsequent five-year demand response program and budget application.

29. The Transmission Loss Factor adder and the Planning Reserve Margin adder for demand response resources are removed beginning with the 2024 Resource Adequacy compliance year and for the 2024 slice-of-day test year.

30. Beginning with the 2024 Resource Adequacy compliance year, all demand response resources, except Reliability Demand Response Resources, are required to be available during all days during which a California Independent System Operator (CAISO) Flex Alert is called, up through the last day for which the CAISO has issued a Grid Warning, Alert, or Notice, or the Governor's Office has issued an emergency notice. The resource must be available for the duration of an Alert, Warning, or Notice that is issued prior and up to the 10 a.m. day-ahead market bid deadline. Load-serving entities are required to implement these requirements in contracts with demand response providers.

31. Demand Response Net Qualifying Capacity filings are required to be made the first business day of the month two months prior to the requested month. Failure to meet the deadline requirement will disqualify a demand response provider's month-ahead supply plan request.

32. Beginning with the capacity awards granted through the LIP process for the 2024 Resource Adequacy compliance year, test performance failures will be considered when making capacity awards to non-investor-owned utility demand response (DR) resources procured by third-party DR providers under the Load Impact Protocols (LIPs). Derates will be applied so that they correspond to performance during test events for the most recently available quarterly test results at the time of the award for the relevant quarter. The average performance results of each quarter will inform the capacity awarded through the LIPs for the respective sub-load aggregation point.

33. In addition to the service list in this proceeding, the proposed decision was served on the service list for Rulemaking 20-11-003, the Order Instituting Rulemaking to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021.

34. The requirements adopted in this decision are effective immediately, unless stated otherwise.

35. Rulemaking 21-10-002 is closed.

This order is effective today.

Dated June 29, 2023, at San Francisco, California.

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

# APPENDIX A